

YUKON ENERGY CORPORATION

2008/2009 GENERAL RATE APPLICATION
INTERROGATORY RESPONSES FILED

February 27, 2009
March 6, 2009
April 14, 2009
&
April 24, 2009

CITY OF WHITEHORSE
(CW)

REFERENCE: **PPA referred to in the Application, page 1, Introduction to Application**

ISSUE: **Purchase Power Agreement**

QUESTION:

a) Please produce a copy of the approved and amended Purchase Power Agreement for the record.

ANSWER:

(a)

The Power Purchase Agreement filed with the Board on February 8, 2007 is on the Yukon Utilities Board website at:

http://yukonutilitiesboard.yk.ca/pdf/186_PPA%20Minto%20and%20YEC%20Application.pdf

The above document, together with the amendments dated May 14th, 2007 and approved by Order 2007-6, comprise the "approved and amended Power Purchase Agreement." The May 14th Amendment is provided as Attachment 1 to this response.

The PPA as amended May 14, 2007 provided [under Section 3.1(m)] that YEC would enter into an agreement with Yukon Development Corporation (YDC) whereby YDC would assume from YEC the financing risk of the Minto Capital Cost Contribution, and YDC would guarantee to YEC all Capital Cost Contribution payments to be made by Minto to YEC under the PPA. Subsequent amendments to the Power Purchase Agreement with Minto specifically relate to identified risks being borne by the Yukon Government, through the Yukon Development Corporation (YDC), and do not affect risks or costs borne by YEC or ratepayers.

Although Yukon Energy has continued as a party to subsequent amendments to the PPA Agreement, these amendments are for the benefit of YDC, not YEC (which pursuant to the May 14, 2007 PPA Amendment and its agreement with YDC, is not exposed to any financial risk of the Minto Capital Cost Contribution).

In Appendix A to Order 2008-13 (at page 2) the Board noted as follows regarding the approval of the subsequent May 25, 2007 PPA amendment:

> The Board notes that the amendments of May 25, 2007, as agreed to by all parties to the PPA, were included to cover some of the risks that YDC was exposed to. However, as Schedule A of OIC 2007/94 does not refer to the May 25, 2007, amendment to the PPA and the amendment is not needed for purposes of Rate Schedule 39, the Board does not need to approve the May 25, 2007, amendments to the PPA.

YUKON ENERGY

YUKON ENERGY CORPORATION
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WHITEHORSE
YUKON Y1A 5L6
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May 14, 2007

Mr. Stephen Quin
Minto Explorations Ltd.
860 - 625 Howe Street
Vancouver, BC V6C 2T5

Dear Mr. Quin:

Re: Power Purchase Agreement Dated February 8, 2007 (the "**PPA**") between Yukon Energy Corporation ("**YEC**") and Minto Explorations Ltd. ("**Minto**")

Capitalized terms used and not defined in this letter have the meanings set out in the PPA.

The Parties entered into the PPA on February 8, 2007. Order 2007-5 (the "**Order**") of the YUB, dated April 30, 2007, denied the PPA. The Parties agree that notwithstanding the Order and Section 3.1 of the PPA, the PPA remains in full force and effect.

The Parties have reviewed the Order, and, following the principles of the PPA and the Order, hereby amend the PPA as follows:

1. Sections 1.1(z), (tt), (aaa), 3.5, and 3.6 and Schedules C and E are deleted. A new Schedule C is added to the PPA in the form attached to this letter.

2. Section 3.1 (a) of the PPA is deleted and replaced with the following:

   "(a) on or before May 31, 2007, the YUB will have approved this Agreement, including the following provisions:

      (i) on an interim basis, the Low Grade Ore Processing Secondary Energy Rate as set out in Schedule D, subject to the provision that the Low Grade Ore Processing Secondary Energy Rate will not be implemented by YEC until proposed audit and control measures and reporting requirements as agreed to by the Parties are filed with and approved by the YUB;

(ii) the Capital Cost Contribution under Part 5 of this Agreement (as amended herein); and

(iii) the Decommissioning Costs under Part 11 of this Agreement;"

3. Section 3.1 (b) of the PPA is amended by deleting the words "February 15" and replacing them with "June 30".

4. Section 3.1 (d) of the PPA is amended by deleting the words "March 31" and replacing them with "June 30".

5. Section 3.1 (e) of the PPA is amended by deleting the words "February 28" and replacing them with "June 30".

6. In order that any financing risk of the Minto Capital Cost Contribution be on account of Yukon Development Corporation ("**YDC**") new Sections 3.1 (m) and (n) are added as follows:

"(m) YEC will have entered into an agreement with YDC on terms and conditions satisfactory to YEC, acting reasonably, on or before May 31, 2007 as follows:

(i) YDC will assume from YEC the financing risk of the Minto Capital Cost Contribution, and YDC will guarantee to YEC all Capital Cost Contribution payments to be made by Minto to YEC under this Agreement and will pay to YEC directly, on behalf of Minto, any amount of the Carmacks-Minto Landing Capital Cost Contribution principal amount in excess of $7,200,000, such amount to be paid by YDC to YEC on Minto's behalf under Section 5.1 on or before the Commencement of Delivery;

(ii) YEC will enforce the YEC Security on behalf of YDC as may be required with regard to Minto's Capital Cost Contribution payments to YEC; and

(iii) YEC will agree that any payment by Minto to YEC under Section 6.2 that is not applied as a credit against the Creditable Amount payable by Minto under Section 6.1(a), as provided for in Section 6.4, will be paid to YDC by YEC; and

(n) on or before May 31, 2007, the Yukon Territorial Government will undertake arrangements to ensure that Rate Schedule 39 that the YUB has stated it will accept on an interim basis, as attached to this Agreement as Schedule C, be fixed as final until December 31, 2012, subject to escalation of the demand and energy charges for this rate schedule once each calendar year, starting January 1, 2010, based each year on the latest percentage increase in the 12 month implicit chain price index for gross domestic product at market prices for Canada as reported by Statistics Canada."

The following sentence be added at the end of Section 3.1:

"Condition 3.1 (m) is for the sole benefit of YEC and may be waived or the time period extended by YEC, in its sole discretion, by written notice by YEC to Minto at any time. Condition 3.1 (n) is for the benefit of both Parties and may only be waived, altered, or the time period extended by written agreement between the Parties."

8. The following new Section 3.5 be added to the PPA:

"With regard to the Low Grade Ore Processing Secondary Energy Rate, within 60 days Minto will propose to YEC audit and control measures and reporting measures as required for the Low Grade Ore Processing Secondary Energy Rate. Upon receipt of Minto's proposal, YEC and Minto will work in good faith to agree as soon as possible thereafter on specific measures and reporting requirements. Upon agreement by the Parties, YEC will forthwith submit the measures and reporting requirements to the YUB for approval by the YUB. The intent of the Parties is to secure YUB approval before the end of 2007 if possible, and in any event before the Commercial Delivery Date if possible."

Section 1.1 (sss) and Sections 6.2, 6.3, and 6.4 are amended as follows to reduce Minto's take or pay obligation from $24,000,000 over eight years to $12,000,000 over four years to match the term of the rate guarantee:

Section 1.1 (sss) is deleted and replaced with the following:

"(sss) '"**Minimum Take Or Pay Amount**" means $12,000,000, less any reduction provided for under Section 6.3;"

Section 6.2 is amended by deleting in the first sentence the word "eighth" and replacing it the word "fourth", by deleting in the second sentence the word "seven" and replacing it with the word "three", and by deleting the word "eighth" immediately prior to the words "Annual Payment Date" in the lead in to Sections 6.2 (c) and (d) and replacing it with the word "fourth".

Section 6.3 is amended by the deleting the number "$24,000,000" and inserting"$12,000,000".

Section 6.4 is amended by deleting the word "ninth" immediately before "Annual Payment Date" and replacing it with the word "fifth".

10. With regard to indexing the capital contribution to the detailed high cost estimates for the Carmacks-Minto Landing Segment, the PPA is amended as follows:

Section 1.1 (l) of the PPA is deleted and replaced with the following:

"(l) '"**Carmacks-Minto Landing Capital Cost Contribution**" means the sum of $7,200,000, representing Minto's contribution to the Capital Costs incurred by YEC for the Carmacks-Minto Landing Segment, plus an amount equal to the "Index Percentage" times $7,200,000, where the "Index Percentage" is the percent, if any, by which the final tendered cost for the Carmacks-Minto Landing Segment at the time the construction contract is awarded exceeds the high cost estimate for the construction of the Carmacks-Minto Landing Segment, estimated in YEC's February 8, 2007 application to the YUB for approval of this Agreement, estimated at $190,000 per km (2005 dollars);"

Section 5.1 of the PPA is amended by adding the following sentence:

"Within 90 days of the Transmission Project Start Date, YEC will provide written notice to Minto of the final tendered cost for the Carmacks-Minto Landing Segment and advise Minto of the increase, if any, required to the Carmacks-Minto Landing Capital Cost Contribution in excess of $7,200,000. YEC acknowledges, covenants, and agrees with Minto that any such increased amount will be paid to YEC by YDC on Minto's behalf on or before the Commencement of Delivery, and, for greater certainty, such increased amount will not be included in Minto payments of interest or principal to YEC for the Carmacks-Minto Landing Capital Cost Contribution under Part 5 of this Agreement."

Except as amended herein the PPA remains in full force and effect and unamended.

This letter may be executed in any number of counterparts which together will form one document. This letter will be duly executed and delivered if executed by the Parties and signature pages exchanged by facsimile or electronically.

YUKON ENERGY CORPORATION

Per:

Authorized Signatory

Agreed to May 14, 2007

MINTO EXPLORATIONS LTD.

Per:

Authorized Signatory

STEPHEN P. QUIN
PRESIDENT.

SCHEDULE C

FIRM MINE RATE
RATE SCHEDULE 39
INDUSTRIAL PRIMARY

AVAILABLE: Throughout the service areas of Yukon Energy Corporation (**"YEC"**) and The Yukon Electrical Company Limited ("**YECL**") served by the Whitehorse-Aishihik-Faro and Mayo-Dawson systems.

APPLICABLE: To all major industrial customers engaged in manufacturing, processing or mining with an electric service capacity in excess of 1,000 kW.

RATE: Charges in any one billing month shall be the sum of the following:

(a) Demand Charge of $15.00/kV.A of Billing Demand

(b) Energy Charge of 7.60¢/kW.h for all energy used.

(c) Fixed Charge

For service to Minto mine site, the Fixed Charge each month shall equal the payments then required under the Power Purchase Agreement (the **"PPA"**) dated February • between YEC and Minto Explorations Ltd. (**"Minto"**) between YEC and Minto for monthly Capital Cost Contributions for transmission connection to the mine.

PEAK SHAVING CREDIT: For customers with an established Winter Contract Load in good standing, a Peak Shaving Credit in each billing month

equal to 50% of the Demand Charge times the Peak Shaved Load.

MINIMUM MONTHLY BILL:

The minimum monthly bill will be the sum of the Demand Charge and the monthly Fixed Charge, less any applicable Peak Shaving Credit.

PEAK SHAVED LOAD:

Peak Shaved Load in any billing month is the amount by which then nominated Winter Contract Load is less than the Billing Demand for the month.

BILLING DEMAND:

The Billing Demand shall be the greater of:

(a) the highest metered kV.A demand recorded in the current billing month, or

(b) the highest metered kV.A demand recorded in the previous 12-month period including the current billing month, excluding the months April through September, or

(c) the contract minimum demand.

WINTER CONTRACT LOAD:

A customer may, by six month written notice to YEC, nominate a Winter Contract Load at not less than two-thirds of the customer's contract maximum demand subject to the following conditions:

a) the customer will thereby contract with YEC not to exceed the nominated Winter Contract Load whenever the temperature at Whitehorse is below -30 degrees Centigrade, based on YEC informing the customer by phone, fax or e-mail as to forecast and actual winter temperatures at Whitehorse as provided for in paragraph (b);

b) YEC will inform the customer at least one hour in advance, and not more than one day in advance, of a forecast temperature at Whitehorse being below -30 degree Centigrade; thereafter, until YEC informs the customer otherwise, the customer will be responsible for ensuring that its metered kV.A demand does not exceed the Winter Contract Load during any hour when the actual temperature at Whitehorse is below -30 degrees Centigrade; YEC will inform the customer forthwith when the temperature at Whitehorse is no longer forecast to be below -30 degree Centigrade within the next 24 hours;

c) the customer agrees that the contract for the nominated Winter Contract Load will continue until terminated by written notice of not less than 12 months by the customer to YEC;

d) if during such contract period for the Winter Contract Load the customer's metered kV.A demand recorded, after YEC has provided notice as specified in paragraph (b), exceeds the Winter Contract Load when the temperature at Whitehorse is less than -30 degrees Centigrade, the Winter Contract Load contract will be terminated forthwith, the customer will forthwith be required to repay to YEC all Peak Shaving Credits determined within the previous 12 billing months, and the customer will also pay for that billing month to YEC as penalty an amount equal to four times the Demand Charge on the metered kV.A demand recorded in excess of the Winter Contract Demand; in addition, YEC reserves the right if so required to meet system loads when the temperature at Whitehorse is less than 30 degrees Centigrade during the then current month and the following 12 months to interrupt electricity supplied to the customer in excess of the previous Winter Contract Load.

BASE LOAD ENERGY:

A Base Load Energy amount per month may be established for a customer of 90% of forecast use when YEC expects to require diesel fuel generation to service use in excess of

such a Base Load Energy amount. At such time, Rate Schedule 39 will be submitted to the Yukon Utilities Board for amendment to adjust the Energy rate as required for a two part rate that yields the same overall energy charge at forecast energy use, with all energy consumed in excess of the Base Load being charged at a rate reflecting the incremental cost of service using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use.

RATE MODIFICATIONS APPLICABLE:

For fuel adjustment rider, see Rider F. Rider F applied to energy charges only, set to $0.0 for fuel price forecast filed November 20, 2006., .

ELECTRIC SERVICE REGULATIONS:

The Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to YEC and every customer supplied with electric service by YEC in the Yukon Territory. Copies of the Electric Service Regulations are available for inspection in the offices of YEC during normal working hours.

REFERENCE: **Application, Tables 2.3 and 2.4**

ISSUE: **Sales Forecasts – Forecasting Methods**

PREAMBLE:

CW wishes to understand YEC's forecasting methods.

QUESTION:

a) Please provide a full explanation and demonstration of the statistical forecasting methods used by YEC to forecast energy sales and/or MWh sales per customer in these tables.

b) If no statistical forecasting methods were used by YEC, to forecast energy sales and MWh sales per customer in these tables, please explain why not.

ANSWER:

(a) and **(b)**

YEC's retail sales forecasting methodology was fully described in the response to LE-YEC-1-7(a). In a letter to the Board filed March 27, 2009, CW noted that the referenced response did not provide "the requested "demonstration" of the statistical forecasting methods used by YEC to forecast energy sales and/or MWh sales per customer in Tables 2.3 and 2.4," contrasting the response to LE-YEC-1-7 to the type of in depth statistical data provided by YECL as part of its 2008/2009 GRA.

YEC has fully described its forecasting methods in responses to LE-YEC-1-7(a); YECL-YEC-1-21 and in YECL-YEC-1-19 (wholesale forecast), YECL-YEC-1-23 (secondary sales), and YECL-YEC-1-20 (industrial sales). However, Order 2009-4 has directed YEC to provide a further response to this information request.

To be clear, the referenced response fully described the requested forecasting methods used by YEC, and confirmed that YEC does not forecast customer sales using the same statistical methods and information as relied upon by YECL. To provide a further response as directed, the basis for YEC's approach is reviewed below.

Yukon Energy is a utility primarily engaged in generation and transmission of energy, supplying 90% of annual Yukon power requirements through WAF and MD transmission facilities. YEC's firm load sales forecasts focus on wholesales and major industrial sales, plus provision for continuation of current trends for sales to the small number of retail customers directly served by YEC.

Yukon Energy indirectly provides power to Yukon retail customers on WAF and MD through wholesale sales to YECL. As the primary distributor, YECL provides retail service to the vast majority of residential and general service customers in the Yukon. YEC only directly serves approximately 1,900 customers in Yukon at the distribution (retail) level (approximately 11% of all electrical retail customers in Yukon) in the areas of Dawson City, Mayo and Faro. Given the basic differences underlying each utility, its role in providing electrical service in Yukon, the types of customers served, and the information available to each utility as regards retail customer sales, each utility has developed its own approach to sales forecasting regarding firm retail customer sales.

As the primary distributor directly serving most residential and general service customers in Yukon, YECL has access to customer specific data for over 90% of Yukon's retail customers. This data can be utilized to develop the detailed statistical forecasting approaches underlying the sales forecasts included in the recent YECL 2008/2009 GRA. Since Yukon Energy primarily provides wholesale service to YECL (and only indirectly provides service to these customers), it does not have access to YECL's detailed customer information. (CW-YEC-1-3(c) notes that Yukon Energy is not provided with the data to track YECL's retail loads in a manner that permits the identification of reasons for variances). As CW noted during the recent YECL GRA hearing, detailed statistical forecasting analysis as provided in YECL's GRA also has certain limitations that may suggest a need to focus on less detailed forecasting assessments.

Yukon Energy does have access to specific retail customer information for customers in the communities where it provides retail service (i.e., Dawson City, Mayo and Faro); however, engaging in detailed statistical analysis for this limited set of customers is not considered cost-effective or reasonable for the purpose of GRA sales forecasting. For its retail forecasts Yukon Energy has developed the forecasting methods described in LE-YEC-1-7, i.e., generally, YEC uses customer data for the prior 3 years to determine the monthly average use per customer, and this is multiplied by the forecast number of customers to derive forecast sales by month by rate class. Specific adjustments for each retail customer class are discussed further in that response. A bottom up numerical

analysis performed in each customer area is considered to be more accurate than using statistical methods due to the small customer class sizes and factors that influence number and size of customer loads outside of Whitehorse. YEC also does not weather normalize its sales due to the small size of the customer classes and the seasonal nature of many of the customer loads in each class. Instead, service personnel provide information on forecast customer changes down to the community and subdivision level.

YECL-YEC-1-19(d) notes similar limitations with regard to YEC's wholesale forecasts:

> YEC's WAF forecast for the Resource Plan Hearing as well as for the current Application have focused on wholesale loads, and have been prepared based on the adoption of average growth rates as noted in each instance which appear to be reasonable in light of information available to YEC. These forecasts have proven to be useful for YEC planning purposes, keeping in mind that actual individual annual wholesale loads are subject to considerable variability due to weather and other factors...

The response goes on to notes that "Yukon Energy is not provided with YECL's customer-specific data and therefore cannot carry out (even if it wanted to) detailed assessments of underlying customer class growth underlying wholesale growth,," and "it is not apparent that overall wholesale forecast at least for the current application would necessary be improved through prior access to such additional information".

Yukon Energy's initial wholesale monthly load forecast (for all loads other than Pelly Crossing) was to apply a load growth of 2.5%[1] above the same month in 2008 (actual or forecast). The 2.39% in Table 2.1 in Tab 2 arises as in the final GRA preparation, Pelly Crossing load was allocated 2.3 GWh of the total wholesale load, rather than the original estimate of 2.0 GWh which served to reduce the load growth otherwise attributed to "ongoing" sales by about 0.1%.

[1] YECL-YEC-1-19(d) addresses the 2.5% estimate. The 2.2% growth rate for 2001-2004 was provided in the 20 Year Resource Plan hearing at a time when Fish Lake generation was readily available and this value reflects YECL "native" load (i.e., with Fish Lake generation added back). The 2.5% value was calculated for this GRA at a time when YEC did not have YECL Fish Lake generation readily available, and thus was calculated off simple WAF wholesales (i.e., YECL WAF native load net of Fish Lake generation). With Fish Lake generation included, the YECL native load growth over the period 2004 to 2007 is 2.9% per year and over the period 2004 to 2008 is 2.8%.

CW-YEC-1-3(d) notes that YEC cannot provide meaningful temperature normalized analysis of wholesale loads without access to detailed information on the individual customer class information underlying the wholesale loads.

Based on review of the recent YECL GRA filings which set out a range of WAF customer class temperature normalized assessments far beyond what is available to YEC, YEC does not believe that overall wholesale forecasting at least for the current application would necessarily be improved through prior access to such additional information.

REFERENCE: **Application Section 2.2.1, p. 2-4**

ISSUE: **Sales Forecasts – Whole Sales to YECL**

PREAMBLE:

"**2008 Actuals Year-to-Date:** Yukon Energy's load forecasts for 2008 incorporate actual sales through June 2008, which were not available to YECL as of their filing date of April 30, 2008.

2009 Forecast Load Growth: Yukon Energy's 2009 load forecasts are markedly higher than the YECL forecasts in their GRA reflecting Yukon Energy's analysis of wholesale load growth, including the WAF load growth analysis for the 2001-2004 period (averaging 2.2% per year), as reviewed in the Yukon Energy 20-Year Resource Plan 2006-2025 ("Resource Plan") and the more recent experienced growth rate in WAF wholesales from 2004 to 2007 actuals, at 2.5% per year. Yukon Energy has utilized a growth rate in this range (2.39%) as the basis for estimating load increases from 2008 to 2009 based on this evidence of the experienced longer-term load trends."

QUESTION:

a) For 2008, YEC forecast Wholesale sales growth (1.38%)[1] to be less than that forecast by YECL (2.39%).[2] Is there any reason for YEC's lower forecast other than the incorporation and consideration of actual sales through June 2008?

b) Absent the incorporation of these actual sales through June 2008, would YEC have expected growth for 2008 to be greater than that forecast by YECL, as is the case in 2009. Please explain.

c) How does YEC account for the seeming anomaly of reduced growth in 2008?

d) Please provide an explanation and rationale for the use of the forecast growth of 2.39% for 2009. Please explain exactly what YEC means by the "evidence of the experienced longer-term load trends" and how it was used to determine the 2.39%.

[1] Table 2.1, Page 2-5.
[2] Table 2.1, Page 2-5.

ANSWER:

(a)

Please see YECL-YEC-1-19(c).

(b)

Not Necessarily. Yukon Energy worked with YECL to define the 2008 and 2009 forecasts in late 2007, and ultimately accepted YECL's forecast for 2008 and 2009 for the purposes of business planning. During preparation of Yukon Energy's GRA, it was apparent that the load growth levels assumed for 2009 were below what might be expected for 2009 based on past experience. At the same time, the early months of 2008 were indicating below forecast loads. Consequently, Yukon Energy did not adjust 2008 forecasts upwards during the GRA preparation process, but did adjust 2009 upwards.

(c)

Yukon Energy is not provided the data required to track YECL's retail loads in a manner that permits identification of the reasons for variances. The lower loads in early 2008 could have been due to a lower number of customers connecting, or lower average loads due to weather or other factors. It is also possible that some of the reason for 2008 load growth was loads that would not arise until later in the year (such as new construction) but which was not incorporated in any detail into the monthly forecasts.

(d)

Yukon Energy's initial wholesale monthly load forecast (for all loads other than Pelly Crossing) was to apply a load growth of 2.5% above the same month in 2008 (actual or forecast). The 2.39% in Table 2.1 arises as in the final GRA preparation, Pelly Crossing load was allocated 2.3 GW.h of the total wholesale load, rather than the original estimate of 2.0 GW.h, which served to reduce the load growth otherwise attributed to "ongoing" sales by about 0.1%.

Also see YECL-YEC-1-19(d) in regards to the 2.5% estimate.

REFERENCE: **Application, Tables 2.2 to 2.4, pages 2-16 to 2-18**

ISSUE: **Sales Forecasts – Summary of Customers, Energy Sales and Revenues**

PREAMBLE:

CW wishes to understand YEC's forecasting accuracy.

QUESTION:

a) Please expand Tables 2.2 to 2.4 to include "Forecast" columns for the years 2006 and 2007.

b) For these expanded tables, please provide an explanation for any variances greater than 5% between forecast and actual energy sales for the years 2006 and 2007 for the Residential, General Service, Street Lights and Secondary Sales classes.

c) Please provide an explanation for any variances greater than 5% between forecast and actual "MWh sales per customer" for the years 2006 and 2007 for the Residential and General Service Classes.

d) Please provide an explanation for any variances greater than 5% as per (b) and (c) above for the year 2008, at the time the 2008 update information is provided.

ANSWER:

(a)

Please see Attachment 1 to this response.

(b)

There are only three variances of more than 5% in 2006 or 2007 in Table 2.2: Streetlights in 2006 and secondary sales in 2006 and 2007.

For streetlights, both Dawson and Mayo added street lights that were not anticipated at the time of preparing the business plan forecast in the prior year.

Secondary sales in 2006 were higher than forecast due to 2 new customers and one large established customer using approximately 1.5 GWh more than forecast. (For expanded information on secondary sales forecasting please refer to YECL–YEC–1-23).

The 2007 secondary sales variance was due to 3 of the largest customers all having a high load year and surpassing their historic averages by in excess of 1 GWh each. This level of coincident load was atypical and did not continue into 2008, where a certain level of equipment breakdowns resumed.

(c)

There are no variances of more than 5% in 2006 or 2007 in Table 2.2.

(d)

Yukon Energy has not fully compiled all 2008 sales in the form requested. It is possible to confirm that only 3 categories of sales saw material variances from forecast (greater than 1 GW.h): wholesales (see UCG-YEC-1-22 for 2008 preliminary actuals), secondary sales (2008 sales were well below forecast due to equipment break downs at major secondary customers and material interruptions in the latter part of the year – see UCG-YEC-1-28) and industrial (due to later than expected in-service of Minto, see YUB-YEC-1-17).

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues (excluding Riders) - Company

Table 2.2
September 2008
CW-YEC-1-4

Line No.	Description	Approved 2005	Actual 2005	Forecast 2006	Actual 2006	Forecast 2007	Actual 2007	Forecast Existing 2008	Forecast Existing 2009
1	**Residential**								
2	Customers	1,302	1,336	1,323	1,365	1,377	1,390	1,416	1,432
3	Sales in MWh	10,201	10,169	10,271	10,666	10,497	10,908	11,155	11,183
4	MWh sales per customer	7.8	7.6	7.8	7.8	7.6	7.8	7.9	7.8
5	Revenue ($000s)	1,208	1,215	1,223	1,267	1,251	1,313	1,319	1,335
6	Cents per KWh	11.84	11.95	11.91	11.88	11.92	12.04	11.83	11.94
7	**General Service**								
8	Customers	447	450	453	447	457	450	450	457
9	Sales in MWh	16808	18438	17805	17037	17531	17507	18193	19543
10	MWh sales per customer	37.6	41.0	39.3	38.1	38.4	38.9	40.4	42.8
11	Revenue ($000s)	2,304	2,470	2,420	2,301	2,349	2,376	2,442	2,637
12	Cents per KWh	13.71	13.40	13.59	13.51	13.40	13.57	13.42	13.49
13	**Industrial**								
14	Sales in MWh	0	0	0	0	0	0	6,845	29,023
15	Revenue ($000s)	0	0	0	0	0	0	709	3,142
16	Cents per KWh	7.00	7.00	7.00	7.00	7.00	7.00	10.36	10.83
17	**Street lights**								
18	Sales in MWh	252	256	256	270	270	274	278	278
19	Revenue ($000s)	65	66	66	69	70	70	71	71
20	Cents per KWh	25.75	25.64	25.82	25.64	25.88	25.62	25.64	25.63
21	**Space lights**								
22	Sales in MWh	13	14	15	14	14	14	14	15
23	Revenue ($000s)	2	3	3	3	2	3	3	3
24	Cents per KWh	19.76	21.90	20.58	21.48	14.18	22.00	21.82	21.54
25	**Total Company - Firm Retail & Ind.**								
26	Customers	1,749	1,786	1,776	1,812	1,834	1,840	1,866	1,889
27	Sales in MWh	27,274	28,877	28,346	27,987	28,313	28,704	36,485	60,042
28	Revenue ($000s)	3,579	3,754	3,712	3,641	3,672	3,763	4,545	7,188
29	Cents per KWh	13.12	13.00	13.10	13.01	12.97	13.11	12.46	11.97
30	**Wholesale sales**								
31	Sales in MWh	234,542	237,419	241,862	251,861	253,227	254,914	258,989	266,926
32	Revenue ($000s)	16,043	16,239	16,543	17,227	17,321	17,436	17,715	18,258
33	Cents per KWh	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.84
34	**Total Company - Firm**								
35	Sales in MWh	261,816	266,296	270,208	279,848	281,541	283,618	295,474	326,968
36	Revenue ($000s)	19,622	19,993	20,255	20,868	20,993	21,199	22,259	25,446
37	Cents per KWh	7.49	7.51	7.50	7.46	7.46	7.47	7.53	7.78
38	**Secondary**								
39	Sales in MWh	20,613	18,933	20,550	22,185	21,183	24,225	20,557	16,613
40	Revenue ($000s)	854	767	849	917	875	1,000	850	688
41	Cents per KWh	4.14	4.05	4.13	4.13	4.13	4.13	4.13	4.14
42	**Total Company**								
43	Sales in MWh	282,429	285,229	290,758	302,033	302,723	307,843	316,031	343,581
44	Revenue ($000s)	20,476	20,760	21,104	21,785	21,868	22,199	23,109	26,134
45	Cents per KWh	7.25	7.28	7.26	7.21	7.22	7.21	7.31	7.61

Note:

Excludes revenues from Rider J, Industrial Rider F, and offsets in new Revenue Reduction Rider as set out in Tab 4

Yukon Energy Corporation

Summary of Customers, Energy Sales and Revenues (excluding Riders) - Mayo Dawson

Table 2.3
September 2008
CW-YEC-1-4

Line No.	Description	Approved 2005	Actual 2005	Forecast 2006	Actual 2006	Forecast 2007	Actual 2007	Forecast Existing 2008	Forecast Existing 2009
1	**Residential**								
2	Customers	1,015	1,031	1,024	1,056	1,064	1,073	1,095	1,108
3	Sales in MWh	8,112	7,982	8,129	8,346	8,252	8,510	8,739	8,759
4	MWh sales per customer	8.0	7.7	7.9	7.9	7.8	7.9	8.0	7.9
5	Revenue ($000s)	960	954	968	992	984	1,025	1,033	1,046
6	Cents per KWh	11.84	11.95	11.91	11.88	11.92	12.04	11.83	11.94
7	**General Service**								
8	Customers	370	370	372	366	375	370	372	378
9	Sales in MWh	10,786	11,139	11,224	11,289	11,546	11,808	11,937	13,976
10	MWh sales per customer	29.2	30.1	30.2	30.8	30.8	31.9	32.1	37.0
11	Revenue ($000s)	1,493	1,492	1,525	1,525	1,547	1,603	1,602	1,886
12	Cents per KWh	13.84	13.40	13.59	13.51	13.40	13.57	13.42	13.49
13	**Industrial**								
14	Sales in MWh	0	0	0	0	0	0	0	0
15	Revenue ($000s)	0	0	0	0	0	0	0	0
16	Cents per KWh	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	**Street lights**								
18	Sales in MWh	154	159	158	173	173	177	181	180
19	Revenue ($000s)	40	41	41	44	45	45	46	46
20	Cents per KWh	25.75	25.64	25.82	25.64	25.88	25.62	25.64	25.63
21	**Space lights**								
22	Sales in MWh	10	12	12	13	13	13	13	13
23	Revenue ($000s)	2	3	3	3	2	3	3	3
24	Cents per KWh	19.75	21.90	20.58	21.48	14.18	22.00	21.82	21.54
25	**Total - Firm Retail and Industrial**								
26	Customers	1,385	1,401	1,396	1,423	1,439	1,443	1,467	1,486
27	Sales in MWh	19,063	19,293	19,524	19,821	19,984	20,508	20,870	22,928
28	Revenue ($000s)	2,495	2,490	2,537	2,564	2,577	2,675	2,685	2,980
29	Cents per KWh	13.09	12.90	12.99	12.93	12.90	13.05	12.86	13.00
30	**Wholesale sales**								
31	Sales in MWh	581	390	695	854	810	855	891	916
32	Revenue ($000s)	40	27	48	58	55	58	61	63
33	Cents per KWh	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.84
34	**Total - Firm**								
35	Sales in MWh	19,644	19,684	20,219	20,675	20,794	21,363	21,761	23,844
36	Revenue ($000s)	2,535	2,516	2,584	2,622	2,633	2,734	2,746	3,043
37	Cents per KWh	12.90	12.78	12.78	12.68	12.66	12.80	12.62	12.76
38	**Secondary**								
39	Sales in MWh	800	570	550	630	600	659	652	630
40	Revenue ($000s)	42	30	29	33	31	34	34	33
41	Cents per KWh	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20
42	**Total**								
43	Sales in KWh	20,444	20,254	20,769	21,305	21,394	22,022	22,412	24,474
44	Revenue ($000s)	2,576	2,546	2,613	2,655	2,664	2,768	2,780	3,076
45	Cents per KWh	12.60	12.57	12.58	12.46	12.45	12.57	12.40	12.57

Yukon Energy Corporation

Summary of Customers, Energy Sales and Revenues (excluding Riders) - WAF

Table 2.4
September 2008
CW-YEC-1-4

Line No.	Description	Approved 2005	Actual 2005	Forecast 2006	Actual 2006	Forecast 2007	Actual 2007	Forecast Existing 2008	Forecast Existing 2009
1	**Residential**								
2	Customers	288	305	299	309	313	317	322	324
3	Sales in MWh	2,089	2,186	2,142	2,320	2,245	2,398	2,416	2,424
4	MWh sales per customer	7.3	7.2	7.2	7.5	7.2	7.6	7.5	7.5
5	Revenue ($000s)	247	261	255	276	268	289	286	289
6	Cents per KWh	11.84	11.95	11.91	11.88	11.92	12.04	11.83	11.94
7	**General Service**								
8	Customers	77	80	82	80	82	80	78	79
9	Sales in MWh	6,022	7,299	6,581	5,747	5,986	5,699	6,256	5,568
10	MWh sales per customer	78.2	91.5	80.7	71.5	73.0	71.2	80.2	70.5
11	Revenue ($000s)	811	978	894	776	802	774	840	751
12	Cents per KWh	13.47	13.40	13.59	13.51	13.40	13.57	13.42	13.49
13	**Industrial**								
14	Sales in MWh	0	0	0	0	0	0	6,845	29,023
15	Revenue ($000s)	0	0	0	0	0	0	709	3,142
16	Cents per KWh	N/A	N/A	N/A	N/A	N/A	N/A	10.36	10.83
17	**Street lights**								
18	Sales in MWh	97	97	97	97	97	97	97	97
19	Revenue ($000s)	25	25	25	25	25	25	25	25
20	Cents per KWh	25.75	25.64	25.82	25.64	25.88	25.62	25.64	25.63
21	**Space lights**								
22	Sales in MWh	2	1	2	2	1	1	1	1
23	Revenue ($000s)	0.5	0.3	0.5	0.4	0.2	0.3	0.3	0.3
24	Cents per KWh	19.76	21.89	20.58	21.48	14.18	22.00	21.82	21.54
25	**Total - Firm Retail and Industrial**								
26	Customers	365	385	380	389	395	397	400	403
27	Sales in MWh	8,211	9,584	8,822	8,166	8,330	8,196	15,615	37,113
28	Revenue ($000s)	1,084	1,264	1,175	1,077	1,095	1,087	1,860	4,208
29	Cents per KWh	13.21	13.19	13.32	13.19	13.15	13.27	11.91	11.34
30	**Wholesale sales**								
31	Sales in MWh	233,961	237,028	241,167	251,007	252,417	254,059	258,098	266,011
32	Revenue ($000s)	16,003	16,212	16,496	17,169	17,265	17,378	17,654	18,195
33	Cents per KWh	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.84
34	**Total - Firm**								
35	Sales in MWh	242,172	246,612	249,989	259,173	260,747	262,254	273,713	303,124
36	Revenue ($000s)	17,087	17,477	17,671	18,246	18,360	18,465	19,514	22,403
37	Cents per KWh	7.06	7.09	7.07	7.04	7.04	7.04	7.13	7.39
38	**Secondary**								
39	Sales in MWh	19,813	18,363	20,000	21,555	20,583	23,566	19,905	15,983
40	Revenue ($000s)	812	737	820	884	844	966	816	655
41	Cents per KWh	4.10	4.02	4.10	4.10	4.10	4.10	4.10	4.10
42	**Total**								
43	Sales in KWh	261,985	264,975	269,989	280,728	281,330	285,820	293,618	319,107
44	Revenue ($000s)	17,900	18,214	18,491	19,130	19,204	19,431	20,330	23,058
45	Cents per KWh	6.83	6.87	6.85	6.81	6.83	6.80	6.92	7.23

REFERENCE: **Application, Tables 2.3, p. 2-17**

ISSUE: **Summary of Customers, Energy Sales and Revenues, Mayo-Dawson**

PREAMBLE:

CW wishes to understand YEC's forecasting accuracy.

QUESTION:

a) Please provide an explanation for the 32% variance between the 2005 approved Wholesale sales of 581 MWh and the actual 2005 Wholesale sales of 390 MWh.

b) Please provide an explanation for the 28% variance between the 2005 approved Secondary Sales of 800 MWh and the actual Secondary Sales of 570 MWh.

ANSWER:

(a)

The 2005 Business Plan forecast 330 MWh of Wholesale sales to YECL for Stewart Crossing. The actual 2005 sales were 140 MWh due to Stewart Crossing not connecting to the Mayo Dawson line until November 2005.

(b)

The 2005 Business Plan forecast a new secondary sales customer connecting in Dawson City in fall 2005 which was forecast to have sales of 250 MWh. The connection did not happen.

REFERENCE: **Application, Tables 2.4, page 2-18**

ISSUE: **Summary of Customers, Energy Sales and Revenues, WAF**

PREAMBLE:

CW wishes to understand YEC's forecasting accuracy.

QUESTION:

a) Please provide an explanation for the 21.2% variance between the 2005 approved sales for the General Service class of 6,022 MWh and the actual 2005 sales of 7,299 MWh. Also please explain the 17% variance between the approved and forecast "MWh sales per customer" for the General Service class.

b) Please provide an explanation for the variance of 3,067 MWh between 2005 approved Wholesale sales of 233,961 MWh and 2005 actual Wholesale sales of 237,028.

c) Please provide an explanation for the 7.3% variance between the 2005 approved Secondary Sales of 19,813 MWh and 2005 actual Secondary Sales of 18,363 MWh.

ANSWER:

(a)

The 2005 Business Plan forecast 3.0 GWh of sales to Anvil Range Mine for dewatering activities. The actual sales were 4.2 GWh due to the combined impact of significant pumping activities in the Vandgorda Pit and an aggressive program to sell off and remove various mill components during the summer of 2005.

The additional significant usage by one single customer increased the MWh sales per customer for the whole General Service class.

(b)

In September 2004, as part of the 2005 business planning process, YECL provided YEC with a monthly forecast of Wholesale sales supporting the 233,961 MWh on WAF. The actual Wholesale sales for 2005 were 237,028 MWh. The difference between forecast versus actual is 1.31%.

Further explanation would require customer level information from YECL (the retail distributor). Yukon Energy does not have access to this information. It is consistent with a relatively consistent positive variance between YECL wholesale forecasts and corresponding actuals, as reviewed in the Resource Plan hearing Exhibit B-19, which has led YEC to adopt wholesale forecasts (such as 2009) which are higher than the forecasts developed by YECL.

(c)

Equipment breakdowns account for approximately 3,416 MWh less secondary sales in 2005 than forecast while new customers consumed approximately 2,003 MWh more than forecast.

REFERENCE: **Overview, p. 10**

ISSUE: **Secondary Sales**

PREAMBLE:

YEC states, "**Secondary Sales:** With the increased utilization of surplus hydro generation in coming years, the existing opportunity to sell secondary energy on an interruptible basis will be basically eliminated. There may remain for a few years a small amount of secondary energy available in summer months, during off-peak hours, but the quantities will be limited. In the test years, Yukon Energy forecasts an ability to maintain secondary sales through most hours of the year, but during cold winter periods there is increased anticipated use of diesel generation for firm load peaking requirements, and consequently much greater forecast interruptions of secondary sales than in recent years (with consequent reductions in secondary sales revenues in the test years).

QUESTION:

a) Please explain how surplus hydro has benefited YEC and its customers to this point and please specify which customers and/or classes of customer have benefited from it and demonstrate how.

b) Please explain how Yukon Energy's forecast decrease in surplus hydro in the test years and the ultimate elimination of surplus hydro in coming years will negatively affect the customers and/or classes of customers cited in a) above.

c) Will YEC be negatively affected by the decrease of surplus hydro in the test years and the ultimate elimination of surplus hydro in coming years? Please explain.

ANSWER:

(a)

The sale of surplus hydro (generation that would otherwise be lost as spilled water over the dam) for substantial revenues as secondary energy (at very little cost to the utility) helps to maintain rates to all firm ratepayers at a level lower than they would otherwise

be, albeit not at as low a level as would be expected by displacing interruptible secondary energy sales with firm sales that typically attract materially higher rate (including rate rider revenue).

This is demonstrated in Tab 4, Table 4-1, which notes that the secondary revenues (approximating $1.4 million in each test year) serves as an offset to the firm rate revenue requirement.

The intent of the secondary sales retail rate is to maximize the amount of revenue available to offset ongoing fixed Yukon Energy costs while still leaving the secondary sales customer with some energy cost savings compared with what the customer would otherwise pay for heating fuel (typically heating oil). All revenue secured from secondary sales directly reduces the amounts needed to be recovered from firm rates.

All firm retail customer classes benefit through paying lower rates than they would otherwise need to due to the lower Yukon Energy Revenue Requirement. Secondary Sales customers benefit through receiving some energy cost savings via service under Rate Schedule 32.

(b)

Reduced revenues due to cessation of service under Rate Schedule 32 will coincide with increased firm sales to the loads that drive increased firm load on the system. Accordingly, with lower amounts of surplus energy available for sale under Rate Schedule 32, the quantity of revenues available to offset the revenue requirement to be made up by rates charged to firm customers will increase and all firm retail customer classes will benefit.

(c)

No, Yukon Energy (and Yukon firm retail customer classes) will not be negatively affected by the decrease in revenues from surplus hydro available for secondary sales, as revenues no longer recovered via secondary sales will be provided by higher rates of service to firm customers. This is a normal and appropriate outcome from serving firm loads, which are required to be the top priority for a regulated franchised utility. Secondary sales, by necessity, must be viewed as a lower quality of service.

REFERENCE: Section 2.2.4, p. 2-9

YEC states, "After the Faro mine closure in 1998, Yukon Energy took significant efforts to market surplus hydro available from Yukon Energy's facilities, with net revenues derived from sales going towards lowering rates compared to what would otherwise be required for firm customers throughout the Yukon.

Yukon Energy total secondary sales (i.e., sales sold at special rates on condition that these sales can be interrupted at any time that surplus hydro generation is not available) increased substantially leading up to the 2005 Required Revenues and Related Matters hearing, to a forecast level of 20,613 MW.h in 2005. As reviewed at that time, further increases in secondary sales quantities were not being aggressively targeted as the remaining surplus on the system was diminishing. Since the 2005 Required Revenues and Related Matters hearing, only two new secondary customers have been added, and total secondary sales increased at a slower pace, increasing to 22,185 MW.h in 2006 and to 24,225 MW.h in 2007."

REFERENCE: Application, p.10

"Secondary Sales: With the increased utilization of surplus hydro generation in coming years, the existing opportunity to sell secondary energy on an interruptible basis will be basically eliminated."

ISSUE: Secondary Sales

QUESTION:

a) Please confirm that YEC's "significant efforts to market surplus hydro" after the Faro mine closure in 1998 involved "aggressively" targeting and convincing customers to utilize electric heating on the premise that secondary sales would be available for that purpose. If not confirmed, please explain.

b) In particular, please confirm that YEC made representations to the City of Whitehorse that secondary sales would be available to serve the heating load in the Canada Games Centre and that YEC encouraged the City to utilize electric heating for that facility on the basis of such representations.

c) If a) or b) are confirmed, and in light of YEC's statement cited above that: "in coming years, the existing opportunity to sell secondary energy on an interruptible basis will be basically eliminated", please comment on the fairness of the predicament these electric heating customers find themselves in, after installing electric heating in response to the urging of YEC and the promise that inexpensive surplus hydro would be available.

d) What will happen to these captive customers when surplus hydro is no longer available? Please provide estimates of cost increases for a number of typical Industrial and General Service secondary sales customer loads.

e) Please describe the types of customers that purchase secondary sales, the purposes to which secondary sales are put and any economic impact upon the Yukon that the "basic elimination" of secondary sales might have.

f) Is YEC planning to assist secondary sales customers to switch to alternative sources of energy, financially or otherwise? Please explain.

ANSWER:

(a)

Yukon Energy's activities with respect to marketing secondary sales were set out in AGB-YEC-3 from the 2005 Required Revenues and Related Matters proceeding, as follows:

> The Renewable Power Sales Incentive Program was initiated in May 2000 by Yukon Development Corporation. The program was administered by Yukon Energy during the first year of the program. In 2001 it was transferred to the Energy Solutions Centre. The program remained under the Energy Solutions Centre until the termination of the program in 2003. The program's original scheduled termination date was March 31, 2003. The program was not extended past its original termination date.

The materials provided by ESC typically referenced the typical pattern of secondary energy customers to experience a payback period of 2-5 years for their investment in secondary energy service. Ongoing as well as seasonal interruption were noted as an essential element of secondary sales customer risk, as well as the requirement that each secondary sales customer have in place prior to service (and fully maintained during any service) an actively available alternative heating source to rely upon in the event of any such secondary sales interruptions.

(b)

YEC discussed the future availability and price of secondary sales in 2003 and 2004 with The City of Whitehorse representatives as follows:

- Secondary power is fully interruptible in the event diesel generation is required.
- The future price could change based on the avoided cost of diesel fuel.
- Secondary power was available in 2004 and may be available in the future for several years unless there was significant growth of firm power sales, such as new industrial customers.

The City confirmed their understanding that there was no guarantee of supply, and that this was particularly true if another mine came into operation. The City indicated that the particular concern was that there be a reasonable level of expectation for continued power supply for a period of 5 years.

YEC further discussed the future availability of secondary power as part of regulatory filings since that time:

- The 2005 Required Revenues and Related Matters application noted, at YECL-YEC-1-46(d): “The Company has been assessing an annual secondary sales ceiling on the WAF system over the past year. Based on the analysis work done in 2004, a ceiling of 30 GWh per year would result with a 90% annual availability of secondary sales (70% availability during peak winter months) for the next 5 years. The analysis was based on a review of monthly hydro energy and monthly load duration curves.” No availability analysis beyond 5 years was cited.

- The 2005 Resource Plan (page 25 of the Overview document) explained that in a high load growth scenario secondary power could be unavailable as early as 2009, and that in a low growth scenario, available as long as 2025.

(c)

As noted above, there were no promises or guarantees of availability provided by YEC to secondary sales customers. Regardless, the key timeframe for analysis at the time of the City's discussions with YEC was a reasonable level of expectation of continued power supply for 5 years, i.e., to 2008-2009.

At the present time, Yukon Energy expects continued availability of secondary energy at a high percentage through 2009 and, subject to water conditions, for some period beyond 2009 until material load growth occurs. This could occur by 2011, as noted at Tab 2, page 2-7.

(d)

Secondary sales customers are not "captive" customers. Quite the reverse, each secondary sales customer is required to have in place prior to service (and fully maintained during any service) an actively available alternative heating source to rely upon in the event of any such secondary sales interruptions.

Yukon Energy expects that during any interruption period, the customers in question will make use of their primary form of heating (typically oil) as is required by the rate schedule. Based on the design of the secondary rate, set at 66.7% of the cost of the alternative heating fuel, customers would be expected to pay about 50% more for heating energy using oil than from using secondary energy.

(e)

The customers who purchase secondary energy are typically government customers. These customers have been experiencing significant savings compared to the cost of heating with oil since 2005 (electricity cost at 33.3% below the cost of oil) and larger percentages before that time. The costs to these entities will return to the default level (oil), during periods where secondary sales are interrupted.

(f)

No. As noted above, customers who purchase secondary energy are required to already have the alternative source of energy installed and fully operational.

REFERENCE: **Section 4.2.1, p. 4-4**

ISSUE: **Secondary Sales**

PREAMBLE:

YEC states, "In order to address fuel price related variance in income, the Rider F Deferred Fuel Price mechanism was used to normalize the secondary sales revenues and act as a natural hedge to the Rider F account, reducing variability that would otherwise be charged through the joint Yukon Energy/YECL rate rider.

QUESTION:

a) Please fully explain and demonstrate by using an example(s) what YEC means by the comment that, "the Rider F Deferred Fuel Price mechanism was used to normalize the secondary sales revenues and act as a natural hedge to the Rider F account."

ANSWER:

(a)

Yukon Energy's 2005 revenue requirement and rates were based on a calculated secondary sales rate of 5.2 cents/kW.h at the retail level (4.1 cents/kW.h at the wholesale level).

Since 2005, actual prices paid by secondary customers were adjusted quarterly to track the value of oil savings that the customers were experiencing, based on the ongoing changes in the price of oil. When these quarterly adjusted values exceeded 5.2 cents/kW.h (i.e., when oil prices rose), all collections in excess of the 5.2 cent/kW.h level were credited to the Deferred Fuel Price account (the "Rider F account").

As the Deferred Fuel Price account is typically used to track cost increases (or decreases) arising from oil price increases (or decreases), crediting additional revenues to the account at a time when oil prices rise serves as a natural offset or hedge to the costs being charged to this account related to the same oil price rise.

REFERENCE: **Section 4.2.1, p. 4-5**

ISSUE: **Secondary Sales**

PREAMBLE:

YEC states, "In the 2005 proceeding, Yukon Energy received approval for a procedure related to determining the timing of scheduled secondary sales interruptions based on forecasting the quantity (hours) of diesel generation expected to be required over the coming seven day period in winter (i.e., interruptions were to be initiated if YEC forecast a requirement to dispatch diesel generation for more than 10% of the hours over the coming seven day period). It has become apparent that a seven day forecast period is not practical, given the Environment Canada long-range forecasts are focused on the coming five days. Accordingly, Yukon Energy is seeking approval to adjust the rate schedule provision to reflect interruptions being initiated for any forecast requirement to use diesel for more than 10% of the hours over the subsequent five day period. No material effect is expected on the amount of time secondary energy is expected to be made available.

QUESTION:

a) Please describe what difficulties, if anything arose from the use of a seven day forecast period that would be rectified with the use of a 5 day forecast?

b) On what evidence does YEC base its expectations that there will be no material effect on the amount of time secondary energy is to be made available as a result of changing to the 5 day forecast period?

c) If there is no material effect on the amount of time secondary energy is to be made available, please explain the value added to making this change?

ANSWER:

(a)

There is no readily available 7 day forecast, which required Yukon Energy to extrapolate from available 5 day forecasts. This is not the preferred approach to determining secondary sales interruptions.

(b)

The addition of a 6th and 7th day for the purposes of forecasting secondary sales interruptions rarely if ever drives the need to trigger a 24 hour interruption notice.

(c)

The change is solely added to relieve Yukon Energy of having to extrapolate from the Environment Canada weather forecast to extend it to 7 days, when Environment Canada is only prepared to forecast 5 days out.

REFERENCE: **Application page 1-6**

ISSUE: **Rate Restructuring within Rate Classes**

PREAMBLE:

YEC states: "Accordingly, given the latest Directive to the Board, Yukon Energy is not, as part of the current GRA submissions, addressing COS and rate design work related to any rate shift program or rate rebalancing as between customer classes. The Application, however, addresses rate design issues within each retail customer class related to OIC 1995/90 directives regarding runoff rates."

QUESTION:

a) Please discuss how rate design issues within each retail customer class, such as recovery of costs at the margin by the second block rate and the appropriateness of customer charges, can be addressed in the absence of a cost of service study?

b) YEC has proposed no change to the customer charges applied to Residential Services (Appendix 4.1, Rate Schedules). Please demonstrate that these fixed charges recover an appropriate share of customer-related costs.

c) Please demonstrate that YEC has applied the amended OIC 1995/90 directives regarding runoff rates equally and fairly to each rate class.

d) Has YEC performed a recent load study in support of its rate restructuring within rate classes? If yes, please provide this study.

ANSWER:

(a) and **(b)**

Based on established practice in Yukon dating back to the 1992 Rate Design review, the design of runoff rates is based on the incremental cost of fuel, and does not require reference to the embedded costs to serve a class as would be developed out of a Cost of Service Study.

The design of customer charges in Yukon has typically not been linked directly to a cost of service study, as these charges are rarely if ever set at a level that fully collects "fixed" or "customer" related costs on a system. As a result, the output of a cost of service study is typically not a determining factor in setting these rates. For example, in the 1997 Cost of Service study, the fully allocated "customer" related costs were $395.00 per customer per year (approximately $33/customer per month), plus demand related costs which for residential customers can also be recovered by the customer charge. The rate design in that hearing set the customer charge at $11.90 per month, bearing no relation to the $33/month calculated value.

(c)

Yukon Energy has equally and fairly applied the principles of the OIC 1995/90 directives regarding runoff rates to all firm retail classes in respect of the rate reduction, which for each class is targeted at only the first block rates, to avoid exacerbating the current pricing issues with respect to the second block for all classes.

The initial steps to re-establish increased runoff rates at an efficient level as required by the OIC have been applied, as noted at Tab 4, only to residential customers at this time. This is because traditional residential class structures in Yukon and existing rate design is amenable to addressing this OIC requirement without rate re-design being required.

As noted in the Application (pages 4-13, 4-14), the first steps at implementation of second block rates at the efficient level for General Service customers cannot be achieved without material rate re-design, which the Application notes requires further analysis and more detailed participation by YECL.

(d)

It is not clear what is meant by a "load study". Sales forecasts by rate block are provided in Tables 4.9 and 4.10. Consistent with past GRAs jointly filed by YEC and YECL in the 1990s, no studies have been carried out to assess potential impacts of proposed rate changes on any of these sales forecasts.

REFERENCE: **Application page 4-12, Table 4.9 and Table 4.10**

ISSUE: **Rate Restructuring within Rate Classes**

PREAMBLE:

YEC states: "Given the Yukon Hydro zone electrical systems are now approaching the point where diesel generation will be required for more peaking occasions, and ultimately for near-term baseload generation (absent the development of added new renewable generation), current run out rates in all rate zones simply are not in keeping with the conservation principles of OIC 1995/90 nor are such rates consistent with the overriding principles outlined in the YTG's climate change policy."

QUESTION:

a) Please confirm that these changes will or will not be revenue neutral for the residential rate class as a whole. Please demonstrate.

b) Please confirm that these changes will or will not be revenue neutral for each separate Residential Service shown in Appendix 4.1, Rate Schedules. If not revenue neutral, please explain YEC's rationale for allowing this to happen.

c) Please confirm that at times during the last 13 years, residential customers were encouraged by YEC to use electric heating. If so, please describe the circumstances of that occurrence(s).

d) YEC proposes to transfer the cost responsibility of collecting $1.488M from Residential block 1 customers to Residential block 2 customers for 2009 as per Table 4.10. Please confirm that the purpose of the proposed increase in block 2 rates to Residential services is to create an incentive for electric heating customers who consume over 1000 kW.h per month to use less electricity in heating or to switch to a different method of heating altogether.

e) If d) is confirmed, please comment on the fairness or unfairness of these proposed changes to these captured customers, whose houses have been built to provide electric heating. How would YEC explain to these customers that this

proposed change to rates is appropriate, and that these customers are not being specifically targeted?

ANSWER:

(a)

Confirmed that these changes will be revenue neutral. Please see Table 4.10.

(b)

These changes will not be revenue neutral for each separate Residential Service shown in Appendix 4.1. As noted in the Application the requested rate changes are designed to be revenue neutral at each rate class level (e.g., non-government residential and government residential retail rate classes) – not the rate schedule level dealing with different rate zones.

Under Yukon's 1996/97 GRA approved rate schedules, and in accordance with OIC 1995/90, the only rate difference at the rate schedule level within a retail residential customer class is related to the runoff rate applicable to each rate zone.

(c)

Not confirmed. See **(d)** below.

(d)

As reviewed in response to YUB-YEC-1-21, in adjusting the runoff rates to better reflect the requirements of OIC 1995/90, Yukon Energy did not develop new rate design principles for runoff rates, it applied established Yukon rate design principles. Such principles are required to comply with OIC 1995/90, and have been consistently applied in Yukon GRAs and YUB Reports extending as far back as 1992, including extensive previous reviews by the Board and previous Board Orders. These principles do not discriminate against any specific users.

Residential customers on WAF and Mayo (Hydro Zone), including those with electric heating, were charged based on these principles in the approved 1996/97 GRA rates. As

reviewed at Tab 4, page 4-11 (line 1 to 7), the net result was that electric heating costs were more than double the cost of home heating oil. For example, with the 1996/97 GRA runoff rates in place, the cost of operating electric heating in Whitehorse, at that time was approximately 120% higher than the cost of heating with fuel oil.

In implementing the forecast rate reduction YEC was cognizant of the fact that any reduction in the second block rate would not adhere to the government direction provided by OIC 1995/90 and last implemented in the approved joint YEC/YECL 1996/97 GRA.

Current runoff rates at the time the Application was filed were only 14.39 cents/kWh in the Hydro zone (Tab 4, Table 4.5), while the approach approved by the Board in the 1996/97 GRA for setting runoff rates would yield runoff rates approximating of 37.37 cents/kWh (Tab 4, page 4-12, footnote 11). A modest increase in the runoff rate by 5.61 cents/kWh (resultant Hydro runoff rate before GST of only 21.12 cents/kWh based on rates and riders then in effect - see Table 4.7) was considered a practical first step towards correcting this problem and better achieving the efficiency required by OIC 1995/90.

(e)

To be clear, an overall change to rate design in Yukon has not been included in this Application. Yukon Energy in its Application has provided modest adjustments to runoff block rates to ensure that these rates better reflect the requirements of OIC 1995/90 and past Board directives by better reflecting the incremental costs of generation.

This modest adjustment to runoff rates is not being undertaken to target any particular customer or type of customer usage. As noted in (d) above, the regulatory framework in Yukon, established by Government OIC, requires that the runoff block for each non-government retail customer class be fixed based on rate design principles that promote economy and efficiency.

In 1992 after a cost of service and rate design review, the Board determined (at page 37) that it “considers efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decisions regarding the future and current use of electricity.” The Board recommended (at page 40 of that report) that runout rates for all zones should be adjusted to reflect short-run incremental costs.

To implement Board recommendations related to the requirement to promote economy and efficiency (required by OIC 1991/62 which was later revoked by OIC 1995/90), adjustments to runoff blocks were designed to more closely reflect the differing incremental costs of energy in each rate zone.

In Order 1993-8 approving the 1993/94 GRA the Board approved as appropriate the principles and methods used to determine runoff rates. These same principles were applied in the 1996/97 GRA filing. In an order approving the negotiated settlement (Order 1996-7) the Board approved the rates applied for noting as follows (at page 8):

> The run-out rates have been designed consistent with rate design principles and specific directions established in 1995/90. The resultant rate in each of the five zones (Hydro-Diesel, Watson System, Dawson System, Small Diesel and Old Crow) reflect short-run variable costs (Exhibit 1, Tables 3.2 and 3.3) which the Companies must meet.

This is past practice in Yukon, as approved by the Board in 1993/94 GRA and in the 1996/97 GRA.

REFERENCE: **Application page 4-12, Table 4.9 and Table 4.10**

ISSUE: **Rate Restructuring within Rate Classes**

PREAMBLE:

YEC states: "Given the Yukon Hydro zone electrical systems are now approaching the point where diesel generation will be required for more peaking occasions, and ultimately for near-term baseload generation (absent the development of added new renewable generation), current run out rates in all rate zones simply are not in keeping with the conservation principles of OIC 1995/90 nor are such rates consistent with the overriding principles outlined in the YTG's climate change policy."

QUESTION:

a) As a means of accomplishing the conservation principles set out in OIC 1995/90, did YEC investigate any conservation strategies other than its proposed increase to run-off rates for residential customers? If yes, please provide the results of this investigation. If no, please explain why not.

b) As a means of accomplishing the conservation principles set out in OIC 1995/90, did YEC investigate adopting any types of conservation rate structures other than "Increasing Block Rates?" If yes, please provide the results of this investigation.

c) The billing determinants for the second block of energy for the Residential rate class in Table 4.9 (Sales at Existing Rates) are identical to those in Table 4.10 (Sales at Proposed Rates). Does this mean that YEC is forecasting no reduction of demand in the second block and, therefore, no meaningful conservation to take place?

d) Assuming YEC's strategy to reduce electric heating demand actually succeeds, and meaningful conservation occurs, which results in significant reductions to demand in the residential second block, please explain how YEC is preparing to address the reduced revenue collected from residential customers? Is YEC concerned that if the Board approves its rate proposal, it may not collect its revenue requirements for the test period?

ANSWER:

(a) and **(b)**

The issue of efficient price signals, and the issue of conservation activities are separate and distinct matters. Pursuant to OIC 1995/90 the Board must fix runoff rates for each non-government retail class on the basis of rate design principles to promote economy and efficiency, and rate design principles related to design of runoff rates have been established and approved by the Board (Order 1996-7). While other conservation measures or rate structures may be appropriate, there is no alternative to designing runoff rates that meet the requirements of the OIC.

For a discussion of Yukon Energy's involvement in conservation and DSM, please see LE-YEC-1-20 through LE-YEC-1-25.

(c) and **(d)**

Both Table 4.9 and 4.10 provide data for 2009, and consequently reflect the same load forecast. This is the reason that they are the same.

The underlying rationale for increasing the runout block rate is not to reduce electric heating demand specifically. The underlying rationale for the increase in runout block rate is to ensure current Yukon rates continue to meet the requirements of OIC 1995/90 by fixing runoff rates for each non-government retail customer class on the basis of rate design principles that promote economy and efficiency.

To the extent that conservation occurs due to consumer response to the second block rate, it is expected that this will occur over time as noted in PWP/HML-YEC-1-6. Any revenue reductions that occurred would form part of future Yukon Energy GRAs.

REFERENCE: **Tables 2.2 to 2.4**

ISSUE: **Billing Determinates and Rates**

PREAMBLE:

YEC indicates that it serves street lighting and space lighting customers. The rate schedules for these customers are not included in Appendix 4.1.

QUESTION:

a) Please provide the rate schedules that these customers are served under.

ANSWER:

(a)

Please see Attachment 1 to this response.

Effective: 1997 01 01
Supersedes: 1996 07 01

RATE SCHEDULE 61/66

MUNICIPAL STREET LIGHTING

AVAILABLE:

Available in all communities serviced by the Company throughout the Yukon Territory for municipal street lighting service, including the installation, operation and maintenance of standard mercury vapour or high pressure sodium luminaries on wood poles and serviced by overhead wiring. Not applicable to private lighting service.

RATE:

Customer Charge

$6.36 per Lamp

Demand Charge

4.03¢ per watt of billing demand

Surcharge for Highmast Fixtures

$1.03 per Lamp

RATE MODIFICATIONS APPLICABLE:

For fuel adjustment Rider, see Rider F.

ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.

Effective: 1997 01 01
Supersedes: 1996 07 01

RATE SCHEDULE 67

STREET LIGHTING (ENERGY ONLY)

AVAILABLE:

Available in all communities serviced by the Company throughout the Yukon Territory for 400 and 250 Watts mercury vapour or high pressure sodium energy only street lighting service

RATE:

For Service rendered in any one billing month:

400 Watts Street Light	$23.66 per month
250 Watts Street Light	$15.47 per month

RATE MODIFICATIONS APPLICABLE:

For fuel adjustment Rider, see Rider F.

ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.

Effective: 1997 01 01
Supersedes: 1996 07 01

RATE SCHEDULE - 75/76

PRIVATE LIGHTING SERVICE

AVAILABLE: In all communities serviced by the Company.

APPLICABLE: To off-street private lighting at 120/240 volt service on a twelve month contract and under special conditions to Municipal Corporations for lighting in summer villages with a minimum six-month billing.

RATE: Exclusive of fuel cost adjustment. For service rendered in any one billing month, as follows:

	100 Watt HPS	A 175 Watt MV 7,000 Lumen	A 250 Watt MV 11,000 Lumen	A 400 Watt MV 20,000 Lumen	400 Watt MV Flood-Light Unit
(1) Normal 12-month unmetered service	$11.64	$14.18	$17.34	$23.03	$25.44
(2) Energy and maintenance only (Customer pays installation cost)	$6.46	$9.87	$13.16	$18.61	$17.75
(3) Twelve month service through customer meter	$7.34	$7.97	$8.23	$7.84	$10.26

NOTE: (A) These are sentinel units having a 30-inch bracket. They are not regular street lighting units. Lamps are energized by a photoelectric controller and operate approximately 4,000 hours per annum.

... Continued on overleaf

Rate Schedule - 75/76 (Continued)

(B) Normal installation includes one duplex span of approximately 150 feet, one 30 foot wood pole and fixture. All additional extension costs will be borne by the customers.

(C) Privately-owned street lighting units will be supplied energy and re-lamped only for the charges shown in #2 above.

RATE MODIFICATIONS APPLICABLE:

For fuel adjustment Rider, see Rider F.

ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.

REFERENCE: **Application Section 2.3.1**

ISSUE: **Aishihik Water Storage Facility**

PREAMBLE:

YEC discusses the relationship between drought conditions, the levels in the Aishihik Water Storage Facility and secondary sales.

QUESTION:

a) What were the water levels during 2008 in the Aishihik Water Storage Facility relative to long-term average levels?

ANSWER:

(a)

Average monthly water levels in 2008 were above the mean Aishihik water levels by the following amounts:

Jan: 0.40m
Feb: 0.40m
Mar: 0.38m
Apr: 0.36m
May: 0.38m
Jun: 0.39m
Jul: 0.49m
Aug: 0.49m
Sep: 0.51m
Oct: 0.46m
Nov: 0.38m
Dec: 0.43m

REFERENCE: **Application page 3 – 4, lines 16 - 18**

ISSUE: **Fuel and Purchased Power**

PREAMBLE:

YEC states: "Forecast fuel prices for the 2008/2009 test years are approximately $1.108 per litre for 2008 and $1.149 per litre for 2009 for Whitehorse. For other Yukon Energy locations, additional costs of 3.2 cents/litre (Faro), 1.5 cents/litre (Dawson) and 0.7 cents/litre (Mayo) apply.

QUESTION:

a) When were these fuel price forecasts for 2008 and 2009 made? What was the basis for these price forecasts at the time the forecasts were made?

b) Are the "additional costs" mentioned additional to the Whitehorse price? If not, please explain the use of the term "additional"?

c) What was the actual average price of diesel fuel for Whitehorse, Faro, Dawson and Mayo during 2008?

d) What was the actual Fuel and Purchased Power cost to YEC during 2008?

e) What is the current (January 2009) wholesale diesel fuel price for Whitehorse? Please revise the 2009 Fuel and Purchased Power revenue requirement forecast to reflect this current price of diesel fuel.

f) Please provide YEC's best current forecast for the average wholesale price of diesel fuel in Whitehorse for 2009. Please advise if such a forecast is or can be derived from the Short-Term Energy Outlook document, page 20, Table 2 which can be accessed at the following link:
http://www.eia.doe.gov/emeu/steo/pub/jan09.pdf

ANSWER:

(a)

Fuel price forecasts for 2008 and 2009 were made on August 28, 2008. The basis for the price forecasts was NYMEX futures market crude oil prices adjusted for refining/shipping costs and exchange rate. At the time, the NYMEX forecasts were relatively constant at a price of approximately $119/bbl in US dollars.

(b)

The "additional costs" mentioned are additional to the Whitehorse price.

(c) and **(d)**

The actual average price for diesel fuel consumed during 2008 operations is as follows:

2008	Cents/L
Faro	84.20
Mayo	62.56
Dawson	97.58
Whitehorse	93.42

The actual average price of diesel fuel purchased during 2008 was:

2008	Cents/L	
Faro	1.074	
Mayo	0.00	No purchases in 2008
Dawson	1.084	
Whitehorse	1.021	

The average price for diesel consumed is lower than average purchase price as YEC uses a weighted average cost for fuel expense and inventory on hand at the beginning of the year at a lower cost than fuel purchases during the year.

(e)

The current wholesale diesel fuel prices for new purchases (January 22, 2009) are as follows:

Faro	77.27
Mayo	78.01
Dawson	79.89
Whitehorse	73.93

Updating the GRA for newer oil price changes requires revision to three components: fuel costs, secondary sales revenues, and "fixed" industrial Rider F amounts.

- **Fuel Costs:** Using the costs shown above, the cost of fuel in 2009 would be expected to be approximately $0.180 million lower than set out in the application.

- **Secondary Sales Rates:** The price of secondary energy is based on oil prices. Current secondary sales prices (at the retail level) are 7.8 cents/kW.h for January-March 2009 and will not be higher than 6.3 cents/kW.h for April-June 2009 (could be lower depending on the February 11 price from the Bureau of Statistics). If one assumes that the 6.3 cents/kW.h price is carried forward to the entire year, the reduction in secondary sales revenues for the year is $0.458 million.

- **Minto Fixed Rider F**: The total revenues from the fixed Rider F charge depends on both YEC's and YECL's forecast fuel price for 2009. Yukon Energy understands YECL forecasts fuel prices for 2009 at approximately 86 cents/litre. Combining an average price for YEC of 77 cents/litre (per above), and an average 2009 secondary price of 6.5 cents/kW.h, yields a fixed Rider F of approximately $0.00, which reduces YEC's revenues by $0.170 million in 2009.

The combined impact of the above is an adverse impact on the revenues required from firm rates of approximately $0.448 million (i.e., the 2009 rate reduction proposed by YEC in this case would be only $0.886 million, instead of the proposed $1.334 million).

(f)

Yukon Energy typically utilizes NYMEX futures values, not forecasts prepared by the Energy Information Administration (EIA). Based on the latest NYMEX forecasts, the 2009 average price for March-December would be on the order of 76 cents/litre in Whitehorse, with appropriate locational adders to the other communities.

REFERENCE: **Application page 3 – 5, lines 13 – 15**

ISSUE: **Fuel and Purchased Power**

PREAMBLE:

YEC states: "For 2009, total forecast diesel generation is 1.262 GW.h, which is forecast to require 350,600 litres of diesel fuel. In addition, 100,700 litres of diesel fuel are forecast for mechanical maintenance purposes. Total forecast fuel consumption for 2009 is 451,300 litres, at an average price of $1.170/litre."

QUESTION:

a) Please provide details of how the forecast fuel requirements are calculated based on the fuel efficiencies provided at page 3-5, lines 1-4.

b) Please provide details of how the total cost of fuel is calculated based on the forecast cost of fuel set out at page 3-4, lines 16-18 and the forecast fuel requirements.

ANSWER:

(a)

Details of calculating the forecast fuel requirements for 2009 are provided below.

	Forecast diesel generation (MW.h)	Fuel efficiency	Fuel requirement (L)
	1	2	1 / 2
Peaking and Unplanned Outages			
Whitehorse	-	3.64	-
Faro	550,000	3.55	154,930
Dawson	396,000	3.71	106,739
Mayo	-	3.71	-
Planned Outages			
Line Maintenance	315,710	3.55	88,932
Mechanical Maintenance	n/a		100,700
Total	**1,261,710**		**451,301**

(b)

Details of calculating the total cost of fuel for 2009 are provided below.

	Fuel requirement (L)	**Forecast fuel price ($/L)**	**Cost of fuel ($)**
	1	2	1 X 2
Whitehorse	-	1.149	-
Faro	154,930	1.181	183,040
Dawson	106,739	1.164	124,291
Mayo	-	1.156	-
Line Maintenance	88,932	1.181	105,069
Mechanical Maintenance	100,700	1.149	115,749
Total	**451,301**		**528,149**

REFERENCE: **Application Table 3.4**

ISSUE: **Non-Fuel and Operating Costs - Labour**

PREAMBLE:

CW wishes to understand the labour costs of YEC.

Table 3.4
Employee Complement History

	Actual 2005	Actual 2006	Actual 2007	GRA 2008	GRA 2009
President	1.60	1.50	2.50	2.50	2.50
Communications	1.00	1.00	1.00	1.00	1.00
Human Resources & Info. Mgmt.	6.06	6.01	6.00	7.00	7.00
Business Development	1.08	1.00	1.00	1.00	1.00
Finance, Cust. Acctg. & Purchasing	11.05	11.49	11.63	12.81	12.81
Operations	34.82	39.43	38.60	40.20	40.10
Engineering Services	13.21	13.58	14.00	12.67	12.00
Health, Safety & Environment	1.00	1.00	3.00	3.33	3.33
Total	69.82	75.01	77.73	80.51	79.74

QUESTION:

a) What is YEC's historical vacancy rate for FTEs for 2005-2007 and the forecast rate for 2008 and 2009?

b) Have these vacancy rates been applied to the above employee complements?

c) Please discuss the reasons for any increases or decreases in employees and relate to growth in output, if possible.

d) Please provide a breakdown of the number of Operations employees by Production, Transmission, Distribution and General Operations and Maintenance.

e) Please provide a current organization chart for YEC that shows the location of each FTE in Table 3.4.

ANSWER:

(a) and **(b)**

For historical vacancy rate from 2005-2007, and the forecast rates for 2008 and 2009, please see response to YECL-YEC-1-41(a).

(c)

Please see LE-YEC-1-32.

(d)

The requested information is provided in the table below.

Breakdown of employees listed under Operations in Table 3.4

	Actual 2005	Actual 2006	Actual 2007	GRA 2008	GRA 2009
Production	13.58	14.57	11.69	13.80	13.46
Transmission & Distribution	8.04	9.00	10.00	10.00	10.00
General O&M	13.20	15.86	16.91	16.40	16.64
Totals	**34.82**	**39.43**	**38.60**	**40.20**	**40.10**

(e)

Please see response provided LE-YEC-1-32.

REFERENCE: **Application page 3-6, lines 7-12**

ISSUE: **Non-Fuel and Operating Costs - Labour**

PREAMBLE:

YEC states: "Increases in labour expense make up the remainder of the increase totaling $1.244 million, or 62%. Most of this increase occurred between 2005 and 2007 ($0.996 million). This reflects additional positions, as well as negotiated and step increases. A further $0.248 million is the forecast increase in labour expenses over 2007-2009 (about 1.9% per year). Detailed information on the labour increases by function is provided in the following sections. The Yukon Energy employee complement (FTE) is shown in Table 3.4."

QUESTION:

a) Please provide a table of the average number of FTEs per year (including the test years), the total cost of labour separated by base salaries, overtime, bonuses and the average cost and year to year increases in average cost of an FTE.

b) What is the 1.9% inflation rate of the cost of an FTE based upon?

c) Please provide copies of any labour agreements that apply to YEC's employees.

ANSWER:

(a) and **(b)**

For the table of FTEs, please see LE-YEC-1-32.

For the costs of labour separated into noted categories, please see UCG-YEC-1-38, and UCG-YEC-1-35. Note that 1.9% is not "the inflation rate of the cost of an FTE"; it is the average annual increase in labour costs from 2007 to 2009.

(c)

Please see response to YECL-YEC-1-37(a).

REFERENCE: **Application Table 3.5**

ISSUE: **Non-Fuel Operating Costs - Labour**

PREAMBLE:

CW wishes to understand the labour costs of YEC.

Table 3.5
Production Costs
($000)

	Actual 2005	Actual 2006	Actual 2007	Forecast Existing 2008	Forecast Proposed 2008	Forecast Existing 2009	Forecast Proposed 2009
Labour	$ 2,161	$ 2,418	$ 2,488	$ 2,114	$ 2,114	$ 2,179	$ 2,179
Diesel	173	189	147	191	191	194	194
Hydro	602	551	602	423	423	560	560
Wind	22	5	21	8	8	8	8
Operation Supervision	0	16	23	35	35	36	36
Total Production	$ 2,958	$ 3,179	$ 3,281	$ 2,771	$ 2,771	$ 2,977	$ 2,977

QUESTION:

a) Please discuss the cause of every year-over-year increase/decrease in each category of Production expense in Table 3.5 greater than 10%.

b) What is the inflation factor applied to each category of Production expense between 2008 and 2009? Why are these inflation factors appropriate?

ANSWER:

(a)

Please see UCG-YEC-1-40(c).

(b)

Ongoing non-labour non-fuel related operations, maintenance and administrative expenses for forecast 2009 are based on 2008 spending requirements which are then adjusted for known changes in work to be completed in the year. YEC applied a 2% inflation increase to 2009 spending. According to the Yukon Bureau of Statistics the

annual average inflation rate in Whitehorse for 2007 was 2.5%; the corporation elected to only add 2% to 2009.

REFERENCE: **Application Table 3.5**

ISSUE: **Non-Fuel and Operating Costs – Labour, Transmission**

PREAMBLE:

YEC states: "Transmission labour costs for 2008 and 2009 are well above the actual 2005-2007 levels due to having a full complement of line crew in 2008 and 2009."

QUESTION:

a) Why wasn't there a full complement of line crew during the 2005-2007 period? What was the vacancy rate for transmission FTEs during the 2005-2007 time period?

b) Why does YEC expect to have a full complement of line crew during the test period? What has changed from the 2005-2007 time period?

c) Did YEC in fact have full complement of line crew throughout 2008? If not, please provide the vacancy rate.

ANSWER:

(a), **(b)** and **(c)**

Recruitment for journey Powerline Technicians is challenging for most utilities with transmission and distribution. There is currently a shortage of skilled workers in Canada. There are additional challenges for utilities in Yukon due to geographic location.

In order to address this situation, YEC has engaged four recruitment agencies to provide assistance in recruiting qualified candidates. YEC increased the employee complement by two apprentice Powerline Technician positions in 2006 as a strategy to develop and train employees in-house. This strategy is proving to be a significant help in addressing the vacancy challenge.

Vacancy Rates and FTEs from 2005 to 2008 for transmission are as follows:

2005	11.88%	0.95	FTE's
2006	17.10%	1.71	FTE's
2007	7.84%	0.78	FTE's
2008	8.16%	0.82	FTE's

REFERENCE: **Application page 3-9, Table 3.8**

ISSUE: **Non-Fuel and Operating Costs – General Operating and Maintenance**

PREAMBLE:

CW requires details of YEC's expenses. YEC provides the following table in support of these costs:

Table 3.8
General Operating and Maintenance
($000)

				Forecast		Forecast	
	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	$ 135	$ 139	$ 116	$ 92	$ 92	$ 94	$ 94
Transportation	291	321	370	386	386	394	394
Maintenance of Company Owned Properties	230	242	290	342	342	384	384
SCADA Communication and Special Projects	71	81	72	79	79	80	80
Total General O&M	$ 727	$ 783	$ 848	$ 899	$ 899	$ 952	$ 952

QUESTION:

a) Please discuss the cause of every year-over-year increase/decrease in each category of General Operating and Maintenance in Table 3.8 greater than 10%, as well as the cause for every increase/decrease from 2007 to 2008 for each category.

b) What is the inflation factor applied to each category of General Operating and Maintenance expense between 2008 and 2009? Why are these inflation factors appropriate?

c) Please break down SCADA communication and special projects by year into these two categories.

d) Please provide a full description of the special projects undertaken in each year from 2005-2007 and those special projects forecast for the test years?

ANSWER:

(a)

Table 3.8
General Operating and Maintenance

$000s	Actual 2005	Actual 2006	Incr/(Decr) Dollars	% Increase or Decrease from Pr YR	Actual 2007	Incr/(Decr) Dollars	% Increase or Decrease from Pr YR	Proposed 2008	Incr/(Decr) Dollars	% Increase or Decrease from Pr YR	Proposed 2009	Incr/(Decr) Dollars	% Increase or Decrease from Pr YR
Labour	135	139	4	2.96%	116	(23)	-16.55%	92	(24)	-20.69%	94	2	2.17%
Transportation	291	321	30	10.31%	370	49	15.26%	386	16	4.32%	394	8	2.07%
Maintenance of Company Owned Properties	230	242	12	5.22%	290	48	19.83%	342	52	17.93%	384	42	12.28%
SCADA Communications and Special Projects	71	81	10	14.08%	72	(9)	-11.11%	79	7	9.72%	80	1	1.27%
Total General O&M	**727**	**783**	**56**	**7.70%**	**848**	**65**	**8.30%**	**899**	**51**	**6.01%**	**952**	**53**	**5.90%**

The decrease in labour costs from 2006 to 2007 and from 2007 to 2008 is due to a decrease in the time spent on maintenance due to a focus on capital projects.

The increase in annual transportation costs before 2008 is due to increased fuel price as well as increased consumption. In addition, between 2006 and 2007 an increase in spending occurred on maintenance of the fleet.

The increase in maintenance of company owned properties from 2006 to 2007 is due to the rental of additional space to store files ($30,000 annually), increased fuel costs for the Aishihik house, and the initiation of payments for fuel for community housing (see UCG-YEC-1-43(c)) which was fully implemented by 2008. Also driving the cost increase from 2007 to 2008 was painting and new flooring for the Dawson customer service office. From 2008 to 2009 increases result from continued repairs to the Dawson customer service office, new windows and a new deck for the Faro house, and painting of the trim on the Whitehorse office building.

The SCADA expenses are within 10% annual changes with the exception of 2006, when $8,000 was spent on maintenance.

(b)

Ongoing non-labour non-fuel related operations, maintenance and administrative expense forecasts for 2009 are based on 2008 spending requirements, adjusted by (a) specific changes in work to be completed in the forecast periods, and (b) a 2% inflation increase to 2008 spending. According to the Yukon Bureau of Statistics the annual average inflation rate in Whitehorse for 2007 was 2.5%; given the outlook the Corporation elected to only add 2% to 2009.

(c) and **(d)**

Please see response to YECL-YEC-1-42(g). Note there are no special projects being undertaken in the test years.

REFERENCE: **Application page 3.8, lines 10-11**

ISSUE: **Non-Fuel and Operating Costs - Administration**

PREAMBLE:

YEC provides the following table in support of its Administration expenses:

Table 3.9
Administration
($000)

	Actual 2005	Actual 2006	Actual 2007	Forecast Existing 2008	Forecast Proposed 2008	Forecast Existing 2009	Forecast Proposed 2009
Labour	$ 2,691	$ 2,846	$ 3,288	$ 3,498	$ 3,498	$ 3,605	$ 3,605
Resource Planning	1	6	21	17	17	17	17
Communications	72	87	118	87	87	105	105
Customer Accounting	164	170	189	201	201	206	206
Environmental Mgmt	46	7	30	35	35	52	52
General	873	805	597	745	745	734	734
Information Systems	213	265	341	351	351	425	425
Fish Hatchery	126	106	132	130	130	136	136
Fish Ladder	18	33	11	25	25	26	26
Safety	38	54	133	59	59	162	162
Training	177	139	142	201	201	211	211
Recruitment	170	19	181	165	165	169	169
Board of Directors	156	91	166	145	145	148	148
Union	54	27	32	25	25	26	26
Regulatory Affairs	0	6	106	93	93	57	57
Material Management	300	155	14	42	42	43	43
Contracting	26	8	6	11	11	11	11
Professional Development	16	0	4	15	15	15	15
Total Administration	$ 5,141	$ 4,824	$ 5,511	$ 5,845	$ 5,845	$ 6,148	$ 6,148

QUESTION:

a) Please discuss the cause of every year-over-year increase/decrease in each category of Administration expense in Table 3.9 greater than 10%, as well as every increase/decrease from 2007 to 2008 for each category not already documented on pages 3-11 to 3-12 of the Application.

b) What is the inflation factor applied to each category of Administration expense between 2008 and 2009? Why are these inflation factors appropriate?

c) Please provide the IT Strategic Plan, IT Security Policy and Business Impact Assessment mentioned at page 3-11, lines 15-16 of the Application.

d) How often is the periodic assessment of YEC's safety procedures mentioned at page 3-11, lines 21-23 of the Application required? Please discuss the basis for the $100,000 cost of performing this assessment.

ANSWER:

(a)

Table 3.9
Administration

	$000s	Actual 2005	Actual 2006	Incr/(Decr) Dollars	% Increase or Decrease from Pr YR	Actual 2007	Incr/(Decr) Dollars	% Increase or Decrease from Pr YR	Proposed 2008	Incr/(Decr) Dollars	% Increase or Decrease from Pr YR	Proposed 2009	Incr/(Decr) Dollars	% Increase or Decrease from Pr YR
1	Labour	2,691	2,846	155	5.76%	3,288	442	15.53%	3,498	210	6.39%	3,605	107	3.06%
2	Resource Planning	1	6	5	500.00%	21	15	250.00%	17	(4)	-19.05%	17	-	0.00%
3	Communications	72	87	15	20.83%	118	31	35.63%	87	(31)	-26.27%	105	18	20.69%
4	Customer Accounting	164	170	6	3.66%	189	19	11.18%	201	12	6.35%	206	5	2.49%
5	Environmental Mgmt	46	7	(39)	-84.78%	30	23	328.57%	35	5	16.67%	52	17	48.57%
6	General	873	805	(68)	-7.79%	597	(208)	-25.84%	745	148	24.79%	734	(11)	-1.48%
7	Information Systems	213	265	52	24.41%	341	76	28.68%	351	10	2.93%	425	74	21.08%
8	Fish Hatchery	126	106	(20)	-15.87%	132	26	24.53%	130	(2)	-1.52%	136	6	4.62%
9	Fish Ladder	18	33	15	83.33%	11	(22)	-66.67%	25	14	127.27%	26	1	4.00%
10	Safety	38	54	16	42.11%	133	79	146.30%	59	(74)	-55.64%	162	103	174.58%
11	Training	177	139	(38)	-21.47%	142	3	2.16%	201	59	41.55%	211	10	4.98%
12	Recruitment	170	19	(151)	-88.82%	181	162	852.63%	165	(16)	-8.84%	169	4	2.42%
13	Board of Dircetors	156	91	(65)	-41.67%	166	75	82.42%	145	(21)	-12.65%	148	3	2.07%
14	Union	54	27	(27)	-50.00%	32	5	18.52%	25	(7)	-21.88%	26	1	4.00%
15	Regulatory Affairs	-	6	6	100.00%	106	100	1666.67%	93	(13)	-12.26%	57	(36)	-38.71%
16	Material Management	300	155	(145)	-48.33%	14	(141)	-90.97%	42	28	200.00%	43	1	2.38%
17	Contracting	26	8	(18)	-69.23%	6	(2)	-25.00%	11	5	83.33%	11	-	0.00%
18	Professional Developmen	16	-	(16)	-100.00%	4	4	0.00%	15	11	275.00%	15	-	0.00%
	Total Administration	**5,141**	**4,824**	**(317)**	**-6.17%**	**5,511**	**687**	**14.24%**	**5,845**	**334**	**6.06%**	**6,148**	**303**	**5.18%**

1. **Labour:** The increase in 2007 relates to 2 new positions (Documentation Specialist, and Manager of Environmental Assessment and Licensing), as well as an increase in labour allocations to Information Systems, Health & Safety, and General Administration.

2. **Resource Planning:** The costs associated with Resource Planning activities fluctuate with the amount of consulting and legal services used in each of the years to meet corporate strategic goals and objectives as they relate to Resource Planning activities in a given year.

3. **Communications:** The increase in costs for 2006 and 2007 relates to additional costs to educate the public by producing brochures and advertisements. The costs for 2008 are lower as the brochures are only printed on a two year cycle.

4. **Customer Accounting:** The 2007 increase in costs was due to improved tracking of telephone costs associated with customer-related activities (as

opposed to being allocated to production activities as they were in 2005 and 2006).

5. **Environmental Management:** Costs associated with Environmental Management fluctuate with the amount of consulting fees and legal fees required to review new environmental legislation, regulations and permitting requirements. Overall these costs remain at approximately the same level as 2005 actuals.

6. **General:** Please see response to YECL-YEC-1-38(b).

7. **Information Systems:** Please see response to YECL-YEC-1-33(a).

8. **Fish Hatchery:** Please see response to UCG-YEC-1-44(d).

9. **Fish Ladder:** The increase in costs for 2006 relates in part to the First Nations Program that was introduced in 2006. The 2007 lower than average annual amounts relate to timing of government contributions.

10. **Safety:** Please see responses to YECL-YEC-1-47 and YECL-YEC-1-48.

11. **Training:** Please see responses to YECL-YEC-1-43 and YECL-YEC-1-48.

12. **Recruitment:** Please see response to YECL-YEC-1-38(c) (i).

13. **Board of Directors:** Please see response to YECL-YEC-1-38(d). In 2005, the board hired a consultant to conduct an IT Security Audit. In 2007, an Engineer was hired to provide advisory services to the board.

14. **Union:** The higher than average costs in 2005 result from services provided by consultants specializing in job evaluation. The increase in costs in 2007 results from consulting services for a chief negotiator for union negotiations.

15. **Regulatory Affairs:** Costs associated with Regulatory Affairs activities fluctuate with the amount of consulting and legal services used in each of the years to review regulatory decisions and orders. In 2007 and 2008 there was a significant amount of consulting and legal services required to review Board Orders as a

result of the Resource Plan, the YECL GRA intervention and related activities. Also see UCG-YEC-1-44(j).

16. **Material Management:** Costs for 2005 and 2006 included substantial inventory write-downs, which are not forecast for the test years, while 2007 had a small positive inventory valuation adjustment.

17. **Contracting:** Higher costs were incurred in 2005 to develop contracting and purchasing policies, procedures and best practices.

18. **Professional Development:** Professional development is a contractual obligation related to employment. The budget was used in 2005, but no activities occurred in 2006 and only limited professional development was taken in 2007. The 2008 and 2009 budgets include the expense as a required component of Yukon Energy's costs.

(b)

Please see CW-YEC-1-22(b).

(c)

The requested reports are related to the security of YEC's systems and as such are confidential and cannot be provided.

(d)

Please see YECL-YEC-1-47(b).

REFERENCE: **Application page 3-12 to 3-15**

ISSUE/SUB-ISSUE: **Insurance and Reserve for Injuries and Damages**

PREAMBLE:

YEC states: "The Reserve for Injuries and Damages ("RFID") is an account maintained as approved by the Board, in order to address uninsured and uninsurable losses as well as the deductible portion of insured losses. The reserve serves two purposes: (1) it allows for a balance to be struck between purchasing additional insurance vs. using a self-insurance type approach via the reserve; and (2) it allows the costs of unforeseen events to be smoothed out over a number of years to avoid rate instability for rate payers."

QUESTION:

a) What is the deductible or deductibles in YEC's insurance policy or policies? Has YEC conducted any reviews of its insurance policies with regard to increasing deductibles to reduce purchased insurance costs? If yes, please provide the results of these reviews.

b) How is the function of risk assessment and insurance requirements performed in YEC? What position in the organization chart is responsible for risk assessment?

c) Please provide a continuity schedule of the Reserve for Injuries and Damages account that clearly sets out all additions, charges, opening and closing balances on a yearly basis.

ANSWER:

(a)

Please see YECL-YEC-1-32 (a) and (c).

(b)

As it relates to insurance requirements, Yukon Energy employs a professional insurance brokerage house that specializes in utilities insurance. On an annual basis, the Corporation provides an update to the broker on assets, incidents and changes in operations. The broker reviews coverages and makes recommendations for enhancements. The program is then marketed to key insurance providers and the broker gets quotations on costs (if any) of enhanced coverages. Decisions on coverage reside with the Chief Financial Officer.

(c)

Please see response provided to YUB-YEC-1-6 (a) and (b) and response provided to YECL-YEC-1-29(b).

REFERENCE: **Application page 3-16, line 22 – page 3-17, line 4**

ISSUE: **Rate Base, Depreciation and Amortization**

PREAMBLE:

YEC states: "As well, the Board directed a termination of any further appropriations to Yukon Energy's Reserve for Future Removal and Site Restoration ('Salvage') which Yukon Energy had forecast at $0.533 million for 2005, until such time as the 'balance of the site removal liability account reaches $2.0 million. The account is not forecast to reach this level in the test years."

QUESTION:

a) Please provide a continuity schedule of the Reserve for Future Removal and Site Restoration account since 2005, including the test years, that clearly sets out all additions, charges, opening and closing balances on a yearly basis.

b) Please extend the continuity schedule requested to the crossover point, i.e. until the year additional appropriations may be required.

ANSWER:

(a)

Please see the table below which sets out the annual continuity for the Reserve for 2005 through 2007.

Actuals for 2008 cannot be provided. The 2008 financial statements are in the process of being finalized but are not yet complete and therefore the requested information based on final 2008 results is not available at this time. However, the Yukon Public Utilities Act sets out a requirement at section 25(1) for each utility to file a statement showing various financial information for the preceding year by March 31. Yukon Energy is currently preparing (unaudited) financial statements for this purpose and expects to meet the requirements of the Act. Once that material has been prepared, it will be possible to update and confirm the 2008 unaudited results in the form of Tab 7 to the Application. As was done in 2005, these schedules will be updated as soon thereafter as possible prior

to the May hearing. It is presently expected that these updates will be filed in late March or early April.

Yukon Energy does not forecast charges to the Reserve, so no amounts are available for 2009.

Specific charges and credits to the Reserve are numerous and cannot be provided individually.

FRSR	2005	2006	2007	
Opening Balance	(5,754,459)	(5,618,138)	(5,083,059)	
Addition/Charges	136,321	535,079	(157,587)	[1]
Closing Balance	(5,618,138)	(5,083,059)	(5,240,646)	

Notes:

(1) The net charge to the reserve consists of $96,632 in retirement-related charges, offset by $254,219 in recoveries. The recovery is for monies collected from the Federal Government for costs incurred to remediate pre-existing contamination at the Whitehorse Rapids Generating Station. The clean-up costs were originally charged against the reserve when incurred; at that time, collection from the Federal Government was uncertain. As the Corporation's efforts were successful, it is appropriate to reimburse the reserve from the monies collected.

(b)

Yukon Energy has no long-term forecast for charges to the Reserve for Future Removal and Site Restoration. The target level is not expected to be achieved in the test years or for many years thereafter.

REFERENCE: **Application page 3-18, footnote 15**

ISSUE: **Return on Rate Base**

PREAMBLE:

YEC states: "Yukon Energy's practice with respect to dividends and issuances of long-term debt is to declare dividends out of equity and issue long-term debt annually, as required in order to maintain a 60% debt: 40% equity capital structure at year end, while retaining a minimum of cash in the utility outside of amounts required to finance the ongoing capital programs."

QUESTION:

a) Has YEC set out its financial policies in written form with respect to issuance of debt, dividends and capital structure? If yes, please provide.

ANSWER:

(a)

The attached financial policy was approved by Yukon Energy's Board at the December 18, 1992 meeting. Note that at the time this policy was written, it was the intent to adjust the long-term interest rates periodically (at each GRA). However, YEC's Board later updated this component at the July 12, 1993 meeting to ensure the rates were locked-in over the long-term, in part to address a concern arising at the 1993/94 GRA.

Please see Attachment 1 to this response.

YUKON ENERGY CORPORATION

FINANCIAL POLICIES

General

The general intention of the Corporation's financial policies are to:

a) maintain a capital structure that results in a debt/ equity ratio of approximately 60/ 40; and

b) to set terms and conditions on long-term loans from Yukon Development Corporation at a level which reflects current market conditions for companies of similar size and business risk to the Corporation.

The policies are intended to be flexible to allow the Corporation to quickly respond to changes in circumstances and market conditions in a cost-effective manner.

Policies

1. Capital Structure

   (i) The Corporation shall maintain a capital structure resulting in a debt/ equity ratio, as this term is defined for the purposes of rate applications to the Yukon Utilities Board by the Corporation, of 60/ 40 at the end of each fiscal year.

   (ii) In any year when the debt/ equity ratio, as defined in (i) above, is expected to fall below 60/ 40 by December 31, the Corporation shall declare a dividend on or before December 31 of that year in an amount that would result in the Corporation's debt/ equity ratio approximating 60/ 40 at the end of that year after taking into consideration the impact of any new long-term debt provided for in (iii) below.

   (iii) In any year when the Corporation declares a dividend pursuant to this policy, the Corporation shall arrange with its shareholder (Yukon Development Corporation) to issue, on the same date, new long-term debt to the Corporation in an amount equal to the dividend and on terms and conditions then applicable to long-term debt issued to the Corporation by Yukon Development Corporation.

... /2

2. Terms and Conditions on Long-Term Loans Issued to the Corporation from Yukon Development Corporation

Long-term loans issued to the Corporation from Yukon Development Corporation shall provide for the following terms and conditions:

(i) interest is payable on a monthly basis;

(ii) interest rate shall be set as 120 basis points above the average of long-term Government of Canada Bonds as specified by the Canadian Bond Rating Service as at the last previous September 30 prior to issue of the loan; and

(iii) in any year when the Corporation submits a general rate application to the Yukon Utilities Board, the interest rate on each long-term loan issued to the Corporation by Yukon Development Corporation shall be adjusted, effective from January 1 of the first year of such rate application, to equal an interest rate set in the same manner as (ii) above.

The Corporation will need to make arrangements with YDC to carry out the above.

Application

Management is expected to follow the above mentioned policies on an annual basis. If management believes circumstances warrant deviation from the general policies stated above, approval of the Corporation's Board of Directors is required prior to deviating from those policies.

For purposes of determining the debt/ equity ratio, long-term debt shall include the current and long-term portion of long-term debt as disclosed in the Corporation's annual financial statements. Equity shall include contributed capital and retained earnings as disclosed on the Corporation's annual financial statements.

"APPROVED BY YEC'S BOARD OF DIRECTORS ON DECEMBER 18, 1992".

FIN-PLCY.SUB/92/12/16

REFERENCE: **Application page 3-19, footnote 16**

ISSUE: **Return on Rate Base – Cost of Debt**

PREAMBLE:

YEC states: "Debt issued between Yukon Development and Yukon Energy is priced based on a "spread" over long Canada bonds of 120 basis points. The long Canada bond yield during the preparation of this filing was 4.08%, supporting a rate for new long term debt of 5.28%."

QUESTION:

a) Please provide the agreement between Yukon Development and Yukon Energy that sets out this pricing arrangement.

b) Please advise as to the source of the funds that Yukon Development lends to Yukon Energy.

c) Does Yukon Development guarantee the debt of Yukon Energy?

d) Does Yukon Development "reflect down" its own debt in the same manner as Canadian Utilities reflects down debt to ATCO Electric and, hence, Yukon Electrical?

e) What was the actual interest rate and amount of debt obtained from Yukon Development in 2008 [e.g. YDC Loan #17 (5.28%) as shown in the Application Section 7, Schedule 13]?

f) Please confirm that BCUC Letter No. L-55-08 uses a 2009 forecast yield of 4.35% on long Canada bonds.

g) Please provide the terms and conditions of the Yukon Development Flexible Promissory Note (for Mayo-Dawson Project) and the 7% Flexible Term Note that sets these debt interest rates.

ANSWER:

(a)

Please see response to CW-YEC-1-26 for the YEC Board policy. YDC has been following the same policy.

(b)

YDC has earnings from interest, investments and dividends (typically interest and dividends from YEC).

(c)

YEC's only external debt is the TD Note which is guaranteed by the Yukon Government through YDC. The Minto Loans are secured by YDC (as provided for in the May 14, 2007 PPA Amendment); Minto provides certain security regarding these loans through the PPA as amended.

(d)

No.

(e)

The 2008 financial statements are in the process of being finalized but are not yet complete and therefore the requested information based on final 2008 results is not available at this time. However, the Yukon Public Utilities Act sets out a requirement at section 25(1) for each utility to file a statement showing various financial information for the preceding year by March 31. Yukon Energy is currently preparing (unaudited) financial statements for this purpose and expects to meet the requirements of the Act. Once that material has been prepared, it will be possible to update and confirm the 2008 unaudited results in the form of Tab 7 to the Application. As was done in 2005, these schedules will be updated as soon thereafter as possible prior to the May hearing. It is presently expected that these updates will be filed in late March or early April.

(f)

Confirmed.

(g)

Please see Attachment 1 and Attachment 2 to this response.

FLEXIBLE TERM NOTE

1. FOR VALUE RECEIVED, YUKON POWER CORPORATION ("YPC") promises to pay to or to the order of HER MAJESTY THE QUEEN IN RIGHT OF CANADA as represented by the Minister of Indian Affairs and Northern Development (the "Minister"), at Ottawa, Ontario, the sum of FORTY MILLION DOLLARS ($40,000,000) in lawful money of Canada as follows:

(a) subject to the payment deferral provisions of this Flexible Term Note, by payment of:

(i) $750,000 of principal on January 1, 1988, and

(ii) equal annual instalments of principal of ONE MILLION DOLLARS ($1,000,000) each on January 1 in each year, commencing January 1, 1989 and continuing until the whole of the said principal is paid hereunder;

(b) subject to the interest abatement provisions of this Flexible Term Note, with simple interest thereon or on so much thereof as shall from time to time remain unpaid at the rate of 7% per annum (without compounding) both before and after maturity, default and judgment, computed from the date hereof until December 31 of each year and payable on January 1 in the following year, commencing January 1, 1988 and continuing until the whole of the principal is paid hereunder.

2. Where, in any calendar year commencing with the entire 1987 calendar year, sales of power on WAFS based upon metered readings (or based upon reasonable estimates thereof consistently applied from year to year where it is unreasonable or impracticable to base such sales upon metered readings):

(a) are equal to or less than 200 GWh, then interest accrued for the 365 day (or in the case of the January 1, 1988 payment, for the 275 day) period ending December 31 of that year under this Flexible Term Note shall abate forever and not be payable and the instalment of principal otherwise falling due on January 1 in the following year under this Flexible Term Note shall not then be due but shall be suspended and deferred until paid in accordance with the foregoing provisions of this Flexible Term Note;

(b) are greater than 200 GWh, but less than 310 GWh, then the instalment of principal otherwise falling

due on January 1 in the following year under this Flexible Term Note shall be reduced to an amount arrived at by applying the following formula:

$$\text{(principal instalment otherwise due hereunder)} \times \frac{\text{(Actual GWh Sales - 200)}}{\text{(310 - 200)}}$$

and the interest accrued for the 365 day (or in the case of the January 1, 1988 payment for the 275 day) period ending December 31 of that year under this Flexible Term Note shall be reduced to an amount arrived at by applying the above formula but substituting interest otherwise due for the principal instalment otherwise due hereunder.

The difference between the amount of interest otherwise due, were it not for the application of the above formula, and the amount payable according to the formula shall abate forever and not be payable, and the difference between the amount of principal otherwise due, were it not for the application of the above formula and the amount payable according to the formula, shall be suspended and deferred until paid in accordance with the foregoing provisions of this Flexible Term Note. The application of this paragraph shall not require YPC to make any principal payment in any year in excess of $1,000,000.

3. In this Flexible Term Note, "WAFS" means the Whitehorse - Aishihik - Faro System for electrical power distribution owned by YPC shown outlined in blue on the attached schedule.

4. YPC covenants and agrees to provide the Minister on or before the 15th days of April, July, October and January in each year commencing July 15, 1987 and continuing until the next such date after the whole of the principal sum and interest hereunder is paid, with a statement certified by the chief financial officer of YPC as to the sales of power on WAFS for the immediately preceding 3 calendar month period. The payments required or not required to be made hereunder on January 1 in each year shall be subject to adjustment as hereafter provided.

5. YPC's auditors shall be required annually by no later than April 30 to provide a certificate to the Minister as to the sales of power on WAFS for the immediately preceding calendar year. If the Minister does not object to the certificate by June 30 of that year, the certificate shall be final and binding as to sales of power on WAFS for the immediately preceding calendar year. If the Minister does object to the certificate by June 30 of that year, the matter shall be referred to a single arbitrator in accordance with the Arbitrations Act (Ontario) whose decision shall be

final and binding. In either event, if the auditor's certificate or arbitrator's decision differs from the basis of calculation for the payment made on January 1, payment of the difference shall be made forthwith by either YPC or the Minister, as the case may be, together with simple interest at the rate of 7% per annum computed from January 1 to the date of payment.

6. YPC agrees to allow the Minister or his representatives access to the books, records and other documents of YPC at all reasonable times for the purposes of verifying the sales of power on WAFS.

7. If YPC sells, transfers or otherwise disposes of all or substantially all the hydro-electrical generating facility commonly known as Whitehorse 1, 2, 3 and 4 ("Whitehorse Facility") without the prior written approval of the Minister, which may be arbitrarily withheld, then the Minister may at any time thereafter demand payment of the entire balance due hereunder, whereupon the entire principal sum then remaining unpaid and all accrued and unpaid interest shall become due and payable notwithstanding any other provision of this Flexible Term Note.

8. In the event of damage to all or part of the Whitehorse Facility for which insurance proceeds are paid to YPC and not used to repair or replace such damage within a reasonable time with work commencing within 6 months of the damage having occurred, YPC shall be required to pay to the Minister the amount of such proceeds first, in reduction of any outstanding balance under the Term Note and then in reduction of any outstanding balance under this Flexible Term Note.

9. As security for the obligations of YPC under this Flexible Term Note, YPC agrees to grant to the Minister a first fixed and specific mortgage and charge containing all the terms of the encumbrance set forth in the schedule to the Security Agreement and such other terms as may be mutually agreed upon, on the Whitehorse Facility to be registered immediately following the registration of YPC's interest in the Whitehorse Facility.

10. The amount due hereunder may be paid in whole or in part at any time or times without notice, bonus or penalty.

11. YPC shall not be entitled to set off against any payments due by it hereunder any amounts owing or alleged to be owing to it by the Minister save and except only: (i) amounts which the Minister admits in writing to be owing by the Minister to YPC pursuant to the Purchase Agreement; (ii) amounts which a court or other competent tribunal or

arbitrator determines to be owing by the Minister to YPC pursuant to the Purchase Agreement; and (iii) reasonable costs incurred by YPC in preparing documents or doing acts as provided for in 10.03 of the Purchase Agreement. This right of set-off shall only be available to YPC following payment in full of principal and interest under the Term Note.

12. YPC covenants to provide cheque(s) for payments required under paragraph 1 hereof to the Minister prior to the close of business on the business day immediately prior to January 1 of each year.

13. In this Flexible Term Note, "Purchase Agreement" means a Purchase and Sale Agreement dated March 31, 1987 among the Minister, YPC, The Government of Yukon, as represented by the Executive Council Member responsible for the Department of Economic Development, Mines and Small Business and by the Commissioner of the Yukon and Northern Canada Power Commission. Where the first letter of a word or term is capitalized in this Flexible Term Note, such word or term shall have the meaning assigned to it in the Purchase Agreement unless the context otherwise requires. The notice provisions of the Purchase Agreement shall apply in all respects with respect to any notice or other document which may be given by one party to the other under this Flexible Term Note.

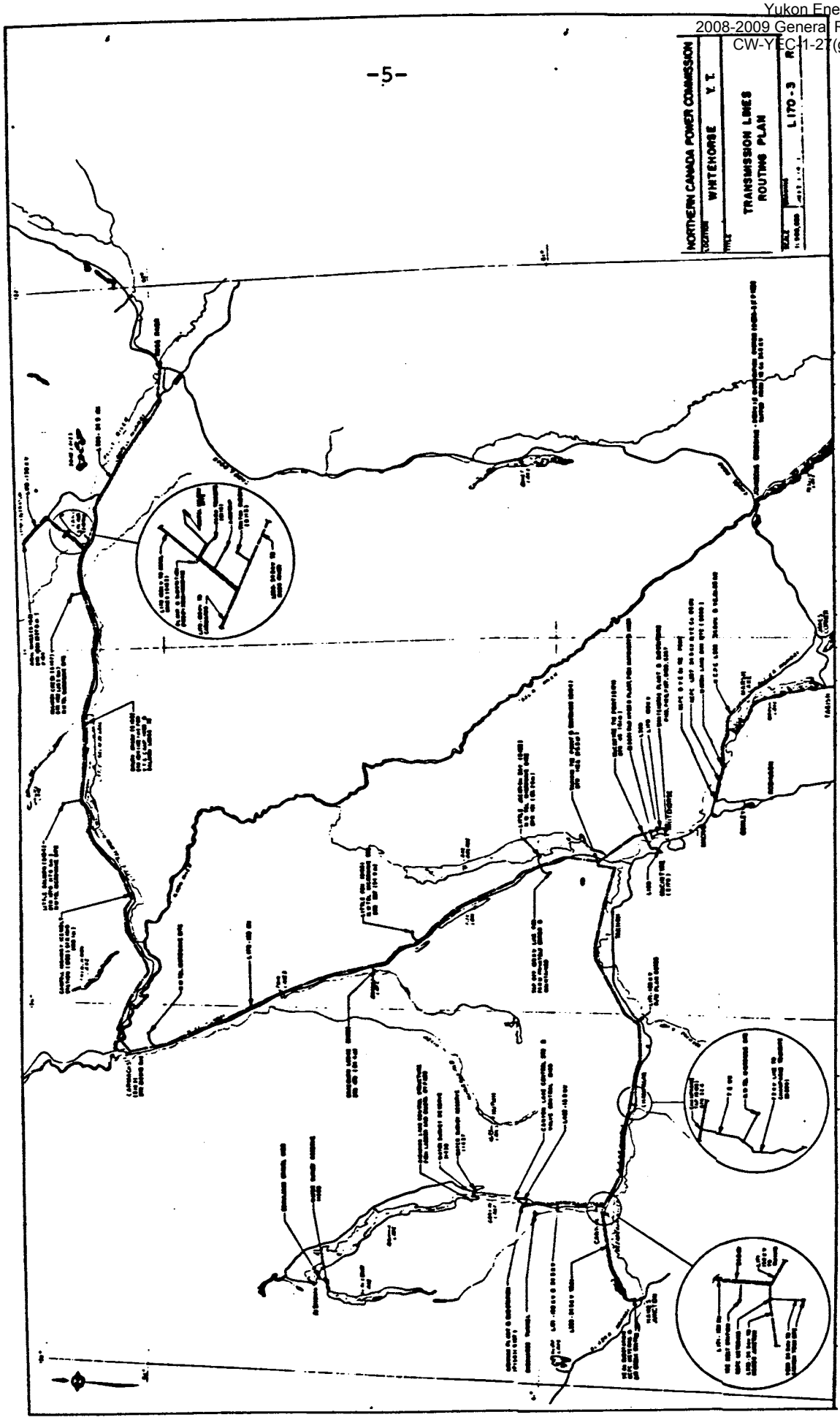
DATED this 31st day of March, 1987.

YUKON POWER CORPORATION

Per: _____

Per: _____

COPY


NORTHERN CANADA POWER COMMISSION
WHITEHORSE Y.T.
TRANSMISSION LINES
ROUTING PLAN
L 170 - 3

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AGREEMENT

This Agreement dated February 13th, 2004 is between:

YUKON DEVELOPMENT CORPORATION, a Yukon Territory corporation, having an office at 206A Lowe Street, Whitehorse, Yukon Territory, Y1A 1W6

("YDC")

and:

YUKON ENERGY CORPORATION, a Yukon Territory corporation, having an office at #2 Miles Canyon Road, Whitehorse, Yukon Territory, Y1A 6S7

("Yukon Energy")

BACKGROUND

A. YDC is a crown corporation, which has a mandate to assure a continuing and adequate supply of energy in the Yukon Territory consistent with sustainable development, and to develop and promote the development of the Yukon Territory resources on an economic and efficient basis;

B. Yukon Energy is the primary generator and transmitter of electrical energy in the Yukon Territory;

C. Yukon Energy has constructed the Project to support reliable, cost-effective, and clean supply of surplus hydro generated power to displace existing high-cost diesel generation, and to progress towards a territorial-wide electrical grid;

D. The Project is the first major infrastructure development undertaken by Yukon Energy since the 1987 transfer of assets from the Northern Canada Power Commission;

E. Under normal conditions, the Project would result in higher costs than diesel generation in the first number of years of operation, and lower costs than diesel generation for the rest of the life of the Project;

F. In order to facilitate the development of the Project YDC has:

(i) agreed to loan to Yukon Energy $18,000,000 under the Note to ensure Yukon Territory electrical ratepayers are not paying more in any year than they would otherwise have paid if the Project had not been built and Dawson City had continued to be served by diesel generation, and

(ii) advanced the YDC Contribution to Yukon energy to assist Yukon Energy in completing the Project, to offset the costs that would otherwise be incurred by Yukon Energy in constructing the Project, and to ensure that the Yukon Territory rate payers do not pay for any costs incurred by Yukon Energy in completing the Project which are the result of Yukon Energy building capacity in executing major projects;

G. YDC has advanced the Other Contribution to secure property that may at some time in the future be required for relocation of the Dawson diesel generators;

H. Yukon Energy wishes to grant the Note to YDC as evidence of the $18,000,000 loan which Note provides for the repayment of the $18,000,000 loan and interest thereon consistent with the principles set out in Recital F; and

I. Yukon Energy and YDC have entered into this Agreement to set out their agreements with respect to the YDC Contribution and the Other Contribution.

AGREEMENTS

The Parties agree as follows:

PART 1
DEFINITIONS AND INTERPRETATION

1.1 Definitions. In this Agreement the following terms have the following meanings:

(a) **"Agreement"** means this Agreement;

(b) **"Business Day"** means any day other than a Saturday, Sunday, or a statutory holiday in the Yukon Territory;

(c) **"Note"** has the meaning set out in Section 1.2;

(d) **"Other Contribution"** has the meaning set out in Section 2.2;

(e) **"Project"** means the approximately 223 km, 69 kV electrical transmission line project owned by Yukon Energy from the Mayo Hydro Generating Substation to the Calliston Substation;

(f) **"YDC Contribution"** means the sum of $5,750,000 contributed by YDC to the capital of Yukon Energy; and

(g) **"YUB"** means the Yukon Utilities Board.

1.2 Capitalized Terms. Capitalized terms used and not defined in this Agreement have the meanings ascribed to them in the promissory note (the "Note") to be issued by Yukon Energy to YDC, a copy of which is attached to this Agreement as Schedule 1.

1.3 Headings. The headings are inserted for convenience of reference only and will not affect the construction or interpretation of this Agreement.

1.4 Governing Law. This Agreement will be governed by, and construed under the laws of the Yukon Territory.

1.5 Invalidity of Any Provision. If any covenant, obligation, or provision contained in this Agreement is invalid or unenforceable, the remainder of this Agreement will not be affected and each covenant, obligation, or provision of this Agreement will separately be valid and enforceable to the fullest extent permitted by law.

1.6 Amendments. This Agreement may only be amended from time to time in writing and any such amendment may be evidenced by a document signed by an authorized officer of each of the Parties.

1.7 Included Words. Whenever the singular or the masculine is used the same will be considered to include the plural or the feminine or the body corporate where the context or the Parties so require.

1.8 Schedules. The following Schedules are attached to and form part of the Agreement:

(a) Schedule 1 – Note.

PART 2
YDC FUNDING FOR THE PROJECT

2.1 YDC Contribution. Yukon Energy hereby acknowledges the advance to Yukon Energy by YDC of the YDC Contribution as a contribution to Yukon Energy's capital and not as a loan. Yukon Energy will have no obligation to repay the YDC contribution, it being the intent of the Parties that the YDC Contribution act to offset the costs Yukon Energy incurs in constructing the transmission line. For greater certainty, YDC has provided the YDC Contribution to Yukon Energy to fund in the first instance any capital costs incurred by Yukon Energy in developing the Project which are not allowed by the YUB as part of Yukon Energy's rate base, with any remainder used to fund a no-cost contribution towards Yukon Energy's rate base.

2.2 Other Contribution. Yukon Energy hereby acknowledges the advance to Yukon Energy by YDC of the sum of $50,000 (the "Other Contribution"), which Yukon Energy shall pay to YDC without interest on the 10th Business Day after Yukon Energy installs diesel generators at the Calliston Substation.

2.3 $18,000,000 Loan. Yukon Energy hereby acknowledges the advance to Yukon Energy by YDC of the sum of $18,000,000 which loan Yukon Energy hereby evidences and agrees to repay by issuing to YDC the Note. Upon execution and delivery of this Agreement the Parties will execute and deliver the Note.

PART 3
GENERAL

3.1 Notices. In this Agreement:

(a) any notice or communication required or permitted to be given under the Agreement will be in writing and will be considered to have been given if delivered by hand, transmitted by facsimile transmission or mailed by prepaid registered post in Canada, to the address or facsimile transmission number of each Party set out below:

(i) if to YDC:

Yukon Development Corporation
206A Lowe Street
Whitehorse, YT Y1A 1W6

Attention: President

Fax No. (867) 393-7071

(ii) if to Yukon Energy:

Yukon Energy Corporation
#2 Miles Canyon Road
Whitehorse, YT Y1A 6S7

Attention: President

Fax No. (867) 393-5323

or to such other address or facsimile transmission number as a Party may designate in the manner set out above;

(b) notice or communication will be considered to have been received:

(i) if delivered by hand during business hours on a Business Day, upon receipt by a responsible representative of the receiver, and if not delivered during business hours, upon the commencement of business on the next Business Day;

(ii) if sent by facsimile transmission during business hours on a Business Day, upon the sender receiving confirmation of the transmission, and if not transmitted during business hours, upon the commencement of business on the next Business Day; and

(iii) if mailed by prepaid registered post in Canada, upon the fifth Business Day following posting; except that, in the case of a disruption or an impending or threatened disruption in postal services every notice or communication will be delivered by hand or sent by facsimile transmission.

3.2 Assignment by Yukon Energy. Yukon Energy may not to assign this Agreement, except with the prior written consent of YDC.

3.3 Assignment by YDC. YDC may assign this Agreement without the consent of Yukon Energy.

3.4 Enurement. This Agreement and all its provisions will enure to the benefit of and be binding upon the Parties, their successors and permitted assigns.

3.5 Set-off. Yukon Energy will not be entitled to set-off against any payments payable to YDC under this Agreement any amounts owing or alleged to be owing by YDC to Yukon Energy.

Each of the Parties has executed this Agreement at Whitehorse, Yukon Territory on February 13th, 2004.

YUKON DEVELOPMENT CORPORATION

By:

Per: _____
Authorized Signatory

YUKON ENERGY CORPORATION

By:

_____
Authorized Signatory

COPY

SCHEDULE 1

PROMISSORY NOTE

September 6, 2003 $18,000,000

Due in installments

1. Promise to Pay.

1.1 Effective as of September 6, 2003, in consideration of the advance by way of loan of the sum of $18,000,000 from Yukon Development Corporation ("YDC") to Yukon Energy Corporation ("Yukon Energy"), Yukon Energy promises to pay to YDC the principal amount of, and interest on, $18,000,000 in lawful money of Canada as follows:

(a) annual installments of principal payable as follows:

(i) $143,000 on December 31, 2003;

(ii) 39 equal annual installments of principal of $450,000 each, payable on December 31 of each calendar year commencing on December 31, 2004 up to and including December 31, 2042; and

(iii) $307,000 on December 31, 2043.

(b) subject to Sections 1.2 and 1.3 below, interest calculated and payable as follows:

(i) interest at the Interest Rate calculated annually, not in advance, on the principal amount from time to time remaining unpaid as of December 31 of each calendar year of this Note prior to the payment of principal in that calendar year, such interest to accrue from and including the effective date of this Note to December 31, 2003 and thereafter during each calendar year of this Note from and including January 1 to December 31;

(ii) interest calculated as set out in Section 1.1(b)(i) above and including additional interest calculated under Section 1.3 below, will be payable on or before March 31 of each calendar year of this Note commencing on or before March 31, 2004, up to and including March 31, 2044.

1.2 **Limitation on Interest.** Notwithstanding Section 1.1(b), the amount of interest payable in each calendar year of this Note will not be more than the Maximum Interest Payable (as defined below), determined as of December 31 of each calendar year of this Note, calculated on or before March 31 of the following year, and if the amount of interest payable does exceed the Maximum Interest Payable then the terms set out in Section 3.1 below will apply. For greater certainty, if the Maximum Interest Payable under this Note is a negative number then YDC will pay to Yukon Energy (together with additional

interest payable under Section 1.3.) the positive dollar amount of that number on or before March 31 of the next calendar year.

1.3 **Additional Interest.** In addition to any interest payable under Sections 1.1 and 1.2, interest at the Interest Rate will be payable on the amount of interest, if any, payable accruing from December 31 of each year until the date that interest is paid.

1.4 **Sample Calculation.** A sample calculation of the Maximum Interest Payable is attached to this Note as Schedule 1.

1.5 **Application of Payments.** Payments received will be applied firstly in payment of unpaid interest and the balance, if any, in reduction of principal.

2. Definitions and Interpretation.

2.1 **Definitions.** In this Note the following terms have the following meanings:

(a) **"Avoided Diesel Capital Cost"** means the depreciation and return on capital on the Diesel Plant estimated to be avoided by the Project each calendar year as set out in Schedule 2;

(b) **"Avoided Diesel Costs"** means for each calendar year of this Note the sum of the:

(i) Avoided Diesel Capital Cost for that calendar year,

(ii) Avoided Diesel Fuel Cost for that calendar year, and

(iii) Avoided Diesel Operating and Maintenance Cost for that calendar year;

(c) **"Avoided Diesel Fuel Cost"** means for each calendar year of this Note the product of:

(i) Total Firm Energy for that calendar year divided by 3.8 kW.h per litre,

(ii) multiplied by the Mean Diesel Fuel Price for that calendar year;

(d) **"Avoided Diesel Operating and Maintenance Cost"** means for each calendar year of this Note the product of the Total Firm Energy for that calendar year multiplied by the Variable Diesel Operating and Maintenance Cost for that calendar year;

(e) **"Business Day"** means any day other than a Saturday, Sunday, or a statutory holiday in the Yukon Territory;

(f) **"Calliston Substation"** means Yukon Energy's electrical substation located at Dawson City, Yukon Territory;

(g) **"Diesel Plant"** means Yukon Energy's diesel powered electrical generating plant located at Dawson City, Yukon Territory;

(h) **"Fuel Price Adjustment"** means for each calendar year of this Note the product of:

(i) the Total Firm Energy for that calendar year divided by 3,ß kW.h per litre,

(ii) multiplied by the Fuel Price Variance for that calendar year;

(i) **"Fuel Price Variance"** means for each calendar year of this Note:

(i) the Mean Diesel Fuel Price,

(ii) less 0.3278 dollars per litre;

(j) **"GRA Years"** means the first two years of Yukon Energy's first General Rate Application to the YUB following 2003;

(k) **"Greenhouse Gas Credit Revenue"** means for each calendar year of this Note all revenue and credits received for that calendar year by Yukon Energy related to reductions in greenhouse gas emissions from the Project, net of any incremental costs to generate such revenue and credits;

(l) **"Incremental Retail Sales"** means in each calendar year of this Note all revenue received in that calendar year by Yukon Energy from non-secondary electricity sales to retail customers from the Project (excluding electricity sales to non-secondary retail customers served through the Calliston Substation) where these customers had not been previously serviced by Yukon Energy or Yukon Electrical Company Limited, net of any incremental costs to generate such sales;

(m) **"Incremental Transmission Costs"** means in each calendar year of this Note the sum of the:

(i) Project Equity Return for that calendar year,

(ii) Project Depreciation for that calendar year,

(iii) Project Operating and Maintenance Expense for that calendar year, and

(iv) Other Project Interest;

(n) **"Interest Rate"** means in each calendar year of this Note that annual rate of interest equal to 6.55%;

(o) **"Maximum Interest Payable"** means for each calendar year of this Note the sum of:

(i) the Avoided Diesel Costs for that calendar year,

(ii) less the Incremental Transmission Costs for that calendar year,

(iii) plus the Other Benefits for that calendar year,

(iv) less, for all calendar years prior to the GRA years, the Fuel Price Adjustment, and

(v) plus in each of the GRA years, one-half of the sum of the Fuel Price Adjustment for all calendar years from 2003 to the year prior to the GRA years;

(p) **"Maximum Interest Payable Statement"** has the meaning set out in Section 3.2;

(q) **"Mayo Hydro Generating Station"** means Yukon Energy's hydroelectric generating station located at Mayo, Yukon Territory;

(r) **"Mean Diesel Fuel Price"** means for each calendar year of this Note the arithmetic mean of twelve monthly price quotes received by Yukon Energy each calendar month during that calendar year for the delivered cost per litre of P40 diesel fuel delivered to Yukon Energy in Dawson City;

(s) **"Mid Year Other Debt"** means for each calendar year of this Note the sum, if any, of:

(i) the Mid Year Rate Base for that calendar year,

(ii) less the Project Equity for that calendar year,

(iii) less the Mid Year Rate Base Debt for that calendar year;

(t) **"Mid Year Rate Base"** means for each calendar year of this Note the mid-year rate base for the Project in that calendar year as included in Yukon Energy's annual filings to the YUB;

(u) **"Mid Year Rate Base Debt"** means for each calendar year of this Note that amount of Yukon Energy's mid year capitalization for that calendar year attributable to this Note as included in Yukon Energy's filings to the YUB;

(v) **"Note"** means this Promissory Note;

(w) **"Other Benefits"** means for each calendar year of this Note the sum of the:

(i) Green House Gas Credit Revenue for that calendar year,

(ii) Incremental Retail Sales for that calendar year,

(iii) Secondary Sales for that calendar year, and

(iv) Stewart Crossing Wholesale Revenue for that calendar year;

(x) **"Other Project Interest"** means the product of the:

(i) Mid Year Other Debt, multiplied by,

(ii) Interest Rate;

(y) **"Parties"** means Yukon Energy and YDC and **"Party"** means any one of them;

(z) **"Project"** means the approximately 223 km, 69 kV electrical transmission line project owned by Yukon Energy from the Mayo Hydro Generating Substation to the Calliston Substation;

(aa) **"Project Depreciation"** means the annual depreciation cost recorded by Yukon Energy on the Project (net of contributions), including the annual appropriation for removal and restoration, as included in Yukon Energy's annual filings to the YUB;

(bb) **"Project Equity"** means for each calendar year of this Note the lesser of:

(i) 40% of the Mid Year Rate Base for that calendar year, and

(ii) the Mid Year Rate Base less the Mid Year Rate Base Debt for that calendar year;

(cc) **"Project Equity Return"** means for each calendar year of this Note the product of:

(i) the Project Equity for that calendar year,

(ii) multiplied by Yukon Energy's rate of return on equity last approved by the YUB;

(dd) **"Project Operating and Maintenance Expense"** means for each calendar year of this Note the sum of:

(i) the annual Project operating and maintenance costs for that calendar year, and

(ii) all other Project non-capitalized expenses for that calendar year;

(ee) **"Secondary Sales"** means in each calendar year of this Note revenues in that calendar year from electricity sales from the Project that are charged at secondary rates approved by the YUB, net of any incremental cost to generate such sales;

(ff) **"Stewart Crossing Wholesale Revenue"** means in each calendar year of this Note the total revenue received by Yukon Energy in that calendar year from electricity wholesale sales from the Project to Stewart Crossing, Yukon Territory, net of any incremental costs to generate such sales;

(gg) **"Total Firm Energy"** means the kW.h of electricity delivered from the Calliston Substation for sales other than Secondary Sales based on metered readings (or based upon reasonable estimates thereof consistently applied from year to year where it is unreasonable or impractical to base such measurement upon metered readings);

(hh) **"Variable Diesel Operating and Maintenance Cost"** means the rate per kW.h of electricity utilized by the Yukon Energy for variable diesel operating and maintenance costs other than fuel costs which is $0.016 per kW.h of electricity until such time as the YUB approves a different variable diesel operating and maintenance cost for the purpose of setting retail electricity rates; and

(ii) **"YUB"** means the Yukon Utilities Board.

2.2 **Headings.** The headings are inserted for convenience of reference only and will not affect the construction or interpretation of this Note.

2.3 **Governing Law.** This Note will be governed by, and construed under the laws of the Yukon Territory.

2.4 **Invalidity of Any Provision.** If any covenant, obligation, or provision contained in this Note is invalid or unenforceable, the remainder of this Note will not be affected and each covenant, obligation, or provision of this Note will separately be valid and enforceable to the fullest extent permitted by law.

2.5 **Amendments.** This Note may only be amended from time to time in writing and any such amendment may be evidenced by a document signed by an authorized officer of each of the Parties.

2.6 **Included Words.** Whenever the singular or the masculine is used the same will be considered to include the plural or the feminine or the body corporate where the context or the Parties so require.

2.7 **Schedules.** The following Schedules are attached to and form part of this Note:

(a) Schedule 1 – Sample Calculation of Maximum Interest Payable; and

(b) Schedule 2- Avoided Diesel Capital Cost.

3. Maximum Interest Payable.

3.1 **Interest Abatement.** The amount of interest, if any, which is payable under this Note as a result of the Interest Rate exceeding the Maximum Interest Payable will abate forever and will not be payable by Yukon Energy to YDC, it being the clear intention of the Parties that the amount of interest payable by Yukon Energy as a result of the Interest Rate payable by Yukon Energy to YDC will not exceed the Maximum Interest Payable.

3.2 **Maximum Interest Payable Statement.** Yukon Energy covenants and agrees to provide to YDC on or before March 31 in each year of the Note commencing March 31, 2004 and continuing until the whole of the principal and interest under the Note is paid, with a statement (the "Maximum Interest Payable Statement") certified by the Chief Financial Officer of Yukon Energy as to the Maximum Interest Payable for the preceding calendar year.

3.3 **Dispute.** If YDC does not object in writing to the Maximum Interest Payable Statement within 30 days of receipt of such statement from Yukon Energy the Maximum Interest Payable Statement will be final and binding on YDC. If YDC does object in writing to the Maximum Interest Rate Statement within such 30 days the Parties will negotiate in good faith a resolution to the dispute for a period of 15 days. If the dispute is not resolved by the Parties the matter will be referred to a single arbitrator under the ***Arbitration Act (Yukon Territory)***, whose decision will be final and binding on the Parties. If the arbitrator's decision differs from the Maximum Interest Rate Statement, payment of the difference will be made forthwith by either YDC or Yukon Energy, as the case may be, together with simple interest at the Interest Rate computed from January 1 to the date of payment.

3.4 **Access to Books and Records.** Yukon Energy agrees to allow YDC and YDC's representatives access to the books, records, and other documents of Yukon Energy at all reasonable times for the purpose of verifying the Maximum Interest Payable.

4. General.

4.1 **Disposition of Project.** If Yukon Energy sells, transfers, or otherwise disposes of the Project without the prior written approval of YDC, which may be arbitrarily withheld, then YDC may, at any time thereafter, demand payment of the entire principal and interest owing under the Note, whereupon the entire principal and interest then remaining will become due and payable notwithstanding any other provision of this Note.

4.2 **Insurance Proceeds.** If there is damage to all or part of the Project for which insurance proceeds are paid to Yukon Energy and which are not used to repair or replace such damage within a reasonable time with work commencing within six months of the damage having occurred, Yukon Energy will be required to pay to YDC the amount of such proceeds first, in reduction of any outstanding interest under the Note and then in reduction of any outstanding principal under the Note.

4.3 **Prepayment.** The principal amount due under the Note may be paid by Yukon Energy in whole or in part at any time or times without notice, bonus, or penalty.

4.4 **Default.** Upon default in payment of any payment when due under this Note, the entire unpaid balance of the principal amount and accrued interest will become immediately due and payable without notice or demand and the undersigned covenants to pay interest on it and on subsequent overdue interest at the Interest Rate, both before and after judgment, until paid in full. The covenants to pay interest will not merge on the taking of a judgment or judgments with respect to any of the obligations stipulated for in this Note.

4.5 **Interest Act of Canada.** For the purposes of the *Interest Act* (Canada), whenever any interest is calculated in respect of this Note on the basis of a period of time other than a calendar

year, the annual rate of interest to which each rate of interest determined pursuant to such calculation is equivalent is such rate as so determined multiplied by the actual number of days in the calendar year in which the same is to be ascertained and divided by the number of days used in the basis for such determination.

4.6 **Notices.** In this Note:

(a) any notice or communication required or permitted to be given under this Note will be in writing and will be considered to have been given if delivered by hand, transmitted by facsimile transmission or mailed by prepaid registered post in Canada, to the address or facsimile transmission number of each Party set out below:

(i) if to YDC:

206A Lowe Street
Whitehorse, YT Y1A 1W6

Attention: President
Fax No.: (867) 393-7071

(ii) if to Yukon Energy:

#2 Miles Canyon Road
Whitehorse, YT Y1A 6S7

Attention: President
Fax No.: (867) 393-5323

or to such other address or facsimile transmission number as any Party may designate in the manner set out above; and

(b) notice or communication will be considered to have been received:

(i) if delivered by hand during business hours on a Business Day, upon receipt by a responsible representative of the receiver, and if not delivered during business hours, upon the commencement of business on the next Business Day;

(ii) if sent by facsimile transmission during business hours on a Business Day, upon the sender receiving confirmation of the transmission, and if not transmitted during business hours, upon the commencement of business on the next Business Day; and

(iii) if mailed by prepaid registered post in Canada, upon the fifth Business Day following posting; except that, in the case of a disruption or an impending or threatened disruption in postal services every notice or

communication will be delivered by hand or sent by facsimile transmission.

4.7 **Assignment by Yukon Energy.** Yukon Energy may not to assign this Note, except with the prior written consent of YDC.

4.8 **Assignment by YDC.** YDC may assign this Note without the consent of Yukon Energy.

4.9 **Enurement.** This Note and all its provisions will enure to the benefit of and be binding upon the Parties, their successors and permitted assigns.

4.10 **Yukon Energy Waiver.** Yukon Energy waives demand and presentment for payment, notice of non-payment, protest, notice of protest, notice of dishonour, bringing of suit, and diligence in taking any action.

4.11 **Set-off.** Yukon Energy will not be entitled to set-off against any payments payable to YDC under this Note any amounts owing or alleged to be owing by YDC to Yukon Energy.

Executed at Whitehorse, Yukon Territory, on February 13th, 2004.

YUKON ENERGY CORPORATION

Per: _____
Authorized Signatory

Per: _____
Authorized Signatory

YUKON DEVELOPMENT CORPORATION

Per: _____
Authorized Signatory

Per: _____
Authorized Signatory

Schedule 1

Sample Calculation of Maximum Interest Rate

Sample calculations of the maximum interest rate for four representative years. This calculation ignores the partial year 2003.

	variable name	YEAR 1	YEAR 2	YEAR 3	YEAR 4
Assumptions for the purposes of the sample calculation					
GRA year?		no	yes	yes	no
Prior to a GRA year?		yes	no	no	no
Avoided Diesel Capital Cost	a	$314,000	$321,000	$312,000	$302,000
Greenhouse Gas Credit Revenue	b	$5,000	$5,000	$5,000	$5,000
Incremental Retail Sales	c	$6,000	$6,100	$6,200	$6,300
Interest Rate	d	6.55%	6.55%	6.55%	6.55%
Mean Diesel Fuel Price	e	$0.45/litre	$0.50/litre	$0.52/litre	$0.53/litre
Mid Year Rate Base	f	$30,000,000	$29,010,000	$28,020,000	$27,030,000
January 1 debt under this note	g	$17,857,000	$17,407,000	$16,957,000	$16,507,000
December 31 debt under this note	h	$17,407,000	$16,957,000	$16,507,000	$16,057,000
Project Depreciation	i	$990,000	$990,000	$990,000	$990,000
Project Operating and Maintenance Expense	j	$130,000	$135,000	$140,000	$145,000
Secondary Sales	k	$20,000	$22,000	$24,000	$25,000
Stewart Crossing Wholesale Revenue	l	$200,000	$202,000	$204,000	$207,000
Total Firm Energy (kWh)	m	14,000,000	14,150,000	14,300,000	14,500,000
Variable Diesel Operating and Maintenance Cost	n	$0.016/kWh	$0.020/kWh	$0.020/kWh	$0.020/kWh
Yukon Energy's Rate of Return on Equity last approved by the YUB	o	9%	10%	10%	10%

	variable name	formula	YEAR 1	YEAR 2	YEAR 3	YEAR 4
Calculations						
Mid Year Rate Base Debt[1]	p	(g + h) / 2	$17,632,000	$17,182,000	$16,732,000	$16,282,000
Avoided Diesel Fuel Cost	q	m / 3.8 * e	$1,657,895	$1,861,842	$1,956,842	$2,022,368
Avoided Diesel Operating and Maintenance Costs	r	m * n	$224,000	$283,000	$286,000	$290,000
Avoided Diesel Costs	s	a + q + r	$2,195,895	$2,465,842	$2,554,842	$2,614,368
Fuel Price Variance	t	e – 0.3278	$0.1222	$0.1722	$0.1922	$0.2022
Fuel Price Adjustment	u	m / 3.8 * t (0 if not prior to the GRA years)	$450,211	$0	$0	$0
Sum of all prior year fuel price adjustments	v	sum of t for all prior years (0 if not GRA year)	$0	$450,211	$450,211	$0
Project Equity	w	the lesser of (f * 40%) and (f – p)	$12,000,000	$11,604,000	$11,208,000	$10,748,000
Project Equity Return	x	w * o	$1,080,000	$1,160,400	$1,120,800	$1,074,800
Mid Year Other Debt	y	the greater of (f – w – p) and 0	$368,000	$224,000	$80,000	$0
Other Project Interest	z	y * d	$24,104	$14,672	$5,240	$0
Incremental Transmission Costs	aa	x + i + j + z	$2,224,104	$2,300,072	$2,256,040	$2,209,800
Other Benefits	bb	b + c + k + l	$231,000	$235,100	$239,200	$243,300
Maximum Interest Payable	cc	s – aa + bb – u + v/2	-$247,420	$625,975	$763,107	$647,868
Interest Otherwise Due	dd	g * d	$1,169,634	$1,140,159	$1,110,684	$1,081,209
Interest Payable[2]		lesser of cc and dd	-$247,420	$625,975	$763,107	$647,868

1 Mid Year Rate Base Debt calculation is illustrative for the sample years – actual Mid Year Rate Base Debt in Section 2.1(u) is the value reported in Yukon Energy's annual filings to the YUB.

2 In Year 1 of the above example, Yukon Development would pay to Yukon Energy $247,420. In year 2 Yukon Energy would pay to Yukon Development $625,975 in interest. In year 3, Yukon Energy would pay to Yukon Development $763,107 in interest. In year 4, Yukon Energy would pay to Yukon Development $647,868 in interest.

Schedule 2

Avoided Diesel Capital Cost

Year	Avoided Diesel Capital Cost
2003	$82,000
2004	$314,000
2005	$321,000
2006	$312,000
2007	$302,000
2008	$293,000
2009	$284,000
2010	$275,000
2011	$265,000
2012	$429,000
2013	$528,000
2014	$527,000
2015 and all years thereafter	$651,000

REFERENCE: **Application Section 7.0, Schedule 13**

ISSUE: **Financial Schedules**

PREAMBLE:

CW wishes to better understand YEC's calculation of mid-year cost of debt.

QUESTION:

a) For all the issues listed in Schedule 13, please provide detailed calculations as to how the mid-year cost of debt is calculated.

b) Is YEC's method of calculating mid-year cost of debt consistent with the method employed by YECL in its general rate application? If not, please provide YEC's reason(s) for any inconsistencies.

c) Why hasn't YEC calculated any mid-year interest in 2009 for YDC Loan #18 (5.28%)? By the mid-year convention, shouldn't YEC include half the annual interest charges?

d) Why hasn't YEC paid any principal in most years for the following issues: YDC Loan #12 (5.88%), YDC Loan #13 (6.03%), YDC Loan #14 (5.40%), YDC Mayo-Dawson Note (6.55%), YDC Loan #15 (5.34%), YDC Loan #16 (5.28%) and YDC Loan #17 (5.28%)?

ANSWER:

(a)

Mid-year Cost of Debt is calculated as the ratio of Total Cost of Interest (line no.26 in Schedule 13) to Mid-Year Long-Term Debt Balance (line no.14). Total Cost of Interest is the sum of annual interest expenses for respective loans (lines no.15-25). Mid-Year Long-Term Debt Balance is the average of the current and previous year-end debt balances (lines no. 12-13). Current year-end balance is calculated as the sum of current year-end balances of respective loans (lines no. 1-11).

For actual calculations please see CW-YEC-1-32 Attachment 1.

(b)

YEC's method of calculating mid-year cost of debt is different from the method employed by YECL in its general rate application for the reason explained below.

YECL's calculation of cost of debt is not based on interest expenses to be actually incurred in the test years but is based instead on a calculation that takes the average cost rate as at January 1 plus the average cost rate at December 31 divided by 2. This calculation reaches back in time (by using the January 1 average cost rate, which is effectively the cost for the previous year) as opposed to looking at interest costs associated with long term debt during the actual year in question. Yukon Energy believes its approach is more accurate.

(c)

YDC Loan #18 becomes effective on December 31, 2009 and has no interest payable in 2009. It is a part of the year-end debt balance.

Any other approach would erroneously indicate that interest is payable on this note in 2009, which is not correct.

(d)

The Mayo-Dawson note (6.55%) does have a principal repayment each year, equal to $0.45 million.

YDC Loan 12 (5.88%) is a long-term issuance that provided for principal payments starting 2007.

All other YDC loans have terms that do not include ongoing principal repayment (i.e. they provide for "bullet" payments at the date the loan is terminated).

REFERENCE: **Application Section 5.2.1**

ISSUE: **Capital Projects**

PREAMBLE:

CW wishes to better understand YEC's proposed capital projects.

QUESTION:

a) For each of the major projects over $1 million listed in Section 5.2.1, please provide comprehensive business cases to the level of detail provided in YECL business cases during the YECL 2008/09 GRA.

ANSWER:

(a)

The requested comprehensive information is provided in Section 5.2.1 separately for each of these five projects, with reference in some cases to earlier reports to the Board.

As noted in Section 5.2.1, the business cases for four of these projects has been previously reviewed and recommended by the YUB in the Resource Plan Hearing (e.g, CSTP, Mirrlees Diesel rebuilds at Whitehorse and Faro, and Aishihik 3rd Turbine) and the Part 3 hearing regarding the CSTP project (CSTP Stage 1 and also Aishihik 3rd Turbine update). These earlier reviews addressed rationale, options, initial cost estimates and benefits, and potential impacts on ratepayers. No similar Board review had occurred for any of the capital projects proposed in the YECL GRA. Updated information provided in Section 5.2.1 has not fundamentally changed the earlier rationale and business case for each of these projects.

Section 5.2.1.2 addresses the comprehensive business case for the Minto Diesels, which the Board had not previously recommended. Please see also discussion of Minto Diesels in YUB-YEC-1-36.

REFERENCE: **Application Section 5**

ISSUE: **Capital Projects**

PREAMBLE:

CW wishes to better understand YEC's proposed capital projects.

QUESTION:

a) To the extent not covered in the preceding information request, and if any new information is available, please provide detailed updates or YEC's plans to develop new renewable generation, including for each project: i) the potential capacity; ii) forecast costs of construction, iii) timelines and iv) money forecast to be spent within the test years.

ANSWER:

(a)

The main renewable energy project under review at the present time is Mayo B. The YESAB submission with respect to this project notes that it comprises an approximately 10-12 MW powerhouse at a cost most recently estimated at $120 million. The project is targeted for a late 2011 in-service date, and the GRA budget for the test years is $1.7 million 2008 and $6.5 million in 2009.

Outside of this project, see YUB-YEC-1-38(a). No other renewable energy projects presently have targeted in-service dates.

REFERENCE: **YEC Technical presentation January 6, 2009, Slide 29; Application, page 5-20**

ISSUE: **Capital Projects**

PREAMBLE:

In the referenced slide YEC states: "No other industrial loads forecast for test years; further mine loads expected after test years" and at page 5-20 of the Application YEC states: "Mayo B has been identified as a potential priority near term hydro generation expansion opportunity to displace about 38 GW.h/yr. of baseload diesel generation that would otherwise be required when additional industrial loads such as the Keno Hill and/or Carmacks Copper mines connect to the grids."

QUESTION:

a) When is this additional industrial load currently forecast to be connected to the YEC system?

b) Please provide the latest forecast information on which specific industrial loads are anticipated, when each is expected to be connected to the grids and quantify the anticipated load or power requirements for each.

c) What will be the effect of this additional industrial load on YEC's energy surplus and operating reserves? Aside from the information cited above from page 5-20 of the Application, what steps is YEC taking to address any requirement for additional base load and peaking generating facilities?

d) What types of generation is forecast to be installed? If more than one type of generation is contemplated, what would be the capital cost and construction lead time for each type of generation?

ANSWER:

(a) and **(b)**

Please see Tab 2, pages 2-5 to 2-7 which notes as follows with regard to service to Western Copper and Keno Hill:

- **Western Copper** - As noted in the GRA filing, Western Copper has provided forecast information to YEC which currently projects an in service date of 2011, and an expected annual requirement averaging approximately 4 GW.h per month (48 GW.h per year) with a mine life of at least six years. This information from Western Copper as stated in Tab 2 of the Application has not been modified to date; current economic conditions might well lead to some delay in this project's financing and construction.

- **Alexco** – The GRA filing notes that Alexco Resource Corp. indicated to YEC plans to commence mining and milling operations at the Keno Hill property in early 2010, with a resultant electricity load in the 21-25 GW.h/yr range and a mine life of at least five years. Since the Application was filed, this load information for Alexco has been updated. Alexco still expects to commence grid service in 2010; however, it is now expected that grid service will commence at 11.7 GW.h for the first 2 years of service and increase to 16.5 GW.h for the next three years of service.

Tab 2 also notes that other WAF near-term mine developments are also under consideration for potential commercial operation beginning within the next 4 to 7 years at locations close to the WAF and MD grids, including the Dublin Gulch project near the MD grid and the Casino mine project near the WAF grid.

(c) and **(d)**

The information provided in the Application (at Tab 1 page 1-8 and at Tab 5 pages 5-19 and 5-20) remains generally current. Where relevant, the information is updated below.

As noted in the Application after CSTP Stage One development and the Minto Mine connection (and before allowing any secondary sales), WAF hydro generation surpluses at long term average flows will likely be fully utilized by firm sales on WAF sometime

between 2011 and 2014. Faro mine reclamation loads that may start as soon as 2012 would, in combination with Minto loads, result in such WAF surpluses being fully utilized by 2012, i.e., absent new renewable generation, baseload diesel generation would be required of about 10 GWh.

The connection of additional new industrial loads (i.e., Alexco and Western Copper) could fully utilize existing hydro generation surplus energy on the WAF and MD grids sooner, to the point where, absent new renewable sources of generation, material near term baseload diesel generation (e.g., 70 to 87 GW.h/yr) could be required during the 2012- to 2015 period even after allowing for CSTP Stage Two and Aishihik Third Turbine developments.

The above estimates reflect simple assessments using long term average hydro generation capability. Yukon Energy is refining these assessments to utilize full-scale water flow modeling that reflects seasonal and annual variations on each grid and for the two grids combined.

As noted during the January 6, 2009 GRA Workshop, Yukon Energy has completed the first stage of an “Orderly Process” to address key regulatory issues facing both utilities in the Yukon. With the 20-Year Resource Plan (filed in 2006), Yukon Energy addressed in Chapter 4 of that filing concerns surrounding the need for new capacity planning criteria and resultant concerns surrounding required near term capacity. Measures to address near term capacity concerns were reviewed at that hearing (and in the case of the CSTP were reviewed in depth as part of other regulatory processes) and Yukon Energy has taken steps to ensure 25.4 MW of near term capacity is now available to meet system needs.

Page 12 of the Application notes as follows with regard to WAF capacity planning:

> Under the present planning sequence, Yukon Energy has secured cost effective options for up to 25.4 MW of WAF capacity in a staged and flexible manner, comprised of recommissioning a 5 MW Mirrlees unit at Faro, acquisition of 6.4 MW of diesel units at Minto, plus staged refurbishment of up to three Mirrlees units at Whitehorse (totaling 14 MW) over the period to 2012. While present plans are to proceed with the full 25.4 MW, in the event this full complement of capacity is not determined to be required, or required in the same time frame as presently assumed,

options exist to adapt the sequence and timing so as to ensure only the required level of capacity is made available.

Yukon Energy does not anticipate major changes in its diesel plant planning due to the new industrial loads currently under discussion.

During the January 6, 2009 Workshop it was noted that with near term capacity requirements now addressed, Yukon Energy has embarked upon a new stage of planning and regulatory review processes focused on meeting energy-focused issues raised in Chapter 5 of the 20-Year Resource Plan (as opposed to capacity concerns now addressed). In this vein, it was noted that areas of focus at this time are (1) the need to plan for new energy supplies to offset future diesel requirements; and (2) the need to ensure adequate rate design and efficiency signals are provided (including updating price signals on 2nd block rates for residential and general service customers).

Developing either enhancements to existing hydro projects, or new renewable generation, is very costly and requires long planning times. However, the anticipated load increases, together with cost and environmental considerations, provide strong incentives for Yukon Energy to expand the available complement of renewable generation, as well as transmission interconnections in order to address long term bulk power needs.

Tab 5, pages 5-19 to 5-21 provide a description of current planning and study activities being undertaking in this regard. Mayo B (as noted page 5-20) has been identified as a potential priority near term hydro generation expansion opportunity that could displace up to 38 GWh/year of baseload diesel generation. Given current schedules, including planning, engineering, YESAA and permitting activities, and potential tendering activities, the earliest feasible in-service date is fall 2011 or fall 2012. These budgets and schedules are subject to ongoing review and assessment.

Other projects in feasibility or prefeasibility planning during the test years (to protect earliest feasibility near term in-service dates) include the Gladstone Diversion project (up to 18 GW.h/year), small scale Atlin winter storage project (up to 18 GW.h/year), Marsh lake fall/winter storage project (up to 7.7 GW.h/year), as well as longer term/ larger scale options such as geothermal generation options and larger scale Hydro (such as Hoole, at 100-300 GW.h/year). Each of the smaller scale developments consists of relatively short construction periods (typically on the order of one year) but it is not possible at this

time to forecast the potential licencing periods required. Larger scale greenfield hydro generation cannot likely be developed in less than 5-6 years even on an expedited schedule. In addition, Yukon Energy continues to consider various supply-side enhancements (SSEs) related to such matters as re-runnering existing units. Budgets and schedules for projects in feasibility or pre-feasibility stages of development are subject to ongoing review after completion of field studies and initial desk studies, as well as ongoing review of project mine loads and timing of new renewable generation requirements.

For capital costs related to each project, see Appendix B of the 20 Year Resource Plan.

REFERENCE: **Application Section 7.0**

ISSUE: **Financial Schedules**

PREAMBLE:

CW wishes to better understand YEC's revenue requirement schedules.

QUESTION:

a) Please provide the financial schedules of Section 7.0 in Excel format.

ANSWER:

(a)

Please see Attachment 1 to this response.

REFERENCE: **Application Section 7.0, Schedule 2**

ISSUE: **Rate Base, Amortization and Depreciation**

PREAMBLE:

CW wishes to better understand YEC's revenue requirement schedules.

QUESTION:

a) Please provide complete details of YEC's calculation of the components of necessary working capital (lines 1-7 of Schedule 2) for both test years. If any of the components of necessary working capital have been determined by means of a lead/lag study, balance sheet method or the 1/8 rule, please provide, including the year in which the lead/lag study was performed.

ANSWER:

(a)

Please see YECL-YEC-1-10.

REFERENCE: **Application page 8-4, lines 3-7**

ISSUE: **Return on Equity**

PREAMBLE:

YEC states: "Yukon Energy proposes to file amendments to this Application as required after BCUC releases its determination for 2009, incorporating the adjusted ROE for 2009 in the requested approvals for 2009 at that time. This will allow the updated values to be available in advance of required Board determinations on this application."

QUESTION:

a) Please confirm that BCUC Letter No. L-55-08 regarding 2009 return on equity for a low-risk utility was issued November 20, 2008.

b) When does YEC propose filing the amended Application?

ANSWER:

(a)

Confirmed. Please see response to YUB-YEC-1-15(d) for the actual BCUC determination and its impact on YEC's proposed 2009 ROE.

(b)

For the relevant updated values, information, please see response to UCG-YEC-1-55 (b) and (c).

REFERENCE: **Application Tab 9, p. 9-9, Change in Accounting Policies**

ISSUE: **Accounting and Regulatory Practices**

PREAMBLE:

CW desires to understand the effects of the change in accounting policy discussed.

QUESTION:

a) Please explain how YEC's financial statements for the year ending December 31, 2007 are different from what they would have been had this change to accounting policy not occurred.

b) Please confirm there is no financial impact on the Company or its customers as a result of this change to accounting policy. If not confirmed, please provide a full explanation as to the financial impact and how it will affect the Company and/or its customers.

c) Please discuss any other changes to accounting and regulatory practices that have occurred since the last GRA.

ANSWER:

(a)

The adoption of these sections expanded the disclosure on the Statement of Income and Retained Earnings to include reference to Other Comprehensive Income.

(b)

Confirmed.

(c)

At the direction of auditors, Yukon Energy amended its inventory accounting policy effective the end of the fiscal year 2005. Previously, transmission and distribution

inventory items had their carrying value increased by a prescribed percentage representing warehousing and freight costs. This treatment had been in place for a number of years. The auditors advised that in their opinion this accounting treatment was not in accordance with generally accepted accounting principles and therefore advised management to remove the effect of this loading from on-hand inventory as at December 31, 2005. The effect of this adjustment was to reduce the value of inventory by $0.278 million. No other adjustments were required.

REFERENCE: **Application, Tab 9**

ISSUE: **Audited Financial Statements**

PREAMBLE:

YEC provides Audited financial statements for the year ending December 31, 2007.

QUESTION:

a) Please provide Audited Financial Statements for the years ending December 31, 2005 and 2006.

b) Please provide Pro-Forma Financial Statements for the years 2008 and 2009, including a statement of Earnings and Retained Earnings, Balance Sheet and Cash Flows.

ANSWER:

(a)

Please see Attachment 1 and Attachment 2 to this response.

(b)

Please see Tab 7, Schedule 6, Schedule 7, Schedule 8 and Schedule 9.

Auditor General of Canada
Vérificatrice générale du Canada

AUDITOR'S REPORT

To the Board of Directors of Yukon Energy Corporation

I have audited the balance sheet of Yukon Energy Corporation as at December 31, 2005 and the statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. My responsibility is to express an opinion on these financial statements based on my audit.

I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In my opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2005 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Further, in my opinion, proper books of account have been kept by the Corporation and the financial statements are in agreement therewith and the transactions of the Corporation that have come to my notice during my audit of the financial statements have, in all significant respects, been in accordance with the *Public Utilities Act* and regulations, *the Business Corporations Act* and regulations, and the articles and the bylaws of the Corporation.

Sheila Fraser

Sheila Fraser, FCA
Auditor General of Canada

Ottawa, Canada
March 24, 2006

240 rue Sparks Street, Ottawa, Ontario K1A 0G6

YUKON ENERGY

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the financial statements and all other financial information relating to the Corporation contained in this annual report. The financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industry in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the financial statements.

Management has established internal accounting control systems to meet its responsibilities for reliable and accurate reporting. These systems include policies and procedures, the careful selection and training of qualified personnel and an organizational structure that provides for the appropriate delegation of authority and segregation of responsibilities.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management and the independent auditor to discuss auditing and financial matters to assure that management is carrying out its responsibilities and to review the financial statements. The auditors have full and free access to the Audit Committee and management.

David Morrison
President & CEO

Wendy Fendrick
Acting Chief Financial Officer

Whitehorse, Yukon
March 24, 2006

Yukon Energy Corporation
Balance Sheet
(in thousands of dollars)

As at December 31,	2005	2004
Assets		
Current		
Cash and cash equivalents	$ 4,068	$ 1,719
Accounts receivable (Notes 4 and 16)	4,018	4,490
Materials and supplies	2,099	2,651
Prepaid expenses	217	838
	10,402	9,698
Diesel contingency fund (Notes 3 and 5)	791	772
Property, plant and equipment (Note 6)	158,016	158,800
Deferred water licensing costs (Note 7)	5,871	5,453
Reserve for uninsured losses (Note 11)	-	797
Deferred charges (Note 8)	2,328	1,384
	$ 177,408	$ 176,904
Liabilities		
Current		
Accounts payable (Note 16)	3,256	4,072
Current portion of long-term debt (Notes 13 and 16)	1,454	1,340
Regulatory liabilities (Note 9)	1,775	2,811
	6,485	8,223
Deferred revenue (Note 10)	8,186	8,457
Reserve for uninsured losses (Note 11)	33	-
Contributions in aid of construction (Note 12)	11,799	11,540
Regulatory provision for future removal and site restoration costs	5,618	5,757
Diesel contingency fund (Notes 3 and 5)	791	772
Long-term debt (Notes 13 and 16)	86,114	84,757
	119,026	119,506
Shareholder's Equity		
Share capital		
Authorized: Unlimited number of a single class of shares with no par value		
Issued: 3,900 shares	39,000	39,000
Retained earnings	19,382	18,398
	58,382	57,398
	$ 177,408	$ 176,904

Contingencies and Commitments (Notes 18 and 19)
The accompanying notes are an integral part of the financial statements.

Approved by the Board

_____, Chair

_____, Director

Yukon Energy Corporation

Statement of Income and Retained Earnings
(in thousands of dollars)

For the year ended December 31,	2005	2004
Revenue (Note 16)		
Sales of power	$ 26,298	$ 24,904
Other	591	878
	26,889	25,782
Operating expenses		
Administration (Note 14)	7,856	6,780
Operations and maintenance (Note 15)	5,433	4,641
Amortization of property, plant and equipment	4,709	6,115
Amortization of deferred charges and water licensing costs	889	531
	18,887	18,067
Income from operations	**8,002**	7,715
Other income		
Allowance for funds used during construction	102	115
Amortization of capital assistance	215	299
Interest income	104	43
	421	457
Other expenses		
Interest on long-term debt (Note 16)	4,500	2,926
Provision for uninsured losses (Note 11)	100	50
	4,600	2,976
Net income	**3,823**	5,196
Retained earnings, beginning of year	**18,398**	16,851
Dividend	**(2,839)**	(3,649)
Retained earnings, end of year	**$ 19,382**	$ 18,398

The accompanying notes are an integral part of the financial statements.

Yukon Energy Corporation
Statement of Cash Flows
(in thousands of dollars)

For the year ended December 31,	2005	2004
Cash provided from Operations		
Cash receipts from customers	$ 27,361	$ 25,516
Cash paid to employees and suppliers	(15,467)	(11,773)
Interest paid	(4,500)	(2,926)
Interest received	104	43
	7,498	10,860
Cash (used for) provided from Financing		
Repayment of long-term debt	(1,368)	(1,326)
Contributions in aid of construction	776	850
Dividend paid to parent	-	(3,444)
	(592)	(3,920)
Cash used for Investment		
Additions to property, plant and equipment	(4,609)	(6,225)
Proceeds on disposal of property, plant & equipment	52	36
	(4,557)	(6,189)
Net increase in cash and cash equivalents	**2,349**	751
Cash and cash equivalents, beginning of year	**1,719**	968
Cash and cash equivalents, end of year	**$ 4,068**	$ 1,719
Cash and cash equivalents consist of:		
Bank balances	4,068	1,719
	4,068	1,719

The accompanying notes are an integral part of the financial statements.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

1. NATURE OF OPERATIONS

Yukon Energy Corporation (the "Utility") was incorporated under the *Yukon Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation, a corporation owned by the Government of Yukon. Yukon Energy Corporation generates, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes.

The Utility is subject to overall regulation by the Yukon Utilities Board ("YUB") and specific regulation by the Yukon Territory Water Board. Both boards are independent from the Utility.

Rate Regulation

All operations of the Utility are regulated by the YUB pursuant to the *Public Utilities Act*. There is no minimum requirement for the Utility to appear before the YUB to review rates. However, the Utility is not permitted to charge any rate for the supply of power that is not approved by an Order of the YUB. The Utility is subject to a cost of service regulatory mechanism under which the YUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment on rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The regulatory hearing process used to establish or change rates typically begins when the Utility makes an application for its proposed electricity rate changes over the next one or two forecast years. The YUB must ensure that its decision, which fixes electricity rates, complies with all relevant legislation including the *Public Utilities Act* and directives issued by the Yukon Government through Orders-In-Council that specify how the interests of the customer and Utility are to be balanced.

The YUB typically follows a two-stage decision process. In the first stage, the total costs that the Utility will incur to provide electricity to its customers over the immediate future are approved. The approval of these costs determines the total revenues the Utility is allowed to collect from its customers. It is the responsibility of the YUB to examine the legitimacy of three classes of costs:

- the costs to the Utility to run its operations and maintain its equipment (personnel and materials);
- the cost associated with the amortization of all capital equipment; and
- the return on rate base (the costs related to borrowing that portion of rate base which is financed with debt, and the costs to provide a reasonable rate of return on that portion of rate base which is financed with equity).

As well, in the first stage, the YUB reviews the addition of costs to rate base and assesses these costs to ensure they are prudent.

In the second stage, the YUB approves how the revenue will be raised. This stage essentially determines the electricity rates for the various customer classes in the Yukon: residential, government, commercial and industrial. This process is guided mainly by requirements of Yukon Government Order-in-Council 1995/90 and can include a cost-of-service study which allocates the overall utility's cost of service to the various customer classes on the basis of appropriate costing principles.

Normally, the Utility applies for rates in advance of the applicable years. The last rate application was for the 2005 year. Interim hearings may be used between rate applications to deal with unforeseen circumstances which could result in the use of interim rates or riders until the next rate application when rates are reviewed and set as final.

Water Regulation
The Yukon Territory Water Board pursuant to the *Yukon Waters Act* decides if and for how long the Utility will have a water license for the purposes of operating hydro generation stations in the Yukon. The licenses will also indicate terms and conditions for the operation of these facilities.

Capital Structure
The Utility's policy is to maintain a relatively constant capital structure of 60% debt and 40% equity. Annual dividends are paid to the parent and typically loaned back in order to maintain this ratio.

2. SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation
Effective December 31, 2005, the Utility retroactively adopted the Canadian Institute of Chartered Accountant's guideline 19 pertaining to the disclosure and presentation of information by entities subject to rate regulation. This change in presentation had no effect on the Utility's current or prior year net income or retained earnings. Impacts of accounting for rate regulated operations are further described in Note 3.

The financial statements of the Utility have been prepared by management. They conform to Canadian generally accepted accounting principles ("GAAP") and take into account generally accepted methods and practices of regulatory bodies. The regulatory accounting policies adopted by the Utility may differ from the accounting policies otherwise expected using GAAP. In particular, the timing of the Utility's recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that of a non-regulated enterprise (see Note 3). Consequently, the significant accounting policies have been classified accordingly in the notes below:

Rate regulated accounting policies
Property, plant and equipment
The Utility capitalizes an allowance for funds used during construction ("AFUDC") at the weighted average cost of capital. Upon retirement or disposal, any gain or loss is charged to income in the current year for assets depreciated on an individual basis, or charged to accumulated depreciation for assets depreciated on a pooled basis.

Regulatory liabilities
Regulatory liabilities represent amounts ordered by the YUB to be held by the Utility on behalf of ratepayers. Typically these amounts are either refunded to the customers or applied to ratepayer deficits through the rate setting process.

Reserve for uninsured losses
As a means of self-insurance, the Utility maintains a reserve for uninsured losses. The reserve is maintained through an annual provision approved by the YUB and collected through customer rates. Variances between the approved annual provision and actual costs incurred are deferred until the following general rate application or until a specific application is made to the YUB requesting recovery from or refund to customers.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

Deferred charges
Deferred charges are recorded at cost less accumulated amortization.

Cost of feasibility studies and infrastructure planning are amortized on a straight-line basis over five and ten years respectively.

Regulatory hearing costs are amortized on a straight-line basis over three years.

Other deferred charges are amortized to earnings on a straight-line basis over various terms approved by the Yukon Utilities Board.

Regulatory provision for future removal and site restoration costs
The Utility maintains a reserve for the future removal of property, plant and equipment and the costs of site restoration related to those assets. The costs of demolishing, dismantling, tearing down, or otherwise disposing of the asset and site restoration, net of actual recoveries, are deducted from this account when they do not relate to an asset retirement obligation.

Deferred revenue
Deferred revenue represents a gain on fire insurance proceeds received related to a fire at the Whitehorse Rapids Generating Station in 1997. The gain is being amortized to income at the same rate as the replacement assets.

Diesel contingency fund
The Utility maintains a trust asset and an offsetting trust liability on behalf of ratepayers. The trust is used to reimburse the Utility for costs associated with diesel generation required when there is not sufficient water for hydraulic generation to meet demand. The Utility is required to file an annual report with the YUB on the fund's activity.

Generally Accepted Accounting Principles
Cash equivalents
Cash equivalents represent short-term highly liquid investments and are carried at cost.

Revenue recognition
All revenues are recognized in the period earned. Revenue from the sale of power is recognized based on cyclical meter readings. Sales of power includes an accrual for electricity deliveries not yet billed.

Materials and supplies
Diesel fuel, materials and supplies are recorded at average cost. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined.

Property, plant and equipment
Property, plant and equipment is stated at cost which includes materials, direct labour, a proportionate share of directly attributable administration overhead, and finance charges capitalized during construction, less accumulated amortization.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

Amortization is based on the straight-line method over the estimated economic life of the assets as follows:

Generation	
Hydro-electric plants	30 to 65 years
Diesel plants	25 to 45 years
Wind Turbines	30 years
Transmission	40 to 60 years
Distribution	25 to 40 years
Buildings	20 to 40 years
Transportation	9 to 31 years
Other equipment	5 to 20 years

Asset retirement obligations
On an annual basis, the Utility identifies legal obligations associated with the retirement of tangible long-lived assets. Where a reasonable estimate of the fair value of these obligations can be determined, the total retirement costs are to be recorded as a liability at fair value, with a corresponding increase to property, plant and equipment.

The Utility has determined that it has tangible long-lived assets with associated future legal obligations for retirement. As the Utility anticipates using the assets for an indefinite period, the date of removal of these assets cannot be reasonably determined, and therefore an asset retirement obligation has not been recorded. When the timing and amount of the retirement can be reasonably estimated, an asset retirement obligation and the corresponding increase in property, plant and equipment asset will be recognized.

Contributions in aid of construction
Certain property, plant and equipment additions are made with the assistance of cash contributions from customers or capital assistance from the Utility's parent. These contributions are amortized to income on the same basis as the assets to which they relate. Amortization of contributions from customers is netted on the statement of income against amortization expense while amortization of capital assistance from the parent is disclosed separately under Other income.

Deferred water licensing costs
Costs related to obtaining water license renewals are deferred and amortized to earnings on a straight-line basis over the term of the license. The Utility operates its hydro generation facilities under three separate water licenses, with terms ranging from 17 to 25 years.

Employee pension plan
The Utility has a defined benefit pension plan which provides for pensions based on length of service and final average earnings. The cost of pension benefits is actuarially determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Adjustments resulting from the plan enhancements, actuarial gains and losses, and changes in assumptions are amortized over the expected average remaining service period of active employees. Pension costs include the current cost of service and amortization of past service benefits and plan enhancements, and actuarial gains and losses. Amortization is on a straight-line basis over the expected average remaining service period of active employees, which is currently 14 years. The transitional asset that arose when this policy was first applied is amortized over the average remaining service period of active employees expected to receive benefits under the benefit plan as of January 1, 2000.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

Measurement uncertainty
The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. This mainly affects revenue, accounts receivable, property, plant and equipment, asset retirement obligations, and employee pension obligations. Actual results could differ by a significant amount from these estimates.

Management's estimates and assumptions, especially those affecting the reported amounts of assets and the Utility's ability to recover the cost of these assets through future rates, are subject to decisions of the Yukon Utilities Board as described in Note 3.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

Certain items in these financial statements are accounted for differently than they would be in the absence of rate regulation.

Where regulatory decisions dictate, the Utility defers certain costs or revenues as assets or liabilities on the balance sheet and records them as expenses or revenues in the statement of income as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the YUB renders a subsequent decision.

Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event:

	2005	2004	Expected remaining recovery/ settlement (years)	For 2005: In the absence of Rate Regulation the Utility's Net Income would have increased (decreased) by:
Regulatory assets:				
Deferred charges (Note 8), net book value				
Feasibility studies	$ 1,498	$ 866	4 to 10	$ (632)
Downsizing costs	119	167	2	48
Hearing costs	622	325	2	(297)
Dam safety review	89	26	2 to 4	(63)
Diesel contingency fund (Note 5)	791	772	Indeterminate	(19)
	3,119	2,156		(963)
Regulatory liabilities:				
Anvil Range Mine dewater revenue (Note 9)	1,775	2,067	Indeterminate	(292)
Insurance proceeds held on behalf of ratepayers (Note 9)	-	744	-	-
Deferred gain on fire insurance proceeds (Note 10)	8,166	8,436	30	(270)
Reserve for uninsured losses (Note 11)	33	(797)	Indeterminate	86
Regulatory provision for future removal and site restoration costs	5,618	5,757	Indeterminate	(139)
Diesel contingency fund (Note 5)	791	772	Indeterminate	19
	16,383	16,979		$ (596)
Net impact	$ (13,264)	$ (14,823)		$ (1,559)

(a) Deferred charges

Deferred charges represent costs which have been deferred and are being amortized over various periods. In the absence of rate regulation, GAAP would require such costs to be recognized in the year incurred.

Feasibility studies

The costs of determining the feasibility of future capital projects that did not result in a capital project are deferred and amortized over five years as approved in the Utility's 1991/92 General Rate Application and re-confirmed in YUB Order 2005-12. Infrastructure planning costs are amortized over ten years as approved by YUB order 2005-12. In the absence of rate regulation, expenses in 2005 would have been $632,000 higher.

Downsizing costs

Costs incurred to assist in downsizing the Utility's workforce are capitalized and amortized to expense over seven years as approved in the Utility's 1993/94 General Rate Application and reconfirmed in YUB Order 2005-12. In the absence of rate regulation, expenses in 2005 would have been $48,000 lower.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

Hearing costs
The Utility incurred $1,133,000 in costs associated with the YUB regulatory proceedings held in 2005. These costs consist primarily of legal and consulting costs incurred by the Utility of $851,000 and reimbursement of YUB and intervener costs of $282,000. YUB Order 2005-16 directed the Utility to reimburse the YUB and interveners for costs they incurred in the amount of $282,000. YUB Order 2005-17 disallowed $200,000 of the $851,000 of costs incurred by the Utility. The disallowed amount has been recorded as Administration expenses in the current year. YUB Order 2005-12 directed the Utility to defer and amortize the approved hearing costs of $933,000 over 3 years commencing January 1, 2005. In the absence of rate regulation, expenses in 2005 would have been $297,000 higher.

Dam safety review
The Utility has a program of conducting reviews of the safety of its dams in accordance with standards set by the Canadian Dam Association. External consultants are hired every five years with intermittent costs incurred in the interim periods. These costs are amortized over five years as approved by the Utility's 1991/92 General Rate Application and reconfirmed in YUB Order 2005-12. In the absence of rate regulation, expenses in 2005 would have been $63,000 higher.

(b) Diesel contingency fund
The Diesel contingency fund ("DCF") was established by YUB Order 1996-6 through the Negotiated Settlement process. The DCF is administered by the Utility on behalf of the YUB, and as such is recorded as a trust asset and a trust liability. The DCF attracts interest based upon short-term bond rates in which the Utility invests the funds held in trust. Any negative balance attracts interest at the lowest short-term borrowing rate available to the Utility through its line of credit. Pursuant to YUB order 1996-6, the Utility from time to time is required to transfer amounts to or from the trust it maintains on behalf of ratepayers to reimburse the Utility for costs associated with diesel generation required when there is not sufficient water for hydraulic generation to meet demand. As directed by Board Order 2002-3, the current balance of the DCF consists of the fire insurance gain of $744,000, realized as part of the settlement of the insurance claim arising from the fire at the Whitehorse Rapids Generating Station, plus interest earned on the funds held in trust. In the absence of regulation, GAAP would have required the amounts transferred to and from the DCF, and any interest earned or incurred to be included in the Utility's net income in the year in which they occurred. In the absence of rate regulation, the Utility's net income in 2005 would have been higher by $19,000 from interest earned on the DCF

(c) Regulatory liabilities

Anvil Range Mine dewater revenue
As directed by YUB Order 1998-5, all revenues, less any incremental costs to provide the service, collected from Anvil Range Mine under Rate Schedule 34 (Faro Mine Firm Shutdown Power) prior to December 31, 2004, were deferred for the benefit of ratepayers pending direction from the YUB. YUB Order 2005-12 confirmed that effective January 1, 2005 the Anvil Range minesite would be charged the General Service-Government rate so there will be no further increases to dewatering revenue. This order also enables the Utility to draw down on the Anvil Range dewater revenue to fund its approved 2005 revenue shortfall. YUB Order 2005-17 set the approved 2005 revenue shortfall at $292,000. In the absence of rate regulation, GAAP would have required only the recognition of actual sales earned during the year. As a result, the Utility's sales of power in 2005 would have been $292,000 lower. The period over which the remaining liability will be recognized as revenue for the benefit of ratepayers is dependent on future YUB Board orders and, therefore, cannot be estimated.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

Insurance proceeds held for ratepayers
Insurance proceeds held on behalf of ratepayers represents the residual balance of insurance proceeds after allocation against all reconstruction and operation and maintenance costs related to a fire at the Whitehorse Rapids Generating Station in 1997, pursuant to Board Order 2002-3. As directed by YUB Order 2005-12, the insurance proceeds of $744,000 were applied to the reserve for uninsured losses deficit during the year. In the absence of rate regulation, the insurance proceeds would have been included in income in the year received. The impact on current year net income would be $0.

(d) Deferred revenue
The deferred gain on fire insurance proceeds relates to a fire at the Whitehorse Rapids Generating Station in 1997 which, pursuant to Board Order 2000-3, is being amortized to income at the same rate as the replacement assets. In the absence of rate regulation, GAAP would have required the gain to have been completely recognized as income in the year received. As a result, the Utility's current year net income would have been lower by the amount of the amortization of $270,000.

(e) Reserve for uninsured losses
The YUB has approved the use of a reserve for uninsured damages and injuries as a means of self-insurance. The reserve is maintained through an annual provision approved by the YUB. In order to eliminate the deficit rate payers held as a result of uninsured losses, the Utility was directed by YUB Order 2005-12 to transfer the insurance proceeds being held on behalf of rate payers of $744,000 to the reserve for uninsured loss, and increase the annual provision from $50,000 to $100,000 for the years 2005 to 2007. The annual provision will revert back to $50,000 unless the YUB subsequently orders otherwise. In the absence of rate regulation, GAAP would require costs to be expensed as incurred and, therefore, expenses in 2005 would have been lower by $86,000. The period over which the reserve will be recovered is dependent on the magnitude of future actual losses incurred and cannot be estimated.

(f) Regulatory provision for future removal and site restoration costs
Pursuant to depreciation rates approved by the YUB in the Utility's previous general rate applications, under section 23(1)(b) of the Public Utilities Act, the Utility has maintained a reserve for future removal and site restoration costs. As a result of the YUB Order 2005-12, effective January 1 2005, the Utility is required to maintain this reserve as a regulatory provision in addition to any asset retirement obligations. The provision is not to exceed the cumulative value of the provision at December 31, 2004 of $5,757,000. In the absence of rate regulation, GAAP would have required the Utility to reverse the reserve to retained earnings in 2004. YUB Order 2005-12 also directs the Utility to notify interveners and interested parties when the balance of the provision reaches $2,000,000. Costs of dismantling capital assets, including site remediation, will be applied to this regulatory liability if they do not otherwise relate to an asset retirement obligation. In a non-regulated industry, future removal and site restoration costs would be limited to asset retirement obligations, and the removal and site restoration costs would be expensed in the year incurred if they did not relate to an asset retirement obligation. In the absence of rate regulation, the Utility's 2005 expense would have been higher by the amount of actual removal and site restoration costs incurred in the year of $139,000. The period over which the provision will be settled is dependent on the future costs of demolishing, dismantling, tearing down, or otherwise disposing of the asset, and site restoration net of actual recoveries, and is, therefore, indeterminate.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

Other items affected by rate regulation
The Utility is required under the *Public Utilities Act* to obtain prior approval from the YUB before making changes to depreciation, amortization, and depletion rates and methods. The YUB permits an allowance for funds used during construction ("AFUDC"), based on the Utility's weighted average cost of capital, to be included in the rate base. AFUDC is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated over future periods as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFUDC component, will be approved for inclusion in future customer rates. Since AFUDC includes not only an interest component, but also a cost-of-equity component, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

It is the Utility's policy to charge to income, in the year of disposal, any gain or loss upon retirement or disposal of land or vehicles. As approved by the YUB, the gain or loss on all other property, plant and equipment is charged to accumulated depreciation and deferred and amortized over the expected life of the remaining pool of similar assets. In the absence of rate regulation, GAAP would require the gain or loss on the disposal or retirement of all property, plant and equipment to be included in income in the period of disposal or retirement.

YUB Order 2005-12 disallowed capital costs related to the Mayo-Dawson transmission line in excess of $28,996,000. As a result of the YUB order, the Utility wrote down the value of property, plant and equipment related to the Mayo-Dawson transmission line by $1,224,000 in 2005. $554,000 related to costs incurred to correct deficiencies and have been recorded as Operations and maintenance costs (line and substation costs). $671,000 related to legal costs incurred to pursue claims and counter claims against the general contractor and have been recorded as Administration (General office and governance costs). In the absence of rate regulation, net income would not change as GAAP would also require the Utility to record the write-down. Additionally, YUB Order 2005-12 disallows the Utility from earning a return on any additional costs incurred with respect to the Mayo Dawson line as a result of pursuing any claims or counter claims against the general contractor and directs the Utility to record any recoveries from the general contractor in an interest bearing deferred account for future review and disposition by the YUB.

The Utility's policy of maintaining a constant capital structure of 60% debt and 40% equity is reviewed by the YUB as part of the rate setting process and in the determination of the return on rate base. In the absence of rate regulation, the Utility would determine the appropriate capital structure solely based on decisions by the Board of Directors of the Utility, which may differ from the current policy.

All amounts maintained as regulatory assets and liabilities are expected to be recovered or settled over the periods noted above. However, there are risks and uncertainties associated with the recovery or settlement related to potential future decisions of the regulator.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

Rate decision
On October 18, 2005, the YUB issued YUB Order 2005-12 related to the Utility's revenue requirements application dated December 13, 2004 which includes the Utility's 2005 fiscal year. The Utility's application requested changes to certain regulated accounts: the rate charged for Rate Schedule 32 (Secondary Energy); and the elimination of Rate Schedule 34 (Faro Mine Firm Shutdown Power). As a result of YUB Order 2005-12 and related follow-up decisions, effective January 1, 2005, the Utility is entitled to a rate of return on common equity of 9.05%. The major items contained in these decisions are:

(a) to set rates for residential and commercial customers as permanent effective January 1, 2005;
(b) to apply amounts currently recorded as regulatory liabilities in the Anvil Range Mine dewater revenue deferral account, to offset 2005 revenue shortfalls totaling $292,000. Additional amounts up to $292,000 per year can be ordered by the YUB for 2006 and 2007;
(c) to apply the $744,000 balance of the regulatory liability recorded as insurance proceeds held for ratepayers against the reserve for uninsured losses deficit;
(d) to increase the annual appropriation to the reserve for uninsured losses to $100,000 for each of the 2005, 2006 and 2007 years;
(e) implementation of new depreciation rates with the cumulative prior years impact of the rate change amortized to income over the average remaining life of the assets;
(f) discontinue the annual provision for future removal and site restoration, and notify interveners and interested parties when the balance reaches $2,000,000;
(g) limit the inclusion of Mayo Dawson transmission line costs in the Utility's rate base to $28,996,000;
(h) to disallow any further costs incurred on the Mayo Dawson line related to claims and counter claims between the general contractor and the Utility;
(i) to record recoveries received with respect to claims and counterclaims between the utility and the general contractor in an interest bearing deferral account with the future disposition of the balance in the account to be determined by the YUB;
(j) to defer $650,000 of the $851,000 direct costs incurred by the Utility related to the hearing costs account (as forecast in the November 17, 2005 compliance filing submitted to the YUB) and amortize equally over 3 years commencing January 1, 2005;
(k) to pay $282,000 to the YUB and interveners for their costs incurred to participate in the hearing, and to include this amount in the deferred hearing costs account to be amortized equally over three years commencing January 1, 2005;
(l) elimination of rate schedule 34 (Faro Mine Shutdown Firm Power);
(m) approval of an automatic quarterly rate setting mechanism for rate schedule 32 (Secondary Energy), whereby the Utility sets the rate on a quarterly basis at 66.7% of the avoided price of fuel oil and is required to provide the YUB with notification of the quarterly rate change; and
(n) to refund to secondary energy customers the difference of $45,000 between the interim and permanent rates, plus interest of $1,000.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

4. ACCOUNTS RECEIVABLE

	2005	2004
Wholesale energy sales	$ 2,666	$ 2,480
Retail energy sales	1,008	590
Other	344	1,420
	$ 4,018	$ 4,490

Wholesale energy sales are made to Yukon Electrical Company Limited, an unrelated company also regulated by the Yukon Utilities Board. Wholesale power energy in 2005 were approximately $16,977,000 (2004 - $16,493,000).

5. DIESEL CONTINGENCY FUND

	2005	2004
Opening balance	$ 772	$ 755
Interest	19	17
Closing balance	**$ 791**	$ 772

6. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2005 Net book Value	2004 Net book Value
Generation	$ 135,571	$ 43,521	$ 92,050	$ 93,754
Transmission	53,645	10,194	43,451	43,785
Buildings and other equipment	14,288	5,087	9,201	9,080
Distribution	13,575	4,825	8,750	8,261
Transportation	1,594	473	1,121	904
Land and land rights	1,074	-	1,074	1,076
Construction-in-progress	2,369	-	2,369	1,940
	$ 222,116	**$ 64,100**	**$ 158,016**	$ 158,800

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

7. DEFERRED WATER LICENSING COSTS

	Cost	Accumulated Amortization	2005 Net book Value	2004 Net book Value
Deferred water licensing costs	$ 8,014	$ 2,143	$ 5,871	$ 5,453

Amortization booked in 2005 was $359,000 (2004 - $336,000)

8. DEFERRED CHARGES

	Cost	Accumulated Amortization	2005 Net book Value	2004 Net book Value
Feasibility studies and infrastructure planning	$ 4,813	$ 3,315	$ 1,498	$ 866
Hearing costs	933	311	622	325
Downsizing costs	334	215	119	167
Dam safety review	231	142	89	26
	$ 6,311	**$ 3,983**	**$ 2,328**	$ 1,384

9. REGULATORY LIABILITIES

	2005	2004
Insurance proceeds held on behalf of ratepayers		
Opening balance	$ 744	$ 744
Applied to Reserve for uninsured losses (Notes 3 and 11)	(744)	-
Closing balance	-	744
Anvil Range Mine dewater revenue		
Opening balance	2,067	2,067
Applied to revenue shortfall YUB Order 2005-17 (Note 3)	(292)	-
Closing balance	1,775	2,067
	$ 1,775	$ 2,811

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

10. DEFERRED REVENUE

	2005	2004
Deferred gain on fire insurance proceeds - capital assets (net of amortization and adjustments of $3,438,000 (2004 - $3,168,000))	$ 8,166	$ 8,436
Other	20	21
	$ 8,186	$ 8,457

11. RESERVE FOR UNINSURED LOSSES

	2005	2004
Opening balance	$ (797)	$ (679)
Provision	100	50
Transfer from Regulatory liabilities (Notes 3 and 9)	744	$ -
Losses incurred		
Asset replacements	(14)	(168)
Closing balance	$ 33	$ (797)

12. CONTRIBUTIONS IN AID OF CONSTRUCTION

			2005	2004
	Gross	Accumulated Amortization	Net	Net
Capital assistance from parent since 1998	$ 8,855	$ 1,061	$ 7,794	$ 8,010
Contributions from customers since 1998	3,354	231	3,123	2,604
Pre-1998 contributions	1,739	857	882	926
	$ 13,948	**$ 2,149**	**$ 11,799**	$ 11,540

The sources of contributions received prior to 1998 were not recorded separately.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

13. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

	2005	2004
Government of Canada		
$40,000,000 flexible term note bearing interest at 7% repayable in annual installments of up to $1,000,000 principal, plus accrued interest and secured by mortgage over specific assets	$ -	$ 28,278
Yukon Development Corporation		
$40,000,000 flexible term note bearing interest at 7% repayable in annual installments of up to $1,000,000 principal, plus accrued interest and secured by mortgage over specific assets	27,867	-
$27,313,661 term note bearing interest at 5.88%, payable monthly, and semi-annual principal payments commencing June 30, 2007 and ending December 31, 2023. The note is unsecured.	27,314	27,314
$18,000,000 flexible term note related to the Mayo to Dawson Transmission Line project bearing interest at 6.55% repayable in annual installments of $450,000 principal, plus accrued interest with the balance of $307,000 due December 31, 2043. The note is unsecured.	16,957	17,407
Unsecured advance bearing interest at 6.03%, due one year after demand	3,649	3,649
Unsecured advance bearing interest at 5.403%, due one year after demand	2,839	-
TD Canada Trust		
$12,400,000 term note bearing interest at 7.81% payable in monthly installments of $102,000 interest and principal, with the balance due September 30, 2011. The note is guaranteed by the Yukon Government.	8,942	9,449
	87,568	86,097
Less current portion	1,454	1,340
	$ 86,114	$ 84,757

$40,000,000 Flexible term note

The Government of Canada flexible term note was purchased by Yukon Development Corporation (the Utility's parent) on March 30, 2005 with all existing terms and conditions remaining the same. The terms of the flexible term note provide for payments of principal and interest to be deferred and abated, respectively, if power sales on the Whitehorse-Aishihik-Faro electrical power distribution system are less than specified amounts. After adjusting for abated interest, the effective interest rate on this instrument for 2005 is 2.90% (2004 - 2.86%).

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

Mayo - Dawson Transmission Line Financing
The Utility obtained financing from its parent in the amount of $18 million for a transmission line from the Mayo hydro generating station to Dawson City. The financing was obtained effective September 6, 2003, the date the transmission line came into service. The financing was made under terms that ensure that ratepayers are not paying more in any year than they would otherwise have paid if the transmission line had not been built and Dawson City had continued to be served by diesel generation. The maximum interest payable on the note in any year is determined by a formula which compares the costs and benefits of operating the line. For example, the costs include depreciation, return on equity, and operating and maintenance expense. The benefits include diesel fuel costs not incurred. As per the agreement, total costs, including interest, cannot exceed the benefits.

If the costs of operating the line exceed the benefits in any year, Yukon Development Corporation will pay Yukon Energy Corporation the difference on or before March 31 of the next calendar year.

In 2005, benefits exceeded costs, which resulted in $1,140,000 in interest paid to Yukon Development Corporation. (In 2004, costs exceeded benefits by $241,000 and YDC was required to pay this amount to the Utility.)

Long -term debt repayment
Scheduled repayments for all long-term debt are as follows:

2006	$ 1,454
2007	3,127
2008	3,190
2009	3,270
2010	3,349
Thereafter	73,178
	$ 87,568

Fair value
Fair value at December 31, 2005 of $101 million (2004 - $98.2 million) for all long-term debt was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

14. ADMINISTRATION EXPENSES

	2005	2004
Wages, benefits and staff recruiting	$ 3,207	$ 2,961
Consulting and legal services	1,155	265
General office and governance costs (Note 3)	1,075	724
Insurance	909	984
Data and bill processing	554	500
Reimbursed and miscellaneous costs	496	1,007
Communications and corporate contributions	232	176
Environmental and safety management	228	163
	$ 7,856	$ 6,780

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

15. OPERATIONS AND MAINTENANCE EXPENSES

	2005	2004
Wages and benefits	2,829	2,662
Maintenance		
- lines and substations (Note 3)	1,058	539
- hydro, diesel and wind	651	578
- building and vehicle	565	470
Water level measurement	193	182
Fuel	137	210
	$ 5,433	$ 4,641

16. RELATED PARTY TRANSACTIONS

Except as disclosed elsewhere, the following table summarizes the Utility's related party transactions for the year:

	2005	2004
Revenue		
Sales of service to:		
- direct parent company	$ 244	$ 469
- wholly-owned subsidiary of parent company	147	136
	$ 391	$ 605
Rate Stabilization Fund revenue from:		
- direct parent company	$ 358	$ 338
Expense		
Payment of interest on long-term & short term debt to:		
- direct parent company	$ 3,780	$ 1,365
Payment for Financial information system usage to:		
- direct parent company	177	177
Other receipts		
Rural Electrification Support Program funding:		
- direct parent company	$ -	$ 60
Other payments		
Payment on contribution agreements to:		
- direct parent company	$ 34	$ 36
- wholly-owned subsidiary of parent company	50	60

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

The transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Revenue from related parties is reported as Other revenue on the statement of income. The corresponding cost of providing these services is reported as part of administration expense on the statement of income.

Rate stabilization fund revenues are received from the parent in accordance with terms established by the Government of Yukon, which established the fund to protect certain ratepayers by minimizing the impact of rate increases. These revenues are reported on the statement of income as a component of sales of power.

Interest on long-term debt is included on the income statement under Other expenses.

Rural Electrification Support Program funds are received from the parent and are recorded as an offset to the capitalized cost of the respective project.

At the end of the year, the amounts receivable from and due to related entities are as follows:

		2005		2004
Direct parent company				
Accounts receivable	$	136	$	574
Accounts payable	$	5	$	6
Current portion of long-term debt	$	904	$	450
Long-term debt	$	77,722	$	47,920
Wholly-owned subsidiary of parent company				
Accounts receivable	$	40	$	63
Accounts payable	$	8	$	-

These balances are non-interest bearing and payable on demand except for long-term debt (Note 13).

17. PENSION COSTS AND OBLIGATIONS

The Utility sponsors a defined benefit pension plan which provides benefits based on length of service and final average earnings as follows:

- years of pensionable service;
- the average annual earnings during any 5 consecutive years of pensionable service where earnings are the highest; and
- the average of the years maximum pensionable earnings (Canada Pension Plan) for the same 5-year period

Annual cost of living increases to a maximum of 3.00% are provided to pensioners. The Utility contributes amounts as recommended by an independent actuary.

Employees make contributions to the plan as follows:

- 3.5% of earnings up to the year's maximum pensionable earnings
- 5.0% of earnings in excess of year's maximum pensionable earnings to a maximum of $2,500 per year.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

The Utility has contracted with external organizations to provide services of trustee, administrator and investment manager for the pension plan.

An actuarial valuation for funding purposes was performed as of January 1, 2004 by the consulting actuarial firm AON Consulting Inc. The next valuation for funding purposes will be conducted as of January 1, 2007. The pension costs and obligations were based on the data used in the January 1, 2004 funding valuation and have been projected to December 31, 2005 in accordance with generally accepted actuarial standards.

The fair value of the plan assets is based on market values as reported by Royal Trust, the plan's custodian as at December 31, 2005. The plan assets are invested in a pooled balanced fund. The distribution of assets by major asset class is as follows:

	December 31, 2005	December 31, 2004
Equities	62.4%	60.5%
Fixed Income Securities	34.6%	30.1%
Short Term Securities and Cash	3.0%	9.4%

Information about the Utility's defined benefit plan as at December 31, in aggregate, is as follows:

	2005	2004
Discount rate-accrued benefit obligation	5.25%	6.00%
Discount rate-benefit costs	6.00%	6.50%
Expected long-term rate of return on plan assets	6.50%	6.50%
Assumed rate of salary escalation	3.00%	3.00%
Assumed rate of pension indexing	2.50%	2.50%
Expected average remaining service period of active employees	14 years	14 years
Benefit obligation determined by actuarial valuation	$ 8,269	$ 6,282
Fair value of plan assets	6,144	5,371
Plan deficit	$ 2,125	$ 911
Unrecognised amount:		
- transitional asset	203	220
- net actuarial losses	(1,907)	(741)
Accrued benefit liability	$ 421	$ 390
Pension expense	$ 337	$ 286
Employer contributions	$ 306	$ 320
Employee contributions	$ 110	$ 132
Benefits paid	$ 97	$ 299

The accrued benefit liability has been recorded on the Utility's books of account and is included in accounts payable on the balance sheet.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the defined benefit plan. The Utility makes contributions to a Registered Retirement Savings Plan ("RRSP") on behalf of these employees and employees hired before January 1, 2002 who belonged to the defined benefit plan and elected to opt out of that plan. The RRSP is a defined contribution plan. The costs recognized for the period are equal to the Utility's contribution to the plan. During 2005, these were $122,000 (2004 - $105,000).

Total cash payments for employee future benefits for 2005, consisting of cash contributed by the Utility to its funded defined benefit pension plan and cash contributed directly to the RRSP were $428,000 (2004 - $425,000).

As at December 31, 2005, the Utility's defined pension plan had 40 members (2004 - 41), and the RRSP had 33 members (2004 - 34).

18. CONTINGENCIES

(a) Mayo to Dawson City transmission line project

As discussed in Note 6, the Utility completed the construction of the Mayo to Dawson City Transmission Line project during 2003. Subsequent to energization of the line, the Utility and the general contractor notified each other that they have numerous claims arising out of the agreement and the construction of the line. These claims total several million dollars on a net basis. To date, no legal action has commenced.

In April 2005, the contractor provided the Utility with some additional information. Management is reviewing this information and anticipates further documentation will be required before claims can be fully assessed. Once the documentation stage is complete, the parties will meet to select an appropriate legal process to resolve the outstanding issues. To date, the Utility has not received sufficient information to assess the Utility's exposure.

(b) Federal transfer agreement

Most of the assets of the Utility were purchased under a March 31, 1987 Agreement of Purchase and Sale between the Government of Canada ("Canada"), Yukon Energy Corporation, the Government of Yukon ("YTG") and Northern Canada Power Commission ("NCPC") (the "Transfer Agreement"). There are several claims that the Utility has against Canada under the Transfer Agreement. The various claims are described below:

Yukon Energy Corporation claims against Canada

(i) Claim against Canada Arising from Requirement to Obtain a Fish Authorization in Relation to the Aishihik Facility

In January, 2004, the Utility filed a Writ of Summons against Canada for damages caused by a breach of the Transfer Agreement arising from Canada's notification of the Utility in May, 1999 that the Aishihik Facility required an authorization under the Fisheries Act. The Utility alleges the requirement for a fish authorization was contrary to Canada's representations and warranties under the Transfer Agreement. More particularly it alleges it reasonably relied on warranties and representations given by Canada under the Transfer Agreement to the effect that the Utility had all authorizations necessary for the generation of electricity from the Aishihik Facility. As a result, the Utility incurred significant costs and expenses in negotiating and obtaining a Fisheries Act authorization for the Aishihik Facility and further, its ability to use the Aishihik Facility has been restricted by the terms of the authorization. It is expected that a legal process will be initiated in 2006, resulting in damages being awarded to the Utility which can not be reasonably estimated at this time.

(ii) Soil Contamination at the Whitehorse Facility
The Utility has notified Canada of a claim it has for indemnification for expenditures it incurred on site restoration at the Whitehorse Rapids Dam site for hydrocarbon contamination caused by a diesel fuel spill which occurred when Canada owned the facility. This contamination was discovered in 1999 and was rectified in 2000. In addition, further testing in 2004 revealed one additional area of contamination caused during Canada's ownership of the site. The Utility's claim of approximately $260,000 for indemnification arises under the Transfer Agreement. It is expected that this matter will be resolved in 2006.

19. COMMITMENTS

(a) Aishihik Water Licence
The Yukon Territory Water Board issued a water use license in 2002, valid until December 31, 2019, for the Utility's Aishihik Lake facility. In addition to maintaining a minimum and maximum water level, this license commits the Utility to meet a number of future requirements including:

a) annual payments of $25,000 until 2011 for the purpose of construction and maintenance of a heritage camp and delivery of programs at the camp;
b) a Heritage Mitigation Plan. The Utility spent approximately $35,000 in 2005 on heritage projects, expects to spend up to $50,000 in 2006 and $30,000 in 2007 on heritage projects, and the balance which has not yet been determined in the future; and
c) annual fish monitoring programs.

Fish monitoring programs are also required under an authorization provided by Canada Department of Fisheries and Oceans valid until December 31, 2019. The costs of meeting these requirements are accounted for as water licence costs in the year they are paid.

(b) Financial Information System Lease
The Utility leases a financial information system from the parent. Minimum lease payments for the remaining four years are as follows:

2006	$	177
2007		177
2008		177
2009		147
Total	$	**678**

(c) Mayo – Dawson Apprenticeship Benefits Agreement
Under this agreement, the Utility is obligated to annual payments of $15,000, adjusted by the percentage change in the Canadian consumer price index, to both The Tr'ondek Hwech'in and the First Nation of Nacho Nyak Dun. The agreement came into effect July 1, 2004 and expires June 30, 2024. The costs of meeting these requirements are expensed to Administration in the year to which they relate.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2005

(d) Mayo – Dawson Transmission Line Option Agreement
The Utility has provided an option to two Yukon First nations to acquire up to a $14,470,000 "indirect interest" in the Mayo-Dawson transmission line system project. The option agreement provides for issuance by the Utility of a long-term debt instrument repayable over forty years, bearing interest equal to the Utility's blended cost of capital, including a component limited to the Utility's realized return on equity. The option expires on January 4, 2007. The option has not been exercised to date.

20. ENVIRONMENTAL LIABILITIES

The Utility's activities are subject to various federal and territorial laws and regulations governing the protection of the environment or to minimize any adverse impact thereon. The Utility conducts its operations so as to protect public health and the environment and believes its operations are materially in compliance with all applicable laws and regulations. Liabilities will be recorded when the occurrence of an environmental expenditure, related to present or past activities of the Utility, is considered probable and the costs can be reasonably estimated. To date, no such specific liabilities have been recorded in the Utility's accounts.

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The fair value of cash and cash equivalents, accounts receivable, diesel contingency fund, and accounts payable approximate the carrying amount of these instruments due to the short period to maturity. The fair value of long-term debt is described in Note 13. The Utility also has access to a $10 million line of credit. The renewal date on the line of credit is October 31, 2009. The account accrues interest on withdrawals at prime rate. The facility was not drawn on at year end.

The Utility is not exposed to significant interest rate risk due to its long-term debt having fixed interest rates. The Utility's credit risk is minimal in that its primary customer is a regulated utility.

22. COMPARATIVE FIGURES

Certain 2004 figures have been reclassified to conform with the current year's presentation.

YUKON ENERGY

YUKON ENERGY CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 5L6
(867) 393-5300

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the financial statements and all other financial information relating to the Corporation contained in this annual report. The financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industry in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the financial statements.

Management has established internal accounting control systems to meet its responsibilities for reliable and accurate reporting. These systems include policies and procedures, the careful selection and training of qualified personnel and an organizational structure that provides for the appropriate delegation of authority and segregation of responsibilities.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management and the independent auditor to discuss auditing and financial matters to assure that management is carrying out its responsibilities and to review the financial statements. The auditors have full and free access to the Audit Committee and management.

David Morrison,
President and CEO

Ed Mollard
Chief Financial Officer

March 23, 2007

Yukon Energy Corporation

Financial Statements

December 31, 2006 **Page**

Auditor's Report	2
Balance Sheet	3
Statement of Income and Retained Earnings	4
Statement of Cash Flows	5
Notes to Financial Statements	6-25

Auditor General of Canada
Vérificatrice générale du Canada

AUDITOR'S REPORT

To the Board of Directors of Yukon Energy Corporation

I have audited the balance sheet of Yukon Energy Corporation as at December 31, 2006 and the statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. My responsibility is to express an opinion on these financial statements based on my audit.

I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In my opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Further, in my opinion, proper books of account have been kept by the Corporation and the financial statements are in agreement therewith and the transactions of the Corporation that have come to my notice during my audit of the financial statements have, in all significant respects, been in accordance with the *Public Utilities Act* and regulations, *the Business Corporations Act* and regulations, and the articles and the bylaws of the Corporation.

Sheila Fraser

Sheila Fraser, FCA

Auditor General of Canada

Vancouver, Canada
March 23, 2007, except for Note 21 which is as of April 30, 2007

240 rue Sparks Street Ottawa Ontario K1A 0G6

Yukon Energy Corporation
Balance Sheet
(in thousands of dollars)

As at December 31,	2006	2005
Assets		
Current		
Cash	$ 5,952	$ 4,068
Accounts receivable (Notes 4 and 15)	4,226	4,018
Materials and supplies	2,039	2,099
Prepaid expenses	181	217
	12,398	10,402
Deferred uninsured losses (Note 10)	**500**	(33)
Diesel contingency fund (Notes 3 and 5)	**821**	791
Property, plant and equipment (Note 6)	**157,992**	158,016
Deferred charges (Note 7)	**9,238**	8,199
	$ 180,949	$ 177,375
Liabilities		
Current		
Accounts payable (Note 15)	$ 3,531	$ 2,896
Current portion of long-term debt (Notes 12 and 15)	3,253	1,454
Regulatory liabilities (Note 8)	1,483	1,775
	8,267	6,125
Long-term pension liability	**560**	360
Deferred revenue (Note 9)	**7,896**	8,186
Contributions in aid of construction (Note 11)	**12,187**	11,799
Regulatory provision for future removal and site restoration costs	**5,083**	5,618
Diesel contingency fund (Notes 3 and 5)	**821**	791
Long-term debt (Notes 12 and 15)	**86,397**	86,114
	121,211	118,993
Shareholder's Equity		
Share capital		
Authorized: Unlimited number of a single class of shares with no par value		
Issued: 3,900 shares	**39,000**	39,000
Retained earnings	**20,738**	19,382
	59,738	58,382
	$ 180,949	$ 177,375

Contingencies and Commitments (Notes 18 and 19)
The accompanying notes are an integral part of the financial statements.

Approved by the Board

Chair

Director

Yukon Energy Corporation

Statement of Income and Retained Earnings
(in thousands of dollars)

For the year ended December 31,	2006	2005
Revenue (Note 15)		
Sales of power	$ 27,528	$ 26,298
Other	533	591
	28,061	26,889
Operating expenses		
Administration (Note 13)	7,461	7,856
Operations and maintenance (Note 14)	5,375	5,433
Depreciation of property, plant and equipment	4,732	4,709
Amortization of deferred charges and water licensing costs	1,098	889
	18,666	18,887
Income from operations	**9,395**	8,002
Other income		
Allowance for funds used during construction	54	102
Amortization of capital assistance	215	215
Interest income	220	104
	489	421
Other expenses		
Interest on long-term debt (Note 15)	4,845	4,500
Provision for uninsured losses (Note 10)	100	100
	4,945	4,600
Net income	**4,939**	3,823
Retained earnings, beginning of year	**19,382**	18,398
Dividend	**(3,583)**	(2,839)
Retained earnings, end of year	**$ 20,738**	$ 19,382

The accompanying notes are an integral part of the financial statements.

Yukon Energy Corporation
Statement of Cash Flows
(in thousands of dollars)

For the year ended December 31,	2006	2005
Cash provided from Operations		
Cash receipts from customers	$ 27,853	$ 27,361
Cash paid to employees and suppliers	(14,988)	(15,467)
Interest paid	(4,845)	(4,500)
Interest received	220	104
	8,240	7,498
Cash (used for) provided from Financing		
Repayment of long-term debt	(1,501)	(1,368)
Contributions in aid of construction	733	776
	(768)	(592)
Cash used for Investment		
Additions to property, plant and equipment	(5,588)	(4,609)
Proceeds on disposal of property, plant & equipment	-	52
	(5,588)	(4,557)
Net increase in cash	**1,884**	2,349
Cash, beginning of year	**4,068**	1,719
Cash, end of year	**$ 5,952**	$ 4,068

The accompanying notes are an integral part of the financial statements.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

1. NATURE OF OPERATIONS

Yukon Energy Corporation (the "Utility") was incorporated under the *Yukon Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation, a corporation owned by the Government of Yukon. Yukon Energy Corporation generates, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes.

The Utility is subject to overall regulation by the Yukon Utilities Board ("YUB") and specific regulation by the Yukon Territory Water Board. Both boards are independent from the Utility.

Rate Regulation

All operations of the Utility are regulated by the YUB pursuant to the *Public Utilities Act*. There is no minimum requirement for the Utility to appear before the YUB to review rates. However, the Utility is not permitted to charge any rate for the supply of power that is not approved by an Order of the YUB. The Utility is subject to a cost of service regulatory mechanism under which the YUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment in rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The regulatory hearing process used to establish or change rates typically begins when the Utility makes an application for its proposed electricity rate changes over the next one or two forecast years. The YUB must ensure that its decision, which fixes electricity rates, complies with appropriate principals of rate making, all relevant legislation including the *Public Utilities Act* and directives issued by the Yukon Government through Orders-In-Council that specify how the interests of the customer and Utility are to be balanced.

The YUB typically follows a two-stage decision process. In the first stage, the total costs that the Utility will incur to provide electricity to its customers over the immediate future are approved. The approval of these costs determines the total revenues the Utility is allowed to collect from its customers. It is the responsibility of the YUB to examine the legitimacy of three classes of costs:

- the costs to the Utility to run its operations and maintain its equipment (personnel and materials);
- the cost associated with the amortization of all capital equipment; and
- the return on rate base (the costs related to borrowing that portion of rate base which is financed with debt, and the costs to provide a reasonable rate of return on that portion of rate base which is financed with equity).

As well, in the first stage, the YUB reviews the addition of costs to rate base and assesses these costs to ensure they are prudent.

In the second stage, the YUB approves how the revenue will be raised. This stage essentially determines the electricity rates for the various customer classes in the Yukon: residential, government, commercial and industrial. This process is guided mainly by requirements of Yukon Government Order-in-Council 1995/90 and can include a cost-of-service study which allocates the overall utility's cost of service to the various customer classes on the basis of appropriate costing principles.

Normally, the Utility applies for rates in advance of the applicable years. The last rate application was for the 2005 year. Interim hearings may be used between rate applications to deal with unforeseen circumstances which could result in the use of interim rates or riders until the next rate application when rates are reviewed and set as final.

Water Regulation
The Yukon Territory Water Board pursuant to the *Yukon Waters Act* decides if and for how long the Utility will have a water license for the purposes of operating hydro generation stations in the Yukon. The licenses will also indicate terms and conditions for the operation of these facilities.

Capital Structure
The Utility's policy is to maintain a relatively constant capital structure of 60% debt and 40% equity. Annual dividends are declared to the parent and typically loaned back in order to maintain this ratio.

2. SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation
The financial statements of the Utility have been prepared by management. They conform to Canadian generally accepted accounting principles ("GAAP") and take into account generally accepted methods and practices of regulated bodies. The regulatory accounting policies adopted by the Utility may differ from the accounting policies otherwise expected using GAAP. In particular, the timing of the Utility's recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that of a non-regulated enterprise. Impacts of accounting for rate regulated operations are further described in Note 3. Consequently, the significant accounting policies have been classified accordingly in the notes below:

Rate regulated accounting policies
Property, plant and equipment
Capitalized assets include an allowance for funds used during construction ("AFUDC") calculated at the weighted average cost of capital. Upon retirement or disposal, any gain or loss is charged to income in the current year for assets depreciated on an individual basis, or charged to accumulated depreciation for assets depreciated on a pooled basis.

Regulatory liabilities
Regulatory liabilities represent amounts ordered by the YUB to be held by the Utility on behalf of ratepayers. Typically these amounts are either refunded to the customers or applied to ratepayer deficits through the rate-setting process.

Deferred uninsured losses
As a means of self-insurance, the Utility provides for uninsured losses. An annual provision is approved by the YUB and collected through customer rates. Variances between the approved annual provision and actual costs incurred are deferred until the following general rate application or until a specific application is made to the YUB requesting recovery from or refund to customers.

Deferred charges
Deferred charges are recorded at cost less accumulated amortization.

Cost of feasibility studies and infrastructure planning are amortized on a straight-line basis over five years.

Regulatory hearing costs are amortized on a straight-line basis over three years.

Other deferred charges are amortized to earnings on a straight-line basis over various terms approved by the Yukon Utilities Board.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

Regulatory provision for future removal and site restoration costs
The Utility maintains a provision for the future removal of property, plant and equipment and the costs of site restoration related to those assets. Per YUB Order 2005-12 no additional provision is permitted. This account provides for the costs of demolishing, dismantling, tearing down, or otherwise disposing of an asset and any site restoration costs, net of actual recoveries. This account is not used when the costs relate to an asset retirement obligation.

Deferred revenue
Deferred revenue represents a gain on fire insurance proceeds received related to a fire at the Whitehorse Rapids Generating Station in 1997. The gain is being amortized to income at the same rate as the replacement assets.

Diesel contingency fund
The Utility maintains a trust asset and an offsetting trust liability on behalf of ratepayers. The trust is used to reimburse the Utility for costs associated with diesel generation required when there is not sufficient water for hydraulic generation to meet demand. The Utility is required to file an annual report with the YUB on the fund's activity.

Generally Accepted Accounting Principles
Revenue recognition
All revenues are recognized in the period earned. Revenue from the sale of power is recognized based on cyclical meter readings. Sale of power includes an accrual for electricity deliveries not yet billed.

Materials and supplies
Diesel fuel, materials and supplies are recorded at average cost. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined.

Property, plant and equipment
Property, plant and equipment is stated at cost which includes materials, direct labour, a proportionate share of directly attributable administration overhead, and finance charges capitalized during construction, less accumulated amortization.

Depreciation is based on the straight-line method over the estimated economic life of the assets as follows:

Generation	
Hydro-electric plants	30 to 65 years
Diesel plants	25 to 45 years
Wind Turbines	30 years
Transmission	40 to 50 years
Distribution	25 to 40 years
Buildings	20 to 40 years
Transportation	9 to 31 years
Other equipment	5 to 20 years

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

Asset retirement obligations
On an annual basis, the Utility identifies legal obligations associated with the retirement of tangible long-lived assets. Where a reasonable estimate of the fair value of these obligations can be determined, the total retirement costs are to be recorded as a liability at fair value, with a corresponding increase to property, plant and equipment.

The Utility has determined that it has tangible long-lived assets with associated future legal obligations for retirement. As the Utility anticipates using the assets for an indefinite period, the date of removal of these assets cannot be reasonably determined, and therefore an asset retirement obligation has not been recorded. When the timing and amount of the retirement can be reasonably estimated, an asset retirement obligation and the corresponding increase in property, plant and equipment asset will be recognized.

Effective January 1, 2006, the Utility retroactively adopted the Canadian Institute of Chartered Accountant's ("CICA") Emerging Issues Abstract regarding conditional asset retirement obligations. This abstract requires an entity to record a liability for an asset retirement obligation where the timing and/or method of settlement are conditional upon the occurrence of a future event that may or may not be within the control of the entity. Adoption of this abstract had no effect on the financial statements for the year ended December 31, 2006.

Contributions in aid of construction
Certain property, plant and equipment additions are made with the assistance of cash contributions from customers or capital assistance from the Utility's parent. These contributions are amortized to income on the same basis as the assets to which they relate. Amortization of contributions from customers is netted on the statement of income against amortization expense while amortization of capital assistance from the parent is disclosed separately under Other income.

Deferred water licensing costs
Costs related to obtaining water license renewals are deferred and amortized to earnings on a straight-line basis over the term of the license. The Utility operates its hydro generation facilities under three separate water licenses, with terms ranging from 17 to 25 years.

Employee pension plan
The Utility has a defined benefit pension plan which provides for pensions based on length of service and final average earnings. The cost of pension benefits is actuarially determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Adjustments resulting from plan enhancements, actuarial gains and losses, and changes in assumptions are amortized over the expected average remaining service period of active employees. Pension costs include the current cost of service and amortization of past service benefits and plan enhancements, and actuarial gains and losses. Amortization is on a straight-line basis over the expected average remaining service period of active employees, which is currently 14 years. The transitional asset that arose when this policy was first applied is amortized over the average remaining service period of active employees expected to receive benefits under the benefit plan as of January 1, 2000. The expected return on plan assets is based on the fair value of these assets.

Measurement uncertainty
The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. This mainly affects revenue, accounts receivable, property, plant and equipment, asset retirement obligations, and employee pension obligations. Actual results could differ by a significant amount from these estimates.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

Management's estimates and assumptions, especially those affecting the reported amounts of assets and the Utility's ability to recover the cost of these assets through future rates, are subject to decisions of the Yukon Utilities Board as described in Note 3.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

Certain items in these financial statements are accounted for differently than they would be in the absence of rate regulation.

Where regulatory decisions dictate, the Utility defers certain costs or revenues as assets or liabilities on the balance sheet and records them as expenses or revenues in the statement of income as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the YUB renders a subsequent decision.

Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process.

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event:

	2006	2005	Expected remaining recovery/ settlement (years)	For 2006: In the absence of Rate Regulation the Utility's Net Income would have increased (decreased) by:
Regulatory assets:				
Deferred charges (Note 7), net book value				
Feasibility studies	$ 2,999	$ 1,498	2 to 5	$ (1,501)
Downsizing costs	71	119	2	48
Hearing costs	311	622	1	311
Dam safety review	49	89	3	40
Diesel contingency fund (Note 5)	821	791	Indeterminate	(30)
	4,251	3,119		(1,132)
Regulatory liabilities:				
Faro mine dewatering deferral revenue (Note 8)	1,483	1,775	Indeterminate	(292)
Deferred gain on fire insurance proceeds (Note 9)	7,896	8,166	29	(270)
Deferred uninsured losses (Note 10)	(500)	33	Indeterminate	(533)
Regulatory provision for future removal and site restoration costs	5,083	5,618	Indeterminate	(535)
Diesel contingency fund (Note 5)	821	791	Indeterminate	30
	14,783	16,383		$ (1,600)
Net impact	$ (10,532)	$ (13,264)		$ (2,732)

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

Regulatory assets
(a) Deferred charges
Deferred charges represent costs which have been deferred and are being amortized over various periods. In the absence of rate regulation, GAAP would require such costs to be recognized as expenses in the year incurred.

Feasibility studies
The costs of determining the feasibility of future capital projects that did not result in a capital project are deferred and amortized over five years as approved in the Utility's 1991/92 General Rate Application and re-confirmed in YUB Order 2005-12. In the absence of rate regulation, expenses in 2006 would have been $1,501,000 higher. (2005 - $632,000 higher expenses)

Downsizing costs
Costs incurred to assist in downsizing the Utility's workforce are capitalized and amortized to expense over seven years as approved in the Utility's 1993/94 General Rate Application and reconfirmed in YUB Order 2005-12. In the absence of rate regulation, expenses in 2006 would have been $48,000 lower. (2005 - $48,000 lower expenses)

Hearing costs
These costs are associated with the YUB regulatory proceedings that were held in 2005. The costs consist primarily of legal and consulting costs incurred by the Utility, and reimbursement of YUB and intervenor costs. YUB Order 2005-12 directed the Utility to defer and amortize the approved hearing costs of $933,000 over 3 years commencing January 1, 2005. In the absence of rate regulation, expenses in 2006 would have been $311,000 lower. (2005 - $297,000 higher expenses)

Dam safety review
The Utility has a program of conducting reviews of the safety of its dams in accordance with standards set by the Canadian Dam Association. External consultants are hired every five years with intermittent costs incurred in the interim periods. These costs are amortized over five years as approved by the Utility's 1991/92 General Rate Application and reconfirmed in YUB Order 2005-12. In the absence of rate regulation, expenses in 2006 would have been $40,000 lower. (2005 - $63,000 higher expenses)

(b) Diesel contingency fund
The Diesel contingency fund ("DCF") was established by YUB Order 1996-6 through the Negotiated Settlement process. The DCF is administered by the Utility on behalf of the YUB, and as such is recorded as a trust asset and a trust liability. The DCF attracts interest based upon short-term bond rates in which the Utility invests the funds held in trust. Any negative balance attracts interest at the lowest short-term borrowing rate available to the Utility through its line of credit. Pursuant to YUB order 1996-6, the Utility from time to time is required to transfer amounts to or from the trust it maintains on behalf of ratepayers to reimburse the Utility for costs associated with diesel generation required when there is not sufficient water for hydraulic generation to meet demand. In the absence of regulation, GAAP would have required any interest earned or incurred to be included in the Utility's net income in the year in which they occurred. In the absence of rate regulation, the Utility's net income in 2006 would have been higher by $30,000 from interest earned on the DCF. (2005 - $19,000 higher net income)

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

Regulatory liabilities

(c) Faro mine dewatering deferral revenue

As directed by YUB Order 1998-5, all revenues, less any incremental costs to provide the service, collected from the Faro Mine under Rate Schedule 34 (Faro Mine Firm Shutdown Power) prior to December 31, 2004, were deferred for the benefit of ratepayers pending direction from the YUB. YUB Order 2005-12 confirmed that effective January 1, 2005 the Faro minesite would be charged the General Service-Government rate so there will be no further increases to Faro Mine Dewatering Deferral Account. This order also enables the Utility to draw down on the Faro Mine dewatering revenue to fund its approved revenue shortfall. YUB Order 2006-4 set the approved 2006 revenue shortfall at $292,000. In the absence of rate regulation, GAAP would have required only the recognition of actual sales earned during the year. As a result, the Utility's sales of power in 2006 would have been $292,000 lower (2005 - $292,000 lower). The period over which the remaining liability will be recognized as revenue for the benefit of ratepayers is dependent on future YUB Board orders and, therefore, cannot be estimated.

(d) Deferred gain on fire insurance proceeds

The deferred gain on fire insurance proceeds relates to a fire at the Whitehorse Rapids Generating Station in 1997 which, pursuant to Board Order 2000-3, is being amortized to income at the same rate as the replacement assets. In the absence of rate regulation, GAAP would have required the gain to have been completely recognized as income in the year received. As a result, the Utility's current year net income would have been lower by the amount of the amortization of $270,000 (2005 - $270,000 lower).

(e) Deferred uninsured losses

The YUB has approved the use of a provision for uninsured damages and injuries as a means of self-insurance. The provision is maintained through an annual provision approved by the YUB. In order to eliminate the deficit rate payers held as a result of uninsured losses, the Utility was directed by YUB Order 2005-12 to transfer the insurance proceeds being held on behalf of rate payers of $744,000 to the provision for uninsured loss, and increase the annual charge from $50,000 to $100,000 for the years 2005 to 2007. In the absence of rate regulation, GAAP would require costs to be expensed as incurred and, therefore, expenses in 2006 would have been higher by $533,000 (2005 - $86,000 lower). The period over which the provision will be recovered is dependent on the magnitude of future actual losses incurred and cannot be estimated.

(f) Regulatory provision for future removal and site restoration costs

Pursuant to amortization rates approved by the YUB in the Utility's previous general rate applications, under section 23(1)(b) of the *Public Utilities Act*, the Utility has maintained a provision for future removal and site restoration costs. As a result of the YUB Order 2005-12, effective January 1 2005, the Utility is required to maintain this provision as a regulatory provision in addition to any asset retirement obligations. The provision is not to exceed the cumulative value of the provision at December 31, 2004 of $5,757,000. In the absence of rate regulation, GAAP would have required the Utility to reverse the provision to retained earnings in 2004. YUB Order 2005-12 also directs the Utility to notify interveners and interested parties when the balance of the provision reaches $2,000,000. Costs of dismantling capital assets, including site remediation, will be applied to this regulatory liability if they do not otherwise relate to an asset retirement obligation. In a non-regulated industry, future removal and site restoration costs would be limited to asset retirement obligations, and the removal and site restoration costs would be expensed in the year incurred if they did not relate to an asset retirement obligation. In the absence of rate regulation, the Utility's 2006 expense would have been higher by the amount of actual removal and site restoration costs incurred in the year of $535,000 (2005 expenses - $139,000 higher). The period over which the provision will be settled is dependent on the future costs of demolishing, dismantling, tearing down, or otherwise disposing of the asset, and site restoration net of actual recoveries, and is, therefore, indeterminate.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

g) Fuel price adjustment
OIC 1998/90 directs the YUB to permit the Utility to adjust electricity rates to reflect fluctuations in the price of diesel fuel. The amount by which actual fuel prices vary from the YUB approved rates is deferred and recovered from or refunded to customers in a future period.

In the absence of rate regulation, GAAP would require that actual diesel fuel expenses be included in the operating result of the year that they are incurred. In 2006, fuel expenses were deferred and consequently lower by $56,000 (2005 - $11,000).

Other items affected by rate regulation
The Utility is required under the *Public Utilities Act* to obtain prior approval from the YUB before making changes to depreciation, amortization, and depletion rates and methods. The YUB permits an allowance for funds used during construction ("AFUDC"), based on the Utility's weighted average cost of capital, to be included in the rate base. AFUDC is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated over future periods as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFUDC component, will be approved for inclusion in future customer rates. Since AFUDC includes not only a cost of debt component, but also a cost-of-equity component, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

It is the Utility's policy to charge to income, in the year of disposal, any gain or loss upon retirement or disposal of land or vehicles. As approved by the YUB, the gain or loss on all other property, plant and equipment is charged to accumulated depreciation and deferred and amortized over the expected life of the remaining pool of similar assets. In the absence of rate regulation, GAAP would require the gain or loss on the disposal or retirement of all property, plant and equipment to be included in income in the period of disposal or retirement.

YUB Order 2005-12 disallows the Utility from earning a return on any additional costs incurred with respect to the Mayo-Dawson line as a result of pursuing any claims or counter claims against the general contractor and directs the Utility to record any recoveries from the general contractor in an interest-bearing deferred account for future review and disposition by the YUB.

The Utility's policy of maintaining a constant capital structure of 60% debt and 40% equity is reviewed by the YUB as part of the rate-setting process and in the determination of the return on rate base. In the absence of rate regulation, the Utility would determine the appropriate capital structure solely based on decisions by the Board of Directors of the Utility, which may differ from the current policy.

All amounts maintained as regulatory assets and liabilities are expected to be recovered or settled over the periods noted above. However, there are risks and uncertainties associated with the recovery or settlement related to potential future decisions of the regulator which could result in material adjustments to these assets and liabilities.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

4. ACCOUNTS RECEIVABLE

	2006	2005
Wholesale energy sales	$ 2,764	$ 2,666
Retail energy sales	1,109	1,008
Other	353	344
	$ 4,226	$ 4,018

Wholesale energy sales are made to Yukon Electrical Company Limited, an unrelated company also regulated by the Yukon Utilities Board. Wholesale power energy in 2006 were approximately $18,111,000 (2005 - $16,977,000).

5. DIESEL CONTINGENCY FUND

	2006	2005
Opening balance	$ 791	$ 772
Interest	30	19
Closing balance	**$ 821**	$ 791

Diesel Contingency Funds are monies invested in a pooled money market fund. The short-term securities held in the fund have an average maturity less than 90 days. Earnings are distributed monthly on a pro-rata share of the total fund. Annual return on investment for 2006 was 4.08% (2005 - 2.75%). The fair market value of these investments is equal to the carrying amount.

6. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Depreciation	2006 Net book Value	2005 Net book Value
Generation	$ 137,571	$ 46,254	$ 91,317	$ 92,050
Transmission	54,314	11,070	43,244	43,451
Buildings and other equipment	15,754	5,533	10,221	9,201
Distribution	14,596	5,113	9,483	8,750
Transportation	1,995	605	1,390	1,121
Land and land rights	1,074	-	1,074	1,074
Construction-in-progress	1,263	-	1,263	2,369
	$ 226,567	**$ 68,575**	**$ 157,992**	$ 158,016

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

7. DEFERRED CHARGES

	Cost	Accumulated Amortization	2006 Net book Value	2005 Net book Value
Deferred water licensing costs	$ 8,352	$ 2,544	$ 5,808	$ 5,871
Feasibility studies and infrastructure planning	3,576	577	2,999	1,498
Regulatory Hearing costs	933	622	311	622
Downsizing costs	334	263	71	119
Dam safety review	213	164	49	89
	$ 13,408	**$ 4,170**	**$ 9,238**	$ 8,199

8. REGULATORY LIABILITIES

	2006	2005
Insurance proceeds held on behalf of ratepayers		
Opening balance	$ -	$ 744
Applied to Reserve for uninsured losses (Notes 3 and 10)	-	(744)
Closing balance	-	-
Faro Mine Dewatering Deferral revenue		
Opening balance	1,775	2,067
Applied to revenue shortfall YUB Order 2005-17 (Note 3)	(292)	(292)
Closing balance	1,483	1,775
	$ 1,483	$ 1,775

9. DEFERRED REVENUE

	2006	2005
Deferred gain on fire insurance proceeds - capital assets (net of amortization and adjustments of $3,707,000 (2005 - $3,438,000))	$ 7,896	$ 8,166
Other	-	20
	$ 7,896	$ 8,186

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

10. DEFERRED UNINSURED LOSSES

	2006	2005
Opening balance	$ 33	$ (797)
Provision	100	100
Transfer from Regulatory liabilities (Notes 3 and 8)	-	$ 744
Losses incurred		
Asset replacements	(633)	(14)
Closing balance	**$ (500)**	$ 33

11. CONTRIBUTIONS IN AID OF CONSTRUCTION

			2006	2005
	Gross	Accumulated Amortization	Net	Net
Capital assistance from parent since 1998	$ 8,855	$ 1,276	$ 7,579	$ 7,794
Contributions from customers since 1998	4,087	295	3,792	3,123
Pre-1998 contributions	1,739	923	816	882
	$ 14,681	**$ 2,494**	**$ 12,187**	$ 11,799

The sources of contributions received prior to 1998 were not recorded separately.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

12. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

	2006	2005
Yukon Development Corporation		
$40,000,000 flexible term note bearing interest at 7% repayable in annual installments of up to $1,000,000 principal, plus accrued interest and secured by mortgage over specific assets	$ 27,316	$ 27,867
$27,313,661 term note bearing interest at 5.88%, payable monthly, and semi-annual principal payments commencing June 30, 2007 and ending December 31, 2023. The note is unsecured.	27,314	27,314
$18,000,000 flexible term note related to the Mayo to Dawson Transmission Line project bearing interest at 6.55% repayable in annual installments of $450,000 principal, plus accrued interest with the balance of $307,000 due December 31, 2043. The note is unsecured.	16,507	16,957
Unsecured advance bearing interest at 6.03%, due one year after demand	3,649	3,649
Unsecured advance bearing interest at 5.403%, due one year after demand	2,839	2,839
Unsecured advance bearing interest at 5.34%, due one year after demand	3,583	-
TD Canada Trust		
$12,400,000 term note bearing interest at 7.81% payable in monthly installments of $102,000 interest and principal, with the balance due September 30, 2011. The note is guaranteed by the Yukon Government.	8,442	8,942
	89,650	87,568
Less current portion	3,253	1,454
	$ 86,397	$ 86,114

$40,000,000 Flexible term note

The terms of the flexible term note provide for payments of principal and interest to be deferred and abated, respectively, if power sales on the Whitehorse-Aishihik-Faro electrical power distribution system are less than specified amounts. After adjusting for abated interest, the effective interest rate on this instrument for 2006 is 3.01% (2005 - 2.90%).

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

Mayo - Dawson Transmission Line Financing
The Utility obtained financing from its parent in the amount of $18 million for a transmission line from the Mayo hydro generating station to Dawson City. The financing was obtained effective September 6, 2003, the date the transmission line came into service. The financing was made under terms that ensure that ratepayers are not paying more in any year than they would otherwise have paid if the transmission line had not been built and Dawson City had continued to be served by diesel generation. The maximum interest payable on the note in any year is determined by a formula which compares the costs and benefits of operating the line. For example, the costs include depreciation, return on equity, and operating and maintenance expense. The benefits include diesel fuel costs not incurred. As per the agreement, total costs, including interest, cannot exceed the benefits.

If the costs of operating the line exceed the benefits in any year, Yukon Development Corporation will pay Yukon Energy Corporation the difference on or before March 31 of the next calendar year.

In 2006, benefits exceeded costs, which resulted in $1,111,000 in interest paid to Yukon Development Corporation. (In 2005, benefits exceeded costs, which resulted in $1,140,000 in interest paid to Yukon Development Corporation.)

Unsecured Advances
The Utility declared a dividend to the parent in the amount of $3,583,000 (2005 - $2,839,000) and this was loaned back to the Utility at an interest rate of 5.34% in order to maintain the capital structure. This advance is unsecured and due one year after demand.

Long -term debt repayment
Scheduled repayments for all long-term debt are as follows:

2007	$	3,253
2008		3,244
2009		3,301
2010		3,357
2011		3,416
Thereafter		73,079
	$	**89,650**

Fair value
Fair value at December 31, 2006 of $105 million (2005 - $101 million) for all long-term debt was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

13. ADMINISTRATION EXPENSES

		2006		2005
Wages and benefits	$	2,767	$	2,622
General office		1,175		1,307
Insurance and taxes		1,062		1,156
Regulatory loss		1,039		671
Information systems		435		554
Intercompany services		372		472
Training, recruitment and development		212		401
Material management and contracting		163		327
Environmental		145		190
Board of Directors		91		156
	$	**7,461**	$	7,856

14. OPERATIONS AND MAINTENANCE EXPENSES

		2006		2005
Wages and benefits	$	3,129	$	2,829
Maintenance				
- lines and substations		664		1,058
- hydro, diesel and wind		641		651
- building and vehicle		643		565
Water level measurement		173		193
Fuel		125		137
	$	**5,375**	$	5,433

15. RELATED PARTY TRANSACTIONS

Except as disclosed elsewhere, the following table summarizes the Utility's related party transactions for the year:

		2006		2005
Revenue				
Sales of service to:				
- direct parent company	$	216	$	244
- wholly-owned subsidiary of parent company		31		147
	$	247	$	391

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

Rate Stabilization Fund subsidy revenue from:				
- direct parent company	$	432	$	358
Expense				
Payment of interest on long-term & short-term debt to:				
- direct parent company	$	4,164	$	3,780
Payment for Financial information system usage to:				
- direct parent company		177		177
Other receipts				
Rural Electrification Support Program funding:				
- direct parent company	$	86	$	-
Other payments				
Payment on contribution agreements to:				
- direct parent company	$	25	$	34
- wholly-owned subsidiary of parent company		-		50

The transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Revenue from related parties is reported as Other revenue on the statement of income. The corresponding cost of providing these services is reported as part of administration expense on the statement of income.

Rate stabilization fund revenues are received from the parent in accordance with terms established by the Government of Yukon, which established the fund to protect certain ratepayers by minimizing the impact of rate increases. These revenues are reported on the statement of income as a component of sales of power.

Interest on long-term debt is included on the income statement under Other expenses.

Rural Electrification Support Program funds are received from the parent and are recorded as an offset to the capitalized cost of the respective project.

At the end of the year, the amounts receivable from and due to related entities are as follows:

		2006		2005
Direct parent company				
Accounts receivable	$	179	$	136
Accounts payable		68		5
Current portion of long-term debt		2,609		904
Long-term debt		75,016		77,722
Wholly-owned subsidiary of parent company				
Accounts receivable		-		40
Accounts payable		-		8

These balances are non-interest bearing and payable on demand except for long-term debt (Note 12).

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

16. PENSION COSTS AND OBLIGATIONS

The Utility sponsors a defined benefit pension plan which provides benefits based on length of service and final average earnings as follows:

- years of pensionable service;
- the average annual earnings during any five consecutive years of pensionable service where earnings are the highest; and
- the average of the years maximum pensionable earnings (Canada Pension Plan) for the same five year period

Annual cost of living increases to a maximum of 3.00% are provided to pensioners. The Utility contributes amounts as recommended by an independent actuary.

Employees make contributions to the plan as follows:

- 3.5% of earnings up to the year's maximum pensionable earnings; and
- 5.0% of earnings in excess of year's maximum pensionable earnings to a maximum of $2,500 per year.

The Utility has contracted with external organizations to provide services of trustee, administrator and investment manager for the pension plan.

An actuarial valuation for funding purposes was performed as of January 1, 2004 by the consulting actuarial firm AON Consulting Inc. The next valuation for funding purposes will be conducted as of January 1, 2007. The pension costs and obligations were based on the data used in the January 1, 2004 funding valuation and have been projected to December 31, 2006 in accordance with generally accepted actuarial standards.

The fair value of the plan assets is based on market values as reported by Group Retirement Services, the plan's custodian as at December 31, 2006. The plan assets are invested in a pooled balanced fund. The distribution of assets by major asset class is as follows:

	December 31, 2006	December 31, 2005
Equities	51.9%	62.4%
Fixed Income Securities	38.3%	34.6%
Short-term Securities and Cash	0.0%	3.0%
Real Estate	9.8%	0.0%

Information about the Utility's defined benefit plan as at December 31, in aggregate, is as follows:

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

		2006		2005
Discount rate-accrued benefit obligation		5.25%		5.25%
Discount rate-benefit costs		6.00%		6.00%
Expected long-term rate of return on plan assets		6.50%		6.50%
Assumed rate of salary escalation		3.00%		3.00%
Assumed rate of pension indexing		2.50%		2.50%
Expected average remaining service period of active employees		14 years		14 years
Benefit obligation determined by actuarial valuation	$	9,181	$	8,269
Fair value of plan assets		7,006		6,144
Plan deficit	$	2,175	$	2,125
Unrecognised amount:				
- transitional asset		186		203
- net actuarial losses		(1,741)		(1,907)
Accrued benefit liability	$	620	$	421
Pension expense	$	506	$	337
Employer contributions	$	307	$	306
Employee contributions	$	115	$	110
Benefits paid	$	60	$	97

The accrued benefit liability has been recorded on the Utility's books of account and its current portion of $60,000 (2005 -$60,000) is included in accounts payable on the balance sheet.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the defined benefit plan. The Utility makes contributions to a Registered Retirement Savings Plan ("RRSP") on behalf of these employees and employees hired before January 1, 2002 who belonged to the defined benefit plan and elected to opt out of that plan. The RRSP is a defined contribution plan. The costs recognized for the period are equal to the Utility's contribution to the plan. During 2006, these were $149,000 (2005 - $122,000).

Total cash payments for employee future benefits for 2006, consisting of cash contributed by the Utility to its funded defined benefit pension plan and cash contributed directly to the RRSP were $456,000 (2005 - $428,000).

As at December 31, 2006, the Utility's defined benefit pension plan had 40 members (2005 - 40), and the RRSP had 40 members (2005 - 33).

17. CONTINGENCIES

(a) Mayo to Dawson City transmission line project

The Utility completed the construction of the Mayo to Dawson City Transmission Line project during 2003. Subsequent to energization of the line, the Utility and the general contractor notified each other that they have numerous claims arising out of the agreement and the construction of the line. These claims total several million dollars on a net basis.

In November 2006, the Utility and the general contractor appeared in Yukon Supreme Court on an application to determine a legal process for settlement. The court has yet to render a decision. To date, the Utility has insufficient information to assess the financial exposure.

(b) Federal transfer agreement

Most of the assets of the Utility were purchased under a March 31, 1987 Agreement of Purchase and Sale between the Government of Canada ("Canada"), Yukon Energy Corporation, the Government of Yukon ("YTG") and Northern Canada Power Commission ("NCPC") (the "Transfer Agreement"). There are several claims that the Utility has against Canada under the Transfer Agreement. The various claims are described below:

Yukon Energy Corporation claims against Canada

(i) Claim against Canada Arising from Requirement to Obtain a Fish Authorization in Relation to the Aishihik Facility

In January, 2004, the Utility filed a Writ of Summons against Canada for damages caused by a breach of the Transfer Agreement arising from Canada's notification of the Utility in May, 1999 that the Aishihik Facility required an authorization under the *Fisheries Act*. The Utility alleges the requirement for a fish authorization was contrary to Canada's representations and warranties under the Transfer Agreement. More particularly it alleges it reasonably relied on warranties and representations given by Canada under the Transfer Agreement to the effect that the Utility had all authorizations necessary for the generation of electricity from the Aishihik Facility. As a result, the Utility incurred significant costs and expenses in negotiating and obtaining a *Fisheries Act* authorization for the Aishihik Facility and further, its ability to use the Aishihik Facility has been restricted by the terms of the authorization. A legal process was initiated in 2006 claiming damages; but the amount of the damages can not be reasonably estimated at this time.

(ii) Soil Contamination at the Whitehorse Facility

The Utility has notified Canada of a claim it has for indemnification for expenditures it incurred on site restoration at the Whitehorse Rapids Dam site for hydrocarbon contamination caused by a diesel fuel spill which occurred when Canada owned the facility. This contamination was discovered in 1999 and was rectified in 2000. In addition, further testing in 2004 revealed one additional area of contamination caused during Canada's ownership of the site. The Utility's claim of approximately $260,000 for indemnification arises under the Transfer Agreement. Although it was expected this matter would be resolved in 2006, this did not occur. The Utility has recently had discussions with Canada and it is expected that this matter will be resolved in 2007.

18. COMMITMENTS

(a) Aishihik Water Licence

The Yukon Territory Water Board issued a water use license in 2002, valid until December 31, 2019, for the Utility's Aishihik Lake facility. In addition to maintaining a minimum and maximum water level, this license commits the Utility to meet a number of future requirements including:

a) annual payments of $25,000 until 2011 for the purpose of construction and maintenance of a heritage camp and delivery of programs at the camp;
b) a Heritage Mitigation Plan. The Utility spent approximately $6,000 in 2006 on heritage projects, expects to spend up to $30,000 in 2007 on heritage projects, and the balance which has not yet been determined in the future; and
c) annual fish monitoring programs.

Fish monitoring programs are also required under an authorization provided by the federal government Department of Fisheries and Oceans, which is valid until December 31, 2019. The costs of meeting these requirements are accounted for as water licence costs in the year they are paid.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

(b) Financial Information System Lease
The Utility leases a financial information system from the parent. Minimum lease payments for the remaining three years are as follows:

2007	$	177
2008		177
2009		147
Total	**$**	**501**

(c) Mayo – Dawson Apprenticeship Benefits Agreement
Under this agreement, the Utility is obligated to annual payments of $15,000, adjusted by the percentage change in the Canadian consumer price index, to both The Tr'ondek Hwech'in and the First Nation of Nacho Nyak Dun. The agreement came into effect July 1, 2004 and expires June 30, 2024. The costs of meeting these requirements are expensed to Administration in the year to which they relate.

(d) Mayo – Dawson Transmission Line Option Agreement
The Utility has provided an option to two Yukon First Nations to acquire up to a $14,470,000 "Indirect Interest" in the Mayo-Dawson transmission system project. The option agreement provides for issuance by the Utility of a long-term instrument repayable over forty years, bearing interest equal to the Utility's blended cost of capital, including a component limited to the Utility's realized return on equity. The option expires January 4, 2007. In accordance with the agreement, one First Nation exercised the option to extend this deadline to July 4, 2007.

19. ENVIRONMENTAL LIABILITIES

The Utility's activities are subject to various federal and territorial laws and regulations governing the protection of the environment or to minimize any adverse impact thereon. The Utility conducts its operations so as to protect public health and the environment and believes its operations are materially in compliance with all applicable laws and regulations. Liabilities will be recorded when the occurrence of an environmental expenditure, related to present or past activities of the Utility, is considered probable and the costs can be reasonably estimated. To date, no such specific liabilities have been recorded in the Utility's accounts.

20. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The fair value of cash and cash equivalents, accounts receivable, diesel contingency fund, and accounts payable approximate the carrying amount of these instruments due to the short period to maturity. The fair value of long-term debt is described in Note 12. The Utility also has access to a $10 million line of credit. The renewal date on the line of credit is October 31, 2009. The account accrues interest on withdrawals at prime rate. The facility was not drawn on at year-end.

The Utility is not exposed to significant interest rate risk due to its long-term debt having fixed interest rates. The Utility's credit risk is minimal in that its primary customer is a regulated utility.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2006

21. SUBSEQUENT EVENT

On February 8, 2007, the Utility signed a Power Purchase Agreement (PPA) with Minto Explorations Limited, an industrial mining customer. Under this agreement, the Utility has agreed to construct a power line to the mine site to deliver electricity from its grid for the mine's operation. The mine is expected to be in operation by mid-2007 and the current estimate of the mine's life is 7.2 years. There is no immediate financial effect on the Corporation from the signing of this agreement. The agreement was conditional on receiving Yukon Utilities Board approval of that agreement by April 30, 2007. On April 30th the YUB denied the Utility's application for approval. In its decision the YUB directed the parties to endeavor to reach a new agreement in principle consistent with the YUB findings. Subject to the parties coming to such an agreement (and that agreement being approved, as and if required, by the YUB) ,and also assuming the Utility receives a number of other regulatory and internal approvals, the line is currently forecast to be constructed and operational by the third quarter of 2008. The cost is expected to be funded by contributions from Minto Explorations Ltd, the Yukon Government and the parent, Yukon Development Corporation.

22. COMPARATIVE FIGURES

Certain 2005 figures have been reclassified to conform with the current year's presentation.

REFERENCE: **General**

ISSUE: **Map of System**

PREAMBLE:

CW wishes to better understand the proposed capital additions and system operation.

QUESTION:

a) Please provide a system map or maps appropriately showing the locations of each of the communities served, transmission facilities by number and generating units (size of units) at each location.

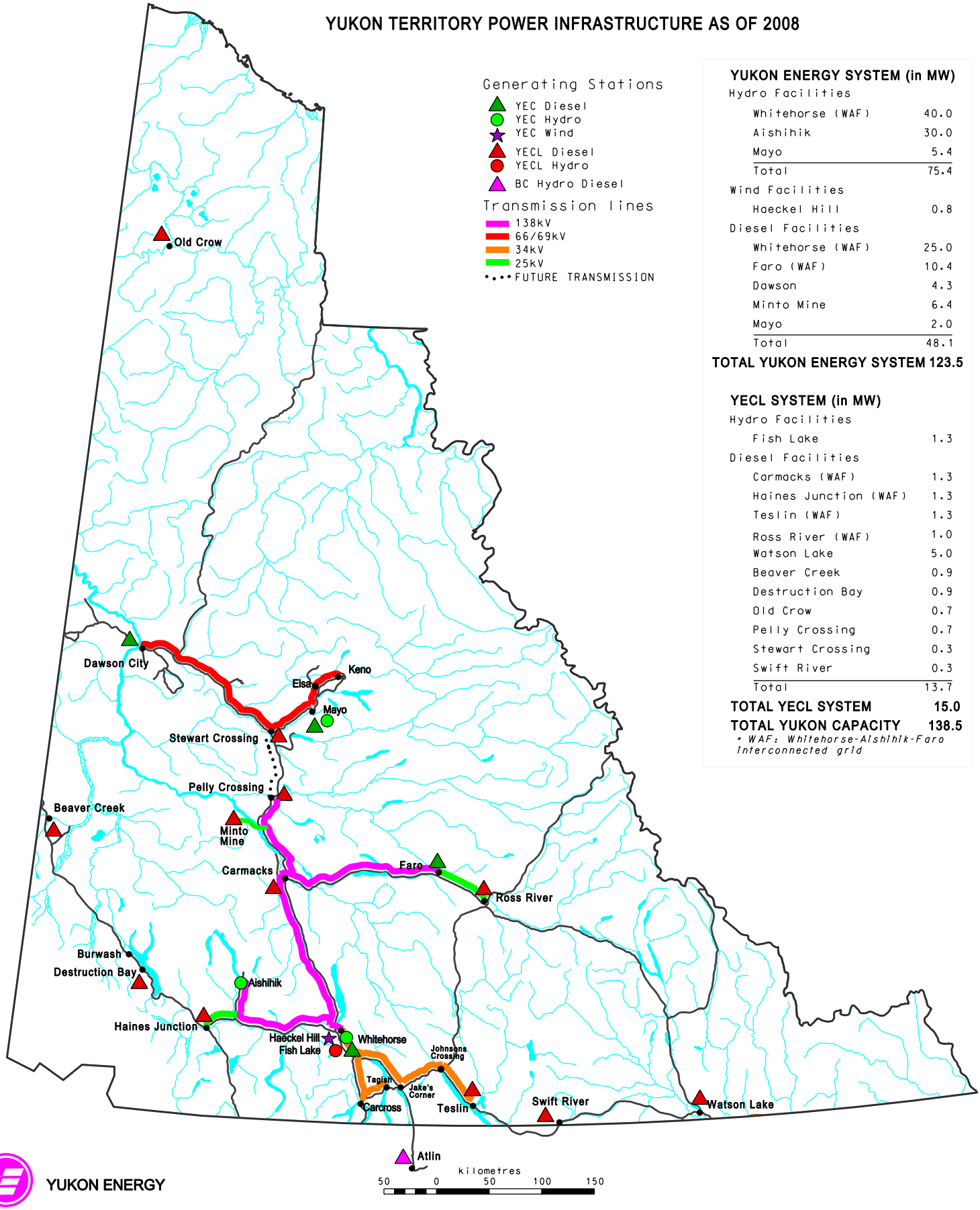
ANSWER:

(a)

The latest map of Yukon power facilities (as of December 2008) is provided as Attachment 1 to this response. The map reflect the following:

- Carmacks-Stewart Stage 1 and Minto Mine Spur
- Minto Mine Diesel Units (6.4 MW)
- Faro Mirrlees diesels (increasing Faro diesel plant to 10.4 MW)
- DD4 and YM-1 mobile removed from Dawson Diesel plant (lowering capacity to 4.3 MW)
- Whitehorse diesel plant (remains at 25 MW, reflecting no derating of the three Mirrlees engines at the plant).

YUKON TERRITORY POWER INFRASTRUCTURE AS OF 2008



YUKON ENERGY SYSTEM (in MW)

Hydro Facilities	
Whitehorse (WAF)	40.0
Aishihik	30.0
Mayo	5.4
Total	75.4
Wind Facilities	
Haeckel Hill	0.8
Diesel Facilities	
Whitehorse (WAF)	25.0
Faro (WAF)	10.4
Dawson	4.3
Minto Mine	6.4
Mayo	2.0
Total	48.1
TOTAL YUKON ENERGY SYSTEM	**123.5**

YECL SYSTEM (in MW)

Hydro Facilities	
Fish Lake	1.3
Diesel Facilities	
Carmacks (WAF)	1.3
Haines Junction (WAF)	1.3
Teslin (WAF)	1.3
Ross River (WAF)	1.0
Watson Lake	5.0
Beaver Creek	0.9
Destruction Bay	0.9
Old Crow	0.7
Pelly Crossing	0.7
Stewart Crossing	0.3
Swift River	0.3
Total	13.7
TOTAL YECL SYSTEM	**15.0**
TOTAL YUKON CAPACITY	**138.5**

* *WAF: Whitehorse-Aishihik-Faro Interconnected grid*

YUKON ENERGY

YUKONMAP.DGN Dec 2008

LEADING EDGE
(LE)

REFERENCE: **Tab Introduction to Application; page (P) 2, first paragraph**

QUESTION:

a) Please confirm that YEC does not serve retail customers in Keno City but does serve retail customers in Faro.

ANSWER:

(a)

Confirmed.

REFERENCE: **Tab Introduction to Application; P 5 top, (1.c.i.)**

QUESTION:

a) Were any of YEC's Board of Directors, or YEC's CEO, or those preparing the Yukon Energy GRA aware that an Order in Council containing the directives ultimately contained in OIC 2008/149 would be coming into effect prior to the filing of Yukon Energy's 2008-2009 GRA? If so which of the above were aware of the coming order?

ANSWER:

(a)

Please see response to YUB-YEC-1-20.

REFERENCE: **Tab Introduction to Application**

QUESTION:

a) If the answer to LE-YEC-1-2 is no, who gave instructions to those preparing the GRA that no provisions for a Phase II hearing were to be made?

ANSWER:

(a)

See response to LE-YEC-1-2 and YUB-YEC-1-20.

REFERENCE: **Tab Introduction to Application; P 11, end of 2, and P 13-14**

QUESTION:

a) Correspondence on this GRA since the filing of Yukon Energy's application suggests that no discussions with YECL regarding adjustments to the General Service customer classes have yet taken place. Is this still the case or are discussions now underway?

ANSWER:

(a)

No discussions are currently underway with YECL in regards to any possible future adjustments to the General Service customer classes.

REFERENCE: Tab 1 Introduction; P 1-6, Line (L) 24

QUESTION:

a) Was the failure being referred to here in the transmission line itself or elsewhere in the plant? Please explain in detail.

ANSWER:

(a)

The failure was related to the cables at the Aishihik Generating Station. A copy of the April 11, 2006 detailed report provided to the Yukon Utilities Board in relation to this matter is provided as Attachment 1 to this response.

YUKON ENERGY

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FAXED 4 11 06

April 11, 2006

Ms. Wendy Shanks
Acting Chair
Yukon Utilities Board
19-1114 First Avenue
Whitehorse, Yukon Y1A 1A3

Dear Ms. Shanks,

RE: January 29, 2006 Outage Response and Reliability Plans

In response to the Yukon Utilities Board ("YUB") letter dated March 2, 2006, this submission contains the information as requested regarding the January 29, 2006 power outage on the Whitehorse-Aishihik-Faro (WAF) electrical grid in terms of emergency response and longer-term power reliability plans.

This submission contains the three questions asked by the Board and the utility's response.

1. ***Outline the circumstances that caused the January 29, 2006 outage (a) and how YEC responded to this emergency (b) the likelihood for the event recurring (c) and what emergency plans YEC has in place for such an event (d). Outline what other system vulnerabilities are present and how they are being addressed, such as a potential fire at either the Aishihik plant or Whitehorse diesel plant (e).***

   a. On January 29 at approximately 13:34 the outgoing feeder at the underground Aishihik powerhouse tripped off due to a differential over-current fault on Aishihik outgoing feeder cables. The trip of the outgoing feeder also caused Aishihik unit 2 to trip off on over-speed. This resulted with the loss of both Aishihik units which, at that time, were supplying 49% of the total WAF generation as shown in the table below:

Generating Unit	Output in MW's	Output in %
Whse. Hydro Unit 4	18.2	37.1
Aish. Hydro Unit 1	11.9	24.3
Aish. Hydro Unit 2	11.9	24.3
Whse. Hydro Unit 3	7.0	14.3
WAF grid total	49.0	100.0

The resulting loss of generation resulted with a Whitehorse area blackout within seconds (WH3 remained on line until 14:03, energizing the 138kV system, with

those customers fed directly from the transmission through PT sub's i.e. Mendenhall and Deep Creek). The cause of the fault at the Aishihik Plant was determined to be a short in one of the cables running from the underground powerhouse to the surface substation. There are nine cables, three cables per phase running from the underground powerhouse to the substation. One of the cables on A-phase suffered a catastrophic insulation failure that also damaged one of the B-phase cables that was adjacent to it. There is no alternate route for power from Aishihik station to be delivered to the transmission system other than through these cables.

b. The following sequence of events describes the outage and subsequent restorative and other actions taken by Yukon Energy in response to this emergency. A more complete review of Yukon Energy's secondary sales management during this period has been provided to the Board in Yukon Energy's March 13, 2006 filing in response to the YUB's letter of February 23, 2006 regarding a Utilities Consumers' Group complaint. For any additional information with respect to the restoration of power within the Whitehorse distribution system the Yukon Electrical Company Limited should be consulted as they have the operational responsibility for that system.

- 13:34 Jan. 29- Aishihik Hydro Plant separated from the 138 kV transmission system. AH1 remained on line feeding Haines Junction until 14:06. The plant was generating approximately 49% of the system generation at the time of the event.
- 13:34 - As a result of the lost generation from Aishihik Hydro Plant the remaining system generation (Whitehorse Hydro Units 3 and 4) were unable to carry the load. As a consequence Whitehorse distribution 34 kV primary feeder breakers trip due to under-frequency and under-voltage conditions.
- 13:34 - WH4 tripped due to over-speed.
- 13:40 - The Takhini switching station reactor tripped due to an over-current fault condition.
- 138 kV transmission line to Aishihik and Faro remained in service, being supplied by WH3.
- 13:42 – local Whitehorse system restoration was started. Restoration of Whitehorse was initiated using Whitehorse Hydro units 1 & 2 and local Whitehorse diesel. Aishihik Hydro Units 1 & 2, Takhini reactor and Whitehorse Hydro Unit 4 were unavailable due to trip conditions requiring further investigation. Whitehorse Diesel Units 1, 2, 3, 4, 6, 7 were available. WD5 was unavailable as it was out-of –service for maintenance.
- 13:44 - Faro and Ross River power was restored using local Faro diesel. Carmacks, Ross River, Haines Junction, and Teslin have their own local diesel owned by YECL.
- 14:03 - WH3 tripped and the head-gate closed.
- 14:06 – AH1, feeding Haines Junction, tripped off.
- Restoring the Whitehorse distribution system is slowed down due to the smaller size of available hydro units limiting their ability to pick up larger

blocks of loads. YECL was advised to sectionalize the Whitehorse distribution system into smaller loads of up to 2 MW's. This was acknowledged and done.

- Around 15:00, Yukon Energy contacted YECL specifically to request that they immediately contact all non-SCADA secondary sales customers and notify then that the 24-hour notice period for disconnection was being triggered and also, due to the current grid emergency, that if their secondary power systems were off, requested that they leave them off, or if they had turned them back on, requested that they shut them off. In addition, YECL was requested to contact the one SCADA-customer to remain off. YECL has informed us that these actions did take place that afternoon.
- 16:19 - WH4 was returned to service, which considerably increased the generation capacity and stability of the system.
- 17:13 - Full re-connection from the 138 kV transmission system and the 34 kV Whitehorse distribution was completed. Full restoration of power to all Whitehorse area distribution customers took several more hours by YECL.
- 22:21 - The Takhini reactor was re-energized followed by the transmission line to Faro at 22:26.
- Jan 30 - The cause of the Aishihik breakdown was found to be a faulty cable (1 of 9 cables, 3 per phase) that runs from the switchgear down stairs in the plant to the substation above.
- 7:00 Jan 31- The faulty cable was disconnected and the plant was synchronized to the system. However the plant output was de-rated to 19 MW due to restricted current carrying capacity of the remaining cables.
- 11:00 – Jan 31 – All WAF diesel was shut down.
- At approximately 15:00 on February 6, Yukon Energy notified YECL of the ability to allow reconnection of the one SCADA secondary sales customer (at that point, all WAF diesel generation had been off for 6 days, on-going availability of hydro generation was forecast and consequently Yukon Energy was able to offer limited availability of secondary power).
- At 11:00 on February 8, Yukon Energy notified YECL of the availability of secondary sales for the purpose of reconnecting the remainder of the Secondary Energy customers (by that time the system no longer faced any material risks with respect to the possible need for diesel generation within the next 7 day period.
- Feb 21 – Aishihik cabling was tested for current imbalance and the plant capacity rating was restored to 30 MW.

c. In addressing the likelihood for the event recurring, it is important to note that loss of any one or more generating units on WAF can cause a grid blackout when such individual generating units are supplying between 14 % and 37 % of the total grid generation (as was occurring on January 29, during the winter season). At times of lower grid loads, such as the summertime, often the grid is being supplied by only one or two hydro units. Loss of one or more such units under the

conditions currently applicable on WAF therefore will almost always cause a grid blackout as there is no interconnection with a larger grid thus no potential to import power when it is needed. The probability of an unplanned loss of any one such hydro generating unit is assessed in system capacity planning studies, and (as demonstrated by system experience) is very low; system capacity planning also addresses the availability of other units to restore quickly the grid loads.

The specific event that occurred on January 29th involved failure of a cable connecting the Aishihik generating units with the transmission system. Absent proper remedy to ensure redundancy with regard to this cable connection, the specific event could well occur again. Prior to this event, Yukon Energy had recently adopted revised capacity planning criteria which had noted the need to address Aishihik-related transmission connection reliability, including the need to be able to deal with continuing supply to residential and commercial retail customers in the event of an emergency of this type in future.

The duration of the outage was longer than anticipated due to the loss of multiple generating units that caused the outage and the failure of some generating units to contribute during the restoration. This required modification to the standard blackout restoration plan listed in section d. below. This modification to the plan required utilization of smaller hydro units (WH1,2 instead of AH1, 2 and/or WH4) to bring up load which required more sectionalization of the distribution into smaller loads.

Work is presently underway by Yukon Energy to improve governor response on the Whitehorse Hydro and Diesel units to improve their load pickup capability that will shorten restoration times by reducing the need to sectionalize distribution loads. Discussions are presently underway with YECL to assess what, if any, improvements can be made by both utilities to shorten the restoration periods and to ensure affected customers can obtain more timely information on the extent and expected duration of major disturbances. Improvements under consideration include remote visibility and control of primary distribution breakers from the System Control Center, improved load shedding of distribution load to match loss of generation.

d. The following restoration steps are followed in a normal system disturbance by Yukon Energy's System Control Center (SCC) using its computerized supervisory control and data acquisition (SCADA) system.

- SCC will stabilize the system frequency and voltage if the grid is not in a total blackout situation.
- In a grid blackout SCC will begin restoring power by restarting the larger hydro units, typically Whitehorse Unit 4 and the Aishihik Hydro units.
- Utilizing the SCADA system, SCC will identify which transmission/distribution system breakers have operated and/or the generating unit(s) that have tripped.

- SCC contacts YECL (if the event is on the WAF system) and informs them of the distribution feeders affected and any requirement to sectionalize the load (i.e. breaking up the load into smaller blocks). Sectionalizing the load is dependent on specific feeder loading and the season / temperature i.e. winter.
- SCC contacts the appropriate on-call YEC maintenance staff and prioritizes their activities.
- With the loss of any hydro generation in Whitehorse the operator is also required to spill water to maintain safe operating levels on Schwatka Lake as well as meeting the minimum down stream flow requirements on the Yukon River.
- If the original generation prior to the disturbance remained on line, SCC will, at the direction of YECL, re-close any effected feeder breakers.
- If the cause of the disturbance is a loss of generation SCC will replace the lost output with backup units. Units that have tripped off line may, depending on the cause, be placed back to service and used during the restoration.
- The SCC, in conjunction with YECL service staff (on WAF), restores the system as quickly as possible by utilizing all available generation include diesel. On WAF, YECL prioritizes the order in which distribution customers are restored. The restoration process can and does work around the cause of the disturbances. If there are lines down the other feeders will be restored, if a generator failed others will be used until the repairs have been completed.

e. Loss of multiple generating units or transmission line components remain a vulnerability to the WAF grid, in particular to the Whitehorse area as this is the area of the grid that has had significant growth in both energy sales and local demand since the shutdown of the Faro mine in 1998.

The reasons that the WAF grid is currently vulnerable include the fact that:

- the electrical grid is isolated with no interconnection for backup power,
- it involves (for sound economic reasons) typically radial transmission lines with no alternative transmission routes, and lastly,
- due to small grid loads, it can often be supplied with very few generating units thus making loss of even one generating unit problematic at times and loss of multiple units almost always causing a grid blackout.

The matter of system vulnerabilities and plans to address such capacity planning requirements has been addressed in recent years by various studies. Following these studies, as reviewed below in response to question 2, Yukon Energy has adopted a revised generation capacity planning criteria to address system vulnerabilities (particularly as regards radial transmission connection to the Aishihik generation) and to reduce the duration of major outages and blackouts and the potential for brown-out situations to occur.

With respect to specific vulnerabilities of facilities such as the Whitehorse Diesel Plant, reduction of the vulnerabilities is addressed as part of the Corporation's specific facility corrective action plans listed in Appendix 1 to this letter. See also the response to YUB Question #2. The specific vulnerabilities of the Aishihik plant which led to the January 29th emergency are also addressed in this appendix and the installation of a redundant cabling system from the underground powerhouse to the surface substation has been advanced from 2009 to 2007. The existing 7 cables remaining in the plant are being replaced before the end of June this year with 9 new cables.

With reference to BC Hydro's comments (at page 4-2 of its May 2004 Condition Assessment report) on the low maintenance costs observed on WAF generating units in 2002 and 2003 relative to industry experience, the Corporation notes that major overhauls are amortized in its accounts and thus do not show up in the Corporation's maintenance budgets as reviewed by BC Hydro. Major overhauls are done on hydro units every 10 years. Diesel unit major overhauls are also amortized and thus do not show up as "overhauls" in the Corporation's maintenance budgets. Diesel unit major overhauls are done on the basis of number of hours run and can be run up to 20,000 hours between major overhauls. As all of Yukon Energy's diesel units are now standby units they get very few hours run per year; accordingly, these diesel units currently may get 10 or more years between major overhauls.

With respect to fire vulnerability at the Whitehorse Diesel Plant there is a full dry-pipe sprinkler system throughout the diesel plant and fire shut-off valves are being installed in 2007 on the individual fuel lines to the diesel units.

At the Aishihik Plant there is a sprinkler system in the underground plant, elevator and cable shaft and the above ground service building. In addition there is a sprinkler system surrounding the surface buildings and substation in case of a forest fire. Emergency egress by the plant operator now utilizes both a safe room underground (the surge chamber) and provision for egress out the tailrace tunnel.

2. ***Outline YEC's assessment of system reliability and expand on YEC's response to IR YUB-YEC-1.33.3 in light of the BC Hydro report and the January 29, 2006 power outage.***

Yukon Energy has completed its extensive review of its capacity planning criteria, including the reliability of system supply to the Whitehorse area, and as a result of that review Yukon Energy's Board of Directors in December 2005 adopted new capacity planning criteria applicable to the Whitehorse Aishihik Faro (WAF) grid and Mayo Dawson (MD) grid systems. Yukon Energy has also developed proposals to address near term requirements related to the new capacity planning criteria.

The following new capacity planning criteria have been adopted for the WAF and MD grid systems as a result of its review (no change has been made to the capacity planning criteria for isolated diesel communities):

WAF and MD Systems:

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

b) **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Each integrated grid system (WAF and MD) will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source. This criterion is not extended to major industrial customer loads which typically maintain sufficient on-site diesel for their own emergency purposes (these customers would be informed that they would not receive full supply should the Aishihik line be out of service during the coldest days of winter).

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

The new criteria is based on the approach used by other Canadian utilities today. It requires that Yukon Energy plan its grid systems so that on average no more than two hours of system outages per year would be expected as a result of the amount of generation and related transmission installed. It also ensures that even if a grid system's single largest winter generating or transmission source is lost, the utility can continue to provide power to residential and commercial customers.

The new two-part capacity planning criteria for each Yukon Energy transmission grid system are essentially the same as the capacity criteria recently approved by the regulator for the Yellowknife system. The approach ensures that two different concerns are addressed on an ongoing basis:

- **Probability-based Criteria**: Most Canadian utilities today apply a probability-based approach to evaluate the maximum loads that a given system can safely carry. The new Yukon Energy criteria require each grid system to be planned so that the long-term average number of hours of system outages per year (including outages to

industrial customer loads) due to inadequate installed generation and transmission does not exceed 2 hours/year.

- **Emergency Criteria**: Each grid system will also be planned under the new criteria to carry the forecast peak winter loads (excluding major industrial loads) under the loss of the system's single largest generating or transmission-related source. These emergency criteria address the potential seriousness in Yukon of a sustained outage of the critical component in winter when there is the least amount of sunlight to effect repairs such as to transmission facilities.

The net effect of the new criteria is a 2006 WAF system capacity shortfall of 700 kW, compared with a WAF capacity surplus of about 11,300 kW under the previous capacity planning criteria. Under the new criteria any further load growth on WAF, as well as all future WAF system diesel unit retirements, will require new generation capacity for peak winter loads. Based on assessment of these factors, Yukon Energy has determined that near term projects (i.e., commitments prior to 2009) are required to increase WAF system capacity by between 15 and 27 MW within the next six years (i.e., by 2012) as load grows and certain diesel units are retired at Whitehorse. Capacity shortfalls begin to arise as soon as 2006, even before any Whitehorse diesel units are retired, and become sufficiently material in 2007 to require overall spending commitments exceeding the $3 million level.

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

Yukon Energy has identified three near-term generation or transmission projects of $3 million or more which it is presently considering to commit prior to 2009 to address load growth, the scheduled retirement of certain diesel units at Whitehorse, opportunities to enhance existing facilities, and the adoption of the new capacity planning criteria. Together, these proposed projects along with other system enhancements, will provide over 21 MW of new firm winter capacity, which meets WAF capacity shortfalls by 2012 of 18.7 MW under the current Base Case load forecast as well as 21.5 MW under the Base Case forecast plus the Minto and Carmacks Copper mine loads (assuming new transmission connection for these mines to at least the WAF grid). The major proposals are summarized below along with contingency options to meet WAF loads to 2012.

Aishihik Third Turbine

This is a proposal that was initially reviewed by the Yukon Utilities Board in 1992. A third turbine can be installed at the existing Aishihik generation station at a cost of about $7 million to reduce future costly diesel generation. Yukon Energy received environmental and Water Board approvals for this project under its new Aishihik Water License. If this project proceeds, Yukon Energy expects the turbine to go into production between late 2009 and 2012, depending on electrical needs and what other initiatives are put in place.

Carmacks-Stewart Transmission Line

This project would see a transmission line running from Carmacks to Stewart Crossing, connecting Yukon Energy's two power transmission systems. It will provide long-term benefits to all Yukon ratepayers in that it allows for more efficient use of existing surplus hydroelectric generation and enhances the future development of new least cost power options. The line is forecast to provide the Whitehorse-Aishihik-Faro grid with an additional 5.6 megawatts of firm winter capacity in 2012 at a cost in 2005 dollars of between $30- and $35-million. If the line is built, Yukon Energy is currently planning for it to be in service by late 2008, assuming that all permits and approvals are in place by the end of 2006 and construction commences in early 2007. This project will only go ahead after meaningful consultation occurs with First Nations and all environmental permits are obtained. As well, this project will only proceed if Yukon government infrastructure funding ensures no adverse impact on ratepayers.

Diesel Units Life Extension or Replacement

There are seven diesel generators at the Whitehorse Rapids Generating Station. The three oldest ones are currently scheduled for retirement between 2007 and 2011. Yukon Energy has been looking at whether it is technically feasible to refurbish these units, thus extending their lives by 10 to 20 years at a cost of up to $4.5 million. Refurbishing these units would provide an added 14 megawatts of winter power on the Whitehorse-Aishihik-Faro grid. In order to secure in-service of the first unit by October 2007, planning and commitments for construction/implementation would need to begin by the summer of 2006 of the first unit, plus the plant updating, at an estimated cost of up to $2.5 million.

If it is determined that refurbishing the three units is not technically feasible, Yukon Energy will likely focus on replacing those three units with new and larger diesel generators of at least 8 to 11 megawatts each. The cost in 2005 dollars of new diesel units is expected to be in the range of $0.8 to $0.9 million per megawatt. The first unit would need to be installed in 2007, requiring final planning work on this project by summer 2006, including orders for the necessary engine unit (with cancellation provisions) in order that the unit can be installed by October 2007.

Another option to replacing these three units is to build a second, back-up, transmission line from Aishihik to Whitehorse. The largest single factor affecting the winter reliability on the WAF grid is the Aishihik transmission line: if it goes down the WAF grid loses a large amount of its winter power supply. However, since the option to build a second, back-up, transmission line from Aishihik to Whitehorse appears to be more expensive than diesel-related improvements, it would only be examined if new mines are connected to the Whitehorse-Aishihik-Faro grid without the completion of the Carmacks-Stewart line and without the diesel generators' life extension being technically feasible.

No final decision has yet been made to implement any of these proposed projects. However, given the magnitude of the identified near term requirements on WAF, Yukon Energy is proceeding as required to carry out planning activities that will enable near term development of essential new capacity required on the WAF grid.

Yukon Energy will 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. The last time we submitted a Resource Plan to the YUB was in 1992. The Resource Plan will provide background information on the Yukon's power systems and give an overview of what we expect our near-term and longer-term requirements will be, taking into account a number of industrial development scenarios as well as the new capacity criteria recently adopted by Yukon Energy to better protect customers from outages.

3. ***Outline YEC's priority for responding to items in the BC Hydro report, indicating what recommendations have been implemented and the priority assigned to outstanding recommendations in terms of steps being taken to improve system reliability both in terms of the short and long terms.***

   In 2004 the Corporation commissioned a number of independent engineers to provide an assessment of the current condition and remaining life of the Corporation's key generation and transmission assets and to make recommendations regarding the on-going operation, life extension, and replacement of these assets. The Corporation remains committed to addressing all of the recommendations contained in these reports. A corrective action plan arising from a review of the recommendations is contained in Appendix 1.

   Yukon Energy allocates budgets in its capital plans for each year for upgrades to infrastructure (Transmission lines, Substations, and Generating plants). As there were numerous recommendations arising out of the Generation and Substation Assessment reports, Yukon Energy budgeted over three years; 2005, 2006, & 2007, to complete all of the action plans. Appendix 1 contains the list of Generation and Substation corrective action plans and the current status of each plan. Of 133 items, 44 are complete, and 49 are in progress. The most critical action plans were scheduled to be started in 2005 with the rest scheduled over the subsequent 2 years to balance resourcing requirements. The 2005 action plans included the following high priority activities: purchase of critical maintenance tools such as infrared camera, circuit breaker analyzer, replacement of various battery banks, overhaul of Whitehorse Hydro Unit 1, correcting of Aishihik overhead crane and bulkhead gate deficiencies and the planned replacement of Mayo Hydro T1 transformer in 2007.

   Yukon Energy's ongoing capital and resource planning also focuses on near or longer-term major capital project requirements to the extent that these may arise from the earlier conditions assessment reports.

Yours truly,

David Morrison,
President and CEO

Appendix 1 Detailed Generation and Substation Condition Assessment Corrective action plans

List of Facility/Plant Numbers and Descriptions

Facility Number	Description
P125	Whitehorse Hydro Plant – Units 1,2,3
P126	Whitehorse Diesel Plant –Units 1 thru 7
P127	Whitehorse Hydro Plant – Unit 4
P130	Aishihik Hydro Plant - Units 1,2
S150	Whitehorse Hydro/Diesel Substation
S164	Takhini Substation
S167	Aishihik Hydro Substation
S170	McIntyre Substation
S171	Riverside Substation (in Riverdale)
S249	Mayo Hydro Substation

FACILITY CORRECTIVE ACTION PLAN

Plant	Description	Comments	Planned or Completed	Count of Item	Complete	In Progress
Other						
	1 spare 38kV Vacuum Circuit Breaker	2006 Breaker Install will make one SF6 unit spare	2006	1		1
	1 spare Surge Arrester 108kV(rated 86kV MCOV, 5kJ/kV)	Part of 2005 / 2006 Insulation Coordination	2006	1		1
	3 spare Current Transformers 600/400/100: 5:5:5	Under review	2007	1		
	3 spare Ring disconnect 34.5kV, 600A	Under review	2007	1		
	3 spare Surge Arresters 30kV(rated 24kV MCOV, 5kJ/kV)	Part of 2005 / 2006 Insulation Coordination	2006	1		1
	Purchase Infrared Camera	Completed 2005	2005	1	1	
	Purchasing a Circuit Breaker Analyzer	Complete-Dec 2005	2005	1	1	
	Governor Testing	Governors overhauled every 2 years	2005+	1	1	
	Oil Separators	Oil detection to be added to sumps	2006	1		1
	Brake Dust Collection system - all units	Asbestos linings removed , no further action required	2007	1	1	
	Inspect Reactor phases at Kulan Storage area		2006	1		1
P125						
	HVDC absorption testing of WH1, 2 stators	PI and power factor tests performed annually.	2005+	1	1	
	HVDC testing of WH3 stator and 6.9kV AC Cables	PI and power factor tests performed bi-annually.	2005+	1	1	
	Investigate about spare coils for WH3	Under review	2007	1		
	Load testing the Battery Bank	Will investigate in 2006.	2006	1		1
	Relocation or Automation of Deluge valves	Part of 2006 Gen Capital Work	2006	1		1
	Replace 125VDC cable to Intake Gate house	Looked at in 2005 - decided to keep system as it is.	2005	1	1	
	Unit Protection Documentation and Review, adding or setting up inter-turn winding failure protection	Review as part of overall hydro unit protection standard	2007	1		
	WH1 & 2 single unit operation at the 6.9kV Bus	Under review	2007	1		
	WH2 slip-ring brush gear run-out on positive Slip-ring	Corrected in early 2006	2006	1	1	

FACILITY CORRECTIVE ACTION PLAN

Plant	Description	Comments	Planned or Completed	Count of Item	Complete	In Progress
	Center Rotor & Adjust Guide Bearings	To be done at next major overhaul	2007	1		
	WH1 Overhaul	Completed 2005	2005	1	1	
	WH2 Overhaul	Completed 2004	2004	1	1	
	East Gate Rollers	Completed 2004	2004	1	1	
P126						
	Belly tank fuel level float switch installation or restoration	WD5 comp in 2005, WD4/6 to be done in 2006/7.	2007	1		1
	Check and replace non-functional instruments	WD5 expected completion in April 2006. WD4 in 2006/7 budget.	2007	1		1
	Restore WD7 PLC	Complete Feb 2006. Reconditioned HMI and purchased new power supply.	2006	1	1	
	Thermocouple mechanical switch replacement with a solid state scanner	WD5 completed in 2005. Installed new switch and digital display.	2005	1		1
	WD4,5,6 Cable Replacement		2007	1		
	Winding Insulation Testing	Part of 2006 PM plan	2006	1		1
	Waste Fuel System	Part of Diesel plant modernization	2007	1		
	Fuel Utilidor		2006	1		1
	Refill Swing Arm	Under review	2007	1		
	Testing of pressure vessels		2007	1		
	Air Dryers	Part of Diesel plant modernization	2007	1		
	Crankcase doors on WD4, 5 & 6	Under review	2007	1		
	Belly Tank Controls on WD 4, 5 & 6		2006	1		1
	Maint. Sched. on WD4 & 5 Heat Exchangers	(blank)	2005	1	1	
	Fire Valve	Location of valve under review	2007	1		
	Lube Oil Systems WD4, 5 & 6	Under review	2007	1		
	Positive Ventilation for the 125VDC battery room	Completed in Aug 2004	2004	1	1	
P127						
	Check, Calibrate and Replace the gauges of T9	Protection upgrade in 2004, Planned in 2006	2004	1	1	
	Excitation bus bar replacement	Replaced in 2005. Additional upgrades In progress.	2005	1		1
	Excitation system augmentation	Excitation assessed in 2005 - Excellent condition	2005	1	1	

FACILITY CORRECTIVE ACTION PLAN

Plant	Description	Comments	Planned or Completed	Count of Item	Complete	In Progress
	Excitation transformer forced cooling	Plant Cooling Upgraded instead	2005	1	1	
	Fuse installation on 3 phase cables or replace with single phase cables (excitation and SS xfmr)	Will be done with exciter upgrade	2008+	1		
	HVDC absorption Testing	PI and power factor tests performed annually.	2005+	1	1	
	Implementing dual battery chargers in place of present single charger	Chargers Purchased in 2005, Installation in 2006	2005/6	1		1
	Lower pole brush gear run-out problem	Inspected in 2006, will monitor to next major overhaul	2006	1	1	
	Modification to the generator terminal equipment	Under review	2007	1		
	Power Cable HVDC testing	Currently perform PI and power factor tests.	2005+	1	1	
	Relocate PDA couplers to the bottom of the unit	Couplers were slightly relocated; GE assessment is location is good.	2005	1	1	
	Station service DC Battery replacement	Battery Bank purchased in 2005, Install in 2006	2005/6	1		1
	Rough Load Zone	Study completed in 2001, no further action required	2001	1	1	
	Start Problems	Part of governor work planned in 2006	2006	1		1
	Servo Isolating valves		2005	1	1	
	Oil Containment	Part of 2006 Capital Plan	2006	1		1
P130						
	48VDC battery replacement with station batteries or moving the auto batteries to different location		2006	1		1
	Automatic transfer of DC battery chargers	Reviewed in 2006, not required	2006	1	1	
	Connect motor operators for intake square butterfly valves	Bulkhead gates done in 2005	2007	1		1
	Fire Protection	Generator housing deluge system under review	2007	1		
	HVDC Absorption testing	Currently perform PI and power factor tests.	2005+	1	1	
	HVDC testing of 13.8kV Power Cables	Will develop schedule after new cables installed.	2007	1		

FACILITY CORRECTIVE ACTION PLAN

Plant	Description	Comments	Planned or Completed	Count of Item	Complete	In Progress
	Load testing of Battery bank	Battery Bank replaced in 2005.	2005	1	1	
	PDA testing	Done bi-annually since 2005.	2005	1	1	
	Slip ring brush replacement with standard brushes in place of brushes with copper insert	Exist brushes have performed satisfactory for 30 years	2005+	1	1	
	Split generators at metal clad to two separate units and run cables to a tie breaker at switch yard	Identified in 2007 capital plan	2007	1		1
	Unit Protection upgrade	May be postponed for timing with AH3	2006	1		1
	AH2 Rewind	Rewind Planned for 2006	2006	1		1
	TIV Seal Leaks & positive Pressure		2007	1		
	Crane Cables & Maintenance	Completed 2005	2005	1	1	
	Governor Tests	Governors overhauled every 2 years	2005+	1	1	
	Draft Tube Crane Structure	Sandblasted & repainted	2005	1	1	
	Intake Valves - Align and Motorize		2007	1		
	Air Receivers	Under review	2007	1		
	Oil skimmer in sump	Oil detector	2006	1		1
	Aishihik Bulkhead Gates	Completed 2005	2005	1	1	
	AH2 Vibration Running Signature	Part of Rewind Project	2006	1		1
	AH2 Install Vibration Probes	During Rewind Project	2006	1		1
	Install automatic water deluge system for generators	Needs assessment in 2006 for possible 2007 capital project	2007	1		
S150						
	52-1, 2, 3, 4, 5, 8, 9 Fire stops at cable entry	Part of next PM in 2006	2006	1		1
	52-1, 2, 3, 4, 5, 8, 9 Fixing Rear panel Bolts	Part of next PM in 2006	2006	1		1
	52-11 fixing leaks on phases B & C	Part of next PM in 2006	2006	1		1
	52-12 fixing porcelain damage	Part of next PM in 2006	2006	1		1
	52-15, 52-19 install heaters inside the operating mechanism	Complete breakers being replaced in 2005/2006	2006	1		1
	52-23 grounding	Needs Investigation	2007	1		
	Battery bank replacement	Completed in 2004	2004	1	1	
	Check, Calibrate and Replace the gauges of T2	Part of next PM in 2006	2006	1		1

FACILITY CORRECTIVE ACTION PLAN

Plant	Description	Comments	Planned or Completed	Count of Item	Complete	In Progress
	Check, Calibrate and Replace the gauges of T7	Part of next PM in 2006	2006	1		1
	Phase Identification	Part of next PM in 2006	2006	1		1
	Replacement of 138kV Nucletron switches with post type disconnect switch (89-HT2, 89-HT7)	Inspect and repair as necessary	2007	1		
	Replacement of 34.5kV Circuit breakers	2 Purchased in 2005, Installation in 2006	2006	1		1
	T3, T4 HV arrestor relocation	Insul Coord Study completed in 2005, Arrestor work planned for 2006	2006	1		1
	Timing test - Various Breakers	S150-52-11,12,13,14, & 15 completed in 2005	2005	1	1	
S164						
	Check, Calibrate and Replace the gauges of T7	Part of next PM in 2007	2007	1		
	Installation of a PT sub for Station Service	Under review	2007	1		
	Oil conditioning of R1	Part of next PM in 2007	2007	1		
	Phase Identification	Part of next PM in 2007	2007	1		
	Replacement of damaged insulators	Part of next PM in 2007	2007	1		
	Surge arresters upgrade with MOV type	Insul Coord Study 2005, Arrestor work 2006	2006	1		1
	Timing testing of Circuit breakers	S164-52-1,2,3 tested in 2004	2004	1	1	
	89-1L, 89-1S, 89-1B, 89-2L, 89-2S, 89-2B, 89-3L, 89-3S, 89-3B, 89-R1 disconnect switch (Morgan Power VBV) wiper alignment or replacement with new ones	Inspect and align as equipment is available	2007	1		
S167						
	89-2S, 89-2L, 89-2B, 89-HT3, 89-LT3 bases to be connected to station ground grid	Already done	2004	1	1	
	Battery bank to be fixed to the floor	Part of 2006 PM plan	2006	1		1
	Better mechanical support to the cable risers near R1, 89-LT3	Part of 2006 PM plan	2006	1		1
	Check LV bushings of T3	Planned PM in 2007	2007	1		
	Check, Calibrate and Replace the gauges	Planned PM in 2006	2006	1		1

FACILITY CORRECTIVE ACTION PLAN

Plant	Description	Comments	Planned or Completed	Count of Item	Complete	In Progress
	of T1					
	Phase Identification	Part of 2006 PM plan	2006	1		1
	Repairs to Air Core reactor	Planned PM in 2007	2007	1		
	Retrofitting of 52-R1 pressure relief flaps, door latching and ventilation	Planned PM in 2007	2007	1		
	Surge arresters upgrade and installation for T1 & R1	Insul Coord Study 2005, Arrestor work 2006	2006	1		1
	TI pad to be leveled	Completed in 2005	2005	1	1	
	Timing testing of Circuit Breaker 52-1 ABB HLR	S167-52-1,2 tested in 2004	2004	1	1	
	89-1L, 89-1S, 89-1B disconnect switch (Morgan Power VBV) wiper alignment immediately or replacement with new ones	Inspect and align as equipment is available	2007	1		
S170						
	Check LV Bushings of T1	Planned Maint in 2006	2006	1		1
	Fence Grounding issues to be addressed	Completed in 2004	2004	1	1	
	Phase Identification	Part of 2006 PM plan	2006	1		1
	Rectify oil leaks of 52-1, b phase	Planned Maint in 2006	2006	1		1
	S170-52-1 Circuit Breaker Timing Tests	Both S170-52-1 & 2 were tested	2005	1	1	
	Surge arresters upgrade on T1 with MOV type	Insul Coord Study 2005, Arrestor work 2006	2006	1		1
S171						
	Installation of a PT sub for Station Service	Under review	2007	1		
	Installation of surge arrestors	Insul Coord Study in 2005, Arrestor work in 2006	2006	1		1
	Phase Identification	On-going, as equipment is scheduled out-of-service	2006	1		1
	Replacement of damaged insulators	Breaker insulators replaced	2005	1	1	
	Replacement of L172PT B phase leaking top Capacitor	Under review	2007	1		
	Timing testing of Circuit breakers	S171-52-1, 3 & 4 tested in 2004	2004	1	1	
S249						
	Grounding issues with 6.9 &12 kV hook stick operated disconnect bases to be	Under review	2007	1		

FACILITY CORRECTIVE ACTION PLAN

Plant	Description	Comments	Planned or Completed	Count of Item	Complete	In Progress
	addressed					
	Phase Identification	On-going, as equipment is scheduled out-of-service	2007	1		
	Refurbish or replace T1	Part of Capital plan for 2007	2007	1		
	Refurbish or replace T2	T1, T2, & T3 back each other up	2007	1	1	
	Refurbish or replace T3	T1, T2, & T3 back each other up	2007	1	1	
	S7745,7747,7749,7750 & S249 bases to be connected to station ground grid	To be done during T1 replacement	2007	1		
	Surge arresters relocation & Upgrade	Mayo Arrestor work in 2007, will coordinate with T1 replacement	2007	1		1
Grand Total				**133**	**44**	**49**

REFERENCE: **Tab 1 Introduction**

QUESTION:

a) Further to LE-YEC 5, a fault at the Aishihik plant also caused a system wide outage and kept the Aishihik plant off-line for a period of time late in 2008. Please describe the faulted component and indicate how long the plant was restricted in its output.

ANSWER:

(a)

On December 1, 2008 a pothead connecting a reactor to buss work at the Aishihik switchyard failed. This caused the Aishihik plant to shutdown and subsequently caused the entire WAF grid to shutdown. The output of the plant was restricted from approximately 2:00 pm on December 1, 2008 to 7:00 pm on December 2, 2008.

REFERENCE: **Yukon Energy System Sales and Generation; P 2-2, L 13**

QUESTION:

a) Please describe the forecasting methodology that was used for the 2008 and 2009 retail sales forecasts.

ANSWER:

(a)

YEC uses customer data for the prior 3 years in order to determine the monthly average use per customer. This average use per customer is multiplied by the forecast number of customers to derive forecast sales by month by rate class.

For each community, customer counts and usage from the most recent year are reviewed in order to determine whether the number of residential or general service customers, or usage, was impacted (or is forecast to be impacted) by a major project.

Based on consultations with each YEC community Senior Serviceman and Distribution Technician, provisions are made regarding the timing of new customer connections and the forecast additional load that they will represent. These new customers are added to the average use per customer analysis to arrive at the business plan forecast.

To achieve more accurate monthly average usage forecasts for General Service customers in Faro and Mayo, the larger loads of Anvil Range Mine and Alexco Resource Corp. (Alexco) are removed before determining the monthly average use per customer. These larger accounts are then forecast based on consultation with each customer regarding upcoming season events. For example, the 2009 General Service forecast includes 2 GWh of sales to Alexco for a bulk sampling program (based on discussions with Alexco), while Anvil Range water treatment is forecast to be average this year subject to whether there is a larger than average snow pack or a very rainy spring/summer.

Streetlights and Sentinel Lights are assumed to be the same levels as the prior year unless YEC is informed in advance that a municipality is engaging in a subdivision

expansion program during the upcoming year. YEC was not advised of any additions at the time of preparation of our 2009 forecast.

REFERENCE: **Tab 2 Yukon Energy System Sales and Generation; P 2-7, L 18**

QUESTION:

a) Are discussions with Alexco Resource Corp. on a power purchase agreement now underway?

ANSWER:

(a)

Discussions with Alexco Resource Corp. are currently underway but have not concluded. The special issues and considerations peculiar to the Power Purchase Agreement with Minto Mine are not anticipated with regard to providing service to an area previously service by YEC, i.e., United Keno Hill Mine.

Order in Council 2007/94 stipulates that rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39 provided as an Attachment to the OIC. This effectively diminishes rate concerns to be addressed with regard to the service to be provided to Alexco. Further, risks relating to financing of capital cost contributions that were present in the Power Purchase Agreement with Minto are not expected to arise in relation to any agreement with Alexco.

REFERENCE: Tab 2 Yukon Energy System Sales and Generation; P 2-7, L25

QUESTION:

a) What was the reason for the 3.1% decline in firm retail sales in 2006?

ANSWER:

(a)

This decline is due to decrease in general service sales. As detailed on page 2-8 of the Application (lines no. 7-11), lower general service sales starting in 2006 and 2007 compared to 2005 can be attributed to a decline in total Faro load, related to the varying load for dewatering activities at the Faro mine site. Total Faro general service load dropped from 7,091 MW.h in 2005 to 5,488 MW.h in 2006 and 5,398 MW.h in 2007. This change in load is fundamentally due to changes at the Faro Mine site.

REFERENCE: **Tab 2 Yukon Energy System Sales and Generation; P 2-9, L 23**

QUESTION:

a) Please indicate on how many days in 2009 peaking diesel is forecasted to be required.

ANSWER:

(a)

Yukon Energy does not have daily peaking diesel forecasts; however, hourly forecasts based on monthly load duration curves are provided in YECL-YEC-1-23(b).

REFERENCE: **Tab 2 Yukon Energy System Sales and Generation; P 2-9, L 23**

QUESTION:

a) Please confirm the indication in the Application that on days that diesel peaking is required this is only for portions of those days? Please confirm that this has not already been required in the 2008-2009 winter season.

ANSWER:

(a)

Peaking diesel is typically only required for portions of the day. This occurred on WAF from approximately December 16-23, 2008 and from December 29, 2008 to January 11, 2009.

REFERENCE: **Tab 2 Yukon Energy System Sales and Generation; P 2-9, L 23**

QUESTION:

a) At approximately what Whitehorse temperature will peaking diesel be required? At what Whitehorse temperature will 24 hour peaking diesel be required?

ANSWER:

(a)

Peaking diesel requirements are dependent on more variables than just temperature, such as other loads and time of day. Peaking diesel is generally required on the WAF grid once daytime temperatures reach below -25 Celsius.

Under current loads, there is no reasonable temperature at which peaking diesel would be expected to be required on a 24 hour basis.

REFERENCE: **Tab 2 Yukon Energy System Sales and Generation; P 2-9, L 23**

QUESTION:

a) At approximately what Dawson City / Mayo temperature will peaking diesel be required on the M-D system? At what Dawson City temperature will 24 hour peaking diesel be required?

ANSWER:

(a)

At present loads, peaking diesel will be required on the Mayo/Dawson system at approximately -40 Celsius. Under present loads, 24 hour peaking diesel is not anticipated.

REFERENCE: **Tab 2 Yukon Energy System Sales and Generation; P 2-12, L 4**

QUESTION:

a) At approximately what percentage of long term average water inflow into the Aishihik system (or the Whitehorse Rapids hydro system) will there be an energy constraint on secondary sales?

ANSWER:

(a)

There is no specific threshold Aishihik inflow that would be used to constrain secondary sales at any given point in time. Any decision to constrain secondary sales would be based on several factors that would include actual and forecast inflows to both Whitehorse and Aishihik systems, actual and forecast water levels in Marsh Lake and Aishihik Lake reservoirs, water license constraints and forecast firm and secondary power sales.

In regards to the test years, Yukon Energy assessed the situation where Aishihik started fall 2008 at full levels, and using forecast loads (including secondary sales) determined that even with Aishihik inflows at 50% of normal during the following 1.5 year period (to spring 2010) Aishihik would not reach its lower supply level by that time.

REFERENCE: **Tab 2 Yukon Energy System Sales Generation**

QUESTION:

a) Further to LE-YEC-1-14, at what percentages of these flows will diesel energy be required to serve firm load, assuming no net drawdown from storage?

ANSWER:

(a)

Baseload diesel generation is not anticipated to be required to serve firm load in 2009 under basically any water flow conditions.

As noted in LE-YEC-1-14(a), in the event very low flows occur at Aishihik during 2009, and forecasts indicate that Aishihik will reach its lower supply level by spring 2010 (necessitating diesel baseload generation to serve firm load), secondary sales would be interrupted for water flow reasons, which would reduce the extent of Aishihik drawdown and help ensure baseload diesel is not required in 2010.

In general, any time secondary sales are constrained, hydro generation is at the maximum available. Diesel would be required to serve any loads that exceed the hydro generation available from actual inflows to YEC's hydro reservoirs, in order to have no net drawdown from storage.

REFERENCE: **Tab 2 Yukon Energy System Sales Generation; P 2-11, L 18 and L 21**

QUESTION:

a) Please explain in detail the range of summer (June through August) capacity and energy loads, the hydro capacity and energy available, and the surplus capacity and energy available to serve secondary sales.

b) How much load following from day to night can and is being carried out by the Whitehorse Rapids hydro facility during winter season?

ANSWER:

(a)

Please see the monthly load duration curves provided in response to YECL-YEC-1-50 (a) to (c).

(b)

During the wintertime the Whitehorse Rapids Hydro facility output is varied from day to night for load following; the maximum amount varied is as much as 7 MW from peak daytime periods to low load nighttime periods.

REFERENCE: Tab 2 Yukon Energy System Sales Generation; P 2-12, L11

QUESTION:

a) What is the winter capacity of the Mayo Hydro plant?

ANSWER:

(a)

The winter capacity of the Mayo hydro plant is currently approximately 4.9 MW, depending on water conditions such as the level of Wareham Lake.

REFERENCE: **Tab 2 Yukon Energy System Sales and Generation; P 2-12, L 25**

QUESTION:

a) Are the diesel generation efficiencies specified before or after auxiliary and station service loads (including step-up transformers)?

ANSWER:

(a)

Diesel generator efficiencies used are gross efficiencies as measured at the generator output leads. They do reflect generator losses and any parasitic losses for devices that are mechanically directly connected to the engine. They do not reflect any electrical station service losses or transformer losses.

REFERENCE: **Tab 1 Introduction; P 2-13, L6**

QUESTION:

a) Has any diesel generation occurred at either Faro or Minto to date this winter? If not, why not, and when will the Faro and Minto units be available for diesel peaking?

ANSWER:

(a)

There has been 66 MWh of generation in Faro for the period of November 2008 to January 2009. For further information on the FD1 unit please see response to LE-YEC-1-54.

Minto diesels have not been used over this period for general WAF support or peaking.

REFERENCE: **Tab 2 Yukon Energy System Sales Generation; Introduction; P 2-13, L 6**

PREAMBLE:

In this application Yukon Energy describes the need, starting in the test years, for diesel generation to meet peak loads during very cold weather (P 2-11 and elsewhere), and the need for higher residential runoff rates to discourage the installation of electric baseboard heating (Introduction to the Application P 10-11 and elsewhere) and that Yukon Energy will be spending $15.8 million on feasibility studies and planning for new renewable energy supplies (page 5-20). Conspicuous by their absence in any of these discussions and financial requests are descriptions of any plans to manage customers to discourage the installation of electric baseboard heaters.

QUESTION:

a) Please describe, for all consumer classes, the energy efficiency programs that Yukon Energy has studied and provide copies of these studies.

ANSWER:

(a)

Yukon Energy has not carried out any material studies related to energy efficiency programs or DSM programs. Energy efficiency programs are most effective when established with a sufficient public profile and coordinated across fuels and across customers in Yukon. This coordination role is currently undertaken by Energy Solutions Centre (ESC) as a department of government.

The link below is EMR's compilation of relevant Yukon Government programs.
http://www.gov.yk.ca/energy/

Yukon Housing Corporation also administers the EnerGuide for New Houses, or EcoEnergy programs (which appears to only be applicable if the houses are electric heat). See also response to UCG-YEC-1-59(c).

Yukon Energy continues to work cooperatively with ESC on these issues.

Further, it is noted that energy efficiency and DSM activities focus on end-uses of electricity. Yukon Energy does not primarily serve end users as these customers are primarily served by YECL.

Please see also response to UCG-YEC-1-20 for more detailed discussion on DSM.

REFERENCE: Yukon Energy System Sales Generation

PREAMBLE:

In this application Yukon Energy describes the need, starting in the test years, for diesel generation to meet peak loads during very cold weather (P 2-11 and elsewhere), and the need for higher residential runoff rates to discourage the installation of electric baseboard heating (Introduction to the Application P 10-11 and elsewhere) and that Yukon Energy will be spending $15.8 million on feasibility studies and planning for new renewable energy supplies (page 5-20). Conspicuous by their absence in any of these discussions and financial requests are descriptions of any plans to manage customers to discourage the installation of electric baseboard heaters.

QUESTION:

a) Please describe, for all consumer classes, the peak load shaving programs that Yukon Energy has studied and provide copies of these studies.

ANSWER:

(a)

Yukon Energy developed a peak shaving component of the new Rate Schedule 39 for major industrial customers (See Application, Tab 4, Appendix 4.1, Rate Schedule 39).

Please see response to LE-YEC-1-20. Yukon Energy has not undertaken any material studies related to energy efficiency programs, including peak load shaving programs.

REFERENCE: Yukon Energy System Sales Generation

PREAMBLE:

In this application Yukon Energy describes the need, starting in the test years, for diesel generation to meet peak loads during very cold weather (P 2-11 and elsewhere), and the need for higher residential runoff rates to discourage the installation of electric baseboard heating (Introduction to the Application P 10-11 and elsewhere) and that Yukon Energy will be spending $15.8 million on feasibility studies and planning for new renewable energy supplies (page 5-20). Conspicuous by their absence in any of these discussions and financial requests are descriptions of any plans to manage customers to discourage the installation of electric baseboard heaters.

QUESTION:

a) Please describe the consumer and contractor awareness and education programs that Yukon Energy has undertaken to inform them about the negative impacts of baseboard electric heating.

ANSWER:

(a)

Please see response to LE-YEC-1-20. These activities would be undertaken by ESC.

REFERENCE: Yukon Energy System Sales Generation

PREAMBLE:

In this application Yukon Energy describes the need, starting in the test years, for diesel generation to meet peak loads during very cold weather (P 2-11 and elsewhere), and the need for higher residential runoff rates to discourage the installation of electric baseboard heating (Introduction to the Application P 10-11 and elsewhere) and that Yukon Energy will be spending $15.8 million on feasibility studies and planning for new renewable energy supplies (page 5-20). Conspicuous by their absence in any of these discussions and financial requests are descriptions of any plans to manage customers to discourage the installation of electric baseboard heaters.

QUESTION:

a) Please describe the support programs that Yukon Energy has undertaken to assist the consumers (residential and commercial) who wish to be rid of baseboard or other electric heating to install non-electric heating systems.

ANSWER:

(a)

Please see response to LE-YEC-1-20.

REFERENCE: Yukon Energy System Sales Generation

PREAMBLE:

In this application Yukon Energy describes the need, starting in the test years, for diesel generation to meet peak loads during very cold weather (P 2-11 and elsewhere), and the need for higher residential runoff rates to discourage the installation of electric baseboard heating (Introduction to the Application P 10-11 and elsewhere) and that Yukon Energy will be spending $15.8 million on feasibility studies and planning for new renewable energy supplies (page 5-20). Conspicuous by their absence in any of these discussions and financial requests are descriptions of any plans to manage customers to discourage the installation of electric baseboard heaters.

QUESTION:

a) If Yukon Energy has not done some or all of the above programs please provide a detailed cost justification for each program not undertaken. Please provide any studies performed in support of Yukon Energy's decisions.

ANSWER:

(a)

Please see response to LE-YEC-1-20. The cost analysis described has not been undertaken and cannot be provided.

REFERENCE: Yukon Energy System Sales Generation

PREAMBLE:

In this application Yukon Energy describes the need, starting in the test years, for diesel generation to meet peak loads during very cold weather (P 2-11 and elsewhere), and the need for higher residential runoff rates to discourage the installation of electric baseboard heating (Introduction to the Application P 10-11 and elsewhere) and that Yukon Energy will be spending $15.8 million on feasibility studies and planning for new renewable energy supplies (page 5-20). Conspicuous by their absence in any of these discussions and financial requests are descriptions of any plans to manage customers to discourage the installation of electric baseboard heaters.

QUESTION:

a) What energy efficiency projects and what off-electric heat projects does Yukon Energy have planned for its facilities?

ANSWER:

(a)

YEC uses electric heat in its facilities, such as space heating for diesel generating stations, only when it is available from surplus hydro. Yukon Energy also expects that by 2009 it will complete a substantial program of turbine performance testing on Whitehorse and Aishihik Hydro units. Please see YUB-YEC-1-38(b).

REFERENCE: Yukon Energy System Sales Generation; Table 2.5

QUESTION:

a) Please explain why the energy supplied by the wind generators has been falling steadily in recent years, and, since wind energy is more abundant in winter than summer, what are Yukon Energy's plans to improve their winter performance to reduce diesel generation?

ANSWER:

(a)

In recent years, production from the wind turbines has been curtailed for the following reasons:

1. The remote and harsh operating environment has resulted in a greater number of equipment failures and caused lengthier periods to effect repairs. Rime icing is common in the early part of winter and often causes the units to shut down for lengthy periods even though the blades are heated.

2. The Vestas turbine was not purchased as a unit designed for operating in a "harsh northern" environment. Hence, the retrofitting has been experimental in nature with little support from Vestas.

3. With no SCADA, the SCC operator was calling the turbines 2x a day. It is often not obvious that there is a problem, since the unit may be in alarm due to icing, etc. that may clear once the weather changes.

4. Due to exterior ladder design, the WW1 unit is not accessible in windy conditions.

5. WW2 (the Vestas 660kW) lost production in 2004 due to failure in its yawing gear. It became a lengthy repair process due to the combination of the remote and harsh operating environment (as noted in item 1 above) and the requirement to transport a 150 tonne crane from Edmonton.
6. Parts from the suppliers are quite expensive for YEC to purchase, and as a result very few spares are kept on site.

7. Due to small size and remote location, support from the vendors has been problematic.

8. Wind on the mountain tops is quite variable; it can often be outside of the operating parameters of the turbines or can prevent work on the units.

9. The priority for repair of the two units is lower than other firm production units, due to lower amounts of generation available from the two turbines.

The actual wind generator output for 2008 was 437 MWh.

The higher forecast for 2009 takes into account the remediation activities planned for 2009. YEC's plan for increasing the output of the wind turbines is to reduce the amount of downtime associated with these units. A comprehensive list of outage issues will be prepared and remediation plans for the high priority items will be made.

REFERENCE: **Yukon Energy System Sales Generation**

QUESTION:

a) Are the leading edge blade heaters on the wind turbines operative?

ANSWER:

(a)

Yes.

REFERENCE: **Yukon Energy System Sales Generation**

QUESTION:

a) Are the wind turbines SCADA controlled, and if not when will they be brought under SCADA control?

ANSWER:

(a)

Please see response to LE-YEC-1-26 which notes they are not SCADA controlled. At the current time there are no plans to bring them under SCADA control.

REFERENCE: **Yukon Energy System Sales Generation**

QUESTION:

a) Where in the order of priority for operational attention and maintenance response are the wind turbines placed relative to other generators on the WAF system?

ANSWER:

(a)

Please see response to LE-YEC-1-26 which lists reasons for curtailed production from the units over the past few years. That response notes that due to the smaller generation offered by the two turbines, the priority for repairing the two units is less than other firm production units.

REFERENCE: **Tab 3 Revenue Requirement; P 3-4, Table 3.2**

QUESTION:

a) At what locations does Yukon Energy purchase wholesale power and what rates are paid for power at these locations?

ANSWER:

(a)

As noted in the Application at page 3-5, Yukon Energy purchases wholesale power from YECL at Johnson's Crossing at a rate of 20 cents/kWh.

REFERENCE: Tab 3 Revenue Requirement; P 3-5, L18

QUESTION:

a) It is stated here that Yukon Energy purchases power from YECL at Johnson's Crossing for $0.20 per kWh. This seems exorbitant considering YECL will purchase this power for $0.0685 per kWh (about one third of the cost) from Yukon Energy. Please explain why Yukon Energy has not addresses this issue with YECL to date.

ANSWER:

(a)

The following was provided in response to YUB-YEC-1-8 (provided during YEC's Required Revenues and Related Matters hearing):

> The current rate schedule for Johnson's Crossing was initially set in 1986 (before Yukon Energy existed) as a result of the construction of the 34 kV powerline line from Whitehorse area south to Teslin. At that time there was a premium put on all customer rates served by this new powerline in order to pay for the line. Retail customers served by the new line were paying in excess of 20 cents per kWh for their energy use. The rate schedules for retail customers served by this line were reduced in 1991 to match the large hydro zone rate schedules. The rate schedule for YECL Wholesale power sales to Yukon Energy at Johnson's Crossing was left virtually unchanged. At the time Yukon Energy's assets and operation were being managed by YECL.

Yukon Energy expects to address this issue at an appropriate time in conjunction with a more detailed review of rate design.

REFERENCE: Tab 3 Revenue Requirement; P 3-7, Table 3.4; and P 3-12

QUESTION:

a) Please provide the organization chart in effect at the start of 2005 and the number of full time equivalents (FTEs) in each position. Please provide an organization chart (and FTEs in each position) that will be in effect for 2009. Please provide a detailed substantiation for each FTE added since 2005.

ANSWER:

(a)

For the organizational chart in effect for 2009 please see Attachment 1 to this response. The organizational chart for 2005 is provided as Attachment 2 to this response.

The employee complement history from 2005 to 2009 is as noted in the table below:

Yukon Energy Corporation
2008/09 GRA
Employee Complement History

Perm & Term	**GRA 2005**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**GRA 2008**	**GRA 2009**
President	2.00	2.00	2.00	3.00	3.00	3.00
Communications	1.00	1.00	1.00	1.00	1.00	1.00
HR & IT	6.00	6.00	6.00	6.00	7.00	7.00
Res Plan & Reg. Affairs	1.00	1.00	1.00	1.00	1.00	1.00
Finance, Billing & Purchasing	10.60	11.60	11.60	11.60	12.80	12.80
Operations	32.00	33.00	37.00	37.00	38.00	38.00
Engineering Services	13.00	13.00	13.33	14.00	12.67	12.00
Health, Safety & Environ	1.00	1.00	1.00	3.00	3.00	3.00
	66.60	**68.60**	**72.93**	**76.60**	**78.47**	**77.80**
Casual & Temporary						
President	-	-	-	-	-	-
Communications	-	-	-	-	-	-
HR & It	-	0.06	0.01	-	-	-
Res Plan & Reg. Affairs	-	0.08	-	-	-	-
Finance, Billing & Purchasing	0.11	0.04	0.10	0.24	0.22	0.22
Operations	1.28	1.82	2.43	1.60	2.20	2.10
Engineering Services	0.23	0.21	0.25	-	-	-
Health, Safety & Environ	-	-	-	-	0.33	0.33
	1.62	**2.21**	**2.79**	**1.84**	**2.75**	**2.65**
Total Before Allocation to YDC	**68.22**	**70.81**	**75.72**	**78.44**	**81.22**	**80.45**
Allocation to YDC						
President	(0.40)	(0.40)	(0.50)	(0.50)	(0.50)	(0.50)
Communications	-	-	-	-	-	-
HR & It	-	-	-	-	-	-
Res Plan & Reg. Affairs	-	-	-	-	-	-
Finance, Billing & Purchasing	(0.75)	(0.75)	(0.21)	(0.21)	(0.21)	(0.21)
Operations	-	-	-	-	-	-
Engineering Services	-	-	-	-	-	-
Health, Safety & Environ	-	-	-	-	-	-
Allocation to YDC	**(1.15)**	**(1.15)**	**(0.71)**	**(0.71)**	**(0.71)**	**(0.71)**
Net						
President	1.60	1.60	1.50	2.50	2.50	2.50
Communications	1.00	1.00	1.00	1.00	1.00	1.00
HR & It	6.00	6.06	6.01	6.00	7.00	7.00
Res Plan & Reg. Affairs	1.00	1.08	1.00	1.00	1.00	1.00
Finance, Billing & Purchasing	9.96	10.89	11.49	11.63	12.81	12.81
Operations	33.28	34.82	39.43	38.60	40.20	40.10
Engineering Services	13.23	13.21	13.58	14.00	12.67	12.00
Health, Safety & Environ	1.00	1.00	1.00	3.00	3.33	3.33
Total Net	**67.07**	**69.66**	**75.01**	**77.73**	**80.51**	**79.74**

Positions Added in 2005

1. **New position added in 2005: Network/Systems Administrator –** This position was required to meet workload demands resulting from the expanding amount of work in the information systems department, primarily in the areas of client support or first line support of workstations, laptops, printers etc. It was needed to improve quality and cost-effectiveness of IS services. Functions performed by the new network/systems administrator had been previously outsourced; however, the performance was deemed unacceptable.

2. **New position added in 2005: Procurement and Contract Administrator –** As the company has grown and the capital requirements have increased the need for support in procurement became acute. This position was added to meet this demand and increasing workload in purchasing areas of the Corporation. This position was carefully reviewed by senior management and considered to be essential and required to meet workload demands in the contracting and purchasing areas of the Corporation.

3. **New position added in 2005: Powerline Technician –** This position was required to build capacity in-house and ensure continued availability of a transmission and distribution crew to meet ongoing construction and maintenance requirements necessary to provide efficient and timely customer service. Further, foreseeable construction work in transmission and distribution justified the need for increasing staffing levels in order to create the capacity to perform this type of work in-house. This includes recent expansion of the grid (CSTP Stage 1), potential future projects (CSTP Stage 2) and required maintenance for aging facilities. Reliance on a single local qualified contractor to address core business requirements exposes the utility to risk as there is no guarantee that resources will be available when required.

4. **Land Technician added in 2005 is scheduled to end December 2009 -** This position was required to ensure that YEC secures the tenure documentation necessary to manage its risks and to ensure access for maintaining system assets, including securing leases, rights of way, easements and title for various land parcels. Once again workload volume in this area was growing dramatically and a decision to hire a land technician was essential.

Positions Added in 2006

5. **Electrical Engineer in Training (EIT) added in late 2006, scheduled to end August 2008 (2 year term) –** This position is essential and required to alleviate work load issues over the short term in the electrical engineering department.

6. **Four new positions added in 2006: 2 Apprentice Power line Technician, SCC Operator, and Manager Operations –** These positions are essential to provide continued efficient and timely customer service. Further, a material portion of Yukon Energy's workforce is becoming eligible for retirement. This includes powerline technician positions in Mayo and Faro, and these technicians will be needed to take over those positions.

   Also, in relation to SCC Operator and Manager Operations positions, Yukon Energy faces material risks due to the loss of significant numbers of employees at a time when the labour force in general is constrained due to an aging workforce and decreasing pool of skilled labour. Loss of workers of retirement age also represents a loss of critical knowledge, skills and experience in operating and maintaining core assets. Yukon Energy has focused on attracting and developing new talent that can develop skills and capture and retain the knowledge base of existing workers.

Positions Added in 2007

7. **New Position added in 2007: Vice President, Operations and Engineering -** The position was created upon the recommendation of the YEC Board and was due to high levels of work load requiring engineering experience at senior levels.

8. **New Position added in 2007: Documentation Specialist –** This position was required to address current limitations in the documentation of procedures at YEC prior to the retirement of employees with expertise in various technical areas. After a review by senior management it was decided that it was necessary to begin to preserve the Corporation's "intellectual capital" by documenting critical operations and maintenance procedures (as well as developing preventive maintenance schedules), transferring knowledge/ skills into procedure manuals. This process will also be linked to developing safe work procedures required to comply with OH&S regulations.

9. **New position added in 2007: Manager, Environmental Assessment and Licensing –** This position was required to address the increased legislated requirements and ongoing workload related to implementing, managing and maintaining environment management systems.

Positions Added in 2008

10. **New Position added in 2008: Records Management Analyst –** This position was required to address material file storage space issues faced by YEC related to records management and library systems. Yukon Energy requires polices, guidelines and procedures be developed and implemented to provide for economy and efficiency in the creation, use, maintenance and disposal of obsolete records.

11. **New Position added in 2008: 2-Year Term Financial Administrator** – This position was required to address additional and material workload requirements in the finance department in 2008 and 2009 related to two major projects (i.e., the GRA and Financial System Replacement).

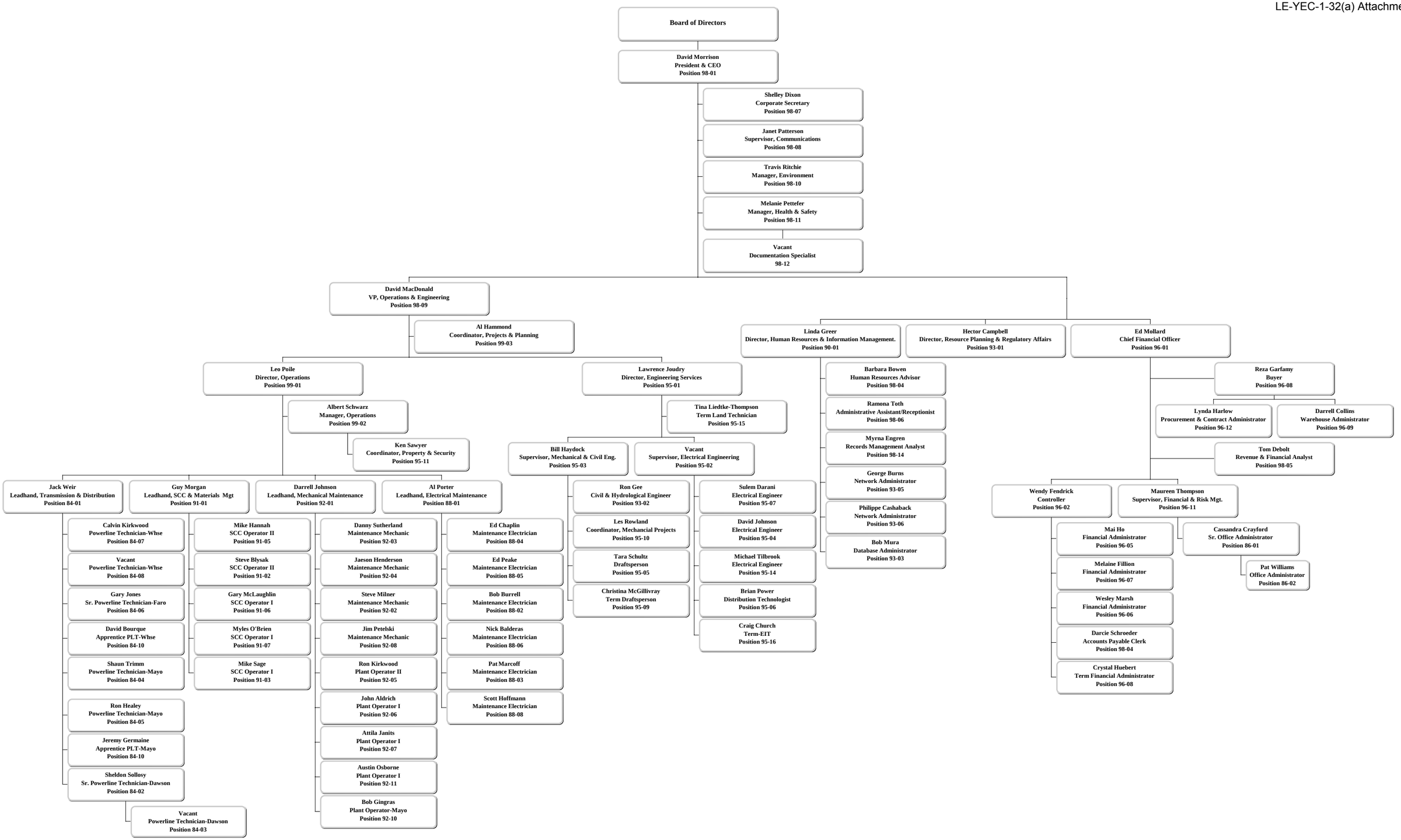
12. **In 2008 Office Administrator will be increased to .80 FTE from .60 FTE due to CIS System Conversion –** This position was deemed necessary to increase by .2 additional hours the FTE of the Office Administrator in order to address increased workload associated with the customer billing system replacement project.

13. **New position added in 2008: Coordinator, Capital Projects –** This position was required to provide coordination support for the various capital projects being undertaken by YEC at this time. It was considered essential to have a position dedicated to prioritizing project activities in order to ensure that they are scheduled with effective timelines and resources consistent with achieving corporate goals and strategies.

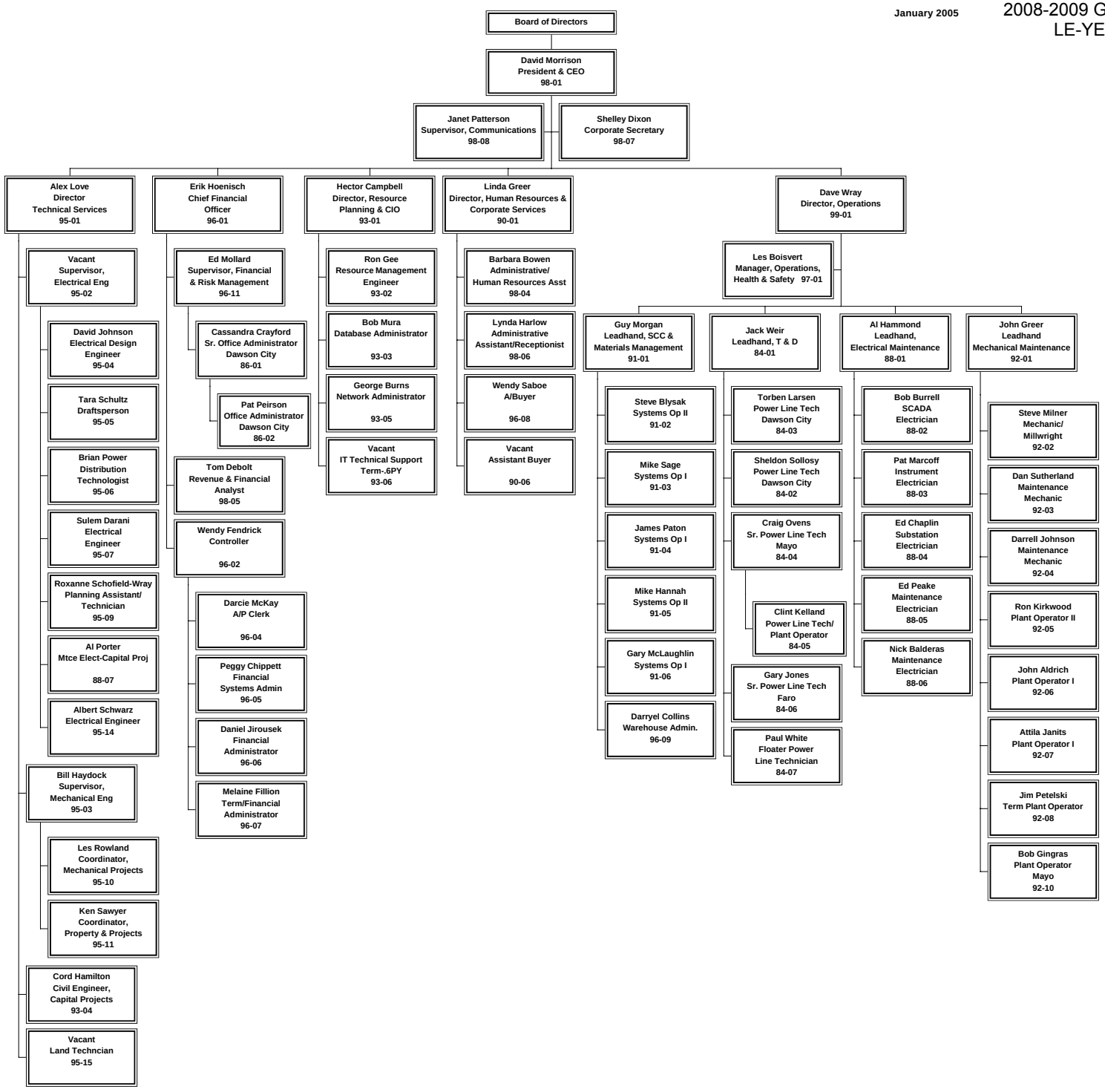
14. **Temp Jr. Environmental Technician summer student for 2008 and 2009 -** This position was required to provide assistance to address the increased legislated requirements and ongoing workload related to implementing, managing and maintaining environment management systems.

For each position added since 2005 workload in each department and area was reviewed in detail by senior management. Each position was considered essential.

Yukon Energy Corporation
January 2009



January 2005



REFERENCE: Tab 3 Revenue Requirement; P 3-8, Table 3.6

QUESTION:

a) For 2008 and 2009 please provide a breakdown of the brushing cost, and kilometers to be brushed, by transmission line.

ANSWER:

(a)

The breakdown of brushing cost and the length of kilometers to be brushed in 2009 is as follows:

Line	Budget %	Estimated Distance (km)
L170 (Faro – Takhini)	60%	50
L355 (Faro Ross River)	30%	15-20
L174 (Mayo-Dawson)	10%	12

The 2008 preliminary actuals are not available.

REFERENCE: Tab 3 Revenue Requirement; P 3-9, L 8

QUESTION:

a) Please describe in detail what the full labour crew will be doing that was previously not done, and justify why these things need to be done now.

ANSWER:

(a)

There is a capital budget increase from 2008 to 2009 of 40% ($0.175 million to $0.300 million) for transmission upgrades. As noted in Tab 5 (page 5-18) transmission lines on the WAF system were constructed in the late 1960's to early 1970's. Due to the age of the YEC transmission system, there is a requirement to replace old or damaged structures. This work includes cross-arms, sway braces and insulation replacement. Any additional damage or wear found by aerial or ground patrols will be prioritized and addressed as required. This work is required to maintain reliability on the transmission system. The "full labour crew" will allow the majority of this work to be performed by YEC, at the necessary levels.

REFERENCE: Tab 3 Revenue Requirement; P 3-19, L 13

QUESTION:

a) Please provide the most recent available information on the present and forecast of future long term Canada bond interest rates.

ANSWER:

(a)

The most recent available information on long-term Canada bond interest rates, as of February 5, 2009, is as follows:

- Current long-term Canada benchmark bond yield per Bank of Canada: 3.72%.

- Forecast 2009 long-term Canada bond yield, per BCUC letter L-55-08 (Nov 20, 2008): 4.35%.

REFERENCE: **Tab 3 Revenue Requirement; P 3-19, L 19**

QUESTION:

a) Why did Yukon Energy finance the purchase of the Minto mine diesels at 7.5% when Yukon Energy has available to it financing from YDC at substantially lower interest rates?

ANSWER:

(a)

The acquisition of the Minto mine diesels was a term of the Minto Power Purchase Agreement (PPA).

The monthly payments by YEC to Minto for the Assignment of the Diesel Units at the Mine Site, pursuant to the PPA, were designed to enhance YEC's security with regard to Minto's obligations to pay the Mine Spur Capital Cost Contribution. In this sense, the payments to Minto for the diesel units mirror the payments to be made by Minto regarding its Capital Contributions for the Mine Spur, with YEC paying for the Diesel Units as Minto pays the costs of the Mine Spur and on the same general terms as the Mine Spur costs are paid off, i.e., in equal blended monthly payments of interest and principal over the first seven years of YEC service (unless otherwise provided for in the PPA). Since Minto's contributions were secured at an interest rate of 7.5%, the financing of the Minto Diesel units was secured at a similar rate of interest.

REFERENCE: Tab 3 Revenue Requirement; P 3-20, L 8

QUESTION:

a) How was the 6.55% interest rate on the Mayo – Dawson Note set?

ANSWER:

(a)

The face value of interest payable on the Mayo-Dawson note is 6.55%. The 2005 Required Revenues and Related Matters Application (Page 5-18 at Footnote 5) provides that the face interest on the note was calculated based on the following criteria:

> Interest rate at 120 basis points over a Canada Benchmark long-term bond at 5.35%, of similar 20-year average life to the Note, and assessed approximately as at the Project in-service date (September 6, 2003).

While the interest payable on the note has a face value of 6.55%, the terms and conditions of the promissory note provide that the actual interest payable in each year may be adjusted downwards to ensure that during the life of the project ratepayers do not pay any more in a given year than otherwise would have been paid had Dawson remained on diesel generation. Please see also UCG-YEC-1-52.

REFERENCE: Tab 3 Revenue Requirement; P 3-20, L 25

QUESTION:

a) Why is the TD Canada Trust note not replaced with YDC debt at a much lower interest rate?

ANSWER:

(a)

As noted in YUB-YEC-1-21 from the 2005 Required Revenues and Related Matters hearing, securing lower financing for this debt is not possible. The balance outstanding on the TD loan is due in 2011, and the terms of the note contain pre-payment provisions that are designed to effectively prevent Yukon Energy from seeing any practical savings from refinancing.

REFERENCE: Tab 3 Revenue Requirement; P 3-21, L 8

QUESTION:

a) What is the purposed ROE for Yukon Energy for 2009 based on the BCUC decision?

ANSWER:

(a)

BCUC Letter No. L-55-08 provides a 8.47% benchmark return on equity for a low risk utility. Considering the 0.52% risk premium proposed for Yukon Energy together with the 0.50% deduction directed by OIC 1998/32, the 2009 fair ROE for Yukon Energy is 8.49%.

REFERENCE: Tab 3 Revenue Requirement; P 3-22, L 16

QUESTION:

a) What is the interest rate earned by the Diesel Contingency Fund?

ANSWER:

(a)

Diesel Contingency Funds are monies invested in a pooled market fund. The short-term securities held in the fund have an average maturity of less than 90 days. Earnings are distributed monthly on a pro-rata share of the total fund. Annual return on investment for 2007 was 4.63%.

REFERENCE: **Tab 4 Rates; P 4-5, L 13**

QUESTION:

a) What is Yukon Energy's forecast of secondary energy rate should world oil prices stay at the current level of about $40 to $50 per barrel?

ANSWER:

(a)

The latest forecast from Bureau of Statistics (January 28, 2009) is consistent with a retail rate of approximately 6.4 cents/kW.h.

The most recent secondary sales advisory report is provided as Attachment 1 to this response.

YUKON ENERGY
CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 5L6
(867) 393-5300

File: 3305-02-04

February 19, 2009

Yukon Utilities Board
Box 31728
Whitehorse, YT
Y1A 6L3

Attention: Ms. Wendy Shanks, Chair

Re: Quarterly Adjustment to Secondary Sales Rates as of April 1, 2009

Pursuant to Rate Schedule 32 Secondary Energy (as approved in Board Order 2005-12), the following sets out the quarterly adjustment to the Secondary Energy rate effective for bills issued on or after April 1, 2009.

April 1, 2009 Rate Determination

As outlined in Rate Schedule 32, the Secondary Energy rate for April 1, 2009 is based on the published Yukon Territorial Government – Bureau of Statistics biweekly price for Furnace Oil in Whitehorse for the three reporting periods prior to the 20th day of February 2009. The lowest value of the three (net of GST) is the "Oil Price Index". The three reported values (including GST) are as follows:

January 14, 2009	= $ 0.963 /litre
January 28, 2009	= $ 0.958 /litre
February 11, 2009	= $ 0.953 /litre

Consequently the Oil Price Index for the April 1, 2009 rate is 90.76 cents/litre (the February 11, 2009 value of 95.3 cents/litre less the GST included in that value). An Oil Price Index of 90.76 cents/litre equals a Secondary Energy price of 6.3 cents/kW.h (compared to the January 1 revised price of 7.8 cents/kW.h) and results in a Rate Schedule 43 Wholesale Secondary energy price of 5.2 cents/kW.h (compared to the January 1 revised price of 6.7 cents/kW.h).

Notification of Interested Parties

Rate Schedule 32 provides that the Secondary Energy Charge is to be filed with the Board at least 30 days in advance of the Rate Period. As with past notifications regarding the rate change Yukon Energy is providing Yukon Electrical Company Limited with notification of quarterly rate changes at the same time as notice is sent to the Board. Retail customers will be notified by a billing advisory message which will appear on their January bills.

Sincerely,



Hector Campbell, P.Eng, I.S.P.
Director, Resource Planning & Regulatory Affairs

c: Yukon Electrical Company Limited

REFERENCE: **Tab 4 Rates; P 4-5, L 22**

QUESTION:

a) Given that diesel generation for peaking will be required more and more starting in 2009, what efforts have Yukon Energy expended to shorten the notice period to cut off and reconnect secondary customers more quickly than the existing 7 days, or the proposed 5 days, to maximize secondary sales during shorter periods of availability? What plans does Yukon Energy have on a go forward basis to deal with this opportunity?

ANSWER:

(a)

First, the notice period for interruption is currently not seven days. The current, approved Rate Schedule 32 provides that customers' supply will be interrupted after 24 hours notice at any time that Yukon Energy forecasts a need to run diesel units for more than 10% of the hours in the subsequent seven day period, or that Yukon Energy begins running diesels for unforecast reasons and expects the diesel operation to continue for more than 48 hours.

Under Rate Schedule 32 secondary sales customers currently have two options for service available with respect to interruption:

- The customer can opt for a standard manual service with their supply interrupted after 24 hours notice at any time that Yukon Energy forecasts a need to run diesel units for more than 10% of the time in the subsequent seven day period, or that Yukon Energy begins running diesels for unforecast reasons and expects the diesel operation to continue for more than 48 hours.

- Alternately, the customer can opt for (and pay for) the costs of installing a SCADA-controlled service which allows Yukon Energy to initiate interruptions on short notice as needed only for actual real-time diesel generation being required on the system. Customers opting for a SCADA controlled load are expected to have more hours of Secondary Energy availability than those with standard service.

REFERENCE: **Tab 4 Rates; P 4-8, L 5**

QUESTION:

a) Given the much lower world oil price today than when the GRA was prepared, does Yukon Energy propose to update their fuel price forecast for 2009, and if so what is the forecast price?

ANSWER:

(a)

Please see response to YUB-YEC-1-30.

REFERENCE: Tab 5 Capital Projects; P 5-3, L 8

QUESTION:

a) Are the final costs for Stage One of the Carmacks – Stewart Crossing Transmission Project (CSTP) and the Minto Spur line now known, and if so what are they? If still not known exactly, what are the most recent estimates?

ANSWER:

(a)

Please see LE-YEC-1-46 and LE-YEC-1-47.

REFERENCE: **Tab 5 Capital Projects; P 5-3, L 28**

QUESTION:

a) What is the length of the Minto Spur line, and what is the cost breakdown between the line and substations?

ANSWER:

(a)

The approximate length of the Minto spur transmission line is 27 km.

The construction costs are set out at LE-YEC-1-47.

REFERENCE: **Tab 5 Capital Projects; P 5-7, L 7**

QUESTION:

a) Please provide a detailed cost breakdown of the $22.6 million CSTP Stage One budget and the same breakdown for the final or latest known costs ($28,394 or otherwise).

ANSWER:

(a)

A detailed cost breakdown of the original CSTP Stage One budget and current (not yet finalized) CSTP Stage One budget is provided below ($000s):

	Original Budget		Construction Approval	Current
CSTP Stage 1 Costs				
Planning	2.700		2.382	2.550
Project Management	n/a	(1)	0.756	1.187
Line Construction	16.400		20.760	21.081
Substations	1.900		1.654	3.250
Owners Costs	n/a	(1)	1.054	1.112
AFUDC	1.000		0.940	0.504
Inflation	0.500		0.242	
	22.500		27.788	29.684
	(2)		(3)	

Notes:

(1) At early stages of planning, project management and owner's costs were not budgeted separately, but instead provided for in the construction costs.

(2) These estimates were prepared prior to any engineering costing. Differences between the Original Budgets totals and $22.6 million total quoted are due to rounding.

(3) Construction approval budget included tendered costs for project management and line construction (including clearing and survey) and engineering cost estimates (substations).

REFERENCE: **Tab 5 Capital Projects; P 5-7, L 17**

QUESTION:

a) Please provide a detailed cost breakdown of the $3.83 million Minto Spur budget and the same breakdown for the final or latest known costs ($9.989 million or otherwise).

ANSWER:

(a)

The detailed cost breakdown of the original Minto Spur budget and the current (not yet finalized) Minto Spur cost budget is provided below ($000s):

Minto Spur Costs	Original Budget		Construction Approval	Current
Planning	0.300		0.904	0.917
Project Management	n/a	(1)	0.492	0.588
Line Construction	2.700		3.623	3.313
Substations	0.500		3.132	5.345
Owners Costs	n/a	(1)	0.289	0.455
AFUDC	0.200		0.298	0.182
Inflation	0.100		0.075	
	3.800		8.813	10.800
	(2)		(3)	

Notes:

(1) At early stages of planning, project management and owner's costs were not budgeted separately, but instead provided for in the construction costs.

(2) These estimates were prepared prior to any engineering costing.

(3) Construction approval budget included tendered costs for project management and line construction (including clearing and survey) and engineering cost estimates (substations).

REFERENCE: Tab 5 Capital Projects; P 5-9, L 1

QUESTION:

a) In table form please provide complete information on each of the Minto diesel units including manufacturer, model, RPM, year of manufacture, total hours of use on each unit, continuous loading capacity in MW, and fuel efficiency in kWh per litre.

ANSWER:

(a)

Please see Schedule G from the Minto PPA provided as Attachment 1 to this response which provides unit descriptions. Section 10.2(e) of the PPA provides that as at Commencement of Delivery each of the units was to have a continuous rating of at least 1600 kW per generator at 4160 V output and conform to the specifications and description in Schedule G. Most recent information of hours of use for each unit is as follows:

- S/n 7RN01200 Current Hours 7,229
- S/n 7RN01123 Current Hours 10,371
- S/n 7RN01208 Current Hours 10,006
- S/n 7RN01079 Current Hours 8,138

Schedule G

FINNING (CANADA)
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Generator Packages

Engine – Caterpillar Model 3516 B
2000 kW Standby/1825 kW Prime Power/ 1600 kW Continuous Duty
Electronic fuel injection turbocharged-after cooled

AIR INLET SYSTEM
Air cleaner, dual element heavy duty with service indicators

CHARGING SYSTEM
Battery charger, current limiting 20 amperes, automatic equalize/float
Charging alternator, 24 VDC, 35 ampere

CONTROL SYSTEM
Governor, Caterpillar ADEM Electronic

COOLING SYSTEM
Radiator, ECO52F stacked dual circuit dual core, 100° ambient with 50/50 glycol/water
Fuel cooler
Jacket water heater, dual 3kW, 120/240 VAC, single phase, 60 Hz
Low coolant level sensor

ENCLOSURES
ISO/TC104, ANSI/MH5.1, UIC592.1 ISO Container With:
Galvanized steel deck on floor, nine motorized air intake louvers, and motorized radiator air discharge roof doors to protect generator set from the weather. Switchgear located in front end of container.
Sound attenuation, including doors and louvers, to give a four point logarithmic average Of 85 dB (A) sound pressure level at a distance of 50 feet measured perpendicular to center of each side of the site at an elevation of 1.5 m (5 ft) above the ground.
Interior walls and ceiling are insulated with 50 mm (2 in) of acoustic glass and covered with aluminum for durable interior wall surface.
Safety decals on interior and exterior of container as required.
120 VAC incandescent light and 24 VDC light, switchgear and generator area

Switchgear has access door on side of module for external access to side of switchgear for cable connections and service. A side load cable opening is provided under bus bars of switchgear for connections. Container has three (3) entrance doors with stainless steel handle and steel hinges with brass pins, which allow access into engine room and switchgear area. ABS and CSC rated. Interior loads feed from circuit breaker distribution located at front of container by the switchgear (jacket water heaters, battery charger, space heaters, 120 V duplex receptacles, lights and fuel transfer pump) are powered off of the load bus, supplied by the utility source.

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Two only portable stairs for access doors
Two only five 5 kW 240 VAC interior space heaters provided in switchgear area and in the generator area

EXHAUST SYSTEM
18" diameter with rain cap, bolt on
Flexible fitting, 305 mm (12")
Muffler, 30 dBA sound reduction of exhaust noise only, internally insulated, mounted inside the container
Exhaust system insulated with 25 mm (1") thick, soft-wrap insulation blanket from engine to module wall

FUEL SYSTEM
Fuel tanks, including level gauge and UL listed
1400 Gallon Double Wall Tank in container with leak detection alarm
Fuel priming pump, RH
Fuel Water Strainer
Automatic/manual fuel transfer system
Level switches control start/stop operation of the fuel transfer system when in the automatic mode
High-level switch prevents over filling in the automatic or manual mode
Low fuel level alarm
Low fuel level shutdown

GENERATORS AND GENERATOR ATTACHMENTS
Brushless PM excited, SR4B
Six lead generator with cable access box, R.H. side
4160V 826F frame (2 bearing) generator vacuum/pressure impregnation insulation protection on stator, form wound.
Volts per hertz automatic voltage regulator-switchgear mounted, BASLER DECS
Space heater, 115/230 VAC, 1200 watts, with cut-out relay

INSTRUMENTATION AND CONTROLS, EMCP II PLUS
Generator mounted, dust proof
Digital (LCD) Indication, keypad accessible
AC voltage (L-L & L-N)
AC amps
kW (total & per phase)
kV-A (total)
kV-AR (total)
kWhr (total)
kV-ARhr (total)

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PF (Average total & per phase)
% of rated kW (total)
Frequency
DC voltage
Coolant temperature
Oil pressure
Rpm
Hours run
System diagnostic
Controls
Auto start/stop
Emergency stop
Lamp test
Cycle crank
Voltage control
Phase selector switch
Load demand relay
Spare relay - programmable
Enclosure
NEMA 1, IP22
Vandal door
Panel lights
Auxiliary relay

INSTRUMENTATION AND CONTROLS, EMCP II PLUS - continued
Indicating Lights
Low oil pressure
High coolant temperature
Over Speed
Over Crank
Coolant level sensor, shutdown or alarm
Emergency stop
Fault shutdown
Fault alarms
3 Spare lights/4 spare inputs
Pre-alarm and LED indicators for:
- Approach high coolant temperature
- Low coolant temperature (70° F.)
- Approach low oil pressure
- Low DC volts
- System not in "automatic"
- Low fuel level

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Charger failure
Low coolant level (shutdown or alarm)
Two (2) spares
Customer programmable (shutdown or alarm) to spare alarm or fault LEDs
Protective relaying
Programmable relays for:
- Over voltage
- Over/under frequency

Customer communication module for ZTR interface

LUBE SYSTEM
Lubricating oil - SAE 10W30, CF4 diesel engine oil
Lube oil drain (located on engine rail)
Lube oil sample valve
Sump pump, RH mounted
Low oil level alarm

STARTING SYSTEM
Batteries and battery rack: CCA rating 2600, 380 ampere-hours, includes 4 batteries above -30°C (-22°F)
Electric starter motor, dual, heavy duty

UNDERCARRIAGE:
Three (3) Axle container under carriage
Mechanical Suspension System
DOT Lighting Package
Air Brakes

GENERAL
Fire extinguisher, two (2), 10 LB, carbon dioxide
First Aid Kit
Literature
Generator test report



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5 KV SWITCHGEAR

Utility paralleling 4160 VAC class switchgear is intended for automatic, manual and black start operation involving a microprocessor based automatic loading control with soft loading, base load control and soft unloading. The controls allow for automatic operation, initiated locally or remotely.

Floor Standing Switchgear Featuring the Following:

Protection
Shutdowns: over speed, over crank, high water temperature, low oil pressure, emergency stop and coolant loss with indicator for each condition.

AC Metering
Three (3) phase volts, three (3) phase amperes and frequency with phase select push-button.
Metering accuracy is 1%.
Power factor meter along with wattmeter

Control
Automatic starting with field adjustable cycle cranks over crank and cool down timer
Programming and diagnostics
Includes field programmable set points for engine control
Failure of the Programmable Logic Controller initiates a visual and audible alarm.

Alarm module
Flashing led warnings for: Low coolant temperature, high coolant temperature (pre-alarm), low oil pressure (pre-alarm), engine control switch not in automatic and low DC voltage. Includes alarm horn and acknowledge push-button.

CONTROLS

Engine Control Switch
Snap action rotary switch, four (4) position - off/reset, automatic, manual, stop/cool down
Off/reset for engine shutdown and resetting faults, automatic for local or remote automatic operation, when initiated by switch operation or contact closure, manual for local starting and manual paralleling, stop/cool down for manual operation cool down.

Circuit Breaker Control Switch
Heavy duty, three (3) position spring return to center with momentary trip and close position and slip contacts (NAC) for automatic closing.
Includes circuit breaker position indicating lamps, lamp test switch, momentary pushbutton

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Emergency Stop Push Button
Mushroom head, twist to reset, causes engine shutdown and tripping of the generator circuit breaker.
Prevents engine starting when depressed

Remote Start/Stop Circuit
Accepts signals (normally open dry contact closure) from remote control or other device to initiate operation
Requires ZTR signals for generator start and generator stop.

Failed to Auto-Parallel
Time delay circuit to cause engine shutdown if the generator circuit breaker fails to close after initiation of automatic operation

Dead Bus Closing Circuit
For Prime power operation only. Permits automatic or manual closing of the generator set circuit breaker to a dead bus.
Low Fuel Level Shutdown
Circuit to cause engine shutdown via dry contact and trip the generator circuit breaker with approximately 15 minutes of fuel remaining in the power module day tank

Electric Louver Control Circuit
Circuit to control power module electrically operated louver.

CIRCUIT BREAKER

Draw out, vacuum type 3 pole, electrically operated 1200amp circuit breaker.
Includes 24 VDC shunt trip coil activated on any monitored engine or electrical fault
Circuit breaker is sized for full load capacity of the generator set at 0.8 power factor, with 36ka RMS interrupting capacity at 4160 VAC.

DIGITAL SPEED, SYNCHRONIZING AND LOAD CONTROL:

Electronic Load Sharing Governor and Associated Circuitry
Woodward DSLC w/Raise-Lower Voltage Switch & Raise-Lower Frequency Switch
Includes VAR/PF Control, Import & Export Capability
Speed Matching Automatic Synchronizer
Automatically synchronizes and parallels the generator with a utility source.
Manual Paralleling
Synchronizing lights (2) and switch for manual paralleling with sync-scope
Automatic Base Load Control

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PLC based system provides soft loading and unloading of the generator set as it transitions on and off of the utility grid. Once the generator is connected to the utility generator output is gradually increased (one (1) minute time frame) up to the base load setting of the load control. Generator output will remain at the base load level until the generator is signalled to shutdown. When signalled to shutdown the load control will gradually decrease (one (1) minute time frame) generator output and trip open the generator circuit breaker when the unload setting of the load control is reached, the engine is then placed in cool down mode.
Field adjustable parameters include load time unload time and base load level (generator steady state output)
The load control is disabled operating isolated from the utility source.
Load Sharing
During prime power operation the engine governor set shall be set for isochronous load sharing with other parallel units.
Site interconnect of the load share lines is required.

Voltage Regulation and Power Factor Control
Switchgear mounted voltage regulator with voltage adjust raise-lower switch.
Power factor control for maintaining constant generator power factor while paralleled with the utility
Includes provisions for manual power factor adjustment
Controls are disabled when operating isolated from the utility.
Current Transformers (3) – Relay Class, Suitable For Metering
5 ampere secondary with shorting terminal strips
Potential Transformers (4) – Relay Class, Suitable For Metering
120 VAC secondary with primary and secondary fuse protection, two (2) connected to the generator side of the circuit breaker, two (2) connected to the utility side of the circuit breaker.
Potential transformers-draw out construction
Control Power Transformers (2)
120 VAC secondary connected to both sides of circuit breaker to supply 120 VAC in open or closed position. Transformer is fixed.
Electrical System Protective Relays
Schweitzer Model SEL-300G Multifunction-relay
Relays include field adjustable pick-up and time delay. Operation of relays is indicated by lamp and sounding of alarm horn, draw-out relay operation is indicated by trip target and sounding of the alarm horn.

Reverse Power Relay
ANSI device 32, single phase sensing, activation of relay causes tripping of the generator circuit breaker and immediate engine shutdown
Reverse VAR Relay
Acting as loss of excitation relay, ANSI device 40, single phase sensing, activation of the relay causes tripping of the generator circuit breaker and immediate engine shutdown.

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Under Voltage Relay
ANSI device 27, three phase sensing. Activation of relay causes tripping of the generator circuit breaker and places the engine in cool down mode.

Over Voltage Relay
ANSI device 59, single phase sensing, activation of relay causes tripping of the generator circuit breaker and immediate engine shutdown.

Over/Under Frequency Rely
ANSI device 81O/U, Ssetting's for over frequency and under frequency with time delays, adjustable in cycles. Activation of relay causes tripping of the generator circuit breaker and places the engine in cool down mode. Relay is disabled when operating isolated from the utility.

Over Current Relay
ANSI device 50/51 activation of relay causes tripping of the generator circuit breaker and immediate engine shutdown. Relay is solid state with instantaneous setting.

Ground Over Current
ANSI device 51G, activation of relay causes tripping of the generator circuit breaker and immediate engine shutdown. Includes current transformer mounted on generator neutral - ground connection.

Lock-out Relay
ANSI device 86, high speed, manually re-settable, operated by protective relays, causes tripping of the generator circuit breaker and prevents resoling of the circuit breaker until reset.
Generator Differential Relay
ANSI device 87, solid-state draw-out type with field adjustable pick-up and time delay. Operation of a relay is indicated by relay trip target and sounding of alarm horn. Relay trips the generator circuit breaker via the generator lockout relay (ANSI device 86) and causes immediate engine shutdown. Includes six (6) current transformers, three (3) mounted within the generator housing on the neutral side of each stator winding and three (3) mounted at the generator circuit breaker.

Auxiliary Trip Circuit
Circuit accepts input (normally open dry contact) from customer's system protective relay(s) or other controlling device. Operation of contacts causes tripping of the generator circuit breaker via the generator lockout relay ANSI device 86, and places the engine in cool down mode. Circuit is disabled when operating isolated from the utility.

Bus Bars - Stabs Only
Three phase plus fully rated neutral bus bars are silver plated copper with NEMA standard hole pattern for connection of load cables and generator cables, bus bars are sized for full load

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capacity of the generator set at 0.8-power factor. Also includes ground bus, silver plated copper, connected to generator frame ground and container frame with holes for connection of field ground cable. Bus bars are accessible from outside of the power module via hinged, lockable cable access door.

AC Distribution
Distributes voltage to power module AC panel board
Provides sufficient power for all module accessories

Customer Monitoring Outputs
Form 'C' contacts for customer monitoring indicating the following conditions:
Circuit Breaker status, engine running, system in auto
Form 'A' contacts for customer monitoring indicating the following conditions: electrical lockout, summary alarm.

UTILITY CONTAINER MONITORING AND CONTROL SYSTEM

One ZTR-Lynx™ Data Collection and Communication Hardware is mounted inside each Utility Container Switchgear. The hardware for the generators can be networked together and as a system or signally they provide following minimum monitoring and control points:
Points Monitored on the Generator Set
Engine Running
EMCPII+ (ECS) Not In Auto
Generator Set Locked Out
High Coolant Temperature Alarm
Low Coolant Temperature Alarm
Low Oil Pressure Alarm
EMCPII Diagnostic Code Shutdown
Emergency Stop Shutdown
Coolant Loss Shutdown
High Coolant Temperature Shutdown
Low Oil Pressure Shutdown
Over Crank Shutdown
Over Speed Shutdown
Engine Coolant Temperature
Engine Oil Pressure
Fuel Consumption
Exhaust Temperature Left / Right
Protective Relay function trip (as provided on the SEL Relay)
Generator Set Run Time Hours
Generator Voltage, Current (Amps/Phase), kW, kWh, and Frequency
Points Monitored on the Switchgear

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Utility Status
Generator Available/Not Available
Control Locked Out
Common Alarm
Generator Connected to Utility
Control Power Status
Not in auto
Controller Failure
Remote Enable Status
Operational Mode Status
Failed to Sync Alarm

ZTR-Lynx System's Internal Alarms
Alarm and Event History Overflow
Communication Failure
Additional Generator Set System Points Monitored
Day and Main Tank Low / High Fuel Alarm
Day and Main Tank Fuel Level
Rupture Base Tank Alarm
Battery Charger Failure Alarm
Starting Battery Voltage
Container Internal Ambient Temperature
Supervisory Control Outputs
Remote Start/Stop
Scheduled Start/Stop
Generator Remote Load Adjust
Louver Control – Open and Close
Warning of Start – Start Warning Horn
Generator Set Start Alarm Horn Enclosure – It is mounted in the container to provide 30 seconds (continuous) warning prior to Generator Set start.

ZTR-Lynx Monitoring HMI Server Software
PC Based, installed on the on-site PC (see next item). MS Windows® NT based user-friendly graphical interface which provides easy to use menus and screens to display relevant Generator Set information, alarms, and events. In addition, provides the user the ability to adjust GenSet output power. Using the ZTR Monitoring and Control software on an off-site PC, the user is able to dial into the site and monitor and control the Generator Set and the breaker operation.

On-site PC Running HMI Server Software – by others
As a minimum – Pentium II Class PC, 300 MHz, MS Windows NT, Mouse Pointing Device, 128 Megabytes of Memory, 10 Gigabytes hard drive, SVGA Monitor, Modem.

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Remote Access to the Monitoring System
A user can access the monitoring system using a PC located offsite (supplied by others), equipped with modem and MS Internet Explorer Version 5 browser. The user shall dial the On-site PC (running the server software as described above) and use the browser software to link to the HMI Server Software. Once connected then the user has access to the monitoring and control items as described above.

SERVICES – BY OTHERS

Engineering services as required
Electrical Installation
- All Permits as required

Mechanical Installation
- Suitable pad for module placement
- Main fuel supply tank
- Supply and return piping from main fuel supply tank as required to modules
- Cranes for unloading as required
- Trenching as required

FINNING SUPPLIED SERVICES/COMPONENTS

Engineering Services as required including:
- Power module grounding design
- Complete drawing package
- Complete operation and maintenance manuals

Electrical Installation as required including:
- Cabling and system connection from container to container as required
- Ground grid connection as required
- Final termination to the distribution system
- Control cabling for networking modules

Mechanical Installation as required including:
- Spotting modules on customer supplied pad
- Installation of Finning (Canada) supplied fuel header
- Connection of fuel header to main fuel supply piping as required

Package to consist of three 1.6 MW continuous rated power modules, with total plant capacity being 4.8 MW

REFERENCE: **Tab 5 Capital Projects; P 5-9, L 3 to 7**

QUESTION:

a) Has the work on the Minto diesels described now been completed? If not all completed what has been completed, what remains to be completed, and what is the expected completion date?

ANSWER:

(a)

A portion of the work on the Minto Diesels has been completed. Work undertaken on the units is as follows:

- The diesel generator sets are mobile units enclosed in highway style trailers and sitting on wooden pilings. The wheels are still in place. Prior to the start up of the Carmacks Stewart Transmission Project and the Minto Mine Spur Line, the units were operated essentially 24 hours/day, 7 days/week. With their shutdown it was necessary to install auxiliary heating for fuel and lubrication systems, as well as space heating for the electrical controls. Mechanical work was also required to enclose the units to ensure they would retain as much heat as possible. This work has been completed.

- Electrical work was undertaken to connect the station service supply to grid power and ensure switchover capability in circumstances where the grid was down. This work has been completed.

- The ability to operate the switchgear in the Mine substation and to control the diesel remotely from the System Control Center is required. This work has not been completed and is expected to be complete by September 1, 2009. This work comprises a portion of the $0.750 million included in the 2008/2009 GRA for 2009 related to future expenditures on the units.

Upgrades to the enclosures and other systems are also under review for 2009. Project planning for 2009 is currently underway. This work has not been completed and a completion date for this work has not been determined.

REFERENCE: Tab 5 Capital Projects; P 5-9, L 14

QUESTION:

a) What will be the fuel efficiency of the refurbished Mirrlees diesel generators?

ANSWER:

(a)

Please see response to YCS-YEC-2-E6 and YUB-YEC-1-16 (footnote 1) both provided during the Resource Plan hearing.

At that time YCS asked if the refurbished Mirrlees would be more efficient and reduce GHG's. YEC was also asked to provide information on fuel usage/energy efficiency compared for the rebuilt Mirrlees generators compared to new, state of the art energy efficient generators. YEC responded that in general the Mirrlees would not be more fuel efficient, but noted as follows with regard to the fact that the intended use of the units needed to be considered in this regard:

> The intended use of these units is for emergency backup power, with very few hours of actual operation. As a result, they are expected to have a negligible effect on diesel fuel use or GHG emissions due to the low numbers of hours they are expected be run. The Mirrlees units, however, as low speed baseload units, which are typically more efficient than high-speed units.

In YUB-YEC-1-16 YEC was asked to provide economic analysis for the Whitehorse Diesel Replacement/Expansion Project. Footnote 1 of the response notes as follows:

> The project does not give rise to material operating costs distinct from the major alternative of the Mirrlees Life Extension Project (Yukon Energy uses an assumed $4,400/MW/year (2005$) as fixed operating and maintenance costs for diesel units, and 1.6 cents/kW.h (2005$) as variable O&M costs). To the extent WAF hydro generation is not sufficient to supply the full annual energy on the system (leading to baseload diesel requirements) or the hydro capacity is not sufficient to meet the peak

loads without dispatching diesel (leading to peaking diesel requirements), the cost of meeting this energy with the Mirrlees as compared to new diesels is not likely to be materially different (There may be small variances in the efficiency of new units as compared to the Mirrlees units, but under Base Case loads, relatively little diesel is expected to be required in the next 20 years so the cost impact of any efficiency differences is expected to be minimal compared to the capital cost distinction between the Whitehorse Diesel Replacement and Expansion Project and the Mirrlees Life Extension Project.) The project also does not give rise to materially different operating and maintenance costs than the Aishihik 2nd transmission line that would affect the assessment, as in either case operating costs are expected to be relatively insignificant compared to capital costs of the projects.

REFERENCE: **Tab 5 Capital Projects; P 5-9, L 4**

QUESTION:

a) What would be the fuel efficiency of new base load diesel generators of similar nature and capacity to the Mirrlees units? At what fuel price would it be more cost effective to purchase new base load generators rather than refurbish Mirrlees units?

ANSWER:

(a)

Please see response to LE-YEC-1-50.

REFERENCE: **Tab 5 Capital Projects; P 5-10, L 4**

QUESTION:

a) Would the projected cost of new diesels at the mine site of $1.035 million per MW include foundations, buildings, SCADA connection, and all other features the mine diesels will have once Yukon Energy's planned work is complete?

ANSWER:

(a)

The projected all-in cost for the Minto Mine diesels is $0.498 million/MW not $1.035 million/MW. The higher number is the estimate for the purchase of new diesel sets of a similar size to the Minto Mine diesels.

The $0.498 million/MW figure does include the building, SCADA connection, foundations and all of the other features described on page 5-9, lines 3-7.

REFERENCE: Tab 5 Capital Projects; P 5-12, L 1

QUESTION:

a) Please describe in detail how Yukon Energy specifies its large transformers, distribution transformers, and other larger electrical equipment to ensure that the lowest loss equipment that is economically justifiable is purchased.

ANSWER:

(a)

With regard to Large Transformers (i.e. CSTP Transformers) the manufacturer is provided with a detailed specification that lists all the various standards Yukon Energy will be using in order to ensure that the transformer meets Yukon Energy's requirements. Yukon Energy also provides the manufacturer with the Load and No Load loss costs based on the kW quoted to Yukon Energy by the manufacturer. Yukon Energy uses the quoted loss figures and the costs provided to determine the overall cost of the transformer over its life.

For Distribution Transformers Yukon Energy primarily uses the CSA standards with some modifications based on previous experience.

REFERENCE: Tab 5 Capital Projects; P 5-12, L 7

QUESTION:

a) Please confirm that the Faro Mirrlees diesel unit is now available to be operated on the WAF system as required.

ANSWER:

(a)

The Faro diesel unit (FD1) is not operable. Work is currently being performed to complete the project, and the unit is expected to be available March 31, 2009.

REFERENCE: Tab 5 Capital Projects; P 5-14, L 6

QUESTION:

a) Media reports following a number of outages caused by Whitehorse Rapids turbine No. 4 indicated that Yukon Energy had found the problem to be in the governor system. Please describe the problem in detail and indicate whether the necessary repairs or replacements will be completed as part of this budget or whether it will result in additional costs.

ANSWER:

(a)

The failures of the WH4 governor system were primarily a result of the design of the hydraulic manifold that controls the movement of the wicket gates. An internal valve was causing the controls to stick and the electronics in the governor interpreted this as a problem and shut the unit down. The manifold was replaced in 2008. The programmable logic controller will also be replaced in 2009. There will be an increase in the 2009 capital expenditure in part to complete this work.

REFERENCE: Tab 5 Capital Projects; P 5-15, L 6

QUESTION:

a) Please provide a copy of the study completed in 2008, and outline what will be done in 2009 to improve the spill regulation.

ANSWER:

(a)

The referenced study has not been completed.

REFERENCE: **Tab 5 Capital Projects; P 5-17, L 4**

QUESTION:

a) Please provide a copy of the assessment report.

ANSWER:

(a)

Please see the Current & Future State assessment report provided as Attachment 1 to this response.

YUKON ENERGY

eCorall Solutions

YUKON ENERGY CORPORATION

Financial Information Systems (FIS) Replacement Project

Phase 1: Systems Selection

Requirements – Current State & Future State

Version: 1.0


YUKON
ENERGY


eCorall
Solutions

REVISION LOG

Revision	Date	Description	Revised By
1.0	14Jun2008	Initial document; consolidated from individual business area current state and future state documents.	eCorall Solutions Inc.

CONTENTS

1 Executive Summary 6

2 About this document 7
2.1 Document Flow 7
2.2 Current State 7
2.3 Fit/Gap Analysis 7
2.4 Future State 7

3 Terminology 8

4 Accounts Payable 10
4.1 Current State 10
4.2 Future State 15

5 Accounts Receivable 23
5.1 Current State 23
5.2 Future State 27

6 Budgeting & Forecasting 31
6.1 Current State 31
6.2 Future State 33

7 Financial Reporting 36
7.1 Current State 36
7.2 Future State 39

8 Fixed Assets 42
8.1 Current State 42
8.2 Future State 47

9 General Ledger 53
9.1 Current State 53
9.2 Future State 60

10 Human Resources 65
10.1 Current State 65
10.2 Future State 68

11 Inventory Management 70
11.1 Current State 70
11.2 Future State 75
11.3 Document Samples 79

12 Maintenance 81
12.1 Current State 81
12.2 Future State 82

13 Payroll Interface 85
13.1 Current State 85
13.2 Future State 86

14 Procurement 87
14.1 Current State 87
14.2 Future State 90
14.3 US Bank File Interface 94

15 Project Accounting / Job Cost 96
15.1 Current State 96
15.2 Future State 98

1 Executive Summary

Yukon Energy Corporation (YEC) has established the Financial Information Systems (FIS) project to source a replacement system for its current enterprise system. The FIS project is a two-phased project consisting of selecting a replacement system in phase one and implementing the selected system in phase two. This document is part of the phase one project deliverables which captures the "current state", including "fits" and "gaps", and serves to define the "future state" for the potential replacement system.

The business areas included in the Phase One study are:

- General Ledger (including the Chart of Accounts)
- Accounts Receivable
- Accounts Payable
- Fixed Assets
- Project Accounting / Job Cost
- Budgeting & Forecasting
- Financial Reporting
- Inventory Management
- Procurement
- Payroll Interfaces to JDE
- Human Resources
- Equipment Maintenance and Work Orders

2 About this document

2.1 Document Flow

This document is a consolidation of requirements gathered from reviews and meetings with each business area. The business areas studied are as listed in the project scope. The **current state** and **future state** of each business area is defined in its respective section within this document. The sections are ordered alphabetically by business area name.

A **Terminology** section follows consisting of explanations of terms used within this document.

2.2 Current State

Information on the Current State is captured in a tabular format for ease of reference. Functional items of a business area are grouped into Key Areas. The current state of each business area, be it current workings or deficiencies, are described with results of Fit/Gap Analyses where applicable. For each Key Area, a reference link is included to the Future State requirements.

2.3 Fit/Gap Analysis

The Fit/Gap Analysis is based on identifying whether there is a 'Fit' of the current requirement to the current JDE system. Current issues and deficiencies that cannot be accommodated by the JDE system are identified as 'Gaps'. 'Fits' identified allude to the existence of functionality that might support a requirement.

2.4 Future State

The Future State is depicted in a table of requirements. Schematics are included where applicable. Requirements consist of Current State requirements that must continue to be provided in the Future State with equivalent or improved effectiveness, or, new requirements that are not available in the Current State. A column entitled 'Additional Notes' provides further details where applicable.

A Criticality column is included to identify the criticality of each requirement as follows:

- '1' for Critical
- '2' for non-Critical

3 Terminology

For reference purposes, below is a list of acronyms and terminology used within this document.

ADP	Automatic Data Processing Inc.
AP	Accounts Payable
AR	Accounts Receivable
BOM	Bill of Materials
CIS	Customer Information System
Current State	Refers to aspects of the current business processes, deficiencies and the enterprise application system currently in use
EM	Electrical Maintenance
ESC	Energy Solutions Corporation
FA	Fixed Assets
FIS	Financial Information System
Future State	Refers to the 'To Be' model of business requirements and processes.
GL	General Ledger
IFRS	International Financial Reporting Standards
LPO	Local Purchase Order (Manual Purchase Order)
MM	Mechanical Maintenance

O&M	Operations and Maintenance
PID	Project Identification
PM	Preventive Maintenance
PO	Purchase Order
PRC	Project Review Committee
UOM	Units of Measure
Warehouse	Warehouse refers to a geographical site where inventory is held. In the JDE system, it is referred to as a Branch/Plant.
WCB	Workers' Compensation Board
WO	Work order (plural is WO's)
YEC	Yukon Energy Corporation
YTG	Yukon Territory Government
YUB	Yukon Utilities Board

4 Accounts Payable

The accounts payable is an integral part of YEC and YDC accounting system. The primary responsibility of Accounts Payable departments is Supplier Management, Voucher Processing and Payment Processing.

4.1 Current State

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
4.1.1	**Supplier Master Information**	The supplier master information is setup in conjunction with the address book. The following information is captured by YEC: • Alpha Name • Tax ID • Search Type (V is used for vendors) • Business Unit • Mailing Name • Full Mailing Address • Payable Flag • Payee Reference • Hold Payment Code (This is used to hold supplier payments) • Payment Instrument • Payment Terms • Default account codes • Default currency code • Tax Information: o Tax Explanation Code o Tax Rate Area o Add Tax ID o Tax Authority • Contact information • Email Information • Phone information	Fit	Current system functionality exists.	11.2.1
4.1.2	**Payment Terms**	Payment Terms: Payment terms are used by Accounts Payable system. There is consensus between the seller and buyer on when payment is due for goods or services. The use of payment terms makes for efficient entering of invoices and vouchers. The following payment terms are used:	Fit	Current system functionality exists.	4.2.2

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
		• Net 30 days			
4.1.3	**Payment Types**	YEC uses the standard JDE cheque format to print cheques in predefined TD bank cheque stationery. The cheques are manually signed. • Automatic Cheques • Manual Cheques	Fit	Current system functionality exists.	4.2.3
4.1.4	**GL Class Allocation**	The following GL Class accounts are used: • AP trade • Employee • Board	Fit	Current system functionality exists.	11.2.6
4.1.5	**Tolerance Rules**	The following tolerance rules exist under purchase order system; this is directly integrated into the AP module. The voucher match and receipts are applicable. The setup for the tolerance rules are as follows: • Quantity: o Tolerance Percentage o Tolerance Unit • Unit Costs: o Tolerance Percentage o Tolerance Amount • Extended Costs: o Tolerance Percentage o Tolerance Amount This is also supplemented with either a zero tolerance or not for each sub-category.	Fit	Current system functionality exists.	4.2.8
4.1.6	**Voucher Types**	<u>Vouchers Types</u> The invoices are entered into the system as vouchers and are systemically processed by due dates, cash requirements are produced in advance and ultimately paid when due. • Standard Voucher is required where supplier invoice is received and entered into the system. This is manually matched with LPO which typical under $5000, this excludes utilities, freight and employee expenses. The ability to reference LPO (local Purchase Order) in the standard voucher. Include sub-ledger reference field. • Two Way Voucher Match, this is matched to PO. The invoice is the trigger when it's matched to the PO with the dollar value as stipulated on the invoice. Needs to ensure that the PO values default into AP voucher match. • Three Voucher Match, this is a receipting when the	Fit	Current system functionality exists.	4.2.6

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
		inventory is entered to stores and corresponding is (Inventory receipts accrual) received not voucher account. Upon receipt of the invoice this is matched to receipt and paid. Needs to ensure that the PO values default into AP voucher match. • Recurring voucher is required where for similar repetitive invoice • Prepayments (Not used) • Voucher logging (Not used)			
4.1.7	**Holdbacks**	Holdback Process Holdback is the percentage of a committed amount that is withheld until a specified date. The payment being retained is often held until all work under a construction contract, service or receipt has been completed. This holdback amount is paid out at the time the owner has provided written notice of acceptance of the project. The retained portion represents a pre-determined amount to cover any unfinished work. YEC holdback process is manually executed where the holdback values are manually calculated and the corresponding account allocations are manual. • Upon receipt of a holdback invoice, the process is to balance the amount paid from the invoice to trade accounts, this is indicated by an allocation where the gross is debit to expense and the credit to the holdback account. • Where holdbacks are not authorized to be released, this is entered via a zero dollar invoice into the AP system. This clears the holdback account.	Fit	Current system functionality exists.	4.2.7
4.1.8	**AP Cash Forecasting**	Cash Forecasting Activity As part of cash management activities, it's imperative to review open vouchers. This would determine your cash requirements on a future basis. YEC generates the following summarization of information for cash forecasting: • The total amount of all open vouchers • Due dates of open vouchers • The amount required to pay vouchers	Fit	Current system functionality exists.	4.2.10

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
4.1.9	**Taxes**	Taxes: • GST tax calculation is used • PST is used • Date effective GST & PST tax calculations • Tax rules is used by rate and area • Tax Tolerance is used.	Fit	Current system functionality exists.	4.2.9
4.1.10	**Approval Processes**	• Levels of approval are defined for Accounts payable. • Approval by batch. • Approvals are module specific. i.e only can approve AP batches.	Fit	Current system functionality exists.	4.2.5
4.1.11	**Payment Groups**	After the vouchers are entered and posted into the system, then preparation of payments can be undertaken. This is an automated cheque printing process. The manual process is also used where the cheques are hand written and the corresponding detail entered after the fact into FIS system. Both processes are used extensively. Describe below is the automated process. Create Payment Group This is a batch process that groups payments by specified criteria: • Bank Account • Payment Type • Currency • GL Class • Range of dollar value • Payment Due Dates • Discount Due Dates • Payment Status • Company • Business Unit • Supplier • Supplier Type • Only Posted Vouchers Work Payment Group Upon completion of the create payment group, a review of the payments is accepted or changed. The following actions is available for payment group: • Write (This prints to cheque) • Update (Upon completion of the write, the payments are update to GL) • Reset (This allows for a batch reset, in the event of a reprint of a cheque) • Undo (This completes reverse the batch created)	Fit	Current system functionality exists.	4.2.11

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
4.1.12	**System Integration**	The following systems integrate with Accounts Payable. • General Accounting • Procurement • Inventory • Equipment and Plant Maintenance • Job Cost • Fixed Asset • Address Book	Fit	Current system functionality exists. Not used. Not used. Not used.	4.2.16
4.1.13	**Integrity Report**	Integrity Report Integrity reports are used to supplement your internal balancing procedures. Integrity reports locate potential balancing problems and data inconsistencies. The following reports are used: • AP Original Document to GL by Batch Report • AP Payments to GL by Batch Report • AP to GL by offset Account Report	Fit	Current system functionality exists.	4.2.12
4.1.14	**AP Periodic and Annual Close**	• Monthly close routine is executed by fiscal date period. • Can work with both current and future period • Errors when incorrect periods are used. • No posting allowed to closed prior period. • Annual close updates supplier history.	Fit	Current system functionality exists.	4.2.13
4.1.15	**Global Updates and Audit**	• Global updates to vouchers • Global updates to supplier master • Audit list of user and batch approvers • Audit exception report for changes made to predetermined fields in supplier master. Eg bank account	Fit	Current system functionality exists.	4.2.14
4.1.16	**Online AP Inquiries**	The current system functionality allows for a variety of user-defined criteria to view accounts payable information. This includes supplier information, vouchers and payments. Repetitive use is made of the following: • Supplier information detailing all opened, paid, pending voucher information. • Account coding respective to the voucher being queried. • Reference to purchase orders where applicable • Supplier reference invoice numbers • Document type • Payee Number • General Ledger Date	Fit	Current system functionality exists	4.2.15

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
		• Invoice Date • Due Date • Batch Number Reference • Cheque Numbers • Details of items paid with corresponding cheque number • On line “as off” supplier balances • Commitment Inquiry • Open Receipts • Un-posted Batches • Supplier specific information • Voucher information • Pay Status			
4.1.17	**Interface from Third Party Software**	TD Bank Electronic Funds Transfer software	Gap	Need to investigate the interface. This would automate the AP payment process. Immediate benefits can be realized and also fraud prevention with respect to cheque processes.	4.2.18
4.1.18	**Staffing**	Current staffing levels are as follows: To be determined in RFP.			
4.1.19	**Reports**	The following reports are used currently: • AP Ageing Report • AP “As off” Report • AP Audit Log Report • AP Voucher Report • AP Recurring Voucher Report • Post Reports • Cash Requirements Report • Create Payment Group Report • Check Register • Void Cheque Listing Report • Manual Cheque Listing Report • Discount Lost Report • Supplier Analysis Report	Fit	Current system functionality exists	4.2.17
4.1.20	**Security**	AP Module specific security exists. This is configured based on YEC requirements. (For details the security matrix needs to provided)	Fit	Current system functionality exists	

4.2 *Future State*

No.	Key Area	Requirements	Criticality	Additional Notes

No.	Key Area	Requirements	Criticality	Additional Notes
4.2.1	**Supplier Master Information**	The ability to provide for the following fields and functionality: • Supplier Name a minimum of 35 characters. • Supplier ID with a minimum of 6 digit code. • Reference field that specifies it is a supplier. • Department reference (ability to specify line of business) • Mailing Name (Ability to enter a different name from the supplier name if required) • Full Mailing Address (Address fields, city, country, postal code) • Payment Instrument (eg. Cheque, Electronic funds transfer) • Ability to provide for payment terms and discount terms. • Reference field that shows CAD currency code. • Ability to support the following tax setup. o Tax Rates (GST and PST rates) o Tax Area (Location) • Ability to support Bank Accounts details for electronic payments. o Bank Transit Number o Bank Account Number o Account Type • Contact information • Email Address Information • Phone information • Ability to indicate possible duplicate supplier entries.	1	Electronic Funds Transfer will be expedited using TD Bank software. All electronic banking related information is required to be attached to Supplier Master.
4.2.2	**Payment Terms**	• The ability to provide for the establishment of discount and payment term for each vendor. (YEC uses net 30 day term as a minimum required)	1	
4.2.3	**Payment Types**	The ability to provide for the following payment types: • Automatic Cheques • Manual Cheques • Electronic Payment with notifications	1	The TD Balance electronic software will be required. It's recommended that used of electronic banking is utilized to eliminate cheque related fraud.
4.2.4	**GL Class Allocation**	The ability to have differentiated GL class allocation for Accounts Payable Trade accounts. • Regular Accounts Payable Trade • Employee Trade • Board Trade	2	
4.2.5	**Approval Process**	• Ability to support Management Approvals by batch. (The user will entered the batch and this can only be approved by a Manager if required)	1	
4.2.6	**Voucher Types**	Vouchers Types The invoices are entered into the system as vouchers and are systemically processed by due dates, cash requirements are produced in advance and ultimately paid when due. The ability to support the following voucher entry methods: • Ability to generate a payment voucher. (The following information is	1	Automation Possibility: If there is sufficient volume to warrant the use of imaging or digital technology, this would eliminate the need for manual invoice processing and improve efficiency. This will assist with eliminating user errors and also electronic data storage.

No.	Key Area	Requirements	Criticality	Additional Notes
		captured, invoice number, invoice value, invoice date, GL date, description field, GL allocation) • Ability to have a voucher match with purchase order. (A process of liquidating the Purchase order based on the invoice value) • Ability to have a voucher match with receipt voucher. (A process of liquidating the receipts which is referenced to the Purchase Order). • Recurring voucher (The ability to automatically generate with overrides and manual changes) • Voucher Prepayments (The ability to make prepayments without referencing an invoice) • Voucher logging. (The ability to log vouchers when received and send out for approvals before being paid) Voucher Attributes required: • Dates required are o Invoice date o Service date o General ledger • Ability to change account coding on all vouchers • Ability to change dates before the voucher is posted. • Ability to restrict changes once the voucher is posted. • Able to reverse the vouchers before postings • Able to void vouchers • Ability to have taxes default from Supplier Master and auto calculate taxes using effective date tax rules. • Ability to select taxes and override tax values. • Ability to have handling codes. Eg Courier cheque, pickup. • Ability to show discount due dates • Ability to generate a hard error when invoice number is duplicated. • Ability to have a pay status attached to individual vouchers.(Eg Hold, Approved, Pending) • Ability to change payment terms on voucher entry • Ability to override due dates as required. • Ability to change payment bank accounts referenced on the voucher. • Ability to reference PO number when not using the PO voucher match or receipts. • Ability to identify the department originating the voucher. • The ability to force a decision to keep purchase order open or close during a match with a purchase order or receipt. • The ability to automatically retrieve supplier information based on purchase order input. • The ability to distinguish between a debit voucher and a credit voucher. (Possible uses of document types)		Purchasing Cards: For low dollar purchases, P-card is recommended. This eliminates AP transactions.
4.2.7	**Holdbacks**	Holdback Process	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		Holdback is the percentage of a committed amount that is withheld until a specified date. The payment being retained is often held until all work under a construction contract, service or receipt has been completed. This holdback amount is paid out at the time the owner designate has provided written notice of acceptance of the project. The retained portion represents a pre-determined amount to cover any unfinished work. The holdback functionality needs to be automated and the following is required: • Ability to work with purchase order and vouchers. • Ability to enter holdback percentage in PO. • The holdback calculations are automatic at voucher processing. • The holdback account allocations are automatic at voucher processing. • Ability to have partial holdback payments released. • Ability to reverse holdback entries when required. • Ability to have holdback with taxes or without.		
4.2.8	**Tolerance Rules**	The ability to setup tolerance rules for voucher-match and receipts matching with the option of zero tolerance. The following tolerance checks can be executed by the following categories. • Quantity: o Tolerance Percentage o Tolerance Unit • Unit Costs: o Tolerance Percentage o Tolerance Amount • Extended Costs: o Tolerance Percentage o Tolerance Amount	1	
4.2.9	**Taxes**	The following is required for efficient tax calculation and entry. • Ability to support the automatic calculation of taxes. • Ability to have date effective GST & PST taxes. • Ability to support tax rules. (GST is automatically calculated and allocated to tax account, PST is automatically calculated and allocated to the corresponding original expense account entry) • Ability to support tax tolerance rules: o Ability to stipulate percentage tolerance.(eg GST will be allowed from 4.5% to 6%)	1	
4.2.10	**AP Cash**	The ability to provide the following information for cash management	1	

No.	Key Area	Requirements	Criticality	Additional Notes
	Forecasting	activities. Cash requirements for future periods. • The ability to show the amount due by days as required. • The ability to forecast by due dates, invoice date and GL date.		
4.2.11	**Payment Process**	After the vouchers are entered and posted into the system, then preparation of payments can be undertaken. This is an automated cheque printing process. The manual process is also used where the cheques are hand written and the corresponding detail entered after the fact into FIS system. Both processes are required. In addition the EFT payment process will also be required. The basic principle of paying the supplier based on due dates. Create Payment Group or Groups: The ability to create payment group or groups by the following criteria or combination of: • Payment Type (This would be grouping all cheque payment together). • Currency (Grouping all CAD payments together) • GL Class (eg paying all regular AP trade accounts) • Range of dollar value (eg. Greater than $2.00 and less than $100 000) • Payment Due Dates. • Discount Due Dates • Payment Status (Group all payments in “approved” status) • Company (Group payments by company • Supplier (Paid an individual supplier) • Ability to restrict payment to only posted vouchers. Finalizing the Payment Group Upon completion of the create payment group, a review of the payments is undertaken to either accepted or make changes to the payment group. Once finalized, the ability to execute the following is required: • Print a cheque (This prints to cheque stationery stock, showing the remittance detail eg. Supplier ID, Supplier Invoice number, Amount Paid, Discount taken, Purchase Order reference, Explanation Remarks from voucher) • Ability to restart the payment process.(This completes reverse the batch created) • Reset the payment process (This allows for a batch reset, in the event of a reprint of a cheque) • Update process (Upon completion of the cheque printing, the payments entries are update to GL)	1	
4.2.12	**AP Integrity**	Integrity Report Integrity reports are used to supplement your internal balancing procedures. Integrity reports locate potential balancing problems and data inconsistencies. The ability to generate the following reports as a minimum:	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• AP to GL by offset Account Report (Report showing any discrepancy with entries to AP and final postings to GL) • Out of Balance Batches in AP (Report showing any out of balance batch and the detail of the entries)		
4.2.13	**AP Periodic and Annual Close**	• Ability to run monthly close routine by fiscal date periods. • Ability to work with current and future period if required. • Ability to error when incorrect periods are used. • Ability to restrict postings to closed periods.	1	
4.2.14	**Mass Updates and Audits**	Ability to perform the following functions: • Mass updates to vouchers. (eg. Changing the hold code from "pending" to "approved" code for all vouchers to be paid). • Mass updates to supplier master. (eg changes to a payment term) • Ability to support audit list of user and batch approvers. • Ability to track changes made in Supplier Master. (Provide an exception report if changes are made to supplier master information) • Ability to check if duplicate payments are made. (if the same invoice reference and amount is paid twice) • Ability to check if duplicate supplier master information exists.	1	Fraud prevention and detection measures: • Code of Ethics • Segregation of Duties o So that no individual employee can single-handedly authorize and access payments. • Stringent controls to monitor AP o Duplicate invoices o Suspected duplicate payments o Contravention of SOD rules. • Managing Supplier files • Performing random audits.
4.2.15	**AP Online Inquiries**	Ability to view the following information via on-line inquiries. • Supplier information detailing all opened, paid, pending voucher information. • Account coding respective to the voucher being queried. • Reference to purchase orders where applicable • Supplier reference invoice numbers • Reference to debit voucher or credit voucher. • General Ledger Date • Invoice Date • Due Date • Batch Number Reference • Cheque Numbers • Details of items paid with corresponding cheque number • On line "as off" supplier balances • Open Receipts • Un-posted Supplier Batches • Supplier specific information (Supplier Name, Supplier ID, Address, Email Address, Contact Name, Payment terms, taxes) • Voucher information (Supplier Invoice number, Supplier ID, voucher value, invoice date, due date, GL date, Open Value, discount, Cheque Reference) • Pay Status (showing all pending, on hold or approved vouchers) • Ability to provide for supplier history retrieving vouchers, payment references and purchase orders. (This should include current history	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		and prior years)		
4.2.16	**System Integration**	The ability to support systems integration with the following modules: • General Accounting • Procurement • Inventory • Equipment and Plant Maintenance • Job Cost • Fixed Asset	1	
4.2.17	**Reports**	The ability to create the following reports, based on selection criteria when required: • AP Summary Ageing Report (The following data fields are required: Supplier ID, Supplier Name, Phone Number, Company Number, Balance Open, Current , Ageing days 31-60, Ageing Days 61-90, Ageing Days 91-120, Ageing Days Over 120) • AP Detail Ageing Report (The following data fields are required: Supplier ID, Supplier Name, Phone Number, Company Number, Invoice Number, Invoice Date, Due Date, Balance Open, Current , Ageing days 31-60, Ageing Days 61-90, Ageing Days 91-120, Ageing Days Over 120) • AP"As-of" Open Detail Ageing Report (The following data fields are required: Supplier ID, Supplier Name, Company Number, Invoice Number, Invoice Date, Due Date, Balance Open, Balance Original, Current , Ageing days 31-60, Ageing Days 61-90, Ageing Days 91-120, Ageing Days Over 120) • AP Account Totals by Supplier (The following data fields are required: Supplier ID, Supplier Name, Department, Account Code, Sub Account Code, Account Description, Amount) • AP Auto Payments Register (The following data fields are required: Payment Number, Payment Date, Supplier ID, Supplier Name, Payment Stub Message, Voucher Number, Company Number, Amount Paid, Supplier Invoice Number) • AP Payment History report (The following data fields are required: Supplier ID, Supplier Name, Invoice Number, Invoice Date, Due Date, Payment Amount, Voucher Number, Cheque Remark) • AP Voucher Report (The following data fields are required: Supplier ID, Supplier Name, Phone Number, Company Number, Invoice Number, Invoice Date, Due Date, Invoice Amount, PO Number, GL Date, Batch Number, User ID, Batch Date, GL Account Distribution, Department, Account Description)	1	
4.2.18	**Interface from Third Party Software**	• Forms Package (Consider using a forms package that as the ability to have corporate wide usage, eliminating the need for pre-printed stationery, which includes cheque stock, purchase orders and invoices. The forms package also as the ability to automate cheque	2	

No.	Key Area	Requirements	Criticality	Additional Notes
		signatories). • TD Bank for EFT. Check the EDI functionality available from TD bank for EFT payment process. Ensure its audit compliant and also has the security feature required for transfer of funds. Check with automatic notifications for vendors as feature functionality.		

5 Accounts Receivable

YEC's accounts receivable is a manual process with no interface into the existing FIS system. The system of recording invoices and mailing invoices is also manually executed. The account allocations are also manually entered into the GL system in the existing FIS. The balancing of trade accounts is manually done in an excel spreadsheets.

5.1 Current State

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
5.1.1	**CIS**	CIS – Customer Information System • YEC currently uses CIS (Customer Information System). This is not expected to change in the foreseeable future. Customer Information System is stand-alone software used exclusively for a specific customer billing type. The customer master and all related billing information resides in the CIS system. This is includes: o Customer name o Customer number o Billing address o Tax information o Payment terms o Bank information. • Invoices are generated by CIS system based on billing cycle and recorded. • The customer copies of the invoices are mailed. • Incoming cash receipts from CIS based customers are entered into CIS system. This is matched against customer open items. • The ageing reports are generated out of the CIS system. • Only interface into JDE is a manual process. The use of an excel spreadsheet is to facilitate capture entries from CIS system. This includes invoices, credit memos, cash receipts, adjustments, NSF cheques. Entries are summarized and then manually keyed into JDE general ledger module. • Cash receipts are journalized and entered JDE into the CIS bank account.	Gap		11.2.1

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Separate control account that balance to CIS/JDE system • Separate bank account for CIS system. • Monthly control reports and statements are generated by CIS. • Manual accrual for billing cycles.			
5.1.2	**Customer Master**	The customer master information is setup in conjunction with the address book in JDE. The following information is captured by YEC: • Alpha Name • Tax ID • Search Type (C is used for customers) • Business Unit • Mailing Name • Full Mailing Address • Receivables Flag • Hold Payment Code (This is used to indicate that a customer is on hold status) • Payment Terms • Default account codes (Company, balance sheet, subsidiary) • Default currency code • Tax Information: o Tax Explanation Code o Tax Rate Area o Add Tax ID o Tax Authority • Contact information • Email Information • Phone information	Fit	Current system functionality exists.	5.2.2
5.1.3	**Taxes**	Taxes: • GST tax calculation is used • PST is used • Date effective GST & PST tax calculations • Tax rules is used by rate and area • Tax Tolerance is used	Fit	Current system functionality exists.	5.2.3
5.1.4	**Payment Terms**	Payment Terms: Payment terms are used by Accounts Receivable system. There is consensus between the seller and buyer on when payment is due for goods or services. The use of payment terms makes for efficient entering of invoices. The following payment terms are used:	Fit	Current system functionality exists.	11.2.6

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Net 30 days			
5.1.5	**GL Class Accounts**	The following GL Class accounts are used: • Customer Billing- retail • Employee Billing • Generation Billing • Customer Extensions • Miscellaneous Billing	Fit	Current system functionality exists.	5.2.4
5.1.6	**Approval Process**	• Levels of approval are defined for Accounts receivable. • Approval by batch. (This is journal entries) • Approvals are module specific. i.e only can approve AR batches.	Fit	Current system functionality exists. This is not used nor configured to leverage this automated feature.	5.2.5
5.1.7	**Manual Billing**	Manual Billing The manual billing process is direct entry into JDE system with no interface or automation. The customer master information is entered into JDE and is used for billing purposes. JDE address book number is used and also sub-ledger field is referenced. There are essentially three types of manual billing processes. Generation Billing The information is received manually and billed in JDE to Yukon Electric.(Wholesale revenue) Customer Extensions A cost estimate is provided by YEC to the customer. Only upon approval of the estimate, the customer is then billed. There could be potential difference from the initial cost estimates to the final billing. The differences are passed on to the customer by either an additional bill or a credit. Miscellaneous Billing: • A manual invoices are produced in an Excel spreadsheet and keyed in as a journal entry into JDE using the sub-ledger field. The sub-ledger field is used as a unique identifier in the address book as customer. • Invoice numbers are manually controlled. • Cash receipts are expedited through the bank reconciliation process, this mean via JE and then allocated referencing the sub-ledger field. • No statement is produced. • The control reference is by object account and sub-ledger. This is basically used as an AR receivable outstanding. • No integrity report. • No control accounts via invoices. • Cancelling and voiding are done manually done. • No bank charges or interest is captured via this process • No 30/60/90 day report is produced.	Fit	Current system functionality exists.	5.2.6

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
5.1.8	**AR Integrity**	Currently there are no automated integrity checks that are used. This is due to the manual nature of billing operations.	Fit	Current system functionality exists. This is not used nor configured to leverage this automated feature.	5.2.9
5.1.9	**Periodic Close & Annual Close**	• Monthly close is run with GL close. • Monthly close routine is executed by fiscal date period. • Can work with both current and future period • Errors when incorrect periods are used. • No posting allowed to closed prior period. • Annual close updates customer history.	Fit	Current system functionality exists.	5.2.10
5.1.10	**Global Updates and Audit**	Currently none of the global updates or audit functionality is used.	Fit	Current system functionality exists. This is not used nor configured to leverage this automated feature.	
5.1.11	**AR Online Inquiries**	AR online inquiry is currently not used. The collation and inquiry of AR information is a manual process.	Fit	Current system functionality exists. This is not used nor configured to leverage this automated feature.	5.2.11
5.1.12	**System Integration**	System Integration General Ledger Budgeting & Forecasting Fixed Assets Job Costs Address Book	Fit	Current system functionality exists.	5.2.12
5.1.13	**Interface from Third Party Software**	CIS interface (Customer Interface System). Currently not interfaced.	Gap	Current system functionality exists. This is not used nor configured to leverage this automated feature.	5.2.13
5.1.14	**Reports**	No reports used currently off the AR system.	Fit	Current system functionality exists. This is not used nor configured to leverage this automated feature.	5.2.14
5.1.15	**Staffing**	Billing currently undertaken by: • Tom is responsible for wholesale sales • Melaine is responsible for JE as assigned to her. • Darcie is responsible for miscellaneous one offs			
5.1.16	**Security**	AR Module is not used and consequently the security is not setup.	Fit	Current system functionality exists. This is not used nor configured to leverage this automated feature.	

5.2 Future State

YEC would ideally want to maintain an accurate record of customer invoices and payments, along with timely billing which is fundamental to how the business is managed. The efficiency gained from an automated system provides management will timely information on cash flows and collections from the Accounts Receivable system.

No.	Key Area	Requirements	Criticality	Additional Notes
5.2.1	**CIS**	Customer Information System • YEC currently uses CIS (Customer Information System). This is not expected to change in the foreseeable future. Customer Information System is stand-alone software used exclusively for a customer service billing. The customer master and all related billing information resides in the CIS system. This is includes all of the following: o Customer name o Customer ID o Billing address o Tax information o Payment terms o Bank information. • The ability to support CIS interface is required. To interface billing information and general ledger entries into FIS. This process would provide for all Accounts Receivable transactions in a central repository, which in turn facilitates collections and month end balancing process.	2	
5.2.2	**Customer Master Information**	The ability to provide for the following Customer Master Fields: • Customer Name with a minimum of 35 characters. • Customer ID with a minimum of 6 digit code. • Reference field that specifies it is a customer. • Department Reference. (Ability to define revenue department) • Mailing Name (The ability to enter a different customer mailing name if different from customer name). • Full Mailing Address (Address fields, city, country, postal code) • Reference field for a hold code (ability to flag a customer that should not be supplied possibly a delinquent customer). • Payment Terms with a minimum of net 30 days required. • Customer Credit Limit field reference. • Contact information (Reference to customer contact name or department) • Email address field (Ability to use email feature for invoice delivery) • Area code and phone information fields.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
5.2.3	**Taxes**	• The ability to automatically calculate GST and PST based on the tax rates. • Ability to support date effective GST & PST tax calculations. (This is required to support changes in tax rates and also the ability to work with previous rate as required). • Ability to support tax by location.	1	
5.2.4	**GL Class Accounts**	The ability to support the following accounts receivable trade accounts: • CIS Trade Account (This is from the stand alone Customer Information System) • Employee Trade Account (two types- payroll deduction and miscellaneous advances) • Generation Billing Account • Customer Extensions Account • Miscellaneous Billing Account (sometimes captured in a work order request form i.e customer requests)	1	
5.2.5	**Approval Process**	• Ability to support Management Approvals by batch. (The user will entered the batch and this can only be approved by a Manager if required)	1	
5.2.6	**AR Billing**	AR Billing Process • The ability to provide for invoice generation. o The ability to support the following required fields on invoicing system: ▪ GL account allocation (Minimum of 3 segments and minimum of 14 digit code in total. The 3 segments comprising of department, account code and sub account revenue department, account code and sub account code). ▪ Descriptions field with a minimum of 100 characters. ▪ Work Order reference field ▪ Invoice Date ▪ Service Date ▪ General Ledger Date ▪ Discount Due Date ▪ Quantity field ▪ Unit of Measure ▪ Unit Cost ▪ Extended Cost ▪ Discount Amount Field ▪ Payment Terms field ▪ Tax Amount (This is automatically calculated by the rate and area reference or manually overridden if required) ▪ Additional Description field with minimum 100	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		characters. ▪ Department Field ▪ Company Reference Field o Ability to have recurring invoice o Ability to review and approve invoice o Ability to make revisions to un-posted invoices. o Ability to post invoice to GL. o Ability to reverse posted invoices.		
5.2.7	**AR Cash Receipts**	Receipts Process: One of the most important steps in AR process is to enter payments as expeditiously as possible. This is in order to track the cash flow and also know what's outstanding from a collection point of view. The ability to support AR receipts process must have the following capabilities: • Ability to create a cash receipt • Ability to allocate cash receipts to AR or GL accounts. • Ability to support the selection of bank accounts to be debited. • Ability to support the various date options: o Receipt Date o General Ledger Date o Received Date • Ability to review and approve receipts • Ability to reverse receipts • Ability to have automatic write off's for penny differences or amount stipulated in AR account balances. • Ability to have automatic charge back with cash receipt entry. • Ability to have reason codes for write offs with cash receipts entry. (eg Bank Charges written off) • Ability to automatically match invoices with cash receipts amounts or manually select invoices that are being paid. • Ability to offset invoices and credit note entries, this is required so that debit and credit entries are not shown in the aged accounts receivable report.	1	
5.2.8	**Credit Collections**	• Ability to print statements • Ability to print delinquency notices • Ability to charge interest on overdue accounts	1	
5.2.9	**AR Integrity**	Use integrity reports to supplement your internal balancing procedures. Integrity reports locate potential balancing problems and data inconsistencies. The ability to support the following integrity checks: • Accounts Receivables to General Ledger by batch (Shows discrepancies between any AR batch posted into the GL) • Accounts Receivables to General Ledger Trade Accounts (Ability to show that all the AR trade accounts are in balance with the AR sub-ledger)	1	

No.	Key Area	Requirements	Criticality	Additional Notes
5.2.10	**Periodic Close & Annual Close**	• Ability to run monthly close by fiscal date periods. • Ability to work with current and future period if required. • Ability to error when incorrect periods are used. • Ability to restrict postings to closed periods.	1	
5.2.11	**AR Online Inquiries**	Ability to view the following information via on-line inquiries and searchable fields: • Customer information detailing all open, paid, pending invoice information. • GL Account coding respective to the invoice being queried. • Reference to customer sales orders number • Customer ID numbers • Document type (Ability to distinguish between and invoice and credit note) • General Ledger Date • Invoice Date • Due Date • Batch Number Reference • Customer cheque reference numbers • Details of items paid with corresponding cheque number • On line “as off” customer balances • Un-posted Batches • Customer Master information (Customer ID, Customer Name, Billing Address, Taxes, Payment Terms, Contact Information) • Invoice information (Invoice Number, Invoice Date, Due Date, Discount Due Date, Invoice Description, Invoice Amount, Amount Outstanding)	1	
5.2.12	**System Integration**	The ability to support the integration into the following modules: • General Accounting • Equipment and Plant Maintenance • Job Cost • Fixed Asset • Inventory	1	
5.2.13	**Interface from Third Party Software**	The ability to support the interface from: • CIS (Customer information System)	1	
5.2.14	**Report**	The ability to generate the following report: • AR Open Summary Report (The following data fields are required: Customer ID, Customer Name, Customer Phone Number, Invoice Date, Invoice Number, Ageing days 31-60, Ageing Days 61-90, Ageing Days 91-120, Ageing Days Over 120, Total)	1	

6 Budgeting & Forecasting

Budgeting and forecasting for Yukon Development Corporation and Yukon Energy Corporation are extensively prepared on excel spreadsheets with approved budgets entered into FIS system. The process of forecasting revenue and capital is labour intensive with multiple variations of calculations that ultimately culminate into the final forecast projections. It's expected that the revenue projections will be undertaken using excel spreadsheets. The O&M expenses, capital plan and payroll costs can be automated in the new FIS system

6.1 Current State

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
6.1.1	**Budgeting**	**Budgeting** Budgeting provides a projection of future expenses and revenues. Using budget history, you can compare actual amounts to your projections and use the information to improve your budgeting process. **Sales Forecast** Sales forecasting is undertaken in excel spreadsheet. With details itemizing customers, energy requirements and demand forecast. The calculations are complex with varying degrees of data manipulations hence the use of excel. This is a manual process of collecting and collating data. **O&M Expenses (O&M)** Operating and Maintenance (O&M) is also undertaken in excel spreadsheets. The information is extracted out of JDE with two years of prior balances and current YTD for forecasting. **Capital Plan** Capital Plan is also undertaken in excel spreadsheets. This is a manual business process where PID (Project Identification Document) is used to derive at the final capital plan. This is a re-iterative process until the PID are approved and finalized into the budget process. **Total Payroll Costs** The information is extracted from ADP system. Here again the calculations are in an excel spreadsheets and thereafter consolidated and entered into JDE.	Gap Gap Fit Fit	Forecasting on excel spreadsheet. Forecasting on excel spreadsheet. . Current system functionality exists Current system functionality exists	11.2.1 11.2.1 11.2.1 11.2.1
6.1.2	**JDE Budgeting**	**JDE Budgeting Process:** • Uploads are electronically executed into JDE by year. Five separate uploads are executed. • Combination of business unit and account, sub ledger budgeting is done in JDE.(from uploads)	Fit	Current system functionality exists.	6.2.2

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Upon completion of the upload this is reconciled to the Board Approved Business Plan.(five separate only) • Consolidated the budget report to match Board approved Business Plan • Send Approved Budget Reports to Individual Managers. • Verification of allocation and Account Coding • This forms the monitoring of Actual to Budgets on Monthly Basis. • Report to Board on Quarterly basis against approved budget • Report to YUB with the approved Budget and Actual.(only on request) • This forms the basis for audit report and annual financial reports			
6.1.3	**Ledgers Types**	**Ledgers used in Budgeting Process** **Ledgers Types:** Ledger types define the ledgers that you maintain in the budgeting & forecast module. These ledgers contain management and control information for the following: • Actual Expenses • Units • Budgets • Forecasts • Projections Ledgers as referenced in JDE: • AA Actual ledger • BA Budget Ledger • JA (Job Cost) • UA (Units Ledger required) • UB (Units Budget)	Fit	Current system functionality exists.	6.2.4
6.1.4	**System Integration**	**System Integration** • General Ledger • Job Costs • Procurement	Fit	Current system functionality exists.	6.2.9
6.1.5	**Approval Processes**	**Approval Processes:** The approval process is separate into requested, approved and final. • Defined levels of approval. • Approvals by business unit. • Approval by object accounts.	Fit	Current system functionality exists.	6.2.5

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
6.1.6	**Annual Budget Close**	**Annual Budget Close:** • Rollover of budgets to following year. • Populated final budgets into approved Budget ledger type. • Carry forward of capital budgets is undertaken where applicable. • Updates to opening balances when annual budget close is complete. • Budget close programs are company specific.	Fit	Current system functionality exists.	6.2.6
6.1.7	**Global Updates**	**Global Updates:** • Global updates to Budget Spread patterns • Global updates to Object accounts • Audit list of user and batch approvers	Fit	Current system functionality exists.	6.2.7
6.1.8	**Online Inquiries**	**Online Inquiries:** • Budget comparison with actual by object account • Budget comparison with actual by business unit • Budget comparison with actual by subsidiary accounts • Budget comparison with actual by sub-ledger.	Fit	Current system functionality exists	6.2.8
6.1.9	**Interface from Third Party Software**	**Interface from Third Party Software:** • CIS interface (Customer Interface System) • ADP (Easy labour & Pay at work) • Project Identification Document (PID process)	Gap		

6.2 Future State

The emphasis on budgeting and forecasting for the future will be to automate the process for O&M, Capital Plan and Payroll Costs, which will benefit YEC in terms of efficiency and cost savings.

No.	Key Area	Requirements	Criticality	Additional Notes
6.2.1	**Key Budgeting Areas**	Sales Forecast It's expected that sales forecasting will still be undertaken in excel spreadsheet due to complex calculations with varying degrees of data manipulations. This manual process is expected to continue. O&M Expenses (O&M) Operating and Maintenance (O&M) will be an automated process of extracting and forecasting directly out of the proposed FIS system. Capital Plan Ideally an automated interface from PID (Project Identification) is expected to derive at the final budgeted capital plan. This is currently a manual process. Total Payroll Costs	2 1 2 1	

No.	Key Area	Requirements	Criticality	Additional Notes
		The proposed interface between ADP ezlabour manager and the proposed FIS system will automate the extraction of payroll costs for budgeting.		
6.2.2	**Budgeting and Forecasting**	Budgeting and Forecasting Process: • Ability to upload budgets electronically into FIS by year or month from Excel spreadsheets. • Ability to export budgets to spreadsheets. (Analysis can be perform on Excel or other spreadsheet based programmes) • Required to budget by department, account code and sub code. (Ability to support the multi-segment account code structure of minimum of 3 segments and minimum of 14 digit code in total) • Ability to budget in units and dollars. • Ability to support the use of budget spread patterns. (Seasonal spread patterns, regular 1/12 budget pattern, percentage based spreads. This is based on an annual budget amount entered and the system automatically spread the amounts to the months based on the spread pattern used.) • Ability to provide history of prior year expense and revenue. This should ideally span a seven-year period. (This would be used for budget comparisons in the budgeting module) • The ability to roll up budgets into departments, account codes and sub account codes. • The ability to identify budgets by original budget, approved budget and final budget. (This will be used for tracking amendments). • Ability to prevent unauthorized changes to approved budget items. • Ability to perform budget tracking by capital project. • Ability to perform budget reallocation. • Provide ability for 12 month rolling forecast, with total displayed • Provide ability to make adjustments to the forecast • Provide graphical presentations of history and forecast, with a selection of graph styles and options • Provide ability to generate automatic, low intervention forecasting methods. (The use of percentage based changes, or indexed changes) • Ability to attach documents to support budget details.	1	
6.2.3	**Forecast evaluation tools:**	Provide forecast evaluation tools: • Ability to download forecast data to spreadsheet formats • Ability to save forecast versions for accuracy analysis • Provide “what if” analysis tool.	2	
6.2.4	**Ledgers**	Ledgers Types: The ability to support the use of the following ledgers are required: • Budget Units • Budget • Forecast • Projection	1	

No.	Key Area	Requirements	Criticality	Additional Notes
6.2.5	**Approval Process**	• The ability to approve budgets based on delegation of authority. • The ability to support the approval by department, account code and sub account codes.	1	
6.2.6	**Annual Budget Close**	• Ability to rollover budgets to following year. • Ability to carry forward capital budgets if applicable. • Ability to close budget ledger by company.	1	
6.2.7	**Mass Updates**	• Ability to carry out mass updates to budget spread patterns.	1	
6.2.8	**Online Inquiries**	The ability to compare actual amounts with budgeted amounts and display the variances as follows: • Comparison by account code • Comparison by department • Comparison by sub account structure • Comparison by combination of department, account code and sub account.	1	
6.2.9	**System Integration**	The ability to support the integration to the following modules: • General Ledger • Procurement • Job Cost	1	
6.2.10	**Interface from Third Party Software**	The ability to interface from: • ADP (Payroll) • CIS (Customer Information System)	1	
6.2.11	**Reporting**	Budget Reporting: • Monthly budget report by departments and account codes.(The following data fields are required, Department, Department description, Account Code, Account description, Total Budget Amount, Monthly Amounts Period 1-12) • Annual Budget Reports.(The following data fields are required, Department, Department description, Account Code, Account description, Total Budget Amount) • Budget Worksheet (The following data fields are required, Account Description, Prior Year YTD Actual, Current Year YTD Budget, Current Year YTD Actual, Projected, Next Year Requested Budget, % Change, New Year Final Budget, % Change)	1	
6.2.12	**Managing Budget Overages**	• Ability to restrict postings to accounts which exceeds the budget amount.(Have the option to accept this after an approval process) • Ability to generate an exception report for overages. (Where the actual amount exceeds the budgeted amount)	2	

7 Financial Reporting

Yukon Development Corporation (YDC) is a crown corporation created in 1986 by the Yukon Development Corporation Act. With Yukon Energy Corporation (YEC) created in 1987 as its subsidiary of Yukon Development Corporation. YEC is a publicly owned electrical utility that operates a business, at arms length from the Yukon government. Energy Solutions Centre (ESC) was also a subsidiary of Yukon Development Corporation until end of 2005; this is now integrated into Yukon government Department of Energy, Mines and Resources.
YDC and YEC are active companies in the proposed financial information systems (FIS) structure, with its respective diverse business structure and financial reporting requirements. ESC will only be entered into the proposed FIS for historical reporting and regulatory requirements.
Cognizance needs to be taken of reporting for Yukon Territory Government (YTG) and Yukon Utilities Board (YUB).
Financial reporting is largely an effort to assess financial performance, that is, how well or how poorly the YEC performed with money entrusted to it. Financial reporting is critical part of YEC's accountability. Financial reporting is categorized as follows: transactional reporting, monthly reporting, variance reports, annual reporting, statutory reporting and management reporting.

7.1 *Current State*

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
7.1.1	**Transactional Reporting**	YEC uses the following transactional reports: • Account Balance by Month • Account Ledger Print • General Journal by Account • General Ledger by Business Unit • General Ledger by Object Account • General Ledger by Sub-ledger totals • JDE GL Inquiry of account balance export to excel • Journal Entry Details prior to Posting • Journal Entry Posting Report • Transaction Journal • Transactions by Object	Fit	• Current system functionality exists.	11.2.1
7.1.2	**Trial Balance**	YEC uses the following trial balance reports: • Trial Balance by Account Code • Trial Balance by Sub- Account Code • Trial Balance by Business Unit • Trial Balance by Object with roll up • Trial Balance by Object with no roll up • Trial Balance by Company • Monthly Trial Balance Report	Fit	• Current system functionality exists.	7.2.2

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
7.1.3	**Variance Reporting**	YEC uses the following variance reporting: • Variance Analysis used as Control Report	Fit	• Current system functionality exists.	7.2.3
7.1.4	**Income Statement Reporting**	YEC uses the following income statement reports: • Income Statement by function (BOD) • Operating Income Statement • Income Statement by Account Code • Income Statement by Sub-Account Code • Income Statement by Business Unit • Monthly Income Statement • Consolidated Income Statement • Income Statement from JDE by Cat Code2 Function for both labour and Non Labour Costs • Income Statement from JDE by Cat Code2 Function for labour costs only • Income Statement from JDE by Cat Code2 Function for non labour costs only • Income Statement from JDE by Cat Code10 broken out by cost type for all costs • Income Statement from JDE by Cat Code10 broken out by cost type for non labour costs only • Income Statement from JDE by Cat Code10 for labour costs only • Income Statement from JDE by Cat Code10 for non labour and labour costs only • Income Statement from JDE by Cat Code10 for non labour costs only • Income Statement from JDE by Cat Code10 broken out by cost type for labour costs only • Simple Income Statement used as Control report	Fit	• Current system functionality exists.	7.2.4
7.1.5	**Departmental & Management Reporting**	YEC uses the following departmental reports: • YTD Board Expenses • YTD Consultants by Function • YTD General Admin Breakdown • YTD Labour by Department • YTD Labour by Department and Function • YTD Legal Costs by Business unit • YTD Non Labour by Department and Function • Management Reporting	Fit	• Current system functionality exists.	7.2.5
7.1.6	**Balance Sheet**	YEC uses the following balance sheet reports: • Balance Sheet from JDE provides lowest level of category	Fit	Current system functionality exists.	7.2.6

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		totals for Board package • Balance Sheet from JDE rolled up one level to provide Board package support • Balance Sheet from JDE rolled up to provide Board Package totals • Simple Balance Sheet Report used as a control report			
7.1.7	**Cash Flow**	YEC uses the following cash flow statement: • As per current JDE reports	Fit	Current system functionality exists.	7.2.7
7.1.8	**Quarterly Reporting**	YEC uses the following quarterly reports: • Quarterly YTD General Admin Breakdown	Fit	Current system functionality exists.	7.2.8
7.1.9	**Board Reporting**	YEC uses the following Board Reports: • Board Package	Gap		7.2.9
7.1.10	**System Integration**	The financial information is predominantly obtained from the General Ledger. However current functionality allows for integration to other modules. • Accounts Receivable • Accounts Payable • Budgeting & Forecasting • Payroll • Fixed Assets • Job Costs • Procurement • Inventory • Address Book	Fit	Current system functionality exists.	
7.1.11	**Integrity Report**	**Integrity Report** Use integrity reports to supplement your internal balancing procedures. Integrity reports locate potential balancing problems and data inconsistencies. YEC uses these reports to ensure that the financial reports produced comply for accuracy, completeness and validity. • Un-posted batches • Transactions to Batch Header • Batch to Detail • Batches out of Balance • Batch and Company Within Batch Out of Balance • Companies in Balance • Accounts without Business Units • Account Balance with Account Master • Transaction without Account Master	Fit	Current system functionality exists.	7.2.11

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Compare Account Balance to transactions			
7.1.12	**Reporting Security**	Financial Reporting security exists. This is configured based on YEC requirements. The security can be explicit with report reference and data fields for user access.	Fit	Current system functionality exists. This is not configured for optimal performance and security access.	7.2.12

7.2 Future State

No.	Key Area	Requirements	Criticality	Additional Notes
7.2.1	**Transactional Reporting**	YEC requires the following transactional reports: • Account Balance by Month • Account Ledger Print • General Journal by Account • General Ledger by Business Unit • General Ledger by Object Account • General Ledger by Sub-ledger totals • JDE GL Inquiry of account balance export to excel • Journal Entry Details prior to Posting • Journal Entry Posting Report • Transaction Journal • Transactions by Object	1	
7.2.2	**Trial Balance**	YEC requires the following trial balance reports: • Trial Balance by Account Code • Trial Balance by Sub- Account Code • Trial Balance by Business Unit • Trial Balance by Object with roll up • Trial Balance by Object with no roll up • Trial Balance by Company • Monthly Trial Balance Report	1	
7.2.3	**Variance Reporting**	YEC requires the following variance reporting: • Variance Analysis used as Control Report	1	
7.2.4	**Income Statement Reporting**	YEC requires the following income statement reports: • Income Statement by function (BOD) • Operating Income Statement • Income Statement by Account Code • Income Statement by Sub-Account Code • Income Statement by Business Unit • Monthly Income Statement	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• Consolidated Income Statement • Income Statement from JDE by Cat Code2 Function for both labour and Non Labour Costs • Income Statement from JDE by Cat Code2 Function for labour costs only • Income Statement from JDE by Cat Code2 Function for non labour costs only • Income Statement from JDE by Cat Code10 broken out by cost type for all costs • Income Statement from JDE by Cat Code10 broken out by cost type for non labour costs only • Income Statement from JDE by Cat Code10 for labour costs only • Income Statement from JDE by Cat Code10 for non labour and labour costs only • Income Statement from JDE by Cat Code10 for non labour costs only • Income Statement from JDE by Cat Code10 broken out by cost type for labour costs only • Simple Income Statement used as Control report		
7.2.5	**Departmental & Management Reporting**	YEC requires the following departmental reports: • YTD Board Expenses • YTD Consultants by Function • YTD General Admin Breakdown • YTD Labour by Department • YTD Labour by Department and Function • YTD Legal Costs by Business unit • YTD Non Labour by Department and Function • Management Reporting • Year End Income Statement • Year End Balance Sheet • Year End Cash Flow • Year End Lead Sheet	1	
7.2.6	**Balance Sheet**	YEC requires the following balance sheet reports: • Balance Sheet from JDE provides lowest level of category totals for Board package • Balance Sheet from JDE rolled up one level to provide Board package support • Balance Sheet from JDE rolled up to provide Board Package totals • Simple Balance Sheet Report used as a control report	1	
7.2.7	**Cash Flow**	YEC uses the following cash flow statement: • To be determined in RFP.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
7.2.8	**Quarterly Reporting**	YEC requires the following quarterly reports: • Quarterly YTD General Admin Breakdown	1	
7.2.9	**Board Reporting**	YEC requires the following Board Reports: • Board Package	1	
7.2.10	**Project Cost Tracking**	YEC requires the following Project Cost tracking Reports: • Actuals vs Approved BP vs Forecasting (1 year and multi-year projects) • Parents and Subs • Projects with no budgets – contingency • Blanket Budgets for like projects	1	
7.2.11	**Integrity Report**	Integrity Report Use integrity reports to supplement your internal balancing procedures. Integrity reports locate potential balancing problems and data inconsistencies. YEC requires these reports to ensure that the financial reports produced comply for accuracy, completeness and validity. • Un-posted batches • Transactions to Batch Header • Batch to Detail • Batches out of Balance • Batch and Company Within Batch Out of Balance • Companies in Balance • Accounts without Business Units • Account Balance with Account Master • Transaction without Account Master Compare Account Balance to transactions	1	
7.2.12	**Reporting Security**	Financial Reporting security is required. The security can be explicit with report reference and data fields for user access.	1	

8 Fixed Assets

Yukon Development Corporation (YDC) is a crown corporation created in 1986 by the Yukon Development Corporation Act. With Yukon Energy Corporation (YEC) created in 1987 as its subsidiary of Yukon Development Corporation. YEC is a publicly owned electrical utility that operates a business, at arms length from the Yukon government. Energy Solutions Centre (ESC) was also a subsidiary of Yukon Development Corporation until end of 2005, this is now integrated into Yukon government Department of Energy, Mines and Resources.
YDC and YEC are active companies in the proposed financial information systems (FIS) structure, with its respective diverse business structure and fixed asset functionality. ESC fixed asset data will only be entered into the proposed FIS for historical reporting and regulatory requirements.

8.1 *Current State*

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
8.1.1	**Asset Master Information**	Fixed Assets: Fixed Assets are assets owned by YEC that are permanent or have useful life that is used by the business in the production of its revenues. Over time the asset looses it usefulness and is depreciated to provide for the acquisition of a replacement asset. FA structure is unique to YEC for its operational and accounting requirements. Fixed Asset Coding Structure: The fixed asset coding structure consists of balance sheet business unit, object account and subsidiary account. This is a consistent approach for both companies and the object accounts are categorized by asset class. The subsidiary is also used as a sub-class to core operation of both YEC and YDC. The combination of business unit, object account and subsidiary account is used as a norm. Asset Numbering: • Asset Number, this is currently system assigned • Unit Number, this is the preferred reference number as this is referenced with YEC numbering convention. This is a user assigned number. • Serial Number, this is reference to manufacturers reference. • Parent Number, this referenced to system assigned numbering. Used as parent/child relationship. Description Fields: Three fields are used for asset descriptions. The following fields are currently used: • Company Reference	Fit	Current system functionality exists.	8.1.1

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Default Business Unit • Responsible Business Unit • Account Codes • Date Acquired • Date Disposed • Authorization for Expenditure • Status of the asset • Sub-ledger reference • Employee Assigned <u>Categorization of Assets:</u> YEC uses category codes to identify, track and report on assets. Category codes used are: • Accounting Class • Equipment Class • Manufacturer • Model Year • Usage • Customer Extensions • Vintage Year • True Up • Iowa Curve <u>Additional Information fields used:</u> • Three remarks fields • New or Used reference • State or Province • Tax Entity • Investment Tax Credit • Location • Current Item Quantity • Original Item Quantity <u>Accounting Information Used:</u> • Asset Cost Account • Accumulated Depreciation Account • Depreciation Expense Account • Revenue Account • Depreciation Method • Life Months • Computation Method • Start Depreciation Date • Salvage Value • Site Restoration Account used via UD ledger and this is journal back to Actual Ledger.			
8.1.2	**Ledgers**	The following ledgers are used currently:	Fit	Current system functionality exists.	

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Actual Ledger (AA) • Units Ledger (UA) • User Defined Depreciation Ledger (UD) • Would need to create User Defined Ledger.			
8.1.3	**Depreciation Rules**	The current depreciation rules used: • Straight Line Method with defined months (both indefinite YEC and definite YDC) • Negative Depreciation Rule • Positive Depreciation Rule • PP&E Depreciation • True-Up Depreciation. This is A/D from study that is depreciated. • Default Depreciation Codes, this is used to minimize setups • Create user defined rules • Rules is company specific • Rules are by asset classes if required. • Allow for over depreciation.	Fit	Current system functionality exists.	
8.1.4	**Splitting Fixed Assets**	Asset splitting is used to split an existing asset into one or more assets. Currently splits are done on: • Percentage basis • Monetary Value • Quantity • Journal Entry	Fit	Current system functionality exists.	
8.1.5	**Transferring Fixed Asset**	The option exists to transfer single assets of mass transfer. Transferring of assets by the following criteria is available: • Cost Accounts • Accumulated Depreciation • Depreciation Accounts • Responsible Business Unit • Revenue Business Unit • User Defined Category Codes • By asset number	Fit	Current system functionality exists.	
8.1.6	**Fixed Asset Disposal**	The following disposal methods are used: • Simple Disposal • Disposal with cash proceeds • Disposal with trade in • Disposal with trade in and cash proceeds • Journal Entry Disposal can either by done by a single asset disposal or by mass disposals.	Fit	Current system functionality exists.	

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
8.1.7	**Monthly Depreciation Calculations**	With the completion of the deprecation rules, depreciation methods and asset master. Monthly depreciation calculations can be run in a proof mode and in a final mode. • YEC currently calculates the depreciations based on an "as off " date. The system runs a calculation in proof mode for necessary checks and corrections to errors. • Run in final mode. • Creates Journal Entries for posting in General Ledger • Review and posting of Journal Entries • Post Journal Report is produced.	Fit	Current system functionality exists.	
8.1.8	**Approval Processes**	• Levels of approval are defined for Fixed Asset. • Approval by batch, batch type or user ID. • Approvals are module specific. i.e only can approve FA batches.	Fit	Current system functionality exists.	
8.1.9	**Global Updates and Audit**	• Run global updates to depreciation rates • Run global updates to asset master • Run global updates for computation methods • Run global update for life months • Run global update depreciation method • Run to update other modules with FA related entries • Run global update to ledgers to assets • Updates to GL object accounts, translates into the FA system.	Fit	Current system functionality exists.	
8.1.10	**Grants**	Currently tracks grants by: • Contributions by Government • Contributions by Customers • Contributions by YDC	Fit	Current system functionality exists.	
8.1.11	**Integrity**	Use integrity reports to supplement your internal balancing procedures. Integrity reports locate potential balancing problems and data inconsistencies. Reports are available in summary or detail. The following integrity routines are followed: • Fixed Asset to GL integrity • Un-posted FA transactions • FA Transaction Report • GL to FA integrity	Fit	Current system functionality exists.	
8.1.12	**Annual Close**	Annual Close As part of period-end and year-end procedures, the following tasks are performed: • Closing an accounting period – Company specific. • Changing a financial reporting date	Fit	Current system functionality exists.	

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Closing a fiscal year • Annual close is company specific • Updates to opening balances • Can work with future periods.			
8.1.13	**Online FA Inquiries**	The current system functionality allows for a variety of user-defined criteria to view fixed asset information. This includes unit number, asset number and category codes. Repetitive use is made of the following: • Fixed Asset Master Information • Cost Summary • Depreciation Methods and rates • Net Book value • Category codes • Query by example • Depreciation values	Fit	Current system functionality exists.	
8.1.14	**Audit**	The need to track changes of critical information by user, date and approver.	Fit	Current system functionality exists. Not configured.	
8.1.15	**Reports**	Current reports used: • FA Continuity Schedule • Asset Additions • Asset Disposals • Asset Retirements • Asset by Class • Asset by Business Unit • Asset by Location • Asset Cost Summary • Depreciation Expense • Full FA Master Information • Insurance Value • Report by category codes	Fit		
8.1.16	**System Integration**	The following systems integrate with Fixed Assets. • General Accounting • Procurement • Inventory • Job Cost • Address Book • Accounts Payable	Fit	Current system functionality exists	
8.1.17	**Third Party Software**	**Interface from Third Party Software** • Project Identification Document (PID process) • PIDS create projects which close to FA.	Gap		

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Work order close outs to fixed assets – PID creates work order.			

8.2 Future State

Fixed Assets is an integral part of YEC's financial systems. An efficient system of tracking and recording of expenses is needed to meet this inherent requirement. Anomalies in the valuation of assets and reporting need to be addressed.

No.	Key Area	Requirements	Criticality	Additional Notes
8.2.1	**Asset Master Information**	Fixed Assets: Fixed Assets are assets owned by YEC that are permanent or have useful life that is used by the business in the production of its revenues. Over time the asset loses it usefulness and is depreciated to provide for the acquisition of a replacement asset. The ability to support the following are required by YEC: Fixed Asset GL Coding Structure: • Ability to define multi-segment account codes. (Minimum of 3 segments and minimum of 14 digit code in total. The 3 segments (20.140002.004) comprising of department, account code and sub account code eg Balance Sheet department, account code referencing Computer and sub account code referencing hardware or software). Asset Numbering: The ability to have user assigned numbering and system assigned: • Ability to have asset number system assigned with a minimum of 6 digit code. • Unit Number, this is the preferred reference number as this is referenced with YEC numbering convention. This is a user assigned number which is alpha-numeric with a minimum of 6 digit code. • Ability to have a serial number which is user assigned and a minimum of 30 digit code. (This a manufacturer's reference) • Ability to support parent number which can be system assigned or user assigned. This is used to setup the hierarchy of parent/child relationship. Description Fields: The ability to support the following fields are required: • Asset descriptions with a minimum of 60 characters. • Company Reference field (YEC or YDC) • Department Location(Physical location of the asset) • Department that owns the asset.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• Date Acquired • Date Disposed • Reference field to store the authorization number (Project Identification number that is initiated for capital expenditure) • Employee Assigned field (Assigning responsibility to Project Managers) • Reference field for tracking easements • Licences reference field. • Status of the Asset (eg Active, Inactive, scrapped) Categorization of Assets: The ability to support the categorization of assets into the following classes: • Accounting Class (eg. Land, Building, Furniture and Fittings, Computers, Roads, Vehicles) • Equipment Class (eg. Land Operations, Software, Hardware, Trucks, Vans, Cars) • Manufacturer (eg. Caterpillar, Ford Co, Honeywell) • Model Year • Usage (eg. Hydro, Diesel, Wind) • Vintage Year (This is used to flag the assets acquired by YEC from YDC) • Iowa Curve field reference. The codes for the Iowa curve and the corresponding rates are entered. (This is a unique to a YEC corporation where the assets are re-valued for useful life and assigned new depreciation rates based Iowa Curve rate study). The ability to support this is mandatory. Additional Information fields required: • Additional field are required for remarks/explanation(A minimum of 60 characters is required) • New or Used reference (Refers to asset condition) • Financing Methods (eg Leasing, Bank, Owner finance) • Investment Tax Credit field (Amounts received as grants or sponsors for development of assets) • Current Item Quantity (eg poles, structures) • Original Item Quantity Depreciation Information: The ability to support the following depreciation information. • Asset Cost Account • Accumulated Depreciation Account • Depreciation Expense Account • Depreciation Method (eg Straight Line) • Asset Useful Life (ability to show in months or years) • Start Depreciation Date		

No.	Key Area	Requirements	Criticality	Additional Notes
		• Salvage Value • Site Restoration Account (the ability to expense secondary depreciation and have the offset entry in the balance sheet as site restoration account)		
8.2.2	**Ledgers**	The ability to support multiple books of records: • Actual Ledger • Units Ledger • YEC Depreciation Ledger (This is used to calculate depreciation based on the Iowa curve revaluation) • The ability to create additional ledgers as required. (Possible requirement for IFRS)	1	
8.2.3	**Depreciation Rules**	The ability to support predefined depreciation rules calculation and also the ability to create new depreciation rules calculation where required: • Straight Line Method with defined months • Ability to create own depreciation rules. (This would be a deviation from the straight line calculation this requirement will be driven from the Iowa curve study where new depreciation rates and rules are required). • Over-depreciation of an asset must be allowed. (This is unique to the YEC) • Different depreciation start dates is required eg. (1st day following in service date).	1	
8.2.4	**Fixed Asset Splitting**	Asset splitting is used to split an existing asset into one or more assets. • The ability to splits assets by: o Percentage basis o Monetary Value o Quantity • The ability to split by manual journal entry. (Creation of a new asset and transfer the cost and accumulate depreciation as required).	1	
8.2.5	**Transferring Fixed Asset**	The ability to transfer single asset or group of assets. Support the transfer of assets by the following criteria: • Cost Accounts • Accumulated Depreciation • Depreciation Accounts • Owner Department • Categorization codes. (eg Accounting Class, Equipment Class) • Location Department	1	
8.2.6	**Fixed Asset Disposal**	The ability to support the following disposal methods: • Simple Disposal • Disposal with cash proceeds • Disposal with trade in • Disposal with trade in and cash proceeds • Disposal by categorization codes (eg Accounting Class, Equipment	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		Class)		
8.2.7	**Monthly Depreciation Calculations**	The ability to run monthly depreciation calculations in a preliminary mode for review before being run in a final mode. • Ability to automatically calculate the depreciation based on an "as off "date. • Ability to run in preliminary mode. • Ability to run in final mode. • Ability to creates journal entries for posting in general ledger • Ability to review and post entries into General Ledger. • Ability to print a post report. • Ability to reverse depreciation calculations by batch if required. • Ability to re-run depreciation based on updated data.	1	
8.2.8	**Approval Process**	• Ability to support Management Approvals by batch. (The user will entered the batch and this can only be approved by a Manager if required)	1	
8.2.9	**Mass Updates**	Ability to perform the following mass updates: • Run mass updates for changes to depreciation rates in the asset master. • Run mass updates to asset master (eg changes to categorization of assets i.e. Accounting Class) • Run mass update for asset life. (eg a group of assets are now being change to be depreciate from 60 months to 72months) • Run mass update to ledgers. (The ability to attached assets to ledgers as required .i.e. all fixed assets will also be attached to new ledger defined by IFRS requirement)	1	
8.2.10	**Grants**	Ability to track grants by: • Contributions by Government of Yukon • Contributions by Customers • Contributions by YDC	1	
8.2.11	**Integrity**	Integrity Report Use integrity reports to supplement your internal balancing procedures. Integrity reports locate potential balancing problems and data inconsistencies. The ability to check the FA by the following criteria: • Fixed Asset to GL integrity (Ability to show posting discrepancies from the FA to GL) • Un-posted FA transactions (A report showing all un-posted FA transactions by batch number and batch totals) • FA Transaction Report showing transactions posted by batch and batch totals. • GL to FA integrity (Ability to show posting discrepancies from the GL to FA) • Integrity between actual ledger and user defined ledger must be	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		available.		
8.2.12	**Period and Annual Close**	The ability to support the following are required: • Closing a fixed asset period. • Closing a fiscal year (This process will carry forward the asset cost and accumulated depreciation balances to the new year) • Ability to post FA entries into future periods. • Ability to restrict posting to a close accounting period.	1	
8.2.13	**FA Online Inquiries**	Ability to view the following information via on-line inquiries. • Fixed Asset Master Information (The ability to show a minimum of the following searchable fields, Asset number, Unit number, Serial number, Department, Categorization Codes, Company, Asset Description fields) • Asset Cost Summary (The ability to show a minimum of the following searchable fields, Asset number, Unit number, Serial number, Department, Cost Amount, Accumulated Depreciation, Depreciation Expense, Net Book Value, Date Acquired, Asset Description Filed)	1	
8.2.14	**Reports**	The ability to produce the following reports: • FA Continuity Schedule (The following data fields are required: Asset ID, Asset Description, Beginning Asset Cost, Transfer In, Additions, Assets Sold or Retired, Assets Transfer Out, Ending Asset Cost, Beginning Accumulated Depreciation, Assets Transfer In, YTD Depreciation Expense, Asset Sold or Retired, Assets Transfer Out, Ending Accumulated Depreciation, Net Book Value) • Asset Additions (The following data fields are required: Asset ID, Asset Description, Date Acquired, Asset Cost, Accumulated Depreciation, Depreciation Expense, Net Book Value) • Asset Disposals (The following data fields are required: Asset ID, Asset Description, Disposal Date, Date Acquired, Asset Cost, Accumulated Depreciation, Net Book Value, Cash Proceeds, Gain or Loss on Disposal) • Asset by Location Department (The following data fields are required: Asset ID, Asset Description, Serial Number, Unit Number, Date Acquired) • Depreciation Expense Information (The following data fields are required: Asset ID, Asset Description, Asset Status, Ledger reference, Cost, Accumulated Depreciation, YTD Depreciation Expense, Current Period Depreciation Expense, Net Book Value, Start Depreciation Date, Depreciation Method, Asset Life) • Monthly Depreciation Calculation Report (The following data fields are required: Asset ID, Asset Description, Acquisition Date, Depreciation Start Date, Depreciation End Date, Asset Life, Cost, Accumulated Depreciation Inception to Date, Accumulated	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		Depreciation YTD, Depreciation Current, Depreciation Balance Adjustment).		
8.2.15	**System Integration**	The ability to integrate with the following modules: • General Accounting • Procurement • Inventory • Equipment and Plant Maintenance • Job Cost • Address Book • Accounts Payable	1	

9 General Ledger

Yukon Development Corporation (YDC) is a crown corporation created in 1986 by the Yukon Development Corporation Act. With Yukon Energy Corporation (YEC) created in 1987 as its subsidiary of Yukon Development Corporation. YEC is a publicly owned electrical utility that operates a business, at arms length from the Yukon government. Energy Solutions Centre (ESC) was also a subsidiary of Yukon Development Corporation until end of 2005; this is now integrated into Yukon government Department of Energy, Mines and Resources.
YDC and YEC are active companies in the proposed financial information systems (FIS) structure, with its respective diverse business structure and financial reporting requirements. ESC will only be entered into the proposed FIS for historical reporting and regulatory requirements. Cognizance needs to be taken of reporting for Yukon Territory Government (YTG) and Yukon Utilities Board (YUB).

9.1 *Current State*

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
9.1.1		**Company** Companies are organizational entities that required for operational purposes. Companies include information about fiscal patterns and fiscal periods. This setup provides for reporting and accounting at a lower level.			
9.1.2	**Company**	Company Setup Requirements: • Ability to have multiple companies. This would include YEC (Yukon Energy Corporation) and YDC (Yukon Development Corporation). Transactional history of ESC (Energy Solutions Centre) would be needed for data migration, historical reporting purposes and regulatory requirement. • Required that both companies operate as independent companies. Due to the diverse nature of operations of both companies, it's expected that the business unit and chart of accounts are unique to each company. • Given that YEC & YDC are independent companies. No inter-company transactions are expected. • Companies have a base reporting currency of Canadian Dollars. • Consolidation of both YEC & YDC is required. Fiscal periods are expected to be the same for both companies. • Company ID is numerical with digits from two to five. • The Company description should be a minimum of thirty	Fit	• Current system functionality provides for unlimited companies with varying degrees of diverseness as required. • Current system functionality provides for individual company setup. • Current system functionality provides for both inter-company and non inter-company transaction. • Current system functionality provides for multi-currency or domestic currency as required. • Current system functionality provides for consolidations as required. • Current system functionality provides for two to five digits. • Current system functionality provides for minimum as required.	9.2.1

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		characters lengths. • Company as defined date fiscal patterns. Option to select defined date fiscal patterns to respective companies. (YEC uses a calendar year as date fiscal pattern). • Defined number of accounting periods eg. 12 periods or 13 periods. YEC currently uses 12 period reporting. • Ability to set company reporting period.		• Current system functionality provides for flexibility of date fiscal patterns. • Current system functionality provides for reporting periods up to 14 and also 52 weekly reporting if required. • Current system functionality provides for reporting period setup	
9.1.3		**Business Units** Business units are part of the basic J.D. Edwards account structure. A business unit is the "where" portion of an account. It is used to denote where transactions impact the organization, such as a warehouse, department or store. It is the lowest reporting level within your organization at which you need to account for assets, liabilities, equity, revenue, or expenses.			
9.1.4	**Business Units**	• Ability to have multiple business units. The assignment of the business unit is company specific. (This needs to support the unique structure of the respective companies. The number of business units is estimated to be in the region of five hundred per company) • The naming of business units needs to be alphanumeric with 6 to 8 digits. • The description of Business unit should exceed 35 characters. • Business unit needs to be user-defined description. Eg Human Resources Department • Able to have user defined business unit types. Eg Balance Sheet BU, Income Statement BU, Revenue BU, Operating and Maintenance BU, Job Cost BU, Model BU's. • Have a Posting Edit flag. This would be for the purposes of either posting transactions or not. • Ability to flag the business unit for consolidation purposes. i.e. no model business will be include in business unit consolidation • The ability to assign category codes to business units. This would be used predominantly for reporting purposes and consolidations. • Minimum of fifteen category codes are required for business units. (This would be required for reporting purposes) • Level of Detail required on Business Unit. Eg Balance	Fit	• Current system functionality provides for unlimited business units. • Current system functionality exists.	9.2.2

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		Sheet Business Unit is assigned level 2 and job cost assigned level 8. This is for reporting on level of detail and also for rollup purposes. • Ability to assign owner of business unit. Eg. Job cost business unit is assigned a Project Manager. • Ability to make changes to business unit via global updates. Eg changes to a category code or combination of changes. • Ability to attachment document to BU's • Ability to have effective Dates by Business Unit eg. Business Unit 123 is effective end date of 12/31/2007.			
9.1.5		**Chart of Accounts** After you set up your companies and business unit you need to set up object and subsidiary accounts for each business unit. These accounts form your chart of accounts. The object and subsidiary describe the kind of transaction with which you are working—for example, rent expense, office supplies expense, or sales revenue.			
9.1.6	**Chart of Accounts**	• Ability to create user defined chart of accounts, with the combination Business Unit. Object. Subsidiary. Typically the Business Unit length will be 6 to 8 character, Objects will be 4 digits, and subsidiary will be 3 to 4 characters. Eg. 963070.4400.001 • The chart of accounts requires the flexibility to be created in a hierarchy e.g. Balance Sheet Account: With headings under Assets, Liabilities, Owners Equity, Income Statement with Revenue and Expenses. • Level of detail required for object, subsidiary accounts. • Level of details (1 to 9) • The chart accounts are structured with Business Unit. • Require Category Codes for chart of accounts. (O&M 8, Job costs 8, Minimum 12 cat codes required) • Invalid accounts need to be flagged for errors. • Factors that determine whether an account posts or not. o Posting. o Non-posting accounts. o Budget Accounts o Machine generated. o Inactive Account o Units are required. o Monetary Account (USD bank type transactions) • Monetary not required. • Global updates to COA (to new account)	Fit	Current system functionality exists.	7.2.2

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Different COA by Company required. This is for YDC and YEC. • Ability to revise COA with relative ease. • Ability to copy accounts from one business unit to another.			
9.1.7		**Ledgers Types** Ledger types define the ledgers that you maintain in the general ledger. These ledgers contain management and control information for the following: • Actual Expenses • Units • Budgets • Forecasts • Accrual basis amounts • Cash basis amounts • Tax • Projections			
9.1.8	**Ledgers Types**	• AA Actual ledger • UD User Defined for Depreciations (Fixed Assets) • BA Budget Ledger • PA (Commitments Ledger) • JA (Job Cost) • Currency Ledgers (Check if this is required going forward) • UA (Units Ledger required) • Ability to have user defined ledger types • Ledger types rules eg. (Annual close, balancing, direct updates) • Define rules for posting and control • Drill down to transaction level detail from all ledgers	Fit	• Current system functionality exists. • Current system functionality exists, not used. • Current system functionality exists.	
9.1.9	**Taxes**	• GST tax calculation is required • PST is required • Date effective GST & PST tax calculations • Tax rules required by rate and area • Tax Tolerance is required	Fit	Current system functionality exists.	
9.1.10	**System Integration**	• Accounts Receivable (Not used) • Accounts Payable (currently utilized) • Budgeting & Forecasting • Payroll (ADP is used)	Fit	Current system functionality exists.	

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Fixed Assets • Job Costs (used partly) • Procurement • Equipment Maintenance (Not used) • Inventory • Address Book			
9.1.11		**Journal Entry Processing** Use journal entries to adjust or add transactions to accounts in your general ledger. Effective journal entry processing is fundamental to the accuracy of your general ledger.			
9.1.12	**Journal Entry Processing**	• Assign Journal ID's automatically • Ability to create basic journal entries. • Ability to create a reversing journal entry • Ability to create a model journal entry. • Ability to create a percentage journal entry • Ability to upload from Excel (Minimum number of transaction per batch is two thousands) • Ability to input from third party systems • Allocation JE entries • Automatic JE's (Generated from other modules) • Shortcut keys and automatic filling of entry fields • Import spreadsheet data for data entry • Use standard journals as templates/models • Post statistical and monetary amounts in the same journal entry • Reverse accruals or posted journal entries with full audit trail • Allow transactions to be posted to the current period even if the prior period has not been closed. • Prevent posting to a closed period. • Allow posting to future periods • Reverse journal entries. • Ability to copy JE from existing entries. • Ability to delete un-posted JE. • Ability to void JE. • Recurring Journal Entries. Similar journal entry with dates changing. • Require reference field that list Fixed Asset ID's • Require reference field that list sub ledgers • Ability to review JE before being posted. • Ability to make corrections before being posted.	Fit	Current system functionality exists.	7.2.3
9.1.13	**Approval Processes**	• Ability to define levels of approval for Journal Entries. (Compliance with Segregation of Duties).	Fit	Current system functionality exists.	

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Ability to approve by Batch. • Approval should be module specific. i.e. only can approve Journal Batch.			
9.1.14		**Allocations** Allocations can serve many purposes, such as distributing expenses, creating annual or periodic budgets, and calculating currency conversions. Use allocations to redistribute amounts from one or more business units to accounts in other business units, or from one ledger type to another. You can set up model journal entries to work as allocations. Use model journal entries or recurring journal entries if the amounts never change.			
9.1.15	**Allocations**	• Choose multiple allocation types- copy, fixed, pro-rata, spread evenly or arithmetic • Ability to have indexed calculations. (Basically allocating funds from one account to another) • Ability to have variable numerator allocations. • Automatically generate journal entries with a complete audit trail • Allocation used to inception to date and allocate based on cat code. AFUDC (Allowance for funds used during construction) interest to be charged to projects. Credit offset to revenue.	Fit	Current system functionality exists.	7.2.4
9.1.16		**Integrity Report** Use integrity reports to supplement your internal balancing procedures. Integrity reports locate potential balancing problems and data inconsistencies.			
9.1.17	**Integrity Report**	• Un-posted batches • Transactions to Batch Header • Batch to Detail • Batches out of Balance • Batch and Company Within Batch Out of Balance • Companies in Balance • Accounts without Business Units • Account Balance with Account Master • Transaction without Account Master • Compare Account Balance to transactions	Fit	Current system functionality exists.	7.2.5
9.1.18		**Reconciliations** As part of your accounting processes, you might need to reconcile certain types of accounts in your system. For example, you might need to reconcile the balances in your bank accounts with those in your bank statement. Or you might want to reconcile debits to credits within a trade or suspense account.			

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
9.1.19	**Reconciliations**	• Account Reconciliation (For employee accounts, balance sheets accounts) • Bank Reconciliations Manual Process • Auto- reconciliations are electronic file bank Reconciliation feature not used currently.	Fit	Current system functionality exists.	
9.1.20		**Account Consolidations** The account consolidation programs enable you to group, or consolidate, business unit account balances for online review and reports, provided that the balances are in the same currency and all of the companies use the same fiscal date pattern.			
9.1.21	**Account Consolidations**	• Ability to inquire on Account consolidations. • Online consolidations by Business Unit, Cat Code, Owner • Company consolidations by both YEC & YDC • Ability to have rules for consolidation.	Fit	Current system functionality exists.	
9.1.22		**Periodic Close & Annual Close** As part of period-end and year-end procedures, the following tasks must be performed: • Closing an accounting period • Changing a financial reporting date • Closing a fiscal year			
9.1.23	**Periodic Close**	• Monthly close by module, GL, AP, AR, FA and Inventory • Ability to work with current and future period • Error if future period is used (Soft warning) • PBCO, no posting allowed to closed periods	Fit	Current system functionality exists.	7.2.6
9.1.24	**Annual Close**	• Close to Retained Earning • Ability to close any number of times • Ability to work with close period after an annual close. (This is for adjusting entries) • Updates to opening balances when annual close is complete. • Annual close is company specific	Fit	Current system functionality exists.	7.2.7
9.1.25	**Global Updates and Audit**	• Global updates to Business units • Global updates to Object accounts • Audit list of user and batch approvers	Fit	Current system functionality exists.	
9.1.26		**Online Inquiries** The ability to perform on-line inquiries on demand.			
9.1.27	**Online Inquiries**	• Inquiry by Trial Balance • Inquiry by Object Account • Inquiry by Business Unit • Inquiry by Company, Business Unit, Object • Inquiry by Balance Sheet	Fit	Current system functionality exists	

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Inquiry Income Statement • Inquiries should be level of detail • Inquiry should be by period or date • Inquiry by Sub-ledger			
9.1.28	**Interface from Third Party Software**	• CIS interface (Customer Interface System) • ADP (Easy labour & Pay at work) • Project Identification Document (PID process)			
9.1.29	**Reporting**	This is will be covered in Financial Reporting.			Refer to Current and Future state document for Financial Reporting.
9.1.30	**GL Security**	This will be covered globally from a foundation setup.			

9.2 Future State

No.	Key Area	Requirements	Criticality	Additional Notes
9.2.1	**Company**	Companies are organizational entities that are required for operational purposes. This setup provides for reporting and accounting at various levels of the organization. Company Setup Requirements: • Ability to have multiple companies. (YEC and YDC are required). • Required that both companies operate as independent companies. (YEC and YDC function with its own unique chart of accounts) • Transactional currency of Canadian Dollars is required. (All inquiries and financial reporting to be shown in CAD). • Company ID is numerical with at least a 2 digit code. • The Company description must be a minimum of thirty characters in length. (eg Yukon Development Corporation) • Ability to define date patterns as a calendar year or as required. • Ability to define number of accounting periods. (YEC requires 13 periods, the 13th period will be used for audit adjustments) • Ability to specify accounting period on transactions. • Ability to support the use of multiple sub-ledgers (eg. Accounts receivable, accounts payable, fixed assets, job cost and inventory) • Ability to maintain up to 7 years of historical data. This information must be available for both system reports and inquiry functions.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
9.2.2	**Departments**	Department Requirements: • Ability to support the use of multiple departments. (eg Finance, Engineering, Human Resources) • The naming of departments must be alphanumeric with minimum 6 digit code. • The description of department must be a minimum 35 characters. • Ability to support department types. Eg Balance Sheet department, Income Statement department, Revenue department, Operating and Maintenance department, Job Cost department. • The ability to support either the posting or non-posting of transactions to a department. • Ability to flag the department for consolidation purposes.(i.e. group all income statement type departments) • The ability to assign categorization codes to departments. A minimum of 15 categorization codes are required. This would be used predominantly for reporting and consolidations purposes. • Ability to accommodate departmental hierarchy. • Ability to assign owner of department. (i.e. Joe B -Project manager is owner of capital job). • Ability to make changes to department via mass updates.(eg. Changing categorization codes for a number of departments with single update process). • Ability to attach documents/files to a department. • Ability to have effective dates by department. .	1	
9.2.3	**Chart of Accounts**	Chart of Accounts A chart of accounts provides the structure for your general ledger accounts. It lists specific types of accounts, describes each account, and includes account numbers. A chart of accounts typically lists asset accounts first, followed by liability and capital accounts, and then by revenue and expense accounts. • Ability to define multi-segment account codes. (Minimum of 3 segments and minimum of 14 digit code in total) • Ability to support either the posting or non posting of transactions to an account. • Ability to maintain the chart of accounts online and prevent the deletion of any account with activity. • Ability to allow only input of valid account numbers. Invalid account numbers must be shown as an error. • Ability to support account hierarchy. (eg accounts can rollup to into higher level accounts). • The ability to assign categorization codes to accounts. A minimum of 12 categorization codes are required. This would be used predominantly for reporting and consolidations purposes.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• Ability to make changes to accounts via mass updates.(eg. Changing categorization codes for a number of accounts with single update process). • Ability to copy accounts from one department to another.		
9.2.4	**Ledgers**	• Ability to support the following ledger types (Actual Ledger, Depreciations Ledger, Budget Ledger, Commitments Ledger, Job Cost Budget Ledger, Units Ledger, Forecast Ledger) • Ability to define ledger types rules. (the ability to have balance rollover to the following year based on the rule) • Ability to support drill down capabilities on all ledgers to source transactions.	1	
9.2.5	**Taxes**	• Ability to automatically calculate GST and PST. • Ability to support date effective tax rates for both GST and PST. • Ability to define tax rates and tax area. (i.e. 5% for GST) • Ability to support tax tolerance rules. (The ability to adjust the automatically calculated taxes within a percentage or dollar value as stipulated within a tax tolerance rule).	1	
9.2.6	**System Integration**	The ability to integrate into the following modules is required: • Accounts Receivable • Accounts Payable • Fixed Asset • Budgeting and Forecasting • Job Cost • Procurement • Inventory	1	
9.2.7	**Journal Entry Processing**	Journal Entry Processing Journal entries are used to adjust or add transactions to accounts in your general ledger. Effective journal entry processing is fundamental to the accuracy of your general ledger. • Ability to assign Journal ID's automatically • Ability to create basic journal entries. • Ability to create a reversing journal entry • Ability to create a model journal entry. (this will be reused later for repetitive type JE transactions) • Ability to create a percentage journal entry • Ability to upload from Excel (Minimum number of transaction per batch is two thousands) • Ability to input from third party systems (Payroll entries from ADP will be required for JE interface) • Ability to create allocation JE entries. • Ability to allow transactions to be posted to the current period even if the prior period has not been closed. • Ability to prevent posting to a closed period.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• Ability to support posting to future periods. • Ability to reverse journal entries. (Allow for a posted journal entry to be reversed if required) • Ability to copy JE from existing entries. • Ability to delete un-posted JE. • Ability to support recurring Journal Entries which are automatically generated with overrides and manual changes possible before posting. • Ability to reference a field that list Fixed Asset ID's • Ability to support reference field that list sub ledgers • Ability to review JE before being posted. • Ability to attach or enter explanatory notes for all transactions, with substantial field lengths. • Ability to provide for error identification and correction before actual posting occurs and notify the user of the deficiencies. • Ability to provide for convenient online maintenance of rejected batches of journal entries. • Ability to support an audit trial for manual journal entries and subsystem journal entries.		
9.2.8	**Allocations**	Allocations Allocations can serve many purposes, such as distributing expenses, creating annual or periodic budgets, and calculating currency conversions. The use of allocations to redistribute amounts from one or more departments to accounts in other departments, or from one ledger type to another. • Ability to support multiple allocation types. (i.e. fixed, pro-rata, spread evenly or arithmetic. • Ability to have indexed calculations. • Ability to have variable numerator allocations. • Ability to support allocations using inception to date balances and allocate based on categorization code. (eg. AFUDC (Allowance for funds used during construction) interest to be charged to projects. Credit offset to revenue).	1	
9.2.9	**Integrity Report**	Integrity Report Integrity reports are used to supplement your internal balancing procedures. Integrity reports locate potential balancing problems and data inconsistencies. • The ability to demonstrate that the General Ledger system is in balance with transactions and active sub-ledgers. • The ability to demonstrate that the companies are in balance.	1	
9.2.10	**Account Consolidations**	Account Consolidations The account consolidation programs enable you to group, or consolidate, departments account balances for online review and	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		reports. • Ability to inquire on Account consolidations. • Ability to support online consolidations by department, Categorization Code, Owner, account code.		
9.2.11	**Periodic Close**	• The ability to close the General Ledger by period. • The ability to support a close by module, GL, AP, AR, FA and Inventory. • Ability to post transactions to current period and future periods.	1	
9.2.12	**Annual Close**	• The ability to automatically perform the journal entry to close all income and expense items to retained earnings account at year end. • The ability to run the annual close processes any number of times as required. • The ability to run the annual close by company.	1	
9.2.13	**Online Inquiries**	The ability to support the following online inquiries: • Inquiry by Trial Balance • Inquiry by Object Account • Inquiry by Department • Inquiry by Company, Department, Account Code • Inquiry by Balance Sheet • Inquiry Income Statement • Inquiry by Sub-ledger reference.	1	
9.2.14	**Interface from Third Party Software**	• The ability to interface from CIS system using the journal entry process. (Customer Information System) • The ability to interface from ADP Payroll system using the journal entry process.	1	

10 Human Resources

Human Resource department utilizes software called “HR Manager”. This is stand-alone software used by Human Resource department for very specific requirements. The system is used for entering all employee information with predominantly focus on performance reviews and vacation travel allowances. YEC has a combination of union based employees with approximately forty-six and the exempt staff of twenty four. The base salary is entered into HR Manager with no existing interfaces into payroll or the financial systems. A spreadsheet is sent to payroll for base salary and employee changes. The inclusion of Human Resource is to determine the feasibility of including this module in an existing FIS search criteria. List below is the type of information that’s being used currently in HR Manager system.

10.1 Current State

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
10.1.1	**Position Profiling**	The following information is required: • Postion # • Sequence • % FTE • Status (All, Active, Duplicate, Filled, Hold, Inactive, Proposed, Reserved) • Type (Permanent, contract, casual) • Effective Date • Expiry Date • Probation • Position Name (Administration Assistant) • Shift • Department Date • Position Department Level • Position's Location • Position Division • Union position reference	Gap		
10.1.2	**Employee Information**	The following information is required: • Employee Number • Location (Yukon Territory) • Department • Position • Salutations • Suffix • Preferred Name • Name First • Middle	Gap		

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		• Last • Birth Date • Age • Sex • S.I.N/S.S.N • Citizenship • Street Number • City/Town • Prov/State • Country • Email • Special ID • Telephone Home • Telephone Mobile • Telephone Facsimile			
10.1.3	**Main Pay Information**	• Entry Type • Change Reason • Location • Division • Department • Position • Position # • FTE • Shift • Termination Date • Status • Hours Per Day • Hours Per Week • Total Hours Worked • Start Date • End Date • Compensation % • Internal Reason • External Reason	Gap		
10.1.4	**Compensation**	• Status • Frequency • Weeks/Period • Pay Rate • Salary • Prev. Rate • Prev. Salary • % Increase • Reason	Gap		

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
10.1.5	**Budget**	• Rate • Increase • Salary • Increase • Company-ratio • Next Increase Date	Gap		
10.1.6	**Spousal Information**	• Married • Marital Status • Name First • Middle • Last Name • Maiden Name • S.I.N\S.S.N • Sex • Birth Date • Age	Gap		
10.1.7	**Dependent Information**	• Married • Marital Status • Name First • Middle • Last Name • Maiden Name • S.I.N\S.S.N • Sex • Birth Date • Age	Gap		
10.1.8	**Training\Education Tracking**	• Continuing Education • Course • Date • Location • Account Number • Charge To • Results	Gap		
10.1.9	**Performance Reviews**	• Review Type • Date • Next Review • Ranking • Company Rating • Score • Review Period • Reviewed by	Gap		

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
10.1.10	**Travel Allowance**	• Anniversary Date • Email to Employees	Gap		
10.1.11	**Interface from Third Party Software**	ADP (Easy labour, Pay at work & People @work)	Gap		11.2.1

10.2 Future State

With the primary focus being FIS system, there is no intend to replace the existing HR Manager system, although it would be beneficial to explore the benefits of having seamless interfaces to ADP systems for payroll related transactions. The benefits would also extend to budgeting and forecasting of payroll costs. The future state will incorporate all the elements listed under current state and will include the under-listed.

No.	Key Area	Requirements	Criticality	Additional Notes
10.2.1	**Interface to Third Party Software**	HR provides payroll related information to payroll who in turns supplies this to ADP for payment processing. The payroll is exception based where variable items eg (overtime, leave requests) are processed two weeks in arrears.	1	
10.2.2	**Employee Self Service**	Self-Service features enable employees and managers to conduct business, initiate transactions, and obtain needed information with rapid, cost-effective, online access to HR and Payroll at any time. These robust features free HR personnel from administrative details so they can focus on strategic tasks. YEC can benefit from offering the following on-line features to employees: • Leave Balances (ezlabour) • Vacation (ezlabour) • Sick (ezlabour) • Beneficiary information • Pay Stub (e-post) • Overtime (ezlabour) • Years of Service • Performance Reviews • Training	2	
10.2.3	**Auditing**	**Auditing** The ability to track changes is becoming increasing important for compliance issues. Therefore the need for audit ability is needed for critical field tracking. • Employee Personal Information (people@work) • Pay Rate (people@work) • Benefits (people@work)	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• Reports for negative leave balances (ezlabour) • Exception items are two weeks behind (ezlabour)		
10.2.4	**Security**	**Security** The securing of data and access to data needs to be controlled. • Needs to comply all privacy laws • Information - Needs to be secure and access granted by business requirements	1	

11 Inventory Management

The Inventory Management function provides support for inventory at five warehouse locations; Kulan, Faro, Mayo, and 2 warehouses in Dawson. Inventory is purchased into the Main warehouse at Kulan and distributed by way of inventory transfers to the other satellite warehouses. Items stocked in warehouses primarily serve maintenance requirements and any requirements for new development projects.

11.1 Current State

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
11.1.1	**Item Master**	The Item Master is currently used to set up inventory or stock items only. Each item is identified with a unique number and 2 lines of description with an allowable maximum of 30-characters each. Units of measure for tracking, purchasing, shipping, volume and weight are defined for each item and with conversion factors where applicable.			11.2.1, 11.2.4, 11.2.5
11.1.2	**Item Numbers**	Item numbers are uniquely identified in the system with a 10-character code. The current format is 'pg-sg-9999' where - 'pg' is a code denoting a product group - 'sg' is a code denoting a product sub-group - '9999' is a number assigned to identify the item			11.2.2
11.1.3	**Item Categorization**	Items are catalogued and grouped into product groupings and within each group a further sub-grouping as required. For example, the product group 'Poles' and within which subgroups of 'Steel', 'Wood'.			11.2.3
11.1.4	**Item Cross-References**	References to vendor part numbers, alternates/supercedes are based on knowledge from experience and/or manual references to hardcopy manuals.	**Fit**	The current Item Cross-Reference function system function is not used. The system provides for the ability to set up item cross-references by effectivity dates to vendor part numbers, to alternate and superceding numbers.	11.2.6
11.1.5	**Item Locations**	An item's location in the warehouse is denoted by 5 segments; Area, Aisle, Section, Shelf and Slot. A primary location and multiple secondary (overflow) locations are set up for items as required.			11.2.7
11.1.6	**Bill of Material**	Components for building structures are manually compiled, picked and issued.	**Fit**	The current Bill of Material (BOM) system function is not used. The system function enables BOMs/Kits, with several levels of	11.2.8

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
				parent/child components to be defined and corresponding quantities specified for each component. Inventory requests are placed at the parent item level and the system generates the required child components to be issued.	
11.1.7	**Inventory Quantities**	Item quantities are tracked by warehouse. Onhands are tracked for each item at the warehouse location level. In addition onorder, committed and availability quantities are also tracked for each item at the warehouse level.			11.2.13
11.1.8	**Replenishment**	Management and monitoring of inventory levels and replenishment requirements are expedited manually based on experience. Current system suggested replenishment functionality is not used.	**Fit**	The current system Replenishment facility is not used. The system provides for Max/Min Order Quantities, Re-order points and Re-Order Quantities to be specified. Based on the replenish parameters specified, the system generates a suggested replenishments with the option of purchase orders generated.	11.2.9
11.1.9	**Inventory Costs**	Inventory costs are captured by item by warehouse. The inventory cost method used is Weighted Average. Last-In costs and last purchase costs are also captured for each item.			11.2.11
11.1.10	**Safety Stock**	Safety stock levels have been configured for some critical maintenance items. However, the process to release safety stock when required is a cumbersome process. Safety stock can only be released in the current system by reducing the specified stocking level so that it becomes 'available' for release. The safety stock quantity will then have to be re-adjusted back to the required stocking level.	**Gap**	Require a more expedient method to specify a release from safety stock without adjusting the specified safety stock level.	11.2.12
11.1.11	**Availability**	Current availability is configured to equal to physical onhand minus the safety stocking level.			11.2.12, 11.2.13
11.1.12	**Serialization**	Traceability by serial numbers is required for some item, namely Transformers, and is currently manually tracked on spreadsheets.	**Fit**	The current system serial number tracking facility is not used.	11.2.14
11.1.13	**Inventory Issues**	Account Codes: Work Order and Job expense account codes for inventory issues are manually entered per issue.	**Fit**	The current system's Automatic Accounting Instructions are not optimally utilized to eliminate the entry of account codes for issues.	11.2.15
11.1.14	**Inventory Issues**	Picking/Shipping Documents: The system does not generate any picking or shipping documentation for issues. Screenshots or exports to spreadsheets have to be done to generate the required documents.	**Gap**	The current system Inventory Issues application does not generate any documentation for picking/shipping.	11.2.15
11.1.15	**Inventory Transfers**	In-Transit Time Lags: Inventory transfers between warehouses are reflected immediately in the system for the destination warehouse before the parts arrive. Owing to in-transit shipping time lags, the inventory at the destination will therefore be misleading.	**Fit**	The Inventory Transfer function should not be used for transfers where there could be significant shipping time lags between two locations. The Sales Order Transfer application is	11.2.16

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
				an option to overcome this deficiency.	
11.1.16	**Inventory Transfers**	Picking/Shipping Documents: The system does not generate picking/shipping documentation for transfers. Screenshots or exports to spreadsheets have to be done to generate the required documentation.	**Gap**	The system's Inventory Transfer application is primarily a function to be used for transfer of inventory between locations within a warehouse with insignificant transfer time lags	11.2.16
11.1.17	**Inventory Counts**	Frequency: Weekly inventory counts are done for the Main warehouse (Kulan) based on pre-defined cycles by item. For example: 30, 90 day cycles. A yearend full count is expedited for the satellite warehouses.			11.2.17
11.1.18	**Inventory Counts**	Process: The current process to select and generate a count batch, and subsequently print count sheets requires too many steps and is not intuitive.	**Fit**	The current inventory count menus can be re-configured to be more intuitive and reduce the number of navigation steps by pre-configuring count batch generation and count sheet printing menus by warehouse.	11.2.18, 11.2.19
11.1.19	**ABC Classification**	ABC Classification of inventory is currently not used for the management of inventory.	**Fit**	The current system enables ABC Classification of inventory by Sales, Margin, Costs.	11.2.20
11.1.20	**Inventory Purchases**	Purchases are initiated by the warehouse manager in the Main warehouse. The current process to generate a purchase order requires several steps and is fairly manual. A purchase order is entered into the system, routed for approval if required, printed and manually transposed into a spreadsheet Purchase Order template which is printed and sent, via email or fax, to the supplier.	**Fit**	The additional steps taken to transpose the JDE customized purchase order into a spreadsheet template is because the JDE custom version has been deemed not workable for YEC. The custom version can be enhanced to the required format.	11.2.21, 11.2.23
11.1.21	**Purchase Order**	Presentation: Purchases are manually entered into a spreadsheet template because certain standard YEC language text is not printed by the system generated version.	**Fit**	Print Messages and attachment text can be set up in the current system for attachment to purchase orders. The current customized version of the purchase order can then be enhanced to print attached messages and text.	11.2.22
11.1.22	**Purchase Order Approvals**	Process: Orders are automatically routed by the system through various levels of approvals based on a hierarchy of threshold amounts. Changes to approved orders are re-routed for approval if the changed amount exceeds approval limits. Reasons can be entered for rejected orders.			11.2.24
11.1.23	**Purchase Order Approvals**	Notification: There are no system or email alerts to notify approvers that there are orders awaiting their approval and similar alerts to notify originators on whether an order has been approved or rejected.	**Gap**	The current system does not have system alerts for approval notification. Approvers and originators need to initiate periodic system queries via the Approvals Application to monitor approvals.	11.2.24

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
11.1.24	**Purchase Order Approvals**	Time-Driven Approval Workflow: If an approver is away and unavailable to access the system to approve a purchase order, the order is not escalated to the next level approver.	**Gap**	The system does not have a time-driven workflow function whereby if an order is not approved by a certain time period, the order is escalated to the next person on the approval route. Workaround: Approvers prior to being away need to delegate their approval authority to another individual or alternatively, the next level approver can query for and approve all orders pending lower level approvers.	11.2.24
11.1.25	**Quotations**	Obtaining quotes for inventory purchases is currently a manual process. Items to be quoted are manually entered into spreadsheets and sent (emailed/faxed) to suppliers for quote responses. Proof of quotation sourcing, when required, has to be manually compiled from copies of quote responses received.	**Fit**	The current system quotation function is not used. The system function enables quotes to be entered, printed for distribution to suppliers, quote responses to be entered and purchase orders to be generated from user analysis and determination of "best" quotes.	11.2.25
11.1.26	**Receiving**	Receipt of all inventory purchases are expedited at the Main warehouse. A purchase receiver report on items outstanding on a purchase order is printed for validation of goods received. Receipts are then entered into the system and a copy of the packing slip is then forward to Accounts Payable for eventual reconciliation to the invoice when received.			11.2.26
11.1.27	**Tolerances**	Receiving and Voucher Match tolerances are configured for all items, for a commodity class or for a specific item. Depending on the requirement, a combination of units, unit cost, extended amount based on amount and/or percentage is configured.			11.2.26
11.1.28	**Inquiry**	Current system inquiries are minimally used.			11.2.27
11.1.29	**Reports**	Current system reports are minimally used. The most commonly used reports are the Stock Status and Inventory Valuation reports.	**Fit**	The system has several reports for the management of inventory.	11.2.27
11.1.30	**Staffing**	The staffing levels at each warehouse are as follows: • Kulan – 1 warehouse manager. • Dawson – 2 linesmen per site • Faro – 1 linesman • Mayo – 3 linesman			
11.1.31	**Security**	Current security levels are restricted by application and by responsibilities.			11.2.29

11.2 Future State

No.	Key Area	Requirements	Criticality	Additional Notes
11.2.1	**Item Master**	Ability to set up stock and non-stock items including services in a centralized Item Master for use by all warehouses and business units for non-inventory purchases. There should be no threshold on how many items can be set up on the item master.	1	
11.2.2	**Item Identification**	• Unique alphanumeric item number identification of at least a 10-character code including descriptive text of at least 60 characters long. • Identification of the type of item; namely, 'stock', 'non-stock', services. • Identification of item condition or status such as 'Active', 'Obsolete', 'Refurbished', 'Used', 'Discontinued'. • Ability to attach notes such as specifications, handling instructions, WHMIS alerts. • Support for Fortis naming convention of items.	1	
11.2.3	**Item Categorization**	Grouping of items into different categories and 2 additional levels of subcategories. For example, 'Poles' as a main category and within which subcategories 'Steel', 'Wood'.	1	
11.2.4	**Units of Measure**	Configuration of various units of measure (UOM) for tracking, purchasing, shipping/issuing, volume and weight for an item. UOM's should be configurable or available for non-tangible items such as services where, for example, items could be purchased in units of hours.	1	
11.2.5	**Units of Measure Conversion**	Specification of standard and non-standard units of measure conversion factors by item. Examples: 1 gallon =3.79 litres, 32 eaches = 1 box.	1	
11.2.6	**Item Cross-References**	Cross-references to vendor part numbers by effectivity dates including references to alternates and supercedes.	1	
11.2.7	**Warehouse Item Locations**	• Ability to set up multiple (overflow) warehouse locations for an item. • A minimum of a 5-segment warehouse location identification format, AREA-AISLE-SECTION-SHELF-SLOT, with the following minimum requirements: AREA – 4 characters AISLE – 2 characters SECTION – 2 characters SHELF – 3 characters SLOT – 4 characters	1	
11.2.8	**Bill of Materials**	• Configuration of Bills of Material (BOM) for specific tasks or jobs with the ability to specify quantities per BOM component. • Submission of inventory request by BOM identification number for automatic generation of components for picking.	1	.

No.	Key Area	Requirements	Criticality	Additional Notes
11.2.9	**Replenishment**	• Specification of maximum and minimum stocking levels, reorder points, reorder quantities and safety stock levels by item. • Automatic generation of suggested order quantities, based on replenishment parameters, with the option of automatic generation of purchase orders.	1	
11.2.10	**Suppliers**	Configuration of primary and secondary suppliers by item and/or item grouping including the specification of discontinued suppliers.	1	
11.2.11	**Inventory Costs**	Option to cost inventory by item as follows: • Same unit cost across all warehouses • Same unit cost within a warehouse • Unit cost by warehouse location • Different unit costs for new, refurbished/used, obsolete items	1	
11.2.12	**Safety Stock**	Specification of safety stocking levels for emergency (maintenance) items and an expedient process to release safety stocks when required.	1	
11.2.13	**Availability**	• Visibility of inventory levels across all warehouses. • Ability to determine “true” inventory availability taking into account reservations and any safety stocking levels.	1	
11.2.14	**Serialization**	Capture of serial numbers for items such as Transformers requiring serial number traceability from receipts through to issues including installations.	1	
11.2.15	**Inventory Issues**	• Ability to initiate inventory requirements for work orders, jobs, project and other business units including the specification of required dates. • Pre-configured expense codes and automatic defaults of codes with the ability to override defaults as required. • Automatic generation of picking and shipping document when inventory requests are due.	1	
11.2.16	**Inventory Transfers**	• Ability to initiate inventory transfers by either the source or destination warehouse with the specification of required dates. • Automatic generation of picking and shipping documentation when transfers are due.	1	
11.2.17	**Inventory Count**	Frequency: Ability to configure cycle counts by items, by warehouse location and/or by item groups based on number-of-days frequency and/or by activity based on ABC classification.	1	
11.2.18	**Inventory Count**	Controls: Segregation of duties throughout the count process. System security and controls for different personnel to expedite the count generation, count entry, approvals and updates.	1	
11.2.19	**Inventory Count**	Count Sheets: • Option to suppress the display of system onhand quantities on count sheets. • Ability to generate write-in pages.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
11.2.20	**ABC Classifications**	ABC classification of items based on various parameters such as by activity and/or costs.	2	
11.2.21	**Purchase Orders**	Creation: • Creation of purchase orders for goods and services with the option of system generated order numbers or manually assigned numbers for manual PO's. • Identification of different types of purchases orders for analysis. For example, services PO's and goods PO's. • Ability to print purchase orders as required or en masse whereby all purchase orders that are ready to be printed and transmitted to suppliers can be printed in a scheduled background mode without any manual intervention.	1	
11.2.22	**Purchase Order**	Presentation: The presentation of Purchase Orders should enable the following information to be captured, formatted to YEC requirements and printed: 1. YEC Purchase Order Number 2. YEC company logo, name and address 3. "Attention To" and instructions for invoice remittance 4. Supplier name, address, phone and fax number 5. ShipTo address and optional 'Attention To' contact for delivery. 6. Reference to quotation/contract number and date where applicable 7. Shipping/Freight Handling Terms 8. Payment Terms 9. YEC Buyer/Contact (including phone number and email address) 10. Supplier Contact (including phone number and email address) 11. Shipping and delivery instructions 12. Special instructions to be specified as required 13. Additional charges, for example Taxes, Freight, Brokerage 14. Order Date, Requested/Required By Date, Promised Date 15. Standard YEC language/text on terms and conditions 16. Signatures and dates 17. Order quantities and corresponding units of measures 18. YEC item numbers and description 19. Supplier item numbers or catalogue numbers, if required 20. Unit cost 21. Extended costs 22. Applicable taxes 23. Order total	1	
11.2.23	**Purchase Order**	Delivery: Ability to seamlessly automate purchase order transmissions via email or fax including potential support for EDI transmission.	2	

No.	Key Area	Requirements	Criticality	Additional Notes
11.2.24	**Purchase Order Approvals**	• Approvals by budget amount and/or by purchase order amount. • Ability to set up different approvers for different purchase order threshold amounts. For example, amounts >= $10,000 is approved by J.Smith and >=$20,000 is approved by J.Doe. • Automatic routing of purchase orders for approval when budget amounts and/or purchase order amounts have exceeded pre-configured threshold limits. • Automatic alerts to approvers on orders pending their approval. • Automatic notifications to originators on whether purchase orders have been approved or rejected. • Ability to enter reasons for rejected purchase orders. • Automatic escalation of orders to the next level approver if the current approver has not responded by a specified time period. • Automatic re-routing of approved orders for approval when subsequent changes violate approval thresholds.	1	
11.2.25	**Quotations**	• Entry and printing of items to be quoted. • Unique Identification Number to track each quote. • Entry and distribution of quotes to multiple suppliers. • Specification of required by dates. • Specification of special instructions, terms and conditions to suppliers. • Specification of price breaks by quantity. • Seamless transmission of quotes to suppliers via email and/or fax. • Capture of quote responses for comparison analysis. • Expedient release of 'best' quotes for automatic purchase order generation. • Traceability of quotes to purchase orders generated and vice-versa.	1	
11.2.26	**Receiving**	Purchase Orders and Warehouse-To-Warehouse Transfers: • Generation of receiving report by purchase order or by all outstanding purchase orders. • Ability to receive warehouse-to-warehouse transfers at each warehouse. • Ability to enter receipts as fully received, partially received with the option to backorder or cancel residual outstanding quantity and completely backorder any outstanding quantity. • Traceability of receipts by unique receipt numbers. • Capture of serial numbers when items are received. • Advise of designated warehouse stocking location when an item is received and the ability to create overflow locations as required. • Configuration of receiving tolerances by units based on percentage and/or amounts with warning/error alerts. • Option to suppress display of and changes to costs and amounts at receiving.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• Capture of supplier picking/packing slip numbers, container and shipping document information including any additional charges. • Process to return inventory with the ability to track returns with Return Authorization Numbers, notate reasons for returns and generate documentation to accompany return.		
11.2.27	**Inquiries / Reports**	Inquiry and reporting functions should, where applicable, display both quantities and costs. 1. Item Master Directory showing master list of items including description, item group/class, applicable units of measure and item status (for example, 'Obsolete', 'Discontinued', …) 2. Item Cross-References to Supplier numbers, alternates and supercedes. 3. ABC Classifications by item and/or item group at each warehouse and across all warehouses. 4. Stock Status for all items, for a group of item or for a specific item; at a specific warehouse and/or across all warehouses. 5. Overstocks by item at each warehouse and overall across all warehouses.	1	
11.2.28	**Reconciliations**	Reconciliation facility is required, for example a report, to report any discrepancies between inventory values reported from Inventory and the General Ledger.	1	
11.2.29	**Security**	• Limitation of Item Master maintenance to specific personnel. • Creation and maintenance of purchase orders and types of purchase orders by responsibility. • Receiving of inventory by warehouse and by responsibility.	1	
11.2.30	**Interfaces**	1. Technical Services (MSAccess) system for material requirements. 2. Procurement for purchases and receipts of inventory purchases. 3. General Ledger for inventory receipts, adjustments/counts	1	
11.2.31	**Data Conversion**	1. Inventory data from JDE System 2. Purchase Orders from JDE System 3. Warehouses and locations from JDE System	1	

11.3 Document Samples

Inventory Purchase Order



purchaseorderEEcol(7157-000).xls

Quote Request



QuoteformSTELLA(jULY 26 2007).xls

Distribution Structure Manual Sample Table of Contents



Dist Structure Manual Table of Cont

Structure Component Specs



Structure Specs docu0028.jpg

Distribution Structure Series Index



Distribution Structure Series Inde

12 Maintenance

Maintenance is expedited by the Operations and Maintenance Department on all serviceable plant equipment including distribution lines. Electrical maintenance, mechanical maintenance, and line maintenance is expedited by three separate departmental groups with each group responsible for tracking their own maintenance schedules and requirements.

12.1 Current State

As the FIS project scope defines a high-level review of Maintenance requirements, the current state captured is therefore limited to a high-level overview of the current operations of the Maintenance function.

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
12.1.1	**MainBoss System**	The MainBoss system was initially implemented in 2003 for electrical maintenance. Mechanical maintenance was implemented in 2004. Owing to a single instance of the database, the inclusion of mechanical maintenance posed a problem as generation of mechanical maintenance schedules included schedules for electrical maintenance as well and vice-versa. To overcome this problem, mechanical maintenance was segregated into a separate database instance. Owing to staff and job responsibility changes, the system has been found to be under utilized. May 2005 appears to be the last time the MainBoss system was used for mechanical work. It is therefore assumed that *all* mechanical maintenance work is currently initiated, tracked and managed manually. Electrical maintenance uses the system to generate PM (scheduled in MainBoss) work orders only. It is therefore assumed that the unplanned electrical maintenance work is currently initiated, tracked and managed manually. Line maintenance does not use MainBoss and it is therefore assumed that *all* line maintenance work is currently initiated, tracked and managed manually.	**Fit**	The current JDE system has support for an integrated Equipment Maintenance module which enables equipment to be set up in an Equipment Master and preventive schedules defined for the generation of maintenance work orders.	
12.1.2	**PM Schedules**	PM schedules for both mechanical and electrical are programmed in MainBoss. Mechanical and line PM schedules are assumed to be tracked and managed manually. Electrical PM schedules in MainBoss are used to generate PM work orders. Owing to this, schedules for electrical, mechanical, and line maintenance cannot be effectively co-ordinated to minimize equipment service downtimes.	**Fit**	The JDE Equipment Maintenance enables PM schedules to be set up for different types of service and to base service intervals on hours, mileage, fuel, days and specific date.	12.2.6, 12.2.8
12.1.3	**Work Orders**	Electrical maintenance PM work orders are currently generated by MainBoss and include a labour estimate; however, related work order documentation, for example, estimates and actual costs, description of work, status of work, deficiencies, labour and material requirements are not entered when closing the WO's. EM also has an add-on MainBoss program called @Request. This allows requests to be tracked from initiation stage to WO closed	**Fit**	The JDE Work Order system enables work orders to be generated as required or automatically based on PM schedules. Model work orders with pre-defined work steps, labour and material requirements can be set up for different types of maintenance.	15.2.3, 15.2.7, 15.2.8, 12.2.13, 15.2.9, 15.2.10

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		stage while keeping the request initiator up to date on the tasks progress (i.e. request transferred to WO, WO closed). Mechanical and line WO's are assumed to be, as required, compiled, and issued manually. All related work order documentation, for example, estimates and actual costs, description of work, status of work, deficiencies, labour and material requirements and work steps are also assumed to be manually compiled on hardcopy Work Order forms.			
12.1.4	**Spare Parts Inventory**	Repositories of spare parts inventory exist at different plants and are not tracked. Parts could be, and sometimes are ordered without knowledge that units exist in inventory.	**Fit**	The current JDE inventory system in use can be used to set up and track maintenance spare parts inventory with the ability to specify safety stock levels for critical components.	12.2.7

12.2 Future State

No.	Key Area	Requirements	Criticality	Additional Notes
12.2.1	**Equipment Master**	Unique identification of equipment and components by a unit number and serial number. Support for profiling of each piece of equipment as follows: 1. Description of equipment 2. Site / Location 3. Acquisition Date 4. Installation Date 5. In-Service Date 6. Disposal Date 7. Manufacturer profile including product and model number, model year, service and warranty agreements 8. Equipment Status; Available, Active, Inactive, Disposed 9. Parent unit reference for component units 10. Depreciation schedule 11. Salvage proceeds / disposal costs	1	
12.2.2	**Component Relationships**	• Configuration of parent/child component relationships with unlimited child components per level and unlimited number of levels. For example, parent substations with transformers and generators components and within transformers, protection meters, etc. • Tracking of parent history	1	
12.2.3	**Location Tracking**	Ability to maintain and inquire on the location of each component and track start and end dates, status at each location a history of transfers.	1	
12.2.4	**Maintenance History**	Tracking of service history of each piece of equipment including the capture of failures and causes, the number of downtimes, the duration of downtimes, maintenance dates, and the types of maintenance performed, for example, regular or emergency service.	1	
12.2.5	**Meter Readings**	Maintenance of meter readings including capture of original meter readings and readings at meter changes.	1	
12.2.6	**PM Schedule**	• Set up PM Schedules for different service types based on different intervals. For example, hours of operation, fuel usage, number of days interval from last maintenance and specific dates.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• Set up associations to link different types of maintenance to be performed at the same time. • Set up of maintenance loops for identical maintenance of multiple units of same equipment. • Notifications of upcoming maintenance requirements by pre-configured percentage due threshold limits. • Ability to attached model work orders and part lists to different types of maintenance. • Automatic generation of work orders when maintenance is due or coming due. • Ability to attach related documentation and notes to schedules. • Ability to print PM schedules as required.		
12.2.7	**Parts Requirements**	• Tracking of spare parts inventory at different locations with the ability to specify safety stocking levels for critical components. • Set up of parts list for different types of maintenance and association of parts list to work orders. • Automatic generation of parts list to be picked and issued from inventory when maintenance is coming due.	1	
12.2.8	**Maintenance Costs**	• Capture of total maintenance costs to date on a specific piece of equipment and at the parent level. • Capture of estimates and actuals by type of service/maintenance work. • Automatic capture of actual costs, where applicable, from 1. Internal labour timecard entry 2. Materials issued from inventory 3. Materials purchased 4. Subcontract labour 5. Equipment rentals	1	
12.2.9	**Time Entry**	• Set up of hourly labour rates by types of maintenance including overtime rates. • Capture/entry of labour hours by type of maintenance work performed on a work order and with reference to the applicable piece of equipment. • Automatic posting of labour hours to Financial and payroll systems.	1	
12.2.10	**Work-Breakdown Structure**	• Ability to set up parent/umbrella work orders with unlimited 'child' work orders. • Ability to capture and review estimated costs versus actual costs by individual work order and overall roll-up total costs to the parent work order.	1	
12.2.11	**Work Order Initiation**	• Automatic system generation of work orders when PM schedules become due. • Ability to set up work orders as required for unplanned and emergency maintenance. • Ability to route and print work orders to specific printers. • Information required on work orders are as follows: 1. Work Order Number 2. Equipment information including service history 3. Description of maintenance and work steps	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		4. Estimated labour hours 5. Parts list or material requirements 6. Attachments of additional related documentation 7. Planned start and completion dates		
12.2.12	**Work Order Approvals**	• Electronic routing of approvals for unplanned work orders and optional approvals for planned work orders. • Electronic alerts to approvers on work orders awaiting their approval. • Ability to specify rejection reasons by approver. • Automatic notification to originators on whether their work orders have been approved or rejected.	1	
12.2.13	**Work Order Status**	Ability to track the status of work orders from initiation to completion. Examples of statuses are: Initiation, Pending Approval, Approved, Awaiting Parts, Awaiting Labour Allocation, Parts Issued, In-Progress, Held, Completed.		
12.2.14	**Work Order Costs**	Ability to track work order estimated versus actual costs broken down by labour, materials and travel.	1	
12.2.15	**Work Order Close-Out**	Ability to capture and print (when required) the following close-out information on a work order. 1. Actual Start and Completion Dates 2. Description of actual work done 3. Deficiencies found 4. Actual labour hours expended 5. Actual material items used 6. Return of unused parts to inventory or to supplier 7. In-Service Date/Time or expected In-Service Date/Time of equipment 8. Description of additional unplanned maintenance and repairs 9. Meter readings 10. Sign-offs	1	
12.2.16	**Inquiries / Reports**	*To be determined.*	1	
12.2.17	**Interfaces**	1. Inventory for parts issues/returns 2. Procurement for procurement of non-inventory materials, services, equipment rentals 3. Payroll for time and labour costs 4. Finance for capture of all maintenance costs	1	
12.2.18	**Data Conversion**	MainBoss data for planned Electrical Maintenance Manual maintenance data for Mechanical, unplanned Electrical and Line Maintenance	1	
12.2.19	**Security**	To be determined.		
12.2.20	**Staffing**	To be sourced.		

13 Payroll Interface

The staff complement of YEC comprises of seventy employees, with forty-six union employees and twenty-four exempt staff each with two sets of distinct rules for each. The President is under the exempt but also with its own set of rules. ADP is used for Payroll processing specifically using the "people at work" module. The processing of bi-weekly and monthly payrolls is executed through ADP payroll system (pay at work). This payroll payment process and service provider is not expected to change in the foreseeable future. ADP offers the widest range of HR, payroll, tax and benefits administration solutions from a single source. ADP's easy-to-use solutions for employers provide superior value to YEC. ADP offers time and labour distribution integrated computing solutions, which YEC anticipates exploiting in the near future.

13.1 Current State

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
13.1.1	**ADP Pay at Work**	Payroll submits an approved base salary rates to ADP for payment processing. This is included the employee master information. The salary rates submission includes new employees and changes to existing employees where applicable.	Gap	The use of third party software.	
13.1.2	**ADP Pay at Work**	Bi-weekly timesheets are entered into ADP for the payroll processing.	Gap	The use of third party software.	
13.1.3	**ADP Pay at Work**	The payroll is exception based where variable items eg. (overtime, leave taken) are processed two weeks in arrears.	Gap	The use of third party software.	
13.1.4	**ADP Pay at Work**	Payments to employees are processed into employee bank accounts. Notifications are physical pay stubs or e-post.	Gap	The use of third party software.	
13.1.5	**ADP Pay at Work**	Only source deductions are withheld by ADP and subsequently remit to the relevant authorities (CPP, EI, Tax payments).	Gap	The use of third party software.	
13.1.6	**ADP Pay at Work**	YEC bank account is automatically debited with the required funds for pay and source deductions. This is an arrangement with YEC and ADP.	Gap	The use of third party software.	
13.1.7	**ADP Pay at Work**	Standard payroll reports are provided by ADP and include some of the following: • Payroll register • Time-entry report • Audit reports (changes to rates and profiles) • Leave Reports • Other Management Monitoring reports.	Gap	The use of third party software.	
13.1.8	**ADP Pay at Work**	ADP also processes the annual T4's and T4A's. Reconciliation of employee payments is manually reconciled by YEC with ADP T4's.	Gap	The use of third party software.	
13.1.9	**ADP Pay at Work**	Third party payments are assumed by YEC eg. Standard Life, Insurance payments and paid via the Accounts Payable system.	Gap	The use of third party software.	
13.1.10	**ADP Pay at Work**	Audit and exceptions reports are produced and distributed by ADP. This is an ad hoc requested by management.	Gap	The use of third party software.	
13.1.11	**ADP Pay at Work**	Final report and GL distribution is submitted to YEC.	Gap	The use of third party software.	

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
13.1.12	**ADP Pay at Work**	Journal Entries are manually inputted into JDE.	Gap	The use of third party software.	13.2.2
13.1.13	**Interface from Third Party Software**	No interface into FIS system at this time..	Gap		

13.2 Future State

The existing payroll service provider is not expected to change in the foreseeable future, however an automated interface from ADP to the proposed FIS system would be beneficial to YEC.

No.	Key Area	Requirements	Criticality	Additional Notes
13.2.1	**ADP Interface**	Create an electronic interface into the new FIS system from ADP Easy Labour	1	
13.2.2	**ADP Interface**	Create an electronic interface into the new FIS system from Pay at Work.	1	
13.2.3	**ADP Interface**	The interface is expected to map or reference to existing object accounts from the proposed FIS system into ADP. Completion of the payroll payment process which creates the final journal entries that will interface into FIS system.	1	
13.2.4	**ADP Interface**	Once the labour distribution is finalized in ADP Easy labour, this needs to be interface to FIS system also. This is a detailed time and labour distribution as opposed to the final journal entry for payment process.	1	
13.2.5	**ADP Interface**	Validation report for entries entered into FIS system that reconciles with respective Easy Labour and Pay at Work.	1	
13.2.6	**Easy Labour**	Standard labour cost needs to be mapped into FIS system.	1	

14 Procurement

Procurement is segregated into purchasing for inventory items and purchasing for non-inventory items (goods, services and equipment). All inventory purchasing is expedited by the warehouse manager in the Main warehouse (Kulan). Purchasing requirements documented herein are for the procurement of goods, services and equipment. Inventory purchasing requirements are captured within the Inventory Management Current & Future State Requirements document. Purchases greater than $5,000 are expedited by the YEC Buyer. Purchases less than or equal to $5,000 can be expedited using Visa or a Local Purchase Order (LPO) which is a manual purchase order.

14.1 Current State

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
14.1.1	**Goods Purchases**	Goods are purchased by units with pricing options of cost-plus, quantity breaks, quoted contract prices and supplier catalogue prices.			14.2.1
14.1.2	**Services Purchases**	Services are purchased as lump-sum contracts, time and materials contracts or monthly leases.			14.2.2
14.1.3	**Contracts**	Contracts are manually compiled and tracked on a Contract Record form and manually filed with all supporting and associating documents. The Contract Record form tracks all information relating to a contract including contract start and end dates, holdbacks and releases, invoices received and paid, status of Workers' Compensation Board (WCB) coverage, insurance coverage and warranties.	**Fit**	The current system functionality for the processing of contracts is not used.	14.2.3, 14.2.4
14.1.4	**Holdbacks & Releases**	A percentage holdback, usually 10%, is applied to applicable contracts. The processing of holdbacks and releases is labour intensive as they are manually calculated and tracked on a pre-printed Contract Record form. Invoices are forwarded to the Contract Administrator for review and holdback calculation. The invoice plus amount of holdback is subsequently submitted to Accounts Payable for payment processing. Releases are manually tracked and when due are submitted to Accounts Payable for payment.	**Fit**	The current system has a holdback function that automatically calculates, at voucher match, the applicable holdback percentage specified in a purchase order contract. Since contracts are not implemented in the system, the holdback function is not used.	14.2.5
14.1.5	**Commitments**	The tracking of commitments versus actuals is manual and expedited on the Contract Record form. Budgets to commitments and to actuals are not adequately tracked.	**Fit**	The current system Commitment facility is not used.	14.2.6
14.1.6	**Approvals**	Signing authorities for approvals of purchasing agreements are based on the type of expense (whether O&M or Capital), the type of items purchased (whether inventory, non-inventory goods or services) and dollar limits. Approval for non-inventory purchases is a manual process. **Exceptions:** • The Board may delegate signing authority for major purchasing agreements, by resolution of the Board, to the President & CEO and/or Chief Financial Officer or Director of Corporate Services. • All leases and licenses or conditional Sale Agreements (i.e. lease	**Fit**	The current system Approval facility is only used for inventory purchases and not for the purchase of goods, services and equipment.	11.2.24

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		to purchase – operating or capital), regardless of the amount, will require the signature of the Director Corporate Services and the Chief Financial Officer.			
14.1.7	**Requisitions**	Requisitions are internal documents used to initiate purchases greater than $5,000. A manual requisition form is filled out with the required approvals obtained and submitted to the Buyer for issuance of a purchase order.	**Fit**	The current system has a Requisition function that enables purchases to be initiated and routed internally for approvals. Approved requisitions can then be generated into purchase orders by the Buyer. This function is currently not used.	11.2.1
14.1.8	**Visa Purchases**	Visa can be used for purchases less than or equal to $5,000. Monthly reports are received from Visa and manually distributed to employees for reconciliation/validation of purchases. Accounts Payable prints out the statement (from the US Bank website) for each cardholder which then gets coded manually and circulated for signatures (approvals). Reviews of Visa statements are done for duplicate charges and personal charges. Any such charges found are escalated to the Chief Financial Officer for further action.	**Gap**	The current system does not have functions and/or interfaces that are able to initiate or capture Visa purchases effectively.	11.2.2
14.1.9	**Local Purchase Order**	A Local Purchase Order (LPO) is a manual purchase order that can be used for purchases less than or equal to $5,000. LPO books consisting of pre-printed LPO forms are issued to employees for such purchases. LPO purchases are not entered into the system and are only visible in the Accounts Payable system when invoices are entered for payments. 95% of LPOs are entered into the system after the fact, when invoices are received, for attaching to an invoice.	**Fit**	The current system enables different types of purchases to be created and tracked prior to receipt of invoices. This feature is currently not used.	11.2.3
14.1.10	**Purchase Orders**	With the exception of contracts, purchases greater than $5,000 are entered into the JDE system. Purchases are basically initiated by a manual requisition, see 14.1.7, and submitted to the buyer for the issuance of a purchase order to the vendor. Purchase orders are printed from the system and emailed or faxed to the vendor. YEC terms & conditions are manually attached as required. **Inconsistencies:** 1. 2 Purchase Order formats used; inventory and non-inventory formats differ. 2. 3 different ways of printing a purchase order; process steps used by the Buyer, Warehouse Manager and Contract Administrator differ and with different levels of inefficiencies.	**Fit**	The current **inconsistencies** in printing purchase orders are caused by the following: 1. The Buyer uses a customized format that is deployed only to his local PC which only enables him to use. 2. The Warehouse Manager uses an old customized system generated format that does not support his requirements which results in him manually re-entering the order in a spreadsheet template. 3. The Contract Administrator does not have the same print program used by the Buyer and only has access to the Enterprise Server version of an old custom version. The above inconsistencies can be rectified by making the same, latest, custom version available on the Enterprise Server to be used by all.	11.2.21, 11.2.22, 11.2.23
14.1.11	**Quotations**	Obtaining quotes for inventory purchases is currently a manual process. Items to be quoted are manually entered into spreadsheets and sent (emailed/faxed) to suppliers for quote responses. Proof of quotation sourcing, when required, has to be manually compiled from copies of quote responses received.	**Fit**	The current system quotation function is not used. The system function enables quotes to be entered, printed for distribution to suppliers, quote responses to be entered and purchase orders to be generated from user analysis and determination of 'best' quotes.	11.2.25

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
14.1.12	**Receiving**	**Goods** The receipt of goods is manually indicated on packing slips and/or invoices and forwarded to Accounts Payables for payment. The matching of invoices to manual LPO's and system purchase orders is manual.	**Fit**	The current system has a 3-way match function which enables receipts to be entered into the system by the 'receiver' and thereby eliminating any requirements for manual indications and matching of receipts to purchase orders and invoices. This function is currently not used.	11.2.26
14.1.13	**Receiving**	**Services** Invoices received for services rendered are manually forwarded to the respective managers to confirm services and approve the invoice for payment.	**Fit**	The current system has the ability to 'receive' services as a confirmation of services rendered. This function is not in use.	11.2.26
14.1.14	**Tolerances**	Receiving and Voucher Match tolerances are configured for all items, for a commodity class or for a specific item. Depending on the requirement, a combination of units, unit cost, extended amount based on a specified amount and/or percentage is configured.			11.2.26
14.1.15	**Suppliers**	Suppliers are maintained in the current system's Supplier Master File. Supplier performance statistics are manually tracked on a hardcopy Contract Performance Evaluation Report for contracts. Performance statistics are not tracked to inventory or goods purchases.	**Fit**	The current system has a Quality Profile function that is currently not used.	14.2.21, 14.2.22, 14.2.23
14.1.16	**Inquiry**	Current system inquiries are minimally used.			See all Future State Inquiries/Reports
14.1.17	**Reports**	Current system reports are minimally used. The Open Purchase Orders report is used to determine orders that are still outstanding with suppliers. All reports on contracts and agreements are manually maintained.	**Fit**	The system has several reports for the management of Procurement activities.	See all Future State Inquiries/Reports
14.1.18	**Staffing**	• 1 Buyer • 1 Contract Administrator			
14.1.19	**Security**	Current security levels are restricted by application and by responsibilities.			11.2.29

14.2 Future State

No.	Key Area	Requirements	Criticality	Additional Notes
14.2.1	**Goods Purchases**	Ability to purchase goods based on different pricing structures such as quantity breaks pricing, 'Cost Plus', quoted contract prices with effectivity dates and supplier catalogue prices.	1	
14.2.2	**Services Purchases**	Ability to set up service purchase orders or contracts for lump-sum, time and materials, 'Cost Plus' and monthly leases.	1	
14.2.3	**Contracts**	**Contract Profile** The contract data required to be captured and printed are as follows. 1. Contract Number; preferably system generated. 2. Description of contract with the ability to include additional details as required, 3. Vendor information including vendor contact (name, phone, email). 4. YEC Contact/Designate. 5. Contract (Agreement) date plus contract start and end dates. 6. Specification and electronic attachment of required transmittals and submittals such as WCB and insurance coverages 7. Holdback terms. 8. Security deposit specifications. 9. Contract terms and conditions including any additional special comments. 10. Warranties. 11. Applicable expenses. 12. Account (Expense) codes. 13. Contract status, for example, 'Initiated', 'Waiting Approval', 'In Progress', 'Completed', 'On Hold'.	1	
14.2.4	**Contracts**	**Transmittals and Submittals** • Specification of types of transmittals and submittals. For example, WCB and Insurance coverages. • Specification of whether a transmittal or submittal is mandatory and issue alerts to Accounts Payable when mandatory submittals have not been received. • Capture effectivity dates on coverages and issue system alerts, based on a specified number of days prior to expiration, when coverages are about to expire.	1	
14.2.5	**Holdbacks & Releases**	• Specification of a percentage holdback for purchase order or contracts. • Automatic system calculation of holdbacks at invoice voucher match with the option to execute holdbacks inclusive or net of taxes. • Electronic routing of approvals for holdback releases.	1	
14.2.6	**Commitments**	Automated tracking and reporting of commitments as follows: 1. budgets versus actuals 2. variances between commitments and actuals 3. budgets and commitments plus actuals.	1	
14.2.7	**Requisitions**	• Entry of purchase requisitions and routing of requisitions for approval. • Capture of expense codes when requisitions are created.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• Optional printing of requisitions. • Optional attachments of related documents, for example, specifications, drawings, manual quotations. • References to system generated quotes and vendor responses.		
14.2.8	**Visa Purchases**	• Facility to receive an electronic file or spreadsheet downloaded from Visa and route applicable Visa purchases to respective employees for validations and any required managerial reviews. • Electronic capture of Visa purchases for analysis and audit reviews.	1	
14.2.9	**Emergency Purchases**	Support for expedient system capture of emergency purchases ahead of invoice receipts.	2	
14.2.10	**Serialization**	Capture of serial numbers for items such as transformers requiring serial number traceability from receipts through to issues including installations.	1	
14.2.11	**Purchase Orders**	**Creation** • Creation of purchase orders for goods and services with the option of system generated order numbers or manually assigned numbers for manual PO's. • Identification of different types of purchases orders for analysis. For example, services PO's and goods PO's. • Ability to print purchase orders as required or en masse whereby all purchase orders that are ready to be printed and transmitted to suppliers can be printed in a scheduled background mode without any manual intervention. • Ability to create purchase order in foreign currency with pre-configured currency conversion rates. • Specification of applicable taxes and exemptions where applicable. • Ability to distribute a purchase order item line by units, amount or percentage to various business unit account codes. For example, place an order of 100 units of widgets with a supplier and allocate 20 units to account1, 30 to account2, 50 to account3.	1	
14.2.12	**Purchase Order**	**Presentation** The presentation of Purchase Orders should enable the following information to be captured, formatted to YEC requirements and printed: 24. YEC Purchase Order Number 25. YEC company logo, name and address 26. "Attention To" and instructions for invoice remittance 27. Supplier name, full address, phone and fax number 28. ShipTo address and optional 'Attention To' contact for delivery. 29. Reference to quotation/contract number and date where applicable 30. Shipping/Freight Handling Terms 31. Payment Terms 32. YEC Buyer/Contact (including phone number and email address) 33. Supplier Contact (including phone number and email address) 34. Shipping and delivery instructions 35. Special instructions to be specified as required 36. Additional charges, for example Taxes, Freight, Brokerage 37. Order Date, Requested/Required By Date, Promised Date 38. 'Order Taken By' name	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		39. Standard YEC language/text on terms and conditions 40. Order quantities and corresponding units of measures 41. YEC item numbers and description 42. Supplier item numbers or catalogue numbers, as required 43. Currency 44. Unit Price 45. Extended Price 46. Applicable taxes 47. Order total 48. Expense Code, as required 49. Signatures and corresponding dates		
14.2.13	**Purchase Order**	**Distribution** Ability to seamlessly automate purchase order transmissions via email or fax including potential support for EDI transmission.	2	
14.2.14	**Approvals**	• Approvals by budget amount and/or by purchase order amount. • Ability to set up different approvers for different purchase order threshold amounts. For example, amounts >= $10,000 is approved by J.Smith and >=$20,000 is approved by J.Doe. • Automatic routing of purchase orders for approval when budget amounts and/or purchase order amounts have exceeded pre-configured threshold limits. • Automatic alerts to approvers on purchase orders pending their approval. • Automatic notifications to originators on whether purchase orders have been approved or rejected. • Ability to enter reasons for rejected purchase orders. • Automatic escalation of purchase orders to the next level approver if the current approver has not responded by a specified time period. • Automatic re-routing of approved orders for approval when subsequent changes violate approval thresholds. • Various levels of signing authorities for purchasing agreements based on type of expense (whether O&M or Capital), the type of items purchased (whether inventory, non-inventory goods or services) and dollar limits. • Ability to delegate signing authority with effectivity dates,	1	
14.2.15	**Quotations**	• Entry and printing of items to be quoted. • Unique identification number to track each quote. • Entry and distribution of quotes to multiple suppliers. • Specification of required by dates. • Specification of special instructions, terms and conditions to suppliers. • Specification of price breaks by quantity. • Seamless transmission of quotes to suppliers via email and/or fax. • Capture of quote responses for comparison analysis. • Expedient release of 'best' quotes for automatic purchase order generation. • Traceability of quotes to purchase orders generated and vice-versa.	2	

No.	Key Area	Requirements	Criticality	Additional Notes
14.2.16	**Multi-Currency**	• Accommodations for creating purchase orders and contracts in foreign currency. • Ability to maintain foreign currency exchange rates with effectivity dates. • Automatic defaults of exchange rates with the option to overwrite defaults for a specific order.	1	
14.2.17	**Change Orders**	Tracking of changes to original service contracts including goods purchases.	1	
14.2.18	**Receiving**	**Goods** • Receive goods against a purchase order and backorder or cancel any residual outstanding quantities. • Ability to track receipts with a unique receipt identification number. • Capture serial numbers for units requiring serial number traceability. For example, transformers. • Capture supplier packing slips and Bills of Lading (BOL) reference numbers. • Ability to indicate condition of goods received and generate documents for the return of incorrectly shipped or damaged goods. • Electronic notification to buyer/originator of receipts and non-conformance items. • Capture of quality and delivery statistics for Supplier Performance Analysis.	1	
14.2.19	**Receiving**	**Services** Electronic routing of service invoices to respective managers for approvals.	1	
14.2.20	**Supplier Catalogues**	Support for electronic capture of supplier price catalogues.	2	
14.2.21	**Supplier**	**Supplier Profile** Ability to set up and maintain information on suppliers as follows: 1. Supplier Number - to uniquely identify each supplier. 2. Supplier Name, Address, Phone, Fax and Email Address. 3. Supplier (geographical) Locations. 4. Supplier Contacts including job title and contact information. 5. Payment Terms. 6. Types of services and products supplier including whether supplier is a primary/preferred source. 7. Supplier Status for example 'Inactive','Active'	1	
14.2.22	**Supplier**	**Goods Delivery Performance** Capture of performance statistics with the application of ratings for the following: • Fill rates and availability • Timeliness of delivery • Quality of goods delivered • Accuracy of shipments and invoices	1	
14.2.23	**Supplier**	**Contract Performance** Capture of performance statistics with the application of ratings for the following: • Quality of Workmanship including materials and equipment provided. • Timeliness of Completion.	1	

No.	Key Area	Requirements	Criticality	Additional Notes
		• Project Management with regards to co-ordination, quality control, scheduling and implementation. • Contract Management on all aspects of administration of a contract. • Health & Safety with regards to management and administration of all aspects of occupational health and safety provisions as stipulated in the contract, as per provincial/territorial legislature, as per YEC policies and COR Certification. • Automatic generation of Supplier Evaluation Questionnaire, at contract close, to project managers to capture feedback on supplier performance and the ability to customize questionnaires based on the different types of services performed.		
14.2.24	**Security**	• Limitation of Supplier Master maintenance to specific personnel. • Creation and maintenance of purchase orders and types of purchase orders by responsibility. • Receiving of goods by responsibility and/or originator.	1	
14.2.25	**Inquiries/ Reports**	**Supplier Master Directory** All information pertaining to a supplier including types of services and products offered, status ('Active', 'Inactive'), geographical locations whether a supplier is a primary/preferred supplier by product/services offering.	2	
14.2.26	**Inquiries/ Reports**	**Supplier Price Catalogues** Product and services offering including pricing and effectivity dates.	2	
14.2.27	**Inquiries/ Reports**	**Open Purchase Orders** Orders outstanding with suppliers including purchase order number, order date, required date, item number, description, order quantity, outstanding quantity, quantities received to date and last receipt date.	1	
14.2.28	**Inquiries/ Reports**	**Contracts** All information on a contract including history of holdbacks and releases, status of transmittals and submittals, invoices received and payments. Commitments versus actuals and commitments plus actuals versus budgets.	1	
14.2.29	**Inquiries/ Reports**	**Supplier Performance** Qualitative and quantitative statistics on the delivery of goods and services including accuracy of all supplier document such as invoices, packing/slips, contract progress reports.	1	
14.2.30	**Interfaces**	1. Inventory for inventory purchases and receipts. 2. Accounts Payable for invoice voucher match. 3. Maintenance and Work Orders for Procurement of materials, services and equipment rentals. 4. Project Accounting/Job Costing for commitments capture.	1	
14.2.31	**Data Conversion**	• Purchase Orders from JDE System – outstanding and closed • Manually tracked Contracts		

14.3 US Bank File Interface

US Bank currently has two clients that are uploading visa transactions (Statement Billing File, SBF) into Peoplesoft System. The client downloads the visa flat file from US Bank and uploads the data into Peoplesoft and the cardholders perform the cost allocation in Peoplesoft.

US Bank Statement Billing File Layout Specifications Document:



US Bank SBF layout.doc

15 Project Accounting / Job Cost

Project Accounting is a function used in the Engineering Department for the management of capital projects. Capital projects consist of new construction projects such as building a new substation and installing new distribution lines. Installation of new distribution lines or run-offs from existing lines are referred to as Customer Extensions which are customer initiated or driven. The Project Accounting function is currently a manual function, initiated, tracked and managed with a series of manual forms and spreadsheets.

15.1 Current State

No.	Key Area	Current State	Fit/Gap Analysis		Future State Reference
15.1.1	**Project Initiation**	**Process** Business Plans for projects could be initiated by the Engineering Department on a Project Identification form with an initial planned budget amount and submitted for approval. When approved, quotes are obtained and project cost estimates are compiled for final approval to proceed.	**Fit**	The current system supports a Project Accounting / Job Cost module that enable the initiation of a project/job and the capture of the required information pertaining to a project including budgeted costs, estimates and actuals. Variances at any one point in time can be reported.	11.2.1
15.1.2	**Project Identification**	**Form** The Project Identification Document (PID) form is used for initiating a project and obtaining the required approvals to proceed. Information captured on the PID form includes a description of the initiative, alternatives/options, projected start and completion dates, planned and estimated costs, timing of cash flow requirements and, impacts to existing assets. *Further detailing of information capture requirements are documented under various Key Areas in the Future State section.*			11.2.1
15.1.3	**Approvals**	Approvals are obtained by manually routing the PID form to the various signing authorities for signatures. All PID's must be approved by the Project Manager, the respective Department/Section Head, the Director of Technical Services and the Chief Financial Officer. President Approval is required for projects over $250,000 and Board Approval for projects over $1,000,000.	**Fit**	The current system supports a workflow function that enable electronic routing of projects for approvals based on threshold limits.	15.2.2
15.1.4	**Estimations**	Project costs, both internal and external, are manually compiled in spreadsheets. Quotations/tenders for external labour/services, materials and equipment are obtained from suppliers and included in estimates.	**Fit**	The current system supports the capture of various ledgers for capturing estimates on labour, materials and other costs as required.	15.2.3, 15.2.4, 15.2.6
15.1.5	**Work Orders**	Work Orders are initiated on a Work Order Job Description Form. Two different Work Order Close-Out forms are used. One for internal projects and the other for customer extensions. Both forms vary in format but are similar in content. Forms are electronic copies which are manually entered, printed and filed. Internal project close-outs are done at year-end and the process can take from 2 hours to 2 days per project depending on discrepancies especially with the manual reconciliation of costs and expenditures. Customer extensions are closed out at project completion.	**Fit**	The current system supports a Work Order function which can generate a work order printout with close-out information as entered. Additional documentation can also be attached to a work order. Customer-specific information for close-outs can be configured via the Supplemental Data facility provided by the system.	15.2.7, 15.2.8, 15.2.9, 15.2.10, 11.2.6

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
15.1.6	**Actual Costs**	Actual costs are downloaded from the JDE system onto spreadsheets and further compiled into spreadsheets for tracking of actuals against estimated costs.	**Fit**	The current system's Job Cost function supports the capture of actuals costs into the Job Cost management inquiries and reports to enable analysis and comparisons to planned, estimates and actual cost.	15.2.5
15.1.7	**Customer Extensions**	**Initiation** A work order is created when a customer initiates a request for an extension or an installation of a distribution line. A deposit is collected from the customer and a site survey is done. Specifications are drawn up for the requirement and estimates for labour, materials and equipment are compiled and submitted to the customer for approval. The project cost of an extension comprises of the customer portion and possibly a contribution from the company. Extensions are owned by the company. .	**Fit**	The Supplemental Data facility which is customizable could be used to capture information applicable to the processing customer extensions.	
15.1.8	**Customer Extensions**	**Costs** The total project cost primarily consists of 2 components; company investment and customer contribution. The "customer" component is either a direct contribution from one or more end customers or the government. The company investment is basically for electrical services and is regulated based on rate schedules for residential, commercial, size and types of services.			
15.1.9	**Customer Extensions**	**Estimates** Estimates are costed for materials and labour. Estimates for material costs are obtained from the JDE system from most recent material issues cost. Estimates for external equipment rentals and external labour is obtained from vendor quotations. Internal labour rates are based on preset rates for costing purposes. Internal equipment utilization rates are not identified separately but included in the internal labour rate. There has been an expressed need to identify internal equipment rates separately.	**Fit**		
15.1.10	**Customer Extensions**	**Material Issues** Inventory requirements are manually submitted (via email) to the warehouse manager. An inventory issue is created in the JDE system by the warehouse manager for the release of materials. If materials are not in stock, a purchase order is created in JDE and the order placed with vendors. Where applicable, quotations are manually obtained to source "best price" prior to placement of purchase orders.	**Fit**	The JDE system is currently in use to process inventory issues and purchasing as required. The system is able to provide for the processing of quotations.	
15.1.11	**Customer Extensions**	**Material (Actual) Costs Tracking** Currently the tracking of material returns, additions and change outs have been quite challenging. Changes to the initial materials list is more often than not not communicated for the compilation of the actual material used. It could take from 3 to 4 months to realize the actual material costs.	**n / a**	This issue is a procedural issue.	
15.1.12	**Customer Extensions**	**Customer Payments** A letter advising of the estimated costs is sent to the customer and the required deposit to be paid for the project to be initiated. A work order and an accounts receivable record is then set up for the customer in the JDE system.	**Fit**	The JDE system is currently in use to process customer payments.	
15.1.13	**Customer Extensions**	**Procurement** Any required procurement services and equipment rentals are processed via the JDE system. A requisition is	**Fit**	The current JDE system is in use for some procurement.	

No.	Key Area	Current State	Fit / Gap Analysis		Future State Reference
		submitted to the buyer for a purchase order or contract to be expedited. Currently. Standing Agreements are in place with some vendors for brushing and line work.			
15.1.14	**Customer Extensions**	**Cost Sharing** The calculation of cost sharing is currently manual. Costs are shared amongst initial customers requesting for a distribution line. The sharing portion may be adjusted later if another customer joins the community or group. There is also a time period that cost sharing applies. After the specified time period, additional customers could potentially join without incurring any costs.	**Fit**	The JDE system has a Service and Contract Billing module that might support the customization of formulas for the derivation of the cost sharing apportionment by customer.	
15.1.15	**Customer Extensions**	**Refunds to Customers** Projects that come in under the original estimate result in refunds to the customer. All refunds are routed for management approval. A letter is sent to the customer advising of the refund and a request is submitted to cut a refund cheque to the customer. A policy might be developed to only issue a refund if the amount exceeds a specific/tolerance amount.			
15.1.16	**Customer Extensions**	**Customer Extension System** A standalone custom system is currently being developed on the MSAccess platform to support requirements of Customer Extensions. Parts of this system has been developed and is currently in use. Additional functionality is planned to be added as per ongoing development. Feedback on this system has been positive. Interfacing of applicable transactions such as project costs (both estimates and actuals), procurement and customer payments/deposits/refunds to and from this system and the JDE system is manual.			15.1.14
15.1.17	**Inquiries / Reports**	Actual costs captured in the current General Ledger system is extrapolated and reported via MSAccess. Engineering does not have on-line inquiry access to actual costs captured in the General Ledger System. The information provided on MSAccess is not readily usable and have to be further re-worked/re-entered into spreadsheets to compile the required information of management purposes.			15.2.13

15.2 Future State

No.	Key Area	Requirements	Criticality	Additional Notes
15.2.1	**Project Initiation**	Ability to initiate a project with the capture of the following information: 1. Unique Project Identification Number 2. Project Title 3. Detailed Description, Objectives, Scope, discussion of alternatives/options where applicable 4. Project Initiator Name and Contact Information 5. Location of the project 6. Priority 7. Project Start and Completion Dates 8. Justification; Primary and Secondary 9. Initial Planned Costs	1	•

No.	Key Area	Requirements	Criticality	Additional Notes
		10. Timing of Cash Flow Projections 11. Qualification on the impacts on existing assets, if any		
15.2.2	**Approvals**	• Electronic routing of project for approvals based on one or more mandatory signing authorities and/or based on signing authorities by threshold limits. • Electronic notification/alert to approvers of projects awaiting their approval. • Ability to specify additional notes, queries and rejection reasons by approvers. • Notification to originators on whether a project has been approved or rejected.	1	•
15.2.3	**Project Work-Breakdown Structure**	• Ability to set up a parent project with multiple levels of subprojects and within which multiple work orders per subproject. • Ability to capture and review estimated costs versus actual costs by work order, subprojects and overall totals at the parent project level.	1	
15.2.4	**Cost Capture**	Ability to set up estimated costs and track actual costs for the following items: 1. Internal Labour (units and rates) 2. External Labour (units and rates or lump-sum agreements) 3. Material 4. Equipment (including rentals) 5. Travel (Accommodations, travel, meals, incidentals) 6. Salvages 7. Disposals	1	•
15.2.5	**Actuals**	Automatic capture of all actual costs from time/labour entry, material purchases, inventory issues, equipment rentals and contracts.	1	
15.2.6	**Quotations**	Electronic entry and issuance of quotations to multiple suppliers and the entry of responses for analysis. Ability to generate purchase orders from 'best' quote.	1	•
15.2.7	**Work Order Initiation**	Ability to set up and issue work orders for projects including customer extensions. Profiling information of work orders are to include: 2. Work Order Number 3. Reference to project number 4. In Service Date / Initiation Date 5. Contact Name and contact information 6. Service to be provided 7. Company Identification 8. Service Area 9. Customer Identification/Reference (for customer extensions) 10. Description of Work 11. Costs Estimates (labour and materials) including labour units and rates 12. Material Requirements (quantity, specifications) 13. Attachments of additional documentation such as drawings and specifications.	1	• .
15.2.8	**Work Order Approvals**	• Electronic routing of work orders for approvals based on mandatory signatories and/or based on costs levels. • Electronic alerts to approvers on work orders awaiting their approval.	1	•

No.	Key Area	Requirements	Criticality	Additional Notes
		• Ability to specify rejection reasons by approver. • Automatic notification to originators on whether their work orders have been approved or rejected.		
15.2.9	**Work Order Costs**	Ability to track work order estimated versus actual costs broken down by labour, materials and travel.	1	•
15.2.10	**Work Order Close-Out**	Ability to capture and print (when required) the following close-out information for a work order. 11. In-Service Date or expected In-Service Date. 12. Project Status – In Use (Yes/No)? 13. Asset Replacement Information (Historical In-Service Date, Replacement Cost) 14. Purchases of Land, Computer Equipment or Office Equipment 15. Site restoration costs and percentage to total project costs 16. Salvage costs or proceeds 17. Approval of actual transaction amounts 18. Expected additional charges after close-out	1	•
15.2.11	**Project & Work Order Statuses**	Electronic tracking of project status from initiation to completion. Provide identification of parent project, subproject and work order statuses at initiation, review, awaiting approval, commencement, in progress, completion and close-out.	1	
15.2.12	**Labour Time Entry**	*To be determined.*		
15.2.13	**Inquiries / Reports**	*To be determined.*		
15.2.14	**Interfaces**	1. Inventory for material requirements. 2. Procurement for purchases of non-inventory materials, services, equipment rentals. 3. MSAccess Customer Extension System for estimates, work order initiation and status, material requirements, procurement of external services and rentals, customer payments and refunds to customers.	1	Regarding requirement 3, as the Customer Extension MSAccess system will be kept, only requirements for interfaces between this system and the replacement FIS system will be defined.
15.2.15	**Data Conversion**	Job Costs Budgets, Estimates, Forecasts from JDE	1	

REFERENCE: **Tab 5 Capital Projects; P 5-17, L 15**

QUESTION:

a) Please provide a copy of the report and the recommended solutions.

ANSWER:

(a)

No report has been prepared.

REFERENCE: Tab 5 Capital Projects; P 5-17, L 15

QUESTION:

a) Please provide an update on the upgrading or replacement of the power line carrier system.

ANSWER:

(a)

Yukon Energy currently has two Power Line Carrier (PLC) systems in place. The vintage for the systems is as follows:

- Takhini to Aishihik mid-1970s
- Takhini to Faro early 1970s

The scheduled replacement of the Takhini to Aishihik system is on hold, as YEC is this year conducting a Communications System Study to determine if other cost effective solutions are available. If other solutions are not available the replacement of this PLC will be included in the budget.

The Takhini to Faro system is scheduled for replacement this year by implementing a new ABB Digital PLC as part of the CSTP Phase 1 Project. This replacement will result in YEC replacing one old link with the following three new links:

- Takhini Substation to Carmacks Airport Substation (New Substation).
- Carmacks Airport Substation (New Substation) to Faro Substation.
- Carmacks Airport Substation (New Substation) to Minto Landing Substation (New Substation).

REFERENCE: Tab 5 Capital Projects; P 5-18, L 22

QUESTION:

a) Why are portions of the project described here repeated separately on the following page (pole treatment, dead-end insulators)? Are they all one project described here or is the description of the scope of this project incorrect?

ANSWER:

(a)

There is some overlap in the scope description between the projects. The description of WAF Transmission upgrades as provided at page 5-18 (lines 25-26) of the Application should not include the addition of pole test and treatment and dead end insulators (discussed separately at page 5-19 of the Application). The scope of the WAF Transmission Upgrades project properly includes the following: upgrade structures, guys, cross arms, anchors switches and other insulators on the WAF system.

REFERENCE: Tab 5 Capital Projects; P 5-20, L 19

QUESTION:

a) Are there any sources of power other than hydro and geothermal that Yukon Energy is studying, and if so what are they and what are the budgets for these studies?

ANSWER:

(a)

Yes. In 2009, Yukon Energy will be assessing several internal DSM and supply side enhancement (SSE) areas as part of their 20-Year Resource Plan objectives focused first on improving the utilization of their existing facilities. This work will identify potential options for improving water turbine efficiencies and reducing station services losses and fossil fuel use. In addition, prefeasibility work is underway on a potential expansion to the wind generation complement. This is part of the Other Generation Feasibility work discussed on page 5-20 of the application; budgets are still being finalized for the individual components of this work.

REFERENCE: **Tab 5 Capital Projects; P 5-21, L 1**

QUESTION:

a) Has Western Copper advanced Yukon Energy the $1 million? If not when and how will Western Copper pay Yukon Energy? Are there written agreements in place?

ANSWER:

(a)

No. While preliminary discussions with Western Copper related to the provision of electrical service to the mine site have commenced, discussion specifically related to a Power Purchase Agreement or specific details on the spur line have yet to occur. The timing and method of payment of the advance will be addressed in any subsequent PPA negotiations and final PPA agreement.

REFERENCE: Tab 5 Capital Projects; P 5-22, L 1

QUESTION:

a) Why is the cost of this 2008 assessment not included in the cost of the 2009 scaling of this same rock face as described on page 5-15, L 16?

ANSWER:

(a)

The successful completion of the 2008 assessment has led to confirmation that the rock scaling is required. Consequently, the project noted as a feasibility study will now be included in WIP and combined with the rock scaling project when it occurs.

REFERENCE: Tab 5 Capital Projects; P 5-22, L 14

QUESTION:

a) We understand that the Aishihik Fisheries studies were completed. Please provide any reports compiled as part of this assessment and provide the conclusions of the work if not included in the reports. What are the practical implications of the results of this work on the Aishihik water licence?

ANSWER:

(a)

The requested reports are provided as Attachment 1 (Data Report: 2007 Aishihik Lake Whitefish Gillnetting) and Attachment 2 (Aishihik Lake Whitefish Population Monitoring Program 2007 Program: Data Analysis) to this response.

The May 2008 Report provided as Attachment 2 to this response concludes that the fish population in the lakes is healthy. Discussions are on-going with the members of the Monitoring Group. If the Monitoring Group accepts the report's conclusion that the fish population is healthy, the water usage restrictions could be lifted for the operation of the Aishihik Generating station possibly making up to 6 GWh/yr of additional energy per year (on average) available. If the report's conclusions are not accepted by the Monitoring Group the operating restrictions on the plant would continue as has been the case for the past 5 years.

EDI ENVIRONMENTAL DYNAMICS INC.
Natural Resource Consultants

DATA REPORT: 2007 AISHIHIK LAKE WHITEFISH GILLNETTING

Prepared for:

YUKON ENERGY CORPORATION

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EDI Project No.: 07-YC-0047
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TABLE OF CONTENTS

1.0 Introduction 1
2.0 Methods 1
2.1 Gillnetting Locations 1
3.0 Results 2
3.1 Gillnetting Site Data 2
3.2 Aishihik Lake Fish Data 5
3.3 Canyon Lake Fish Data 30
Appendix A: Maps of Sample Locations 50

1.0 INTRODUCTION

During late July and August of 2007, a study was undertaken to assess the current status of lake whitefish populations in the Aishihik Lake system. This report presents a summary of the fish capture data collected during the gillnetting component of the study.

2.0 METHODS

Sampling was completed over a 9 day period from July 25th through August 2nd, by biologists from EDI Envionrmental Dynamics Inc., Environment Yukon staff, and members of the Champange and Aishikik First Nations.

Gillnetting was conducted at twelve locations in both Aishihik and Canyon Lakes, with the latter intended to provide control data. At each location, a gang consisting of seven gillnets with different mesh sizes was set for a duration of approximately twelve hours. Each gillnet panel was 22.9 metres long, 2.4 metres deep, and the seven mesh sizes employed were (in order) 3.8 cm (1.5”), 12.7 cm (5.0”), 6.4 cm (2.5”), 11.4 cm (4.5”), 7.6 cm (3.0”), 10.2 cm (4.0”), 8.9 cm (3.5”). The gangs were set with alternating ends (3.8 cm and 8.9 cm mesh panels) in-shore from location to location. Each fish captured was measured, weighed, and identified to species. The location and mesh size for each capture was recorded. For species other than lake whitefish, fish captured were released unharmed where possible. When this was not possible due to the trauma of capture, they were retained for further sampling. All lake whitefish captured were retained for further sampling. Ageing structures were subsequently removed from all lake whitefish, lake trout, arctic grayling, and subsets of other species captured. Aging structures taken included otoliths from lake whitefish, lake trout, round whitefish, and burbot, scales from Arctic grayling, cliethra from northern pike, and fin rays from longnose sucker. The sex and sexual maturity were also determined (where possible) for all fish captured. A subset of stomach samples were collected from lake whitefish, round whitefish, lake trout, and northern pike.

2.1 Gillnetting Locations

The maps illustrated in Figures 1, 2, and 3 located in Appendix A illustrate all sampling locations on Aishihik and Canyon Lakes. The sampling locations are labelled to correspond with the data tables presented for each location in Section 3.0. Efforts were made to duplicate the sampling locations from the 1991 study, with some modifications and site additions where necessary.

3.0 RESULTS

The sampling results from all data collected in the field are presented in four tables. Section 3.1 contains two tables (1 and 2) which detail the standard data collected regarding each gillnetting site, such as location, duration of set, anchor depth, etc. Section 3.2 contains the other two tables (3 and 4) which detail the information collected regarding each fish captured, such as fork length, weight, sex, maturity, etc.

3.1 Gillnetting Site Data

Tables 1 and 2 detail the standard gillnetting site data from from Aishihik and Canyon lakes, respectively.

TABLE 1: AISHIHIK LAKE GILLNETTING SITE DATA

Site	Waterbody	Sample Date	Surface Water (°C)	Shore Mesh (cm)	Anchor Depth (m)	Duration (hr)	Duration (min)	Location	Comments
1	Aishihik Lake	30-Jul-07	13.2	3.8	10	13	25	61.21525 N / 137.01019 W	
2	Aishihik Lake	30-Jul-07	13.8	8.9	8	13	15	61.21997 N / 136.9932 W	
4	Aishihik Lake	30-Jul-07	14	8.9	8	12		61.250667 N / 137.031611 W	Duration at least 12 hrs, however, time out not recorded
5	Aishihik Lake	30-Jul-07	13	3.8	16	12		61.254278 N / 137.031611 W	Duration at least 12 hrs, however, time out not recorded
6	Aishihik Lake	01-Aug-07	16.2	8.9	7	12		61.594972 N / 137.435222 W	Duration at least 12 hrs, however, time out not recorded
7	Aishihik Lake	01-Aug-07	16	3.8	6	12		61.588333 N / 137.434694 W	Duration at least 12 hrs, however, time out not recorded
8	Aishihik Lake	01-Aug-07	17.7	n/a	3.6	12	10	61.60221 N / 137.48594 W	
9	Aishihik Lake	01-Aug-07	17.7	n/a	2.4	13	15	61.60057 N / 137.49728 W	
10	Aishihik Lake	02-Aug-07	15.8	3.8	9.5	12	55	61.56903 N / 137.32759 W	
11	Aishihik Lake	02-Aug-07	n/a	8.9	18.2	12	40	61.54707 N / 137.32815 W	
12	Aishihik Lake	02-Aug-07	15.4	8.9	14	12		61.53551 N / 137.28645 W	Duration at least 12 hrs, however, time out not recorded
13	Aishihik Lake	02-Aug-07	15.6	3.8	4	12		61.5112833 N / 137.28645 W	Duration at least 12 hrs, however, time out not recorded

TABLE 2: CANYON LAKE GILLNETTING SITE DATA

Site	Waterbody	Sample Date	Surface Water (°C)	Shore Mesh (cm)	Anchor Depth (m)	Duration (hr)	Duration (min)	Location	Comments
1	Canyon Lake	26-Jul-07	n/a	3.8	2.6	12	0	61.08887 N / 137.01548 W	
2	Canyon Lake	26-Jul-07	n/a	8.9	3.8	12	30	61.10052 N / 137.00698 W	
3	Canyon Lake	27-Jul-07	n/a	3.8	5.2	12	15	61.12137 N / 137.00999 W	
4	Canyon Lake	27-Jul-07	n/a	8.9	4.5	12	40	61.12969 N / 137.02329 W	
5	Canyon Lake	28-Jul-07	n/a	3.8	5.8	13	15	61.14537 N / 137.00972 W	
6	Canyon Lake	28-Jul-07	n/a	8.9	7.5	12	45	61.15593 N / 137.00604 W	
7	Canyon Lake	28-Jul-07	16.2	3.8	7	12	15	61.161417 N / 137.012111 W	
8	Canyon Lake	28-Jul-07	n/a	8.9	n/a	12		61.122722 N / 137. 13306 W	duration at least 12 hrs; however time out not recorded
9	Canyon Lake	29-Jul-07	n/a	3.8	6.6	12	55	61.15217 N / 137. 0074 W	
10	Canyon Lake	29-Jul-07	n/a	8.9	7.2	13	35	61.16066 N / 137.00458 W	
11	Canyon Lake	29-Jul-07	16.6	8.9	6.3	11	55	61.173889 N / 137.0175 W	
12	Canyon Lake	29-Jul-07	16.5	3.8	7	12	40	61.162222 N / 137.021 W	

3.2 Aishihik Lake Fish Data

Tables 3 details all data collected from all fish captured in Aishihik Lake. Fish captured are listed numerically by gillnetting site and then by species in alphabetical order.

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Trout	1	6	6.4	353	600	Y	Female	Immature (virgin)	N	insects & unidentifiable fish	Dead	
Lake Trout	1	7	10.2	455	1200	Y	Male	Immature (virgin)	N		Dead	
Lake Trout	1		8.9	855	8200	N	Unknown	NA	N		Good	
Lake Trout	1		11.4	524	1900	N	Unknown	NA	N		Good	
Lake Trout	1		3.8	419	1200	N	Unknown	NA	N		Good	
Lake Trout	1		7.6	820	6600	N	Unknown	NA	N		Good	
Lake Trout	1		6.4	824	6200	N	Unknown	NA	N		Good	
Lake Whitefish	1	52	8.9	457	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	53	8.9	480	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	54	8.9	466	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	55	8.9	473	1300	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	56	8.9	442	1100	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	57	8.9	467	1500	Y	Male	Immature (virgin)	N		Dead	
Lake Whitefish	1	58	8.9	475	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	59	8.9	450	1100	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	60	6.4	440	1200	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	61	6.4	507	2100	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	62	6.4	455	1200	Y	Male	Immature (virgin)	N		Dead	
Lake Whitefish	1	63	12.7	523	2100	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	64	12.7	471	1500	Y	Male	Immature (virgin)	N		Dead	
Lake Whitefish	1	65	12.7	483	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	66	12.7	466	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	67	7.6	465	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	68	7.6	502	1500	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	1	69	7.6	466	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	70	7.6	504	1700	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	71	7.6	454	1300	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	72	7.6	464	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	73	7.6	469	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	74	7.6	480	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	75	10.2	478	1900	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	76	10.2	479	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	77	10.2	480	1600	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	1	78	10.2	480	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	79	10.2	457	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	80	10.2	492	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	81	10.2	455	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	1	82	10.2	506	2000	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	83	10.2	453	1300	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	84	10.2	486	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	85	10.2	483	1600	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	86	10.2	476	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	87	10.2	463	1500	Y	Female	Mature (spawner)	N		Dead	only 1 otolith
Lake Whitefish	1	88	3.8	443	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	89	3.8	498	1800	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	90	3.8	467	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	91	11.4	483	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	92	11.4	486	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	93	11.4	497	1700	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	94	11.4	471	1300	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	95	11.4	445	1300	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	96	11.4	553	2600	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	97	11.4	463	1300	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	98	11.4	454	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	99	11.4	446	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	100	11.4	447	1400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	101	11.4	459	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	1	102	11.4	452	1300	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	1	103	11.4	435	1300	Y	Female	Mature (spawner)	N		Dead	
Round Whitefish	1	10	3.8	244	134	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	1	11	3.8	257	125	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	1	12	3.8	247	150	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Round Whitefish	1	13	3.8	234	119	N	Male	Mature (non-spawner, resting)	Y		Dead	
Round Whitefish	1	14	3.8	216	98	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	1	15	3.8	219	98	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	1	16	3.8	205	83	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	1	17	3.8	243	134	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Round Whitefish	1	18	6.4	361	500	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	1	19	6.4	345	500	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	1	20	6.4	356	500	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	1	21	6.4	342	500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Round Whitefish	1	22	6.4	344	500	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	1	23	6.4	345	500	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	1	24	6.4	350	600	Y	Female	Mature (spawner)	Y		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Round Whitefish	1	25	6.4	357	500	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	1	26	6.4	344	500	Y	Female	Mature (spawner)	Y		Dead	1 otolith sampled
Round Whitefish	1	27	6.4	307	400	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	1	28	6.4	368	600	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	1	29	6.4	363	600	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	1	30	6.4	355	500	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	1	31	6.4	308	400	Y	Female	Mature (spawner)	Y		Dead	
Lake Trout	2	1	7.6	382	700	Y	Female	Immature (virgin)	N	5 slimy sculpin	Dead	
Lake Trout	2	2	8.9	455	900	Y	Female	Immature (virgin)	N		Dead	
Lake Trout	2	3	10.2	468	1100	Y	Female	Immature (virgin)	N	1 slimy sculpin	Dead	
Lake Trout	2	4	6.4	347	500	Y	Unknown	Immature (sex unknown)	N	insect larvae	Dead	
Lake Trout	2	5	3.8	164	49	Y	Unknown	Immature (sex unknown)	N		Dead	1 otolith taken
Lake Trout	2		7.6	377	800	N	Unknown	NA	N		Good	
Lake Trout	2		3.8	350	700	N	Unknown	NA	N		Good	
Lake Whitefish	2	1	12.7	472	1700	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	2	12.7	476	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	3	12.7	484	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	4	12.7	450	1200	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	5	12.7	450	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	6	6.4	461	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	7	6.4	496	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	8	6.4	468	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	9	6.4	472	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	10	10.2	472	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	11	10.2	469	1400	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	12	10.2	463	1200	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	13	10.2	449	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	14	10.2	486	1300	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	15	10.2	449	1300	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	2	16	10.2	500	1500	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	2	17	10.2	468	1300	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	2	18	10.2	460	1300	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	19	10.2	476	1400	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	2	20	10.2	465	1200	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	21	8.9	450	1200	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	2	22	8.9	470	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	23	8.9	457	1500	Y	Female	Mature (spawner)	Y		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	2	24	8.9	507	1700	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	2	25	8.9	474	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	26	8.9	494	1500	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	27	8.9	503	2100	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	2	28	8.9	484	1300	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	29	8.9	480	1300	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	30	8.9	474	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	31	7.6	428	1100	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	2	32	7.6	467	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	33	7.6	475	1500	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	34	7.6	456	1100	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	2	35	7.6	482	1300	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	36	7.6	440	800	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	37	7.6	475	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	38	7.6	465	1400	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	39	7.6	454	1300	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	2	40	11.4	504	1900	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	41	11.4	488	1600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	42	11.4	507	1900	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	2	43	11.4	436	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	44	11.4	482	1500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	45	11.4	482	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	46	11.4	474	1600	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	2	47	11.4	463	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	48	11.4	448	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	49	11.4	500	1800	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	50	11.4	466	1500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	51	11.4	466	1300	Y	Male	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	2	1	3.8	229	104	Y	Unknown	Immature (sex unknown)	Y		Dead	Parr Marks present
Round Whitefish	2	2	3.8	231	112	Y	Unknown	Immature (sex unknown)	Y		Dead	Parr marks present
Round Whitefish	2	3	3.8	228	92	Y	Unknown	Immature (sex unknown)	Y		Dead	Parr marks present
Round Whitefish	2	4	3.8	283	205	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	2	5	6.4	352	400	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	2	6	6.4	361	400	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	7	6.4	314	300	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	8	6.4	308	300	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	9	6.4	336	500	Y	Male	Mature (spawner)	Y		Dead	
Lake Trout	4	55	12.7	628	2825	Y	Male	Mature (spawner)	N	empty	Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Trout	4	56	11.4	441	1000	Y	Male	Immature (virgin)	N	unidentifiable fish	Dead	
Lake Trout	4	57	6.4	473	1225	Y	Female	Immature (virgin)	N	insects & unidentifiable fish	Dead	
Lake Trout	4	58	6.4	412	725	Y	Female	Immature (virgin)	N	insects & unidentifiable fish	Dead	
Lake Trout	4		12.7	892		N	Unknown	NA	N		Good	
Lake Trout	4		12.7	587	2500	N	Unknown	NA	N		Good	
Lake Trout	4		6.4	540	1900	N	Unknown	NA	N		Good	
Lake Trout	4		6.4			N	Unknown	NA	N		Good	
Lake Trout	4		11.4	900		N	Unknown	NA	N		Good	
Lake Trout	4		10.2	440	900	N	Unknown	NA	N		Good	
Lake Trout	4		8.9	448	1000	N	Unknown	NA	N		Good	
Lake Trout	4		8.9	657	2600	N	Unknown	NA	N		Good	
Lake Whitefish	4	307	8.9	446	1325	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	4	308	8.9	460	1325	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	309	8.9	467	1225	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	4	310	8.9	449	1200	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	311	8.9	470	1300	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	4	312	8.9	470	1425	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	4	313	8.9	485	1525	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	314	8.9	441	1100	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	315	8.9	451	1200	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	316	8.9	495	1600	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	317	8.9	482	1425	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	318	8.9	515	1650	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	4	319	8.9	475	1575	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	320	8.9	487	1600	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	321	8.9	462	1350	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	322	8.9	438	1150	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	4	323	8.9	550	1575	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	324	8.9	492	1550	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	325	8.9	500	1550	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	326	8.9	471	1400	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	327	8.9	468	1300	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	328	8.9	469	1375	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	353	3.8	487	1650	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	4	354	3.8	444	1275	Y	Female	Mature (non-spawner, resting)	?		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	4	355	3.8	489	1475	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	4	356	12.7	488	1750	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	357	12.7	480	1500	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	4	358	12.7	490	1725	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	4	359	12.7	468	1400	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	360	12.7	505	1500	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	4	361	12.7	476	1475	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	4	362	12.7	492	1500	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	4	397	7.6	460	1325	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	398	7.6	450	1275	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	399	7.6	466	1325	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	400	7.6	482	1475	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	401	7.6	489	1600	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	402	7.6	463	1300	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	403	7.6	454	1275	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	404	8.9	454	1300	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	405	8.9	539	1700	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	406	8.9	490	1550	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	407	8.9	482	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	408	8.9	475	1550	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	409	8.9	480	1575	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	410	8.9	472	1450	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	411	8.9	459	1225	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	412	8.9	467	1325	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	413		471	1325	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	414	8.9	461	1375	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	415	8.9	471	1350	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	416	8.9	470	1500	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	417	8.9	475	1300	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	418	8.9	474	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	419	8.9	530	2500	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	420	8.9	450	1350	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	421	8.9	496	1600	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	422	8.9	467	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	423	8.9	482	1625	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	424	8.9	472	1450	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	425	8.9	473	1350	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	426	7.6	456	1225	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	427	7.6	439	1075	Y	Female	Mature (non-spawner, resting)	N		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	4	428	7.6	442	1075	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	429	7.6	496	1700	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	430	7.6	480	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	431	7.6	462	1250	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	432	11.4	502	1600	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	433	11.4	459	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	434	11.4	462	1450	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	435	11.4	486	1600	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	436	11.4	466	1650	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	437	11.4	474	1700	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	438	11.4	480	1525	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	439	11.4	467	1225	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	440	11.4	491	1700	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	441	11.4	465	1400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	442	11.4	465	1400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	443	11.4	498	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	444	8.9	484	1650	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	445	8.9	472	1350	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	446	11.4	476	1325	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	447	11.4	461	1400	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	448	11.4	435	1300	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	449	11.4	484	1425	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	450	11.4	478	1475	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	451	11.4	482	1450	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	452	6.4	509	1825	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	453	6.4	504	1775	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	454	6.4	487	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	455	6.4	489	1575	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	456	6.4	414	1025	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	457	6.4	452	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	458	6.4	437	1200	Y	Female	Mature (non-spawner, resting)	N		Dead	one gonad
Lake Whitefish	4	459	6.4	503	1650	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	4	460	10.2	494	1475	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	461	10.2	493	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	462	10.2	451	1250	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	463	10.2	486	1550	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	464	10.2	512	1700	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	465	10.2	478	1525	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	466	10.2	505	1825	Y	Male	Mature (non-spawner, resting)	N		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	4	467	10.2	474	1520	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	468	10.2	463	1275	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	469	10.2	478	1525	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	470	10.2	501	1700	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	471	10.2	475	1550	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	472	10.2	473	1325	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	473	10.2	502	1675	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	474	10.2	494	1675	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	475	10.2	514	1625	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	476	10.2	465	1325	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	477	10.2	458	1528	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	478	10.2	492	1875	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	479	10.2	492	1525	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	480	10.2	439	1200	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	481	10.2	525	2000	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	482	10.2	446	1000	Y	Female	Immature (virgin)	N		Dead	
Lake Whitefish	4	483	10.2	470	1425	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	484	10.2	470	1425	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	485	10.2	498	1800	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	486	10.2	466	1475	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	487	10.2	511	1700	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	488	10.2	501	1850	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	489	10.2	495	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	4	490	10.2	504	1650	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	4	491	10.2	475	1400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	4		6.4	370	500	N	Unknown	NA	N		Good	
Round Whitefish	4		6.4	382	650	N	Unknown	NA	N		Good	
Round Whitefish	4		6.4	375	500	N	Unknown	NA	N		Good	
Lake Trout	5	51	7.6	494	1425	Y	Male	Mature (spawner)	N	shrimp	Dead	
Lake Trout	5	52	7.6	377	525	Y	Female	Immature (virgin)	N	shrimp	Dead	
Lake Trout	5	53	8.9	597	2775	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Trout	5	54	8.9	480	1325	Y	Female	Mature (spawner)	N	shrimp	Dead	
Lake Trout	5		10.2	447	1100	N	Unknown	NA	N		Good	
Lake Trout	5		11.4	475	1250	N	Unknown	NA	N		Good	
Lake Trout	5		10.2	477	1300	N	Unknown	NA	N		Good	
Lake Trout	5		7.6	377	700	N	Unknown	NA	N		Good	
Lake Trout	5		7.6	390	700	N	Unknown	NA	N		Good	
Lake Trout	5		7.6	382	450	N	Unknown	NA	N		Good	
Lake Trout	5		10.2	431	1100	N	Unknown	NA	N		Good	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Trout	5		10.2	447	1100	N	Unknown	NA	N		Good	
Lake Trout	5		10.2	566	2200	N	Unknown	NA	N		Good	
Lake Trout	5		6.4	350	500	N	Unknown	NA	N		Good	
Lake Whitefish	5	301	3.8	450	1300	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	302	3.8	450	1300	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	303	3.8	455	1325	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	304	3.8	480	1350	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	305	3.8	500	1500	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	306	3.8	472	1550	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	329	7.6	480	1475	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	330	7.6	473	1300	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	331	7.6	473	1425	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	332	7.6	489	1500	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	333	7.6	488	1550	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	334	7.6	487	1525	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	335	7.6	514	1775	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	336	10.2	466	1225	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	337	10.2	466	1475	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	338	10.2	482	1478	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	339	10.2	439	1050	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	340	10.2	487	1525	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	341	8.9	477	1550	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	342	8.9	424	1050	Y	Female	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	343	8.9	492	1600	Y	Male	Immature (virgin)	?		Dead	
Lake Whitefish	5	344	8.9	459	1300	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	345	8.9	508	1750	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	346	8.9	424	1250	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	347	8.9	504	1800	N	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	348	8.9	477	1525	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	349	8.9	479	1625	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	350	8.9	467	1425	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	351	8.9	484	1550	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	352	8.9	499	1525	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	363	12.7	509	1525	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	364	12.7	463	1450	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	365	12.7	500	1625	Y	Male	Mature (spawner)	?		Dead	
Lake Whitefish	5	366	12.7	482	1425	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	367	12.7	475	1400	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	368	12.7	496	1675	Y	Female	Mature (spawner)	?		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	5	369	12.7	500	1725	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	370	12.7	485	1600	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	371	12.7	490	1500	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	372	12.7	476	1300	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	373	12.7	490	1850	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	374	12.7	459	1400	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	5	375	12.7	477	1525	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	5	376	12.7	467	1425	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	5	377	6.4	482	1425	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	5	378	6.4	476	1550	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	5	379	6.4	472	1375	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	5	380	6.4	462	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	5	381	6.4	477	1550	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	5	382	6.4	469	1350	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	5	383	11.4	479	1550	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	5	384	11.4	499	1550	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	5	385	11.4	502	1625	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	5	386	11.4	594	1850	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	5	387	11.4	480	1525	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	5	388	11.4	487	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	5	389	11.4	482	1400	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	5	390	11.4	477	1550	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	5	391	11.4	483	1575	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	5	392	11.4	468	1375	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	5	393	11.4	461	1375	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	5	394	11.4	493	1500	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	5	395	11.4	496	1825	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	5	396	11.4	466	1475	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	5	51	7.6	380	600	Y	Female	Mature (non-spawner, resting)	?		Dead	same sample # for 2 fish
Round Whitefish	5	52	7.6	358	450	Y	Female	Mature (non-spawner, resting)	?		Dead	same sample # for 2 fish
Round Whitefish	5		6.4	346	450		Unknown	NA			Good	
Round Whitefish	5		6.4	355	500		Unknown	NA			Good	
Round Whitefish	5		6.4	355	475		Unknown	NA			Good	
Round Whitefish	5		6.4	369	525		Unknown	NA			Good	
Round Whitefish	5		6.4	372	525		Unknown	NA			Good	
Round Whitefish	5		6.4	387	600		Unknown	NA			Good	
Round Whitefish	5		7.6	370	600		Unknown	NA			Good	
Round Whitefish	5		7.6	375	600		Unknown	NA			Good	
Round Whitefish	5		7.6	375	600		Unknown	NA			Good	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Round Whitefish	5		7.6	380	500		Unknown	NA			Good	
Round Whitefish	5		7.6	385	600		Unknown	NA			Good	
Round Whitefish	5		7.6	390	600		Unknown	NA			Good	
Arctic Grayling	6		6.4	275	200	N	Unknown	NA	N		Good	
Lake Trout	6	59	10.2	524	1900	Y	Male	Mature (spawner)	N	6 small LWF	Dead	
Lake Trout	6	60	11.4	577	2025	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Trout	6	61	10.2	578	2125	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Lake Trout	6	62	10.2	607	2800	Y	Female	Mature (spawner)	N	1 small unidentifiable fish	Dead	
Lake Trout	6	63	12.7	605	2475	Y	Male	Mature (non-spawner, resting)	N	1 small LWF	Dead	
Lake Trout	6		11.4			N	Unknown	NA	N		Good	
Lake Trout	6		10.2	600	2700	N	Unknown	NA	N		Good	
Lake Trout	6		3.8	639	2700	N	Unknown	NA	N		Good	
Lake Whitefish	6	492	3.8	272	300	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	6	493	3.8	218	125	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	494	3.8	274	250	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	495	3.8	218	100	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	496	3.8	216	100	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	497	3.8	210	325	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	6	498	3.8	225	150	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	499	3.8	436	1200	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	500	3.8	455	1450	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	501	3.8	455	1425	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	502	8.9	445	1100	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	503	8.9	328	450	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	504	8.9	206	250	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	505	8.9	464	1375	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	506	8.9	476	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	507	8.9	439	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	508	8.9	425	1175	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	509	8.9	435	1125	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	510	10.2	440	1175	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	511	10.2	429	1100	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	512	10.2	475	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	513	10.2	439	1175	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	514	10.2	445	1250	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	515	7.6	455	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	516	7.6	443	1250	Y	Male	Mature (non-spawner, resting)	Y		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	6	517	7.6	396	800	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	518	7.6	414	725	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	519	7.6	441	1250	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	520	11.4	476	1350	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	521	11.4	440	1250	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	522	11.4	427	1075	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	523	11.4	485	1700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	524	11.4	417	1000	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	6	525	11.4	453	1325	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	526	11.4	414	950	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	527	11.4	453	1375	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	528	11.4	433	1150	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	529	11.4	466	1325	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	530	11.4	472	1550	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	531	12.7	500	1950	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	532	12.7	447	1250	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	533	12.7	435	1175	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	534	12.7	405	875	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Northern Pike	6		11.4	750	3000	N	Unknown	NA	N		Good	
Northern Pike	6		7.6	774	3750	N	Unknown	NA	N		Good	
Northern Pike	6		8.9	625	1700	N	Unknown	NA	N		Good	
Round Whitefish	6		11.4	357	400		Unknown	NA			Good	
Round Whitefish	6		6.4	356	400		Unknown	NA			Good	
Lake Trout	7	64	7.6	565	2150	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Trout	7	65	11.4	610	3225	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	7	535	7.6	339	475	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	536	7.6	449	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	537	7.6	472	1400	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	538	7.6	466	1300	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	7	539	7.6	450	1150	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	540	7.6	473	1450	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	7	541	7.6	361	550	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	542	7.6	427	1025	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	543	7.6	462	1375	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	544	10.2	433	1100	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	545	10.2	435	1150	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	546	10.2	524	2000	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	7	547	10.2	467	1275	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	7	548	10.2	476	1525	Y	Female	Mature (spawner)	Y		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	7	549	8.9	487	1525	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	7	550	8.9	440	1250	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	7	551	8.9	429	1100	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	552	8.9	413	950	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	553	8.9	492	1550	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	554	8.9	441	1300	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	7	555	8.9	403	1000	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	556	8.9	457	1300	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	557	8.9	456	1150	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	558	8.9	479	1400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	559	12.7	478	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	7	560	12.7	472	1575	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	7	561	12.7	572	2850	Y	Unknown	NA	N		Good	
Lake Whitefish	7	562	12.7	474	1575	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	563	12.7	436	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	564	6.4	487	1450	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	565	6.4	454	1275	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	566	6.4	456	1350	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	567	6.4	450	1150	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	568	11.4	456	1375	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	569	11.4	477	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	7	570	11.4	453	1200	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	7	571	11.4	476	1525	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	7	572	11.4	472	1450	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	7	573	11.4	461	1300	Y	Female	Mature (spawner)	N		Dead	
Northern Pike	7	101	3.8	790	3625	Y	Male	Mature (non-spawner, resting)	N	1 sculpin, 1 LWF	Dead	
Northern Pike	7	102	3.8	670	2075	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	103	3.8	789	3675	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	104	6.4	644	2000	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	105	6.4	610	1575	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	106	7.6	635	1675	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	107	7.6	747	3025	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	108	7.6	771	3300	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	109	8.9	829	4075	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	110	10.2	769	2850	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	111	10.2	725	2600	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	7	112	12.7	892	6000	Y	Female	Mature (non-spawner, resting)	N		Dead	
Northern Pike	7		12.7	780	3500	N	Unknown	NA	N		Good	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Northern Pike	7		10.2	655	2300	N	Unknown	NA	N		Good	
Northern Pike	7		12.7	673	2475	N	Unknown	NA	N		Good	
Northern Pike	7		11.4	863	4900	N	Unknown	NA	N		Good	
Northern Pike	7		6.4	605	1600	N	Unknown	NA	N		Good	
Northern Pike	7		11.4	680	2400	N	Unknown	NA	N		Good	
Northern Pike	7		3.8			N	Unknown	NA	N		Good	
Northern Pike	7		6.4	548	1475	N	Unknown	NA	N		Good	
Lake Trout	8		3.8	619	3100	N	Unknown	NA	N		Good	
Lake Whitefish	8	104	3.8	438	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	105	3.8	443	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	106	11.4	484	1600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	107	11.4	483	1400	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	108	11.4	477	1700	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	109	11.4	498	1900	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	110	11.4	489	1700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	111	11.4	466	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	112	11.4	486	1800	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	113	11.4	459	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	114	7.6	516	1900	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	115	7.6	499	2000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	116	7.6	499	1700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	117	7.6	542	1900	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	118	10.2	484	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	119	10.2	448	1400	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	120	10.2	484	1700	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	8	121	10.2	477	1500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	122	10.2	489	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	123	10.2	449	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	124	10.2	475	1700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	125	10.2	414	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	126	10.2	476	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	127	10.2	498	1800	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	128	10.2	444	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	129	10.2	491	1700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	130	12.7	489	1700	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	131	12.7	481	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	132	12.7	462	1600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	133	12.7	477	1700	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	8	134	6.4	486	1800	Y	Female	Mature (spawner)	Y		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	8	135	6.4	427	1000	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	136	6.4	468	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	137	6.4	451	1500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	8	138	6.4	500	2200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	139	6.4	464	1900	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	140	6.4	443	1400	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	8	141	8.9	450	1500	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	8	142	8.9	450	1400	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	8	143	8.9	472	1800	Y	Female	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	8	144	8.9	476	1300	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	8	145	8.9	459	1500	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	8	146	8.9	460	1500	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	8	147	8.9	428	1000	Y	Male	Immature (virgin)	?		Dead	
Lake Whitefish	8	148	8.9	475	1800	Y	Male	Mature (non-spawner, resting)	?		Dead	
Northern Pike	8	1	3.8	614	1700	Y	Male	Mature (spawner)	N	empty	Dead	
Northern Pike	8	2	3.8	199	58	Y	Unknown	Immature (sex unknown)	N	8 burbot	Dead	
Northern Pike	8	3	11.4	670	1500	Y	Male	Mature (spawner)	N	empty	Dead	
Northern Pike	8	4	7.6	682	1500	Y	Female	Mature (spawner)	N	unidentifiable fish	Dead	
Northern Pike	8	5	7.6	609	1800	Y	Female	Mature (spawner)	N	LWF	Dead	
Northern Pike	8	6	7.6	564	1400	Y	Male	Mature (spawner)	N	empty	Dead	tapeworms
Northern Pike	8	7	7.6	605	1700	Y	Male	Mature (spawner)	N	unidentifiable fish	Dead	tapeworms
Northern Pike	8	8	7.6	524	1200	Y	Male	Mature (spawner)	N	unidentifiable fish	Dead	tapeworms
Northern Pike	8	9	10.2	596	1600	Y	Male	Mature (spawner)	N	unidentifiable fish	Dead	tapeworms
Northern Pike	8	10	6.4	555	1500	Y	Male	Immature (virgin)	N	unidentifiable fish	Dead	
Northern Pike	8	11	6.4	481	1000	Y	Male	Mature (spawner)	N	slimy sculpin	Dead	
Northern Pike	8	12	6.4	426	700	Y	Female	Mature (non-spawner, resting)	N	unidentifiable fish	Dead	tapeworms
Northern Pike	8	13	8.9	636	2200	Y	Male	Mature (spawner)	N	unidentifiable fish	Dead	
Northern Pike	8	14	8.9	675	2500	Y	Female	Mature (spawner)	N	empty	Dead	tapeworms
Northern Pike	8	15	8.9	822	4000	Y	Female	Mature (spawner)	N	empty	Dead	tapeworms
Lake Whitefish	9	149	11.4	488	1700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	9	150	11.4	454	1600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	9	151	11.4	473	1600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	9	152	11.4	482	1500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	9	153	11.4	500	2100	Y	Male	Mature (spawner)	Y		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	9	154	11.4	418	1300	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	9	155	11.4	554	2700	Y	Unknown	Immature (sex unknown)	N		Dead	
Lake Whitefish	9	156	8.9	496	1700	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	157	8.9	455	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	158	8.9	490	2000	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	159	8.9	475	1500	Y	Female	Mature (spawner)	N		Dead	1 otolith sampled
Lake Whitefish	9	160	8.9	466	1600	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	9	161	10.2	465	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	162	10.2	455	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	163	10.2	480	1800	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	164	10.2	471	1800	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	9	165	10.2	483	1700	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	9	166	10.2	463	1900	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	167	10.2	457	1300	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	168	3.8	456	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	9	169	3.8	522	2200	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	9	170	11.4	464	1800	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	171	11.4	498	1800	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	172	11.4	457	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	173	11.4	473	1700	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	9	174	11.4	479	1600	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	9	175	11.4	495	2000	Y	Female	Mature (spawner)	N		Dead	
Northern Pike	9	16	11.4	750	3200	Y	Male	Mature (spawner)	N	empty	Dead	
Northern Pike	9	17	11.4	613	2000	Y	Male	Mature (spawner)	N	empty	Dead	
Northern Pike	9	18	11.4	643	2100	Y	Male	Mature (spawner)	N	empty	Dead	tapeworms
Northern Pike	9	19	11.4	646	2000	Y	Female	Mature (spawner)	N	unidentifiable fish	Dead	
Northern Pike	9	20	11.4	554	1500	Y	Male	Immature (virgin)	N	empty	Dead	tapeworms
Northern Pike	9	21	11.4	591	1700	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	tapeworms
Northern Pike	9	22	8.9	769	3600	Y	Male	Mature (spawner)	N	unidentifiable fish	Dead	
Northern Pike	9	23	8.9	599	1700	Y	Female	Mature (non-spawner, resting)	N	unidentifiable fish	Dead	tapeworms
Northern Pike	9	24	8.9	618	1600	Y	Female	Mature (spawner)	N	unidentifiable fish	Dead	tapeworms
Northern Pike	9	25	8.9	532	1400	Y	Male	Immature (virgin)	N	burbot	Dead	
Northern Pike	9	26	8.9	560	1500	Y	Male	Mature (spawner)	N	unidentifiable fish	Dead	
Northern Pike	9	27	8.9	738	3000	Y	Male	Mature (spawner)	N	empty	Dead	tapeworms

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Northern Pike	9	28	8.9	541	1400	Y	Male	Mature (spawner)	N	unidentifiable fish	Dead	
Northern Pike	9	29	8.9	530	1300	Y	Male	Immature (virgin)	N	empty	Dead	
Northern Pike	9	30	8.9	542	1300	Y	Female	Mature (non-spawner, resting)	N	unidentifiable fish	Dead	tapeworms
Northern Pike	9	31	7.6	545	1300	Y	Female	Immature (virgin)	N	empty	Dead	tapeworms
Northern Pike	9	32	7.6	616	1800	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	tapeworms
Northern Pike	9	33	7.6	698	2800	Y	Male	Mature (spawner)	N	empty	Dead	tapeworms
Northern Pike	9	34	7.6	600	1800	Y	Female	Mature (spawner)	N	empty	Dead	tapeworms
Northern Pike	9	35	7.6	609	1800	Y	Male	Mature (spawner)	N	empty	Dead	tapeworms
Northern Pike	9	36	7.6	522	1500	Y	Male	Immature (virgin)	N	empty	Dead	
Northern Pike	9	37	7.6	597	1500	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	tapeworms
Northern Pike	9	38	7.6	562	1500	Y	Male	Mature (spawner)	N	empty	Dead	
Northern Pike	9	39	7.6	557	1300	Y	Male	Mature (spawner)	N	unidentifiable fish	Dead	tapeworms
Northern Pike	9	40	7.6	762	3200	Y	Female	Mature (spawner)	N	empty	Dead	
Northern Pike	9	113	10.2	835	4600	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	9	114	10.2	560	1300	Y	Female	Mature (non-spawner, resting)	N	unidentifiable fish	Dead	
Northern Pike	9	115	10.2	745	2875	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	9	116	10.2	705	2600	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	9	117	10.2	575	1425	Y	Male	Mature (non-spawner, resting)	N	LWF	Dead	
Northern Pike	9	118	10.2	557	1375	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	9	119	3.8	536	1125	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	9	120	6.4	544	1175	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	9	121	6.4	560	1250	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	9	122	6.4	596	1700	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	9	123	6.4	555	1325	Y	Male	Mature (non-spawner, resting)	N	LWF	Dead	
Northern Pike	9	124	6.4	663	2200	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	9	125	6.4	625	1650	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Arctic Grayling	10	2	6.4	277	200	Y	Male	Mature (spawner)	N		Dead	
Lake Trout	10		12.7	544	2100	N	Unknown	NA	N		Good	
Lake Trout	10		6.4	500	1500	N	Unknown	NA	N		Good	
Lake Trout	10		7.6	610	3500	N	Unknown	NA	N		Good	
Lake Trout	10		8.9	690	3400	N	Unknown	NA	N		Good	
Lake Whitefish	10	214	12.7	495	1600	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	215	12.7	431	1100	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	216	12.7	483	1700	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	217	11.4	476	1400	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	10	218	12.7	500	1700	Y	Male	Mature (non-spawner, resting)	N		Dead	

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Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	10	219	12.7	493	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	220	12.7	457	1100	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	221	12.7	467	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	222	12.7	476	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	223	11.4	482	1400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	224	8.9	495	2000	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	225	8.9	404	1200	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	226	8.9	526	1700	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	227	8.9	443	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	228	8.9	462	1400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	229	8.9	447	1100	Y	Female	Mature (spawner)	N		Dead	1 otolith sampled
Lake Whitefish	10	230	8.9	424	1200	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	231	3.8	474	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	232	3.8	423	1100	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	233	3.8	162	44	Y	Unknown	Immature (sex unknown)	N		Dead	
Lake Whitefish	10	234	3.8	151	43	Y	Unknown	Immature (sex unknown)	N		Dead	
Lake Whitefish	10	235	10.2	479	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	236	10.2	463	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	237	10.2	463	1100	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	238	10.2	443	1100	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	239	10.2	510	1800	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	240	10.2	451	700	Y	Male	Mature (spawner)	N		Dead	
Lake Whitefish	10	241	10.2	422	1000	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	242	10.2	418	1000	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	243	10.2	442	1100	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	244	10.2	472	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	245	10.2	464	1000	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	246	11.4	440	1000	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	247	11.4	495	1500	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	248	11.4	489	1500	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	10	249	11.4	450	1000	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	10	250	11.4	453	1000	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	10	251	11.4	490	1500	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	10	252	11.4	467	1400	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	10	253	11.4	503	1700	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	10	254	11.4	440	1100	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	10	255	11.4	450	1200	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	10	256	11.4	443	1200	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	10	257	11.4	479	1400	Y	Male	Mature (spawner)	?		Dead	

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Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	10	258	11.4	422	1100	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	10	639	7.6	470	1375	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	640	7.6	467	1400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	641	7.6	493	1775	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	642	7.6	418	1025	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	643	7.6	427	1150	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	644	7.6	449	1100	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	645	7.6	448	1300	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	646	7.6	490	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	647	7.6	456	1350	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	10	648	7.6	423	1000	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	649	7.6	434	1125	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	650	7.6	442	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	10	651	7.6	459	1375	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	10	652	7.6	454	1200	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	10	653	6.4	435	1075	Y	Female	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	10	654	6.4	446	1200	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	10	655	6.4	440	1050	Y	Female	Mature (non-spawner, resting)	?		Dead	
Northern Pike	10	126	6.4	773	3725	Y	Female	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	10	40	3.8	207	73	Y	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	10	49	6.4	256	400	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	10	50	6.4	350	300	Y	Male	Mature (spawner)	?		Dead	
Round Whitefish	10	51	6.4	363	500	Y	Female	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	52	6.4	362	400	Y	Male	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	53	6.4	360	500	Y	Female	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	54	6.4	379	500	Y	Male	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	55	6.4	382	500	Y	Female	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	56	6.4	361	500	Y	Male	Mature (non-spawner, resting)	?		Dead	same sample # for 2 fish
Round Whitefish	10	56	6.4	360	400	Y	Female	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	57	6.4	363	475	Y	Male	Mature (non-spawner, resting)	?		Dead	same sample # for 2 fish
Round Whitefish	10	57	6.4	341	400	Y	Male	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	58	6.4	367	500	Y	Female	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	58	6.4	372	525	Y	Female	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	59	6.4	362	500	Y	Female	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	59	6.4	353	400	Y	Female	Mature (spawner)	?		Dead	same sample # for 2 fish
Round Whitefish	10	60	6.4	363	500	Y	Female	Mature (spawner)	?		Dead	
Round Whitefish	10	61	6.4	340	400	Y	Female	Mature (spawner)	?		Dead	
Arctic Grayling	11	1	6.4	312	300	Y	Female	Mature (spawner)	N		Dead	
Burbot	11		6.4	374	400	N	Unknown	NA	N		Good	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Burbot	11		3.8	235		N	Unknown	NA	N		Good	
Lake Trout	11	8	11.4	608	2200	Y	Female	Immature (virgin)	N	burbot	Dead	
Lake Trout	11	9	12.7	595	2600	Y	Female	Mature (spawner)	N		Dead	
Lake Trout	11	10	12.7	587	2100	Y	Male	Immature (virgin)	N	unidentifiable fish	Dead	
Lake Trout	11	11	7.6	476	1300	Y	Female	Immature (virgin)	N	slimy sculpin	Dead	
Lake Trout	11		3.8	330	350	N	Unknown	NA	N		Good	
Lake Trout	11		12.7	520	2000	N	Unknown	NA	N		Good	
Lake Trout	11		6.4	573	2400	N	Unknown	NA	N		Good	
Lake Whitefish	11	176	10.2	468	1400	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	177	10.2	463	1600	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	11	178	10.2	487	1400	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	179	10.2	448	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	180	10.2	458	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	181	10.2	440	1100	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	182	10.2	444	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	183	10.2	437	1000	N	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	184	11.4	473	1600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	185	11.4	444	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	186	11.4	476	1600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	187	11.4	446	1100	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	188	11.4	485	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	189	11.4	466	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	190	11.4	473	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	191	11.4	470	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	192	11.4	473	1100	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	11	193	11.4	435	900	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	194	11.4	488	1400	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	11	195	11.4	463	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	196	11.4	510	1600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	197	11.4	432	1100	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	198	11.4	495	1500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	199	11.4	450	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	200	6.4	463	1000	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	201	6.4	475	1300	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	202	6.4	460	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	203	12.7	494	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	204	12.7	510	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	205	12.7	464	1300	Y	Male	Mature (non-spawner, resting)	Y		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	11	206	3.8	432	1000	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	11	207	3.8	405	800	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	11	208	8.9	434	1200	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	11	209	7.6	409	900	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	11	210	7.6	430	1000	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	11	211	7.6	445	1200	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	11	212	7.6	443	1100	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	11	213	7.6	433	1300	Y	Female	Mature (spawner)	N		Dead	1 otolith sampled
Northern Pike	11	41	10.2	960	6300	Y	Female	Mature (spawner)	N	empty	Dead	
Northern Pike	11	42	10.2	796	3500	Y	Female	Mature (spawner)	N	empty	Dead	
Northern Pike	11	43	10.2	813	4500	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	tapeworms
Northern Pike	11	44	8.9	805	4100	Y	Female	Mature (spawner)	N	empty	Dead	1 cleithra, tapeworms
Northern Pike	11	45	8.9	724	3000	Y	Female	Mature (spawner)	N		Dead	
Northern Pike	11	46	8.9	833	3700	Y	Female	Mature (spawner)	N	burbot	Dead	
Northern Pike	11	47	8.9	721	3100	Y	Female	Mature (spawner)	N		Dead	
Northern Pike	11	48	8.9	836	4600	Y	Female	Mature (spawner)	N	empty	Dead	
Northern Pike	11	49	7.6	832	4300	Y	Female	Mature (spawner)	N		Dead	
Round Whitefish	11	32	6.4	350	300	Y	Male	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	11	33	6.4	314	200	Y	Female	Mature (non-spawner, resting)	N		Dead	1 otolith sampled
Round Whitefish	11	34	6.4	415	700	Y	Female	Mature (spawner)	N		Dead	
Round Whitefish	11	35	6.4	373	500	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	11	36	6.4	351	400	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	11	37	6.4	372	500	Y	Female	Mature (spawner)	N		Dead	
Round Whitefish	11	38	6.4	342	200	Y	Female	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	11	39	6.4	380	500	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	11	40	6.4	346	500	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	11	41	6.4	344	400	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	11	42	6.4	355	400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	11	43	6.4	355	400	Y	Female	Mature (spawner)	N		Dead	1 otolith sampled
Round Whitefish	11	44	6.4	352	300	Y	Female	Mature (spawner)	N		Dead	
Round Whitefish	11	45	3.8	232	108	Y	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	11	46	3.8	303	300	Y	Male	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	11	47	3.8	365	500	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	11	48	3.8	207	73	Y	Unknown	Immature (sex unknown)	N		Dead	
Lake Trout	12	66	3.8	190	100	Y	Male	Immature (virgin)	N	1 LWF	Dead	
Lake Trout	12	67	10.2	573	2275	Y	Male	Mature (spawner)	N	empty	Dead	
Lake Trout	12	68	11.4	663	2925	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Trout	12	69	11.4	588	825	Y	Male	Mature (spawner)	N	snails	Dead	
Lake Trout	12	70	12.7	610	2350	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Trout	12		7.6	655	3200	N	Unknown	NA	N		Good	
Lake Trout	12		12.7	555	2200	N	Unknown	NA	N		Good	
Lake Trout	12		11.4	610	2300	N	Unknown	NA	N		Good	
Lake Whitefish	12	574	3.8	469	1700	Y	Female	Mature (spawner)	?		Dead	
Lake Whitefish	12	575	8.9	453	1325	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Whitefish	12	576	8.9	443	1150	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	577	8.9	426	1025	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	578	8.9	473	1375	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	579	8.9	447	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	580	8.9	446	1275	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	581	8.9	447	1275	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	582	10.2	454	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	583	10.2	469	1575	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	584	10.2	452	1375	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	12	585	10.2	453	1250	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	586	10.2	477	1500	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	587	10.2	469	1300	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	588	10.2	463	1225	Y	Male	NA	Y		Good	
Lake Whitefish	12	589	10.2	471	1475	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	590	10.2	477	1325	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	591	10.2	482	1600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	592	10.2	463	1475	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	593	10.2	480	1525	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	594	10.2	468	1375	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	595	10.2	485	1450	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	596	10.2	444	1275	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	597	10.2	448	1250	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	598	7.6	464	1350	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	599	7.6	452	1150	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	600	7.6	447	1225	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	601	7.6	484	1475	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	602	7.6	446	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	603	11.4	458	1350	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	604	11.4	498	1650	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	605	11.4	478	1400	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	606	11.4	493	1575	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	607	11.4	473	1475	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	608	11.4	464	1450	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	609	11.4	468	1600	Y	Female	Mature (spawner)	N		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	12	610	11.4	498	1650	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	12	611	6.4	462	1400	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	12	612	12.7	491	1725	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	12	613	12.7	498	1700	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	12	614	12.7	490	1675	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	12	615	12.7	496	1675	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	12	616	12.7	516	1825	Y	Male	Mature (non-spawner, resting)	N		Dead	
Longnose Sucker	12		8.9	388	650		Unknown	NA	N		Good	
Round Whitefish	12		6.4	352	550		Unknown	NA			Good	
Round Whitefish	12		6.4	410	725		Unknown	NA			Good	
Round Whitefish	12		6.4	345	400		Unknown	NA			Good	
Round Whitefish	12		6.4	370	500		Unknown	NA			Good	
Round Whitefish	12		6.4	367	450		Unknown	NA			Good	
Round Whitefish	12		6.4	357	550		Unknown	NA			Good	
Round Whitefish	12		7.6	385	700		Unknown	NA			Good	
Round Whitefish	12		6.4	360	475		Unknown	NA			Good	
Round Whitefish	12		3.8	235	100		Unknown	NA			Good	
Round Whitefish	12		6.4	354	550		Unknown	NA			Good	
Lake Trout	13	71	12.7	444	1150	Y	Male	Immature (virgin)	N	LWF, sculpins	Dead	
Lake Trout	13	72	11.4	513	1550	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Trout	13	73	7.6	423	875	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Trout	13	74	8.9	502	1750	Y	Male	Mature (spawner)	N		Dead	
Lake Trout	13		6.4	500	1700	N	Unknown	NA	N		Good	
Lake Trout	13		11.4	562	2600	N	Unknown	NA	N		Good	
Lake Trout	13		8.9	565	2600	N	Unknown	NA	N		Good	
Lake Trout	13		6.4	576	2300	N	Unknown	NA	N		Good	
Lake Trout	13		7.6	413	1000	N	Unknown	NA	N		Good	
Lake Whitefish	13	617	6.4	470	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	618	12.7	473	1475	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	619	11.4	516	1950	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	620	11.4	489	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	13	621	11.4	482	1500	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	622	7.6	473	1950	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	13	623	7.6	480	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	13	624	10.2	467	1400	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	13	625	10.2	489	1650	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	626	10.2	463	1450	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	627	10.2	500	1725	Y	Male	Mature (non-spawner, resting)	N		Dead	

TABLE 3: AISHIHIK LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	13	628	10.2	467	1350	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	629	10.2	457	1225	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	630	8.9	447	1325	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	631	8.9	454	1275	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	632	8.9	419	1000	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	13	633	8.9	462	1350	Y	Female	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	634	8.9	499	1800	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Whitefish	13	635	8.9	495	1700	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	13	636	8.9	463	1300	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	13	637	8.9	472	1375	Y	Female	Mature (spawner)	N		Dead	
Lake Whitefish	13	638	8.9	463	1375	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	13		6.4	352	600		Unknown	NA	N		Good	
Round Whitefish	13	53	3.8	230	125	Y	Unknown	Immature (sex unknown)	?		Dead	same sample # for 2 fish
Round Whitefish	13	54	3.8	230	100	Y	Unknown	Immature (sex unknown)	?		Dead	same sample # for 2 fish
Round Whitefish	13	55	3.8	270	100	Y	Unknown	Immature (sex unknown)	?		Dead	same sample # for 2 fish
Round Whitefish	13		6.4	337	475		Unknown	NA			Good	
Round Whitefish	13		6.4	371	600		Unknown	NA			Good	
Round Whitefish	13		8.9	355	550		Unknown	NA			Good	
Round Whitefish	13		8.9	357	475		Unknown	NA			Good	
Round Whitefish	13		6.4	370	600		Unknown	NA			Good	
Round Whitefish	13		8.9	363	550		Unknown	NA			Good	
Round Whitefish	13		6.4	336	400		Unknown	NA			Good	
Round Whitefish	13		6.4	342	500		Unknown	NA			Good	
Round Whitefish	13		6.4	337	400		Unknown	NA			Good	
Round Whitefish	13		6.4	382	575		Unknown	NA			Good	
Round Whitefish	13		6.4	355	525		Unknown	NA			Good	

3.3 Canyon Lake Fish Data

Table 4 details all data collected from all fish captured in Canyon Lake. Fish captured are listed numerically by gillnetting site and then by species in alphabetical order.

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	1	1	6.4	340	500	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	1	2	6.4	340	500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	1	4	6.4	315	400	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	1	6	8.9	440	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	1	10	6.4	410	810	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	1	11	6.4	435	1150	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	1	12	6.4	385	700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	1	13	6.4	355	625	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	1	14	6.4	365	600	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	1	15	6.4	360	600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	1	16	6.4	295	320	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	1	17	6.4	345	475	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	1	18	6.4	280	300	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	1	19	6.4	300	300	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	1	20	6.4	290	310	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	1	21	6.4	305	300	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	1	22	6.4	320	350	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	1	23	10.2	410	900	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	1	27	11.4	500	2000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	1	28	11.4	450	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	1		6.4	355		N	Unknown	NA	Y		Good	
Longnose Sucker	1	5	6.4	425	775	Y	Male	NA	N		Dead	
Longnose Sucker	1	8	8.9	430	950	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	1	9	8.9	470	1400	Y	Male	Mature (spawner)	N		Dead	
Longnose Sucker	1	24	10.2	440	1000	Y	Male	Mature (spawner)	N		Dead	
Longnose Sucker	1		8.9	350		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	370		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	415		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	420		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	425		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	435		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	435		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	435		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	440		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	440		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	445		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	450		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	460		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	470		N	Unknown	NA	N		Good	
Longnose Sucker	1		8.9	470		N	Unknown	NA	N		Good	
Longnose Sucker	1		10.2	405		N	Unknown	NA	N		Good	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Longnose Sucker	1		10.2	405		N	Unknown	NA	N		Good	
Longnose Sucker	1		10.2	420		N	Unknown	NA	N		Good	
Longnose Sucker	1		10.2	435		N	Unknown	NA	N		Good	
Longnose Sucker	1		10.2	450		N	Unknown	NA	N		Good	
Longnose Sucker	1		10.2	450		N	Unknown	NA	N		Good	
Longnose Sucker	1		10.2	475		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	385		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	430		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	440		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	440		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	440		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	445		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	450		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	455		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	455		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	455		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	455		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	460		N	Unknown	NA	N		Good	
Longnose Sucker	1		11.4	470		N	Unknown	NA	N		Good	
Northern Pike	1	7	8.9	720	3100	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	1	25	11.4	740	3150	Y	Female	Mature (spawner)	Y		Dead	
Northern Pike	1	26	12.7	780	3750	Y	Female	Mature (spawner)	Y		Dead	
Northern Pike	1		12.7	745		N	Unknown	NA	N		Good	
Round Whitefish	1	3	6.4	320	400	N	Female	Mature (spawner)	Y		Dead	
Round Whitefish	1		3.8	245		N	Unknown	NA	N		Good	
Lake Trout	2		6.4	570		N	Unknown	NA	N		Good	
Lake Whitefish	2	4	10.2	435	1000	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	9	10.2	460	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	10	6.4	460	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	14	6.4	292	300	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	2	54	7.6	364	600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	55	7.6	367	600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	2	56	7.6	347	500	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	2	57	11.4	453	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	2	58	12.7	545	2400	Y	Female	Mature (spawner)	Y		Dead	
Longnose Sucker	2	3	8.9	400	900	Y	Male	NA	N		Dead	
Longnose Sucker	2	6	10.2	415	1100	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	2	7	10.2	461	1300	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	2	19	6.4	305	300	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	20	6.4	313	400	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	21	6.4	283	300	Y	Unknown	Immature (sex unknown)	N		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Longnose Sucker	2	29	3.8	208	100	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	30	3.8	215	101	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	40	3.8	155	45	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	41	3.8	170	54	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	42	3.8	164	48	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	43	3.8	162	51	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	44	3.8	150	44	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	45	3.8	154	43	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	46	3.8	147	41	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	47	3.8	142	34	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	52	8.9	366	700	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	2	53	7.6	332	400	Y	Female	Mature (non-spawner, resting)	N		Dead	
Longnose Sucker	2	470	11.4			N	Unknown	NA	N		Good	
Longnose Sucker	2		6.4	340		N	Unknown	NA	N		Good	
Longnose Sucker	2		11.4	460		N	Unknown	NA	N		Good	
Longnose Sucker	2		6.4	480		N	Unknown	NA	N		Good	
Longnose Sucker	2		3.8	160		N	Unknown	NA	N		Good	
Longnose Sucker	2		3.8	195		N	Unknown	NA	N		Good	
Longnose Sucker	2		8.9	455		N	Unknown	NA	N		Good	
Longnose Sucker	2		3.8	225		N	Unknown	NA	N		Good	
Longnose Sucker	2		11.4	485		N	Unknown	NA	N		Good	
Longnose Sucker	2		7.6	415		N	Unknown	NA	N		Good	
Longnose Sucker	2		6.4	380		N	Unknown	NA	N		Good	
Longnose Sucker	2		6.4	290		N	Unknown	NA	N		Good	
Longnose Sucker	2		3.8	280		N	Unknown	NA	N		Good	
Longnose Sucker	2		10.2	430		N	Unknown	NA	N		Good	
Longnose Sucker	2		8.9	475		N	Unknown	NA	N		Good	
Longnose Sucker	2		6.4	420		N	Unknown	NA	N		Good	
Longnose Sucker	2		3.8	390		N	Unknown	NA	N		Good	
Longnose Sucker	2		8.9	480		N	Unknown	NA	N		Good	
Longnose Sucker	2		10.2	440		N	Unknown	NA	N		Good	
Longnose Sucker	2		8.9	440		N	Unknown	NA	N		Good	
Longnose Sucker	2		10.2	375		N	Unknown	NA	N		Good	
Northern Pike	2	1	7.6	675	2500	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	2	5	10.2	712	2900	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	2	8	10.2	753	3400	Y	Female	Mature (spawner)	Y		Dead	
Northern Pike	2	48	8.9	554	5000	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	2	49	8.9	664	7000	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	2	50	8.9	645	2400	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	2	51	8.9	550	1300	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	2		7.6	770		N	Unknown	NA	N		Good	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Round Whitefish	2		3.8	245		N	Unknown	NA	N		Good	
Round Whitefish	2	11	6.4	330	400	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	2	12	6.4	355	500	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	2	13	6.4	310	300	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	15	6.4	330	400	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	16	6.4	310	300	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	17	6.4	315	300	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	18	6.4	304	300	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	22	3.8	265	200	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	23	3.8	184	75	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	24	3.8	290	200	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	2	25	3.8	264	200	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	2	26	3.8	236	120	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	27	3.8	231	120	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	2	28	3.8	250	143	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	31	3.8	205	76	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	32	3.8	175	62	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	33	3.8	230	111	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	34	3.8	186	65	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	35	3.8	179	64	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	36	3.8	125	82	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	37	3.8	181	62	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	38	3.8	180	58	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	2	39	3.8	162	45	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Trout	3		8.9	695		N	Unknown	NA	N		Good	
Lake Trout	3		8.9	745		N	Unknown	NA	N		Good	
Lake Whitefish	3	3	6.4	472	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	3	4	6.4	469	1525	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	3	5	6.4	426	1025	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	3	6	6.4	441	1225	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	3	12	10.2	466	1550	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	3	13	10.2	461	1450	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	3	14	10.2	433	1275	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	3	15	10.2	419	1050	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	3	18	11.4	537	2625	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	3	19	11.4	498	1800	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	3	20	11.4	446	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	3	21	11.4	467	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	3	22	11.4	434	1050	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Longnose Sucker	3	1	6.4	435	975	Y	Male	Mature (non-spawner, resting)	N		Dead	
Longnose Sucker	3	8	6.4	265	300	Y	Male	Immature (virgin)	N		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Longnose Sucker	3	9	3.8	303	325	Y	Male	Immature (virgin)	N		Dead	
Longnose Sucker	3	10	3.8	281	275	Y	Male	Immature (virgin)	N		Dead	
Longnose Sucker	3	11	10.2	398	850	Y	Male	Spent	N		Dead	
Longnose Sucker	3		6.4	465		N	Unknown	NA	N		Good	
Longnose Sucker	3		6.4	465		N	Unknown	NA	N		Good	
Longnose Sucker	3		6.4	468		N	Unknown	NA	N		Good	
Round Whitefish	3	2	6.4	295	275	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	3	7	6.4	304	300	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	3	16	3.8	238	125	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	3	17	3.8	238	125	Y	Male	Immature (virgin)	Y		Dead	
Lake Trout	4	26	11.4	581	3300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	4	2	8.9	400	800	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	4	4	8.9	390	800	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	4	11	7.6	365	600	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	4	12	7.6	412	1000	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	4	13	7.6	334	500	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	4	14	10.2	446	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	4	19	6.4	434	1100	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	4	20	6.4	410	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	4	21	6.4	353	600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	4	22	6.4	350	500	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	4	24	6.4	417	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	4	25	11.4	470	1600	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Longnose Sucker	4	9	8.9	454	1000	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	4	17	10.2	490	1500	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	4	18	10.2	449	1000	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	4		3.8	267		N	Unknown	NA	N		Good	
Longnose Sucker	4		3.8	467		N	Male	NA	N		Good	
Longnose Sucker	4		12.7	467		N	Unknown	NA	N		Good	
Longnose Sucker	4		7.6	450		N	Unknown	NA	N		Good	
Northern Pike	4	1	8.9	758	3400	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	4	3	8.9	775	3500	Y	Female	Mature (spawner)	Y		Dead	
Northern Pike	4	5	8.9	774	3400	Y	Female	Mature (spawner)	Y		Dead	
Northern Pike	4	6	8.9	772	3700	Y	Female	Mature (spawner)	Y		Dead	
Northern Pike	4	7	8.9	825	4200	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	4	8	8.9	555	1400	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Northern Pike	4	10	12.7	735	3300	Y	Female	Mature (spawner)	Y		Dead	
Northern Pike	4	15	10.2	754	3300	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	4	16	10.2	850	4500	Y	Female	Mature (spawner)	Y		Dead	
Northern Pike	4		8.9	810		N	Unknown	NA	N		Good	
Northern Pike	4		10.2	870		N	Unknown	NA	N		Good	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Round Whitefish	4	23	6.4	315	400	Y	Female	Mature (spawner)	?		Dead	
Round Whitefish	4	27	3.8	204	77	Y	Unknown	Immature (sex unknown)	?		Dead	
Round Whitefish	4	28	3.8	210	93	Y	Unknown	Immature (sex unknown)	?		Dead	
Round Whitefish	4	29	3.8	196	66	Y	Unknown	Immature (sex unknown)	?		Dead	
Round Whitefish	4	30	3.8	198	76	Y	Unknown	Immature (sex unknown)	?		Dead	
Round Whitefish	4	31	3.8	197	67	Y	Unknown	Immature (sex unknown)	?		Dead	
Lake Trout	5	9	8.9	587	2300	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Trout	5	19	11.4	495	1300	Y	Female	Immature (virgin)	N	empty	Dead	
Lake Trout	5		6.4	520	1800	N	Unknown	NA	N		Good	
Lake Trout	5		12.7	560	2500	N	Unknown	NA	N		Good	
Lake Trout	5		3.8	681	3300	N	Unknown	NA	N		Good	
Lake Trout	5		10.2	563	2200	N	Unknown	NA	N		Good	
Lake Trout	5		10.2	715	4600	N	Unknown	NA	N		Good	
Lake Whitefish	5	1	7.6	420	1000	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	5	2	7.6	495	1800	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	5	3	7.6	443	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	5	6	8.9	435	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	5	7	8.9	387	700	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	5	8	8.9	368	600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	5	10	6.4	457	1200	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	5	11	6.4	348	400	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	5	12	6.4	359	400	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	5	13	6.4	364	500	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	5	14	6.4	334	400	Y	Female	Immature (virgin)	N	empty	Dead	
Lake Whitefish	5	15	6.4	347	400	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	5	16	6.4	362	500	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	5	17	6.4	330	300	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	5	18	11.4	450	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	5	20	11.4	445	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	5	21	11.4	413	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	5	22	11.4	490	1500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	5	23	11.4	472	1400	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	5	24	11.4	425	1000	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	5	27	10.2	455	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	5	28	10.2	435	1000	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	5	30	3.8	348	400	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	5	33	3.8	193	78	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	5	34	3.8	178	54	Y	Unknown	Immature (sex unknown)	N	empty	Dead	
Lake Whitefish	5	39	3.8	185	65	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	5	40	3.8	170	49	Y	Male	Immature (virgin)	Y		Dead	
Longnose Sucker	5	4	8.9	436	800	Y	Male	Spent	N		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Longnose Sucker	5	5	8.9	505	1300	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	5	25	11.4	474	1300	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	5		6.4	440	1100	N	Unknown	NA	N		Good	
Longnose Sucker	5		11.4	478	1500	N	Unknown	NA	N		Good	
Longnose Sucker	5		8.9	415	1000	N	Unknown	NA	N		Good	
Longnose Sucker	5		10.2	482	1400	N	Unknown	NA	N		Good	
Northern Pike	5	26	11.4	915	4500	Y	Female	Mature (spawner)	N	empty	Dead	
Round Whitefish	5	29	3.8	318	300	Y	Female	Mature (spawner)	N	empty	Dead	
Round Whitefish	5	31	3.8	254	100	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	5	32	3.8	203	68	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	5	35	3.8	204	72	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	5	36	3.8	229	94	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	5	37	3.8	200	74	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	5	38	3.8	196	69	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	6	2	6.4	324	300	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	6	3	6.4	332	400	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	4	6.4	323	300	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	5	6.4	343	500	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	6	6.4	350	500	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	6	7	6.4	414	1000	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	8	6.4	334	400	Y	Female	Immature (virgin)	N	empty	Dead	
Lake Whitefish	6	9	6.4	415	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	10	6.4	435	1200	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	11	6.4	475	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	6	13	12.7	502	1700	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	14	10.2	435	1000	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	21	8.9	412	800	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	6	22	8.9	395	700	Y	Male	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	6	23	8.9	389	600	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	6	29	7.6	368	600	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	6	30	7.6	435	1100	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	6	31	7.6	375	500	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	6	32	7.6	387	700	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	33	7.6	474	1500	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	6	34	7.6	583	3300	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	6	36	3.8	190	70	Y	Unknown	Immature (sex unknown)	N	empty	Dead	
Lake Whitefish	6	55	3.8	190	73	Y	Unknown	Immature (virgin)	Y		Dead	
Lake Whitefish	6	56	3.8	174	57	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	6	57	3.8	185	65	Y	Unknown	Immature (sex unknown)	Y		Dead	
Longnose Sucker	6	16	10.2	418	800	Y	Male	Mature (spawner)	N		Dead	
Longnose Sucker	6	17	10.2	473	1000	Y	Female	Mature (non-spawner, resting)	N		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Longnose Sucker	6	18	10.2	434	1000	Y	Female	Mature (spawner)	N		Dead	
Longnose Sucker	6	19	10.2	427	900	Y	Male	Mature (spawner)	N		Dead	
Longnose Sucker	6	20	10.2	453	1000	Y	Female	Mature (non-spawner, resting)	N		Dead	
Longnose Sucker	6	28	7.6	354	700	Y	Female	Mature (non-spawner, resting)	N		Dead	
Longnose Sucker	6	37	3.8	160	48	Y	Unknown	Immature (sex unknown)	N		Dead	
Northern Pike	6	15	10.2	780	3700	Y	Female	Mature (spawner)	N	empty	Dead	
Northern Pike	6	24	8.9	836	4300	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	6	25	8.9	762	3200	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	tapeworms
Northern Pike	6	26	8.9	802	4200	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Northern Pike	6	27	8.9	935	6200	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Round Whitefish	6	1	6.4	294	300	Y	Female	Mature (spawner)	N	empty	Dead	
Round Whitefish	6	12	6.4	330	400	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	6	35	3.8	179	62	Y	Unknown	Immature (sex unknown)	N	empty	Dead	
Round Whitefish	6	38	3.8	234	129	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	6	39	3.8	250	154	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	6	40	3.8	235	120	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	6	41	3.8	250	200	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	6	42	3.8	223	160	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	6	43	3.8	240	130	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	6	44	3.8	223	113	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	6	45	3.8	212	87	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	6	46	3.8	224	110	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	6	47	3.8	197	68	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	6	48	3.8	259	177	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	6	49	3.8	200	70	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	6	50	3.8	207	75	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	6	51	3.8	207	76	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	6	52	3.8	191	69	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	6	53	3.8	202	70	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	6	54	3.8	195	65	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	6		3.8	192	65	N	Unknown	Immature (sex unknown)	N		Dead	
Burbot	7		3.8	200	100	N	Unknown	NA	N		Good	
Lake Trout	7	26	11.4	495	1700	Y	Male	Mature (spawner)	Y		Dead	
Lake Trout	7	27	7.6	515	1800	Y	Female	Spent	Y		Dead	
Lake Trout	7	45	10.2	572	2523	Y	Male	Mature (spawner)	Y		Dead	
Lake Trout	7	46	8.9	600	3550	Y	Male	Mature (non-spawner, resting)	N		Dead	
Lake Trout	7		11.4	748		N	Unknown	NA	N		Good	
Lake Trout	7		3.8	620	3300	N	Unknown	NA	N		Good	
Lake Trout	7		8.9	642	3700	N	Unknown	NA	N		Good	
Lake Trout	7		3.8	542	1700	N	Unknown	NA	N		Good	
Lake Trout	7		3.8	503	1725	N	Unknown	NA	N		Good	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Trout	7		6.4	760		N	Unknown	NA	N		Good	
Lake Trout	7		6.4	588	2600	N	Unknown	NA	N		Good	
Lake Whitefish	7	1	3.8	240	200	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	16	6.4	360	525	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	7	17	6.4	372	600	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	18	6.4	375	575	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	7	19	6.4	365	650	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	20	6.4	330	425	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	25	6.4	318	325	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	28	7.6	382	725	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	7	29	7.6	390	825	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	30	7.6	370	650	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	31	7.6	350	500	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	7	32	7.6	346	500	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	33	7.6	344	500	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	34	7.6	390	725	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	35	7.6	360	550	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	36	7.6	352	550	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	37	7.6	371	650	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	38	7.6	347	525	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	39	7.6	410	1025	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	40	7.6	362	525	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	41	7.6	370	550	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	42	10.2	448	1325	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	43	10.2	395	850	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	44	10.2	415	950	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	47	8.9	398	700	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	48	8.9	372	700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	49	8.9	403	875	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	7	50	8.9	358	575	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	7	51	8.9	378	600	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	52	8.9	368	625	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	7	53	8.9	368	625	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	7	54	8.9	415	900	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Longnose Sucker	7	15	3.8	135	35	Y	Unknown	NA	N		Dead	
Longnose Sucker	7		3.8	153	100	N	Unknown	NA	N		Good	
Longnose Sucker	7		3.8	155	100	N	Unknown	NA	N		Good	
Longnose Sucker	7		3.8	175	175	N	Unknown	NA	N		Good	
Longnose Sucker	7		3.8	162	125	N	Unknown	NA	N		Good	
Longnose Sucker	7		7.6	410	900	N	Unknown	NA	N		Good	
Longnose Sucker	7					N	Unknown	NA	N		Good	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Longnose Sucker	7		3.8	160	125	N	Unknown	NA	N		Good	
Longnose Sucker	7		3.8	145	100	N	Unknown	NA	N		Good	
Longnose Sucker	7		3.8	330	500	N	Unknown	NA	N		Good	
Longnose Sucker	7		3.8	137	100	N	Unknown	NA	N		Good	
Longnose Sucker	7		3.8	150	125	N	Unknown	NA	N		Good	
Longnose Sucker	7		3.8	175	100	N	Unknown	NA	N		Good	
Longnose Sucker	7		3.8	185	175	N	Unknown	NA	N		Good	
Round Whitefish	7	2	3.8	265	182	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	7	3	3.8	270	188	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	7	4	3.8	258	157	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	7	5	3.8	245	147	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Round Whitefish	7	6	3.8	230	105	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	7	7	3.8	230	101	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	7	8	3.8	198	66	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	7	9	3.8	215	91	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	7	10	3.8	205	77	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	7	11	3.8	193	66	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	7	12	3.8	185	63	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	7	13	3.8	200	68	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	7	14	3.8	194	68	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	7	21	6.4	328	425	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	7	22	6.4	347	450	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	7	23	6.4	300	300	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	7	24	6.4	290	225	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	7		6.4	290	300	N	Unknown	NA	N		Good	
Round Whitefish	7		6.4			N	Unknown	NA	N		Good	
Round Whitefish	7		3.8	224	200	N	Unknown	NA	N		Good	
Round Whitefish	7		3.8	200	200	N	Unknown	NA	N		Good	
Burbot	8	27	3.8	333	193	Y	Male	Immature (virgin)	Y		Dead	
Burbot	8		6.4	330	200	N	Unknown	NA	N		Good	
Lake Whitefish	8	1	10.2	494		Y	Male	Ripe	Y		Dead	
Lake Whitefish	8	2	10.2	427	1075	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	3	10.2	448	1225	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	8	4	10.2	473		Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	6	7.6	403	900	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	7	7.6	436	1275	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	8	7.6	378	650	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	8	9	7.6	400	750	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	10	7.6	470	1600	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	8	11	8.9	470	1500	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	8	13	6.4	373	600	Y	Female	Mature (non-spawner, resting)	Y		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	8	14	6.4	382	650	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	17	6.4	400	850	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	18	6.4	480	1650	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	19	11.4	460	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	8	20	11.4	512	1750	Y	Male	Immature (virgin)	Y		Dead	
Longnose Sucker	8		3.8	275	275	N	Unknown	NA	N		Good	
Longnose Sucker	8		6.4	510		N	Unknown	NA	N		Good	
Longnose Sucker	8		10.2	470	1300	N	Unknown	NA	N		Good	
Longnose Sucker	8		7.6	455	1300	N	Unknown	NA	N		Good	
Longnose Sucker	8		3.8	155	75	N	Unknown	NA	N		Good	
Longnose Sucker	8		6.4	415	900	N	Unknown	NA	N		Good	
Longnose Sucker	8		3.8	165	150	N	Unknown	NA	N		Good	
Longnose Sucker	8		7.6	377	775	N	Unknown	NA	N		Good	
Longnose Sucker	8		6.4	293	350	N	Unknown	NA	N		Good	
Longnose Sucker	8		3.8	170	150	N	Unknown	NA	N		Good	
Northern Pike	8	5	10.2	825	4375	Y	Male	Spent	N	empty	Dead	
Round Whitefish	8	12	6.4	325	400	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	8	15	6.4	295	300	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	8	16	6.4	300	275	Y	Female	Mature (spawner)	Y		Dead	
Round Whitefish	8	21	3.8	270	200	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	8	22	3.8	260	171	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	8	23	3.8	227	105	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	8	24	3.8	224	105	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	8	25	3.8	224	105	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	8	26	3.8	200	72	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	8		3.8	210	150	N	Unknown	NA	N		Good	
Round Whitefish	8		3.8	210	200	N	Unknown	NA	N		Good	
Round Whitefish	8		3.8	200	175	N	Male	NA	N		Good	
Lake Trout	9	1	11.4	699	4400	Y	Male	Mature (spawner)	Y	1 RWF	Dead	
Lake Trout	9	16	10.2	593	2100	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Lake Trout	9		10.2	455	1100	N	Unknown	NA	N		Good	
Lake Whitefish	9	2	8.9	382	700	Y	Male	Immature (virgin)	N	empty	Dead	
Lake Whitefish	9	3	8.9	423	600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	9	4	8.9	380	800	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	9	5	8.9	418	900	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	9	6	8.9	397	700	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	9	7	8.9	424	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	9	8	11.4	445	1400	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	9	9	7.6	402	800	Y	Female	Immature (virgin)	N	empty	Dead	
Lake Whitefish	9	10	7.6	367	700	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	9	11	10.2	414	1000	Y	Female	Mature (spawner)	Y		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	9	12	10.2	416	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	9	13	10.2	407	900	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	9	14	10.2	417	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	9	15	10.2	420	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	9	17	6.4	354	500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	9	18	6.4	323	400	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	9	19	6.4	324	400	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	9	20	6.4	298	300	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	9	23	6.4	349	500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	9	25	6.4	343	400	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	9	26	6.4	398	800	Y	Female	Mature (spawner)	Y		Dead	
Longnose Sucker	9	27	3.8	276	300	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	9	28	3.8	195	76	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	9	29	3.8	154	44	Y	Unknown	Immature (sex unknown)	N		Dead	
Longnose Sucker	9		6.4	250	200	N	Unknown	NA	N		Good	
Round Whitefish	9	21	6.4	295	300	Y	Male	Mature (spawner)	N	empty	Dead	
Round Whitefish	9	24	6.4	277	200	Y	Male	Mature (spawner)	N	empty	Dead	
Round Whitefish	9	30	3.8	198	68	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	9	31	3.8	265	169	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	9	32	3.8	240	124	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Round Whitefish	9	33	3.8	236	115	Y	Male	Immature (virgin)	Y		Dead	
Round Whitefish	9	34	3.8	197	66	Y	Unknown	Immature (sex unknown)	Y		Dead	
Round Whitefish	9	35	3.8	202	69	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	9	36	3.8	193	61	Y	Female	Immature (virgin)	Y		Dead	
Round Whitefish	9	37	3.8	257	152	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	9	38	3.8	201	71	Y	Male	Mature (spawner)	Y		Dead	
Round Whitefish	9	39	3.8	217	95	Y	Female	Immature (virgin)	Y		Dead	
Burbot	10	8	12.7	736	2500	Y	Male	Mature (non-spawner, resting)	?		Dead	
Lake Trout	10	9	12.7	593	2500	Y	Male	Mature (spawner)	N	insetcs	Dead	
Lake Trout	10	10	12.7	808	8100	Y	Male	Mature (spawner)	N	empty	Dead	
Lake Trout	10	31	10.2	548	2300	Y	Male	Mature (spawner)	?		Dead	
Lake Trout	10		3.8	714	5900	N	Unknown	NA	N		Good	
Lake Trout	10		3.8	550	1900	N	Unknown	NA	N		Good	
Lake Whitefish	10	1	7.6	466	1400	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	10	2	7.6	333	500	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	3	7.6	375	700	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	10	4	7.6	368	600	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	5	7.6	350	600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	10	6	7.6	375	700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	10	7	7.6	366	700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	10	11	8.9	439	1040	Y	Female	Mature (spawner)	Y		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	10	12	8.9	445	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	10	13	8.9	444	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	10	14	8.9	371	700	Y	Female	Mature (non-spawner, resting)	N	empty	Dead	
Lake Whitefish	10	15	8.9	363	700	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	16	8.9	380	800	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	18	6.4	362	700	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	19	6.4	356	500	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	10	20	6.4	353	500	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	10	21	6.4	373	800	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	10	22	6.4	371	600	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	10	23	6.4	370	700	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	24	6.4	305	300	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	25	6.4	394	800	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	10	26	6.4	304	300	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	32	10.2	449	1300	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	10	33	10.2	441	1300	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	10	34	10.2	450	1300	Y	Female	Mature (spawner)	N	empty	Dead	
Lake Whitefish	10	35	11.4	465	1600	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	36	3.8	400	1000	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	37	3.8	372	700	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	10	38	3.8	356	600	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	10	39	3.8	193	77	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	10	40	3.8	186	62	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	10	41	3.8	173	55	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	10	42	3.8	194	75	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	10	43	3.8	167	51	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	10	44	3.8	183	66	Y	Unknown	Immature (sex unknown)	Y		Dead	
Longnose Sucker	10	30	6.4	270	300	Y	Unknown	NA	N		Dead	
Longnose Sucker	10		7.6	404	900	N	Unknown	NA	N		Good	
Longnose Sucker	10		7.6	394	800	N	Unknown	NA	N		Good	
Longnose Sucker	10		8.9	464	1200	N	Unknown	NA	N		Good	
Longnose Sucker	10		10.2	489	1300	N	Unknown	NA	N		Good	
Longnose Sucker	10		7.6	390	800	N	Unknown	NA	N		Good	
Northern Pike	10	17	8.9	619	2100	Y	Male	Mature (spawner)	N	identifiable fi	Dead	
Round Whitefish	10	27	6.4	324	400	Y	Female	Mature (spawner)	N		Dead	
Round Whitefish	10	28	6.4	250	200	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	10	29	6.4	301	400	Y	Female	Mature (spawner)	N		Dead	
Round Whitefish	10	45	3.8	274	188	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	10	46	3.8	269	200	Y	Female	Mature (spawner)	N		Dead	
Round Whitefish	10	47	3.8	225	99	Y	Female	Immature (virgin)	N		Dead	
Round Whitefish	10	48	3.8	240	136	Y	Male	Mature (non-spawner, resting)	N		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Round Whitefish	10	49	3.8	225	113	Y	Male	Immature (virgin)	N		Dead	
Round Whitefish	10	50	3.8	243	140	Y	Female	Mature (spawner)	N		Dead	
Round Whitefish	10	51	3.8	257	152	Y	Male	Mature (spawner)	N		Dead	
Round Whitefish	10	52	3.8	215	81	Y	Female	Immature (virgin)	N		Dead	
Round Whitefish	10	53	3.8	248	125	Y	Female	Immature (virgin)	N		Dead	
Round Whitefish	10	54	3.8	262	159	Y	Male	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	10	55	3.8	198	68	Y	Female	Immature (virgin)	N		Dead	
Round Whitefish	10	56	3.8	228	110	N	Unknown	NA	N		Dead	
Round Whitefish	10	57	3.8	205	82	Y	Male	Immature (virgin)	N		Dead	
Round Whitefish	10	58	3.8	196	60	Y	Female	Immature (virgin)	N		Dead	
Round Whitefish	10	59	3.8	198	70	Y	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	10	60	3.8	291	69	Y	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	10	61	3.8	219	97	Y	Male	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	10	62	3.8	203	79	Y	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	10	63	3.8	199	70	Y	Unknown	NA	N		Dead	
Burbot	11		7.6	465	600	N	Unknown	NA	N		Good	
Burbot	11		8.9	495	800	N	Unknown	NA	N		Good	
Lake Trout	11	6	7.6	760	6500	Y	Male	Mature (spawner)	Y		Dead	
Lake Trout	11	13	11.4	565	2700	Y	Female	Mature (spawner)	Y		Dead	
Lake Trout	11		6.4	482	1400	N	Unknown	NA	N		Good	
Lake Trout	11		8.9	505	1600	N	Unknown	NA	N		Good	
Lake Trout	11		3.8	718		N	Unknown	NA	N		Good	
Lake Trout	11		10.2	487	1500	N	Unknown	NA	N		Good	
Lake Trout	11		8.9	705	6000	N	Unknown	NA	N		Good	
Lake Trout	11		7.6	643	3600	N	Unknown	NA	N		Good	
Lake Trout	11		11.4	495	1400	N	Unknown	NA	N		Good	
Lake Trout	11		6.4	692		N	Unknown	NA	N		Good	
Lake Trout	11		12.7	565	2400	N	Unknown	NA	N		Good	
Lake Whitefish	11	1	8.9	455	1450	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	2	8.9	462	1400	Y	Unknown	NA	Y		Dead	
Lake Whitefish	11	3	8.9	498	1625	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	7	7.6	412	975	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	8	7.6	405	800	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	11	9	7.6	368	625	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	10	7.6	335	475	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	11	7.6	342	475	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	12	11.4	427	1025	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	14	6.4	372	400	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	11	15	6.4	355	495	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	11	16	6.4	343	425	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	11	17	6.4	363	500	Y	Female	Immature (virgin)	Y		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	11	18	6.4	370	625	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	19	6.4	315	450	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	11	20	6.4	315	325	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	11	21	6.4	353	550	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	22	6.4	345	475	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	11	23	6.4	370	600	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	11	24	6.4	350	475	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	11	25	6.4	373	600	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	26	6.4	345	500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	27	6.4	365	600	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	11	28	6.4	365	575	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	11	29	6.4	362	525	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	11	30	6.4	343	500	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	31	6.4	370	600	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	11	32	6.4	353	475	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	11	33	6.4	353	575	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	11	34	6.4	257	225	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	35	3.8	358	825	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	36	3.8	363	625	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	11	37	3.8	350	550	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	11	38	3.8	323	350	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	11	39	3.8	190	79	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	40	3.8	185	70	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	41	3.8	182	75	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	42	3.8	192	80	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	43	3.8	187	72	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	44	3.8	200	91	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	45	3.8	185	64	Y	Male	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	46	3.8	192	77	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	47	3.8	185	65	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	48	3.8	180	64	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	11	49	3.8	170	60	Y	Unknown	Immature (sex unknown)	Y		Dead	
Longnose Sucker	11		6.4	465	1200	N	Unknown	NA	N		Good	
Northern Pike	11	4	8.9	790	4100	Y	Female	Mature (spawner)	Y		Dead	
Northern Pike	11	5	10.2	690	2775	Y	Male	Mature (spawner)	Y		Dead	
Northern Pike	11		8.9	742	3700	N	Unknown	NA	N		Good	
Round Whitefish	11	50	3.8	247	146	N	Unknown	NA	N		Dead	no aging structures
Round Whitefish	11	51	3.8	262	173	N	Unknown	NA	N		Dead	no aging structures
Round Whitefish	11	52	3.8	230	116	N	Unknown	NA	N		Dead	no aging structures
Round Whitefish	11	53	3.8	222	99	N	Unknown	NA	N		Dead	no aging structures
Round Whitefish	11	54	3.8	250	152	N	Unknown	NA	N		Dead	no aging structures

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Round Whitefish	11	55	3.8	202	72	N	Unknown	NA	N		Dead	no aging structures
Round Whitefish	11	56	3.8	200	75	N	Unknown	NA	N		Dead	no aging structures
Round Whitefish	11	57	3.8	200	73	N	Unknown	NA	N		Dead	no aging structures
Round Whitefish	11	58	3.8	248	145	N	Unknown	NA	N		Dead	no aging structures
Round Whitefish	11	50-2	3.8	243	141	N	Female	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	11	51-2	3.8	194	67	N	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	11	52-2	3.8	197	65	N	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	11	53-2	3.8	244	137	N	Male	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	11	54-2	3.8	221	92	N	Female	Immature (virgin)	N		Dead	
Round Whitefish	11	55-2	3.8	220	103	N	Male	Mature (non-spawner, resting)	N		Dead	
Round Whitefish	11	56-2	3.8	199	68	N	Male	Immature (sex unknown)	N		Dead	
Round Whitefish	11	57-2	3.8	249	136	N	Male	Mature (spawner)	N		Dead	
Round Whitefish	11	58-2	3.8	256	162	N	Female	Mature (spawner)	N		Dead	
Round Whitefish	11		3.8	225	100	N	Unknown	NA	N		Good	
Round Whitefish	11		3.8	225	100	N	Unknown	NA	N		Good	
Burbot	12	34	7.6	443	575	Y	Male	Immature (virgin)	Y		Dead	
Burbot	12		6.4	384	400	N	Unknown	NA	N		Good	
Lake Trout	12	32	7.6	580	2600	Y	Male	Mature (spawner)	Y		Dead	
Lake Trout	12	33	10.2	363	575	Y	Female	Immature (virgin)	Y		Dead	
Lake Trout	12	35	8.9	617	2975	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Trout	12	36	8.9	512	1700	Y	Male	Mature (spawner)	Y		Dead	
Lake Trout	12	63	3.8	152	41	Y	Female	Immature (virgin)	Y		Dead	
Lake Trout	12		10.2	810		N	Unknown	NA	N		Good	
Lake Trout	12		10.2	520	2100	N	Unknown	NA	N		Good	
Lake Trout	12		3.8	680	4700	N	Unknown	NA	N		Good	
Lake Whitefish	12	55	3.8	175	54	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	50	3.8	178	61	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	60	3.8	178	56	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	53	3.8	180	65	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	51	3.8	182	63	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	52	3.8	182	63	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	54	3.8	182	65	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	56	3.8	185	67	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	49	3.8	187	65	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	47	3.8	188	69	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	62	3.8	188	73	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	46	3.8	190	69	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	57	3.8	190	71	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	61	3.8	192	71	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	58	3.8	212	92	Y	Unknown	Immature (sex unknown)	Y		Dead	
Lake Whitefish	12	48	3.8	217	116	Y	Male	Immature (virgin)	Y		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Lake Whitefish	12	59	3.8	242	149	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	6	6.4	320	375	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	8	6.4	325	375	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	12	7	6.4	335	450	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	24	10.2	337	450	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	4	6.4	347	500	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	5	6.4	347	500	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	19	7.6	347	475	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	28	10.2	347	475	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	43	8.9	348	525	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	3	3.8	349	525	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	12	23	10.2	351	525	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	12	29	10.2	352	475	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	45	8.9	353	650	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	11	7.6	355	525	Y	Male	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	27	10.2	357	550	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	15	7.6	358	525	Y	Female	Immature (virgin)	Y		Dead	
Lake Whitefish	12	22	10.2	359	525	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	20	7.6	360	475	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	37	8.9	362	650	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	16	7.6	367	575	Y	Male	Immature (virgin)	Y		Dead	
Lake Whitefish	12	26	10.2	368	675	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	39	8.9	368	600	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	12	2	6.4	370	650	Y	Female	Mature (non-spawner, resting)	Y		Dead	
Lake Whitefish	12	44	8.9	373	700	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	17	7.6	374	600	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	21	10.2	380	625	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	25	10.2	390	750	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	38	8.9	390	775	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	12	13	7.6	392	725	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	12	7.6	393	825	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	12	30	10.2	398	875	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	1	6.4	400	825	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	40	8.9	402	875	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	12	42	8.9	414	775	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	18	7.6	419	1025	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	10	7.6	423	1025	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	12	41	8.9	425	1000	Y	Female	Mature (spawner)	Y		Dead	
Lake Whitefish	12	31	10.2	490	1600	Y	Male	Mature (spawner)	Y		Dead	
Lake Whitefish	12	14	3.8	385	775	Y	Male	Mature (spawner)	Y		Dead	
Longnose Sucker	12		3.8	145	60	N	Unknown	NA	N		Good	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Longnose Sucker	12		3.8	225	125	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	155	62	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	152	60	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	147	40	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	167	57	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	174	60	N	Unknown	NA	N		Good	
Longnose Sucker	12		6.4	255	250	N	Unknown	NA	N		Good	
Longnose Sucker	12		6.4	253	200	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	162	49	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	157	50	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	158	60	N	Unknown	NA	N		Good	
Longnose Sucker	12		6.4	270	350	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	172	70	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	175	60	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	140	60	N	Unknown	NA	N		Good	
Longnose Sucker	12		6.4	255	200	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	162	61	N	Male	NA	N		Good	
Longnose Sucker	12		6.4	290	350	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	153	60	N	Unknown	NA	N		Good	
Longnose Sucker	12		3.8	165	50	N	Unknown	NA	N		Good	
Round Whitefish	12	9	6.4	280	275	N	Female	Mature (spawner)	N		Dead	
Round Whitefish	12			188	62	N	Female	Immature (virgin)	N		Dead	
Round Whitefish	12			195	66	N	Female	Immature (virgin)	N		Dead	
Round Whitefish	12			230	109	N	Female	Immature (virgin)	N		Dead	
Round Whitefish	12			233	114	N	Female	Immature (virgin)	N		Dead	
Round Whitefish	12			215	83	N	Female	Immature (virgin)	N		Dead	
Round Whitefish	12			250	142	N	Female	Mature (spawner)	N		Dead	
Round Whitefish	12			250	159	N	Female	Mature (spawner)	N		Dead	
Round Whitefish	12			235	117	N	Female	Mature (spawner)	N		Dead	
Round Whitefish	12			210	82	N	Female	Mature (spawner)	N		Dead	
Round Whitefish	12	82	3.8	253	156	N	Male	NA	N		Dead	
Round Whitefish	12			218	96	N	Male	NA	N		Dead	
Round Whitefish	12			194	68	N	Male	Immature (virgin)	N		Dead	
Round Whitefish	12			251	154	N	Male	Mature (spawner)	N		Dead	
Round Whitefish	12			260	170	N	Male	Mature (spawner)	N		Dead	
Round Whitefish	12			255	158	N	Male	Mature (spawner)	N		Dead	
Round Whitefish	12			225	101	N	Male	Mature (spawner)	N		Dead	
Round Whitefish	12			257	172	N	Male	Mature (spawner)	N		Dead	
Round Whitefish	12	64	3.8	228	107	N	Unknown	NA	N		Dead	
Round Whitefish	12	65	3.8	254	161	N	Unknown	NA	N		Dead	
Round Whitefish	12	66	3.8	260	166	N	Unknown	NA	N		Dead	

TABLE 4: CANYON LAKE FISH DATA

Species	Site	Sample #	Mesh (cm)	Fork Length (mm)	Weight (g)	Aging Structure Collected (y/n)	Sex	Maturity	Stomach Collected (y/n)	Stomach Contents (field)	Release Condition	Comments
Round Whitefish	12	67	3.8	256	150	N	Unknown	NA	N		Dead	
Round Whitefish	12	68	3.8	200	75	N	Unknown	NA	N		Dead	
Round Whitefish	12	69	3.8	213	86	N	Unknown	NA	N		Dead	
Round Whitefish	12	70	3.8	232	109	N	Unknown	NA	N		Dead	
Round Whitefish	12	71	3.8	220	90	N	Unknown	NA	N		Dead	
Round Whitefish	12	72	3.8	255	167	N	Unknown	NA	N		Dead	
Round Whitefish	12	73	3.8	228	80	N	Unknown	NA	N		Dead	
Round Whitefish	12	74	3.8	263	175	N	Unknown	NA	N		Dead	
Round Whitefish	12	75	3.8	238	120	N	Unknown	NA	N		Dead	
Round Whitefish	12	76	3.8	200	73	N	Unknown	NA	N		Dead	
Round Whitefish	12	77	3.8	196	72	N	Unknown	NA	N		Dead	
Round Whitefish	12	78	3.8	267	200	N	Unknown	NA	N		Dead	
Round Whitefish	12	79	3.8	237	116	N	Unknown	NA	N		Dead	
Round Whitefish	12	80	3.8	265	150	N	Unknown	NA	N		Dead	
Round Whitefish	12	83	3.8	212	91	N	Unknown	NA	N		Dead	
Round Whitefish	12	84	3.8	205	82	N	Unknown	NA	N		Dead	
Round Whitefish	12	85	3.8	248	152	N	Unknown	NA	N		Dead	
Round Whitefish	12	86	3.8	263	200	N	Unknown	NA	N		Dead	
Round Whitefish	12	87	3.8	202	85	N	Unknown	NA	N		Dead	
Round Whitefish	12	88	3.8	270	200	N	Unknown	NA	N		Dead	
Round Whitefish	12	89	3.8	238	129	N	Unknown	NA	N		Dead	
Round Whitefish	12	90	3.8	227	105	N	Unknown	NA	N		Dead	
Round Whitefish	12			250	135	N	Unknown	NA	N		Dead	
Round Whitefish	12			252	141	N	Unknown	NA	N		Dead	
Round Whitefish	12			245	148	N	Unknown	NA	N		Dead	
Round Whitefish	12			262	171	N	Unknown	NA	N		Dead	
Round Whitefish	12			267	184	N	Unknown	NA	N		Dead	
Round Whitefish	12			203	72	N	Unknown	NA	N		Dead	
Round Whitefish	12			249	131	N	Unknown	NA	N		Dead	
Round Whitefish	12			196	75	N	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	12			230	105	N	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	12			193	65	N	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	12			207	76	N	Unknown	Immature (sex unknown)	N		Dead	
Round Whitefish	12	81	3.8	250	165	N	Unknown	NA	N		Good	
Round Whitefish	12		3.8	230	125	N	Unknown	NA	N		Good	
Round Whitefish	12		3.8	220	100	N	Unknown	NA	N		Good	
Round Whitefish	12		3.8	205	100	N	Unknown	NA	N		Good	
Round Whitefish	12		3.8	205	100	N	Unknown	NA	N		Good	
Round Whitefish	12		3.8	238	100	N	Unknown	NA	N		Good	

APPENDIX A: MAPS OF SAMPLE LOCATIONS

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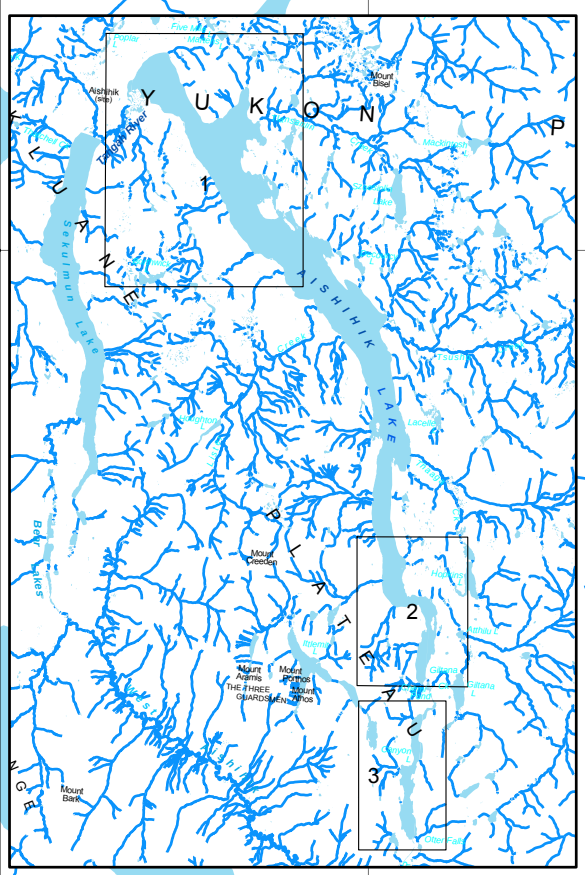
6800000.000000 6795000.000000 6790000.000000

A5
A4
A2
A1



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Checked By:	I. Anderton
Date:	August 23, 2007

Projection: Universal Transverse Mercator Zone 8N
False Easting: 500000.000000
False Northing: 0.000000
Central Meridian: -135.000000
Scale Factor: 0.999600
Datum: North American 1983

Figure 1: Aishihik Lake Gillnetting Locations (South)

EDI ENVIRONMENTAL DYNAMICS INC.
Natural Resource Consultants

0 0.5 1 2 Kilometers

1:50,000

N

368000 000000 371000 000000 374000 000000 377000 000000 380000 000000

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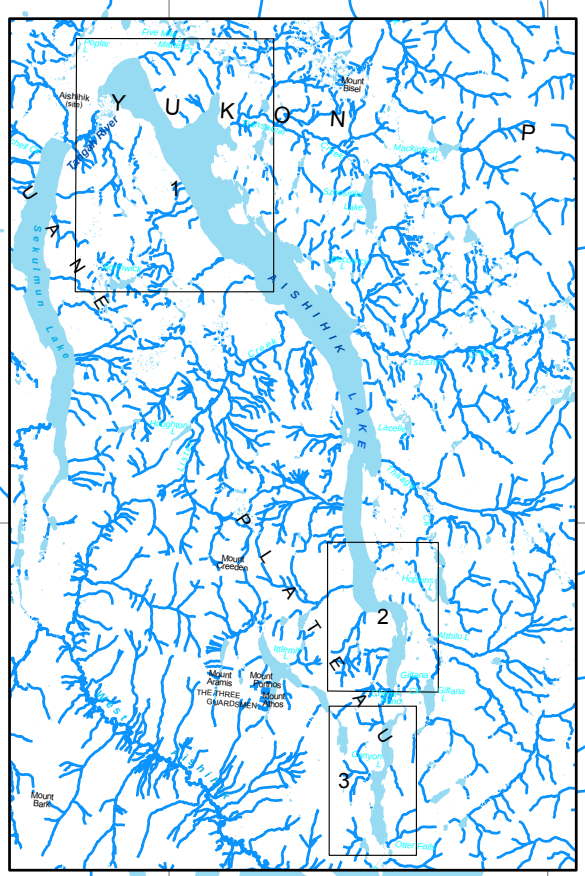
A8
A9
A6
A7
A10
A11
A12
A13



Drawn By:	S. Darling/I. Anderton
Checked By:	I. Anderton
Date:	August 23, 2007

Projection: Universal Transverse Mercator Zone 8N
False Easting: 500000.000000
False Northing: 0.000000
Central Meridian: -135.000000
Scale Factor: 0.999600
Datum: North American 1983

Figure 2: Aishihik Lake Gillnetting Locations (North)

EDI ENVIRONMENTAL DYNAMICS INC.
Natural Resource Consultants

0 1 2 4 Km

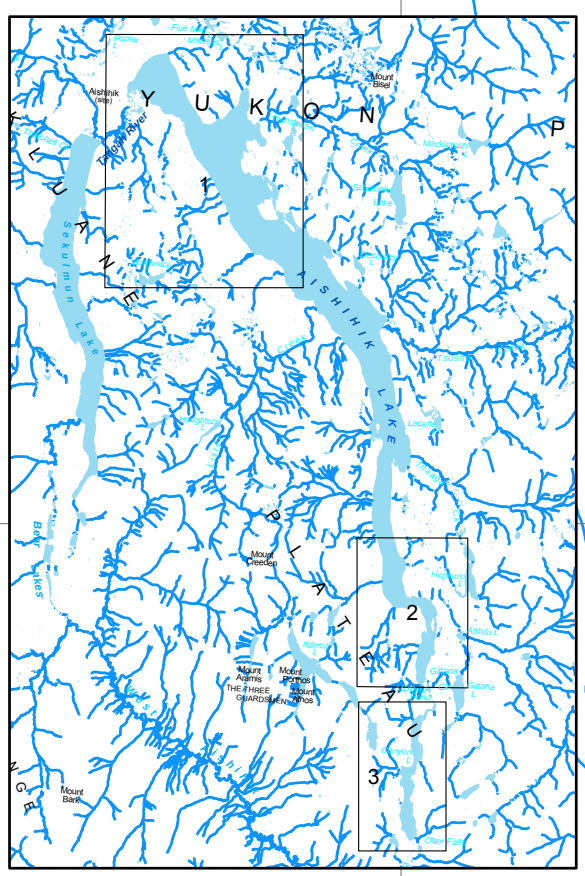
1:60,000

N

389000.000000 392000.000000

6780000.000000 6775000.000000

C11 C12 C7 C10 C6 C9 C5 C4 C8 C3 C2 C1



Drawn By:	S. Darling/I. Anderton
Checked By:	I. Anderton
Date:	August 23, 2007

Projection: Universal Transverse Mercator Zone 8N
False Easting: 500000.000000
False Northing: 0.000000
Central Meridian: -135.000000
Scale Factor: 0.999600
Datum: North American 1983

Figure 3: Canyon Lake Gillnetting Locations

EDI ENVIRONMENTAL DYNAMICS INC.
Natural Resource Consultants

0 0.5 1 2 Kilometers

1:30,000

N

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Aishihik Lake Whitefish Population Monitoring Program

2007 Program: Data Analysis

Prepared for:

Yukon Energy Corporation

Prepared by:

North/South Consultants Inc.

May 2008

TABLE OF CONTENTS

Page

Table of Contents *2*

1.0 INTRODUCTION 4

2.0 ADULT LAKE WHITEFISH MONITORING PROGRAM BACKGROUND 5

2.1 Water Use Licence Requirements 5
2.2 Fisheries Act Authorization Requirements 6

3.0 ADULT LAKE WHITEFISH MONITORING PROGRAM RESULTS 7

3.1 Field Work 7
3.2 Data Analysis 7
3.2.1 Species Composition 7
3.2.2 Catch Per Unit Effort (CPUE) 10
3.2.3 Length-Frequency Distribution 11
3.2.4 Age-Frequency Distribution 14
3.2.5 Determination of Relative Year-Class Strength for Aishihik Lake 19

4.0 ANNUAL BEACH SEINING SURVEYS 28

5.0 ANNUAL AQUATIC MACROPHYTE SURVEYS 30

6.0 REFERENCES 31

Notes on the Final Report

This report is an update of the draft report prepared for, and distributed to the Aishihik Monitoring Program Team (AMPT) in advance of the May 12, 2007, AMPT workshop held in Whitehorse. It includes a number of revisions that reflect the comments, requests and suggestions offered by the AMPT at that workshop. It therefore supersedes the draft report, which should be disregarded in all respects.

In addition to the revisions noted above, this final report also includes several corrections of data errors discovered upon review of the draft report. These included:

1. Section 3.2.1 Species Composition: The original figures comparing 1991 and 2007 relative species composition in Aishihik and Canyon lakes used composition data from de Graff (1993) that were erroneously assumed to represent composition by abundance. Upon review it was noted that the values provided in that report were actually expressed as biomass (i.e., relative composition by weight). The revised figures in this final report compare relative composition by numbers of fish caught, by species, for each lake and survey year.

2. Section 3.2.5 Determination of Relative Year-Class Strength for Aishihik Lake – Mortality Adjusted Age Distribution: Table 3 shows the matrix used to derive relative year-class strength based on mortality adjustment of the 2007 age distribution data. Upon review it was discovered that an incorrect formula had been entered into one of the spreadsheet columns used to populate the matrix. This error has been corrected in this final report. This correction also affected subsequent figures and tables that were based on the matrix-derived data (Figure 10; Tables 4 and 5), and these too have been corrected.

Although some numbers presented in the report have changed as a consequence of the corrections noted above, the changes were all relatively minor in nature and did not affect the results and discussions provided in the draft report.

1.0 INTRODUCTION

The Aishihik Relicensing Project Environmental Impact Assessment (YEC 1998) proposed and described a long-term monitoring program with the goals of protecting the lake whitefish (*Coregonus clupeaformis*) population in Aishihik Lake and ensuring that no significant adverse effects to the lake whitefish fishery result from the operation of the Aishihik Generating Station (the Project). The lake whitefish monitoring program has been designed to provide information that will aid in:

- ascertaining the actual (as opposed to predicted) impacts of the project;
- evaluating the need for mitigation to avoid or minimize potential future impacts; and
- evaluating the need for compensation of harvest losses.

Yukon Energy Corporation (YEC) received a Water Use Licence (HY99-011) for the Project in November of 2002, and in the same month it also received a *Fisheries Act* Authorization (#2002-1) under the provisions of Section 35(2) and Section 32 of the Act. In accordance with condition 1(c) of that Authorization, YEC struck an Aishihik Monitoring Program Team (AMPT) consisting of representatives from YEC, Fisheries and Oceans Canada (DFO), Champagne and Aishihik First Nations (CAFN) and the Yukon Territorial Government (YTG). The role of the AMPT was to cooperatively design a monitoring program agreeable to all its parties, then guide the program for the duration of the current licence. The AMPT met in Whitehorse on December 12-13, 2002, and developed the Aishihik Lake Aquatics Monitoring Program (the Program) that was finalized in January of 2003 and is currently in effect. Participants in the 2002 AMPT workshop included:

Ron Gee (YEC)
Hector Campbell (YEC)
Karl Kroeker (North/South Consultants Inc)
Don Toews (YTG)
Susan Thompson (YTG)
Lawrence Joe (CAFN)
Michael Jim (CAFN)
Harry Smith (CAFN)
Eric Val (DFO, Whitehorse)
Steve Gotch (DFO, Whitehorse)
Barbara Bowen (YEC, recorder)

The 2003 Program described a number of program elements to be conducted annually (e.g., Beach Seining, North End Aquatic Macrophyte Surveys and Subsistence Fishery Monitoring), trial surveys (e.g., Neuston Surveys) and Adult Lake Whitefish Monitoring. The Adult Lake Whitefish Monitoring Program (WMP) was required to be conducted in 2007 and 2017. The 2007 program was conducted in August, 2007 and is the primary focus of this data analysis report.

2.0 ADULT LAKE WHITEFISH MONITORING PROGRAM BACKGROUND

The WMP was developed in response to directives contained in the following authorizing documents:

- Water Use Licence HY99-011: Section 50; page 12
- Fisheries Act Authorization 2002-1: Condition 1 (a); page 2

2.1 WATER USE LICENCE REQUIREMENTS

Although the framework for the 2007 and 2017 WMP had been established and presented in the 2003 Program document, a considerable amount of detail was still to be worked out before this program could be successfully completed in the summer of 2007. To accomplish this, a workshop was convened in Whitehorse on May 10, 2007. At this workshop, details of the 2007 index gillnetting program were finalized according to the Water Use Licence requirements and the following principles:

- the program objective was to obtain age class strength information for adult lake whitefish in Aishihik Lake;
- the program was to be based on index gillnetting, conducted in 2007 and 2017;
- the methodology must be clear enough to all allow future replication; and
- the program must include a schedule for reporting data, conclusions and any proposed mitigation.

The May 10, 2007 workshop was attended by:

Ron Gee (YEC)
Karl Kroeker (North/South Consultants Inc)
Don Toews (YTG)
Susan Thompson (YTG)
Lorne La Rocque (YTG)
Lawrence Joe (CAFN)
Michael Jim (CAFN)
Paul Christensen (DFO)

In addition to the Aishihik Lake survey, workshop participants also decided to conduct index gillnetting on Canyon Lake, to determine the current status of fish populations in that lake. Canyon Lake had not been surveyed (i.e., index gillnetting) since the 1991 survey conducted by the Fish and Wildlife Branch of the Government of Yukon (de Graff 1993).

Other Program changes arising from the May 10 workshop included:

1. Set durations were reduced from 24 hr (i.e., as in 1991) to 12 hr, primarily to increase control over total number of fish captured and reduce lake trout mortalities;

2. The field crew supervisor was granted latitude to omit or move pre-determined fishing sites to reduce lake trout captures and mortalities; and

3. Three sites were added to the north end of Aishihik Lake to improve representation of that portion of the lake.

2.2 FISHERIES ACT AUTHORIZATION REQUIREMENTS

In addition to the Water Use Licence requirements, the *Fisheries Act* Authorization (the Authorization) stipulated that:

- monitoring of the adult lake whitefish population "at Aishihik Facility Watershed" was to use standard index gillnetting (sample size consistent with the 1991 monitoring).

3.0 ADULT LAKE WHITEFISH MONITORING PROGRAM RESULTS

3.1 FIELD WORK

The WMP index gillnetting programs on Aishihik and Canyon lakes were conducted during late July and early August, 2007, by EDI Environmental Dynamics Inc. (EDI). Results were presented in the *Data Report: 2007 Aishihik Lake Whitefish Gillnetting* (EDI 2007).

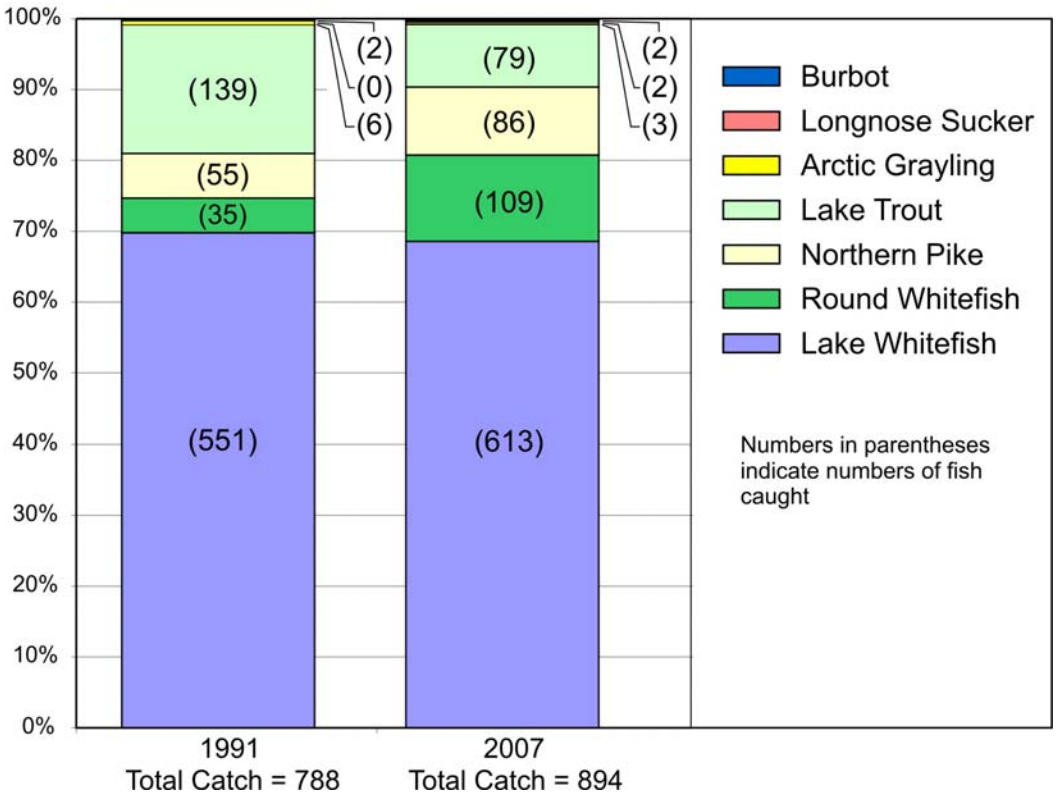
3.2 DATA ANALYSIS

3.2.1 Species Composition

Aishihik Lake

The relative species composition (%), or relative species abundance, for Aishihik Lake (1991 vs. 2007) is presented in Figure 1.

Figure 1 Aishihik Lake: Species Composition 1991 vs. 2007

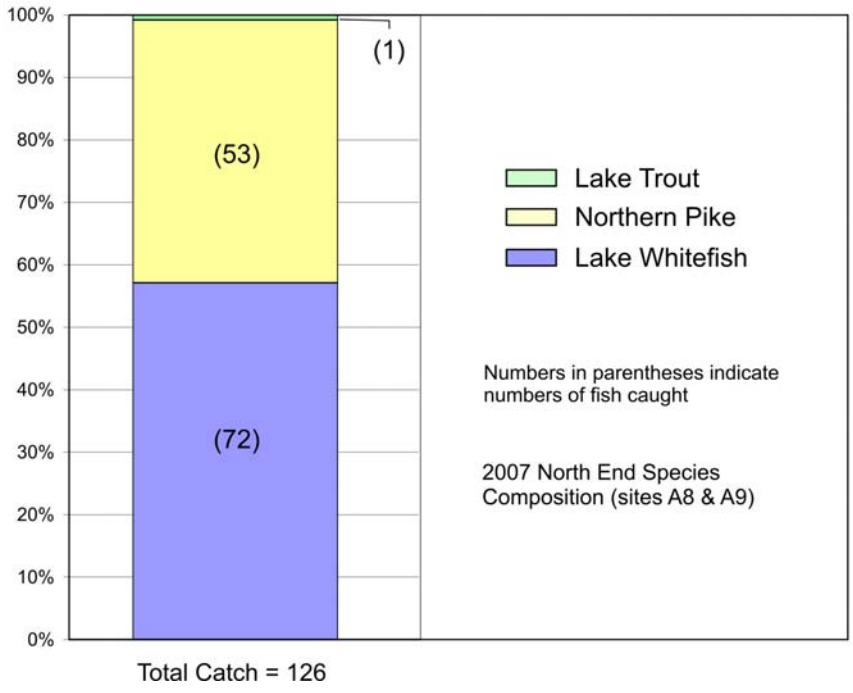


The figure shows several differences in the relative species composition between 1991 and 2007:

1. An increase in the relative abundance of round whitefish;
2. An increase in the relative abundance of northern pike; and
3. A reduction in the relative abundance of lake trout.

Although it is possible that the results reflect some differences in the actual species assemblages between the two years, it is likely that the differences are attributable largely to differences in sampling methodology. The focus on lake trout avoidance in 2007 likely reduced the number of lake trout captured, and may also have influenced the catch of other species that may be associated with lake trout. Switching from 24 hr sets to 12 hr night sets may have favoured the capture of species that are more active at night. Finally, addition of the three north end sites, particularly the near shore sites, probably increased the number of northern pike that were captured. CAFN fishermen have observed that pike numbers have increased in the north end of the lake since completion of the hydroelectric facilities, and this was recognized in the relicensing EIA (YEC 1998). To illustrate, the 2007 data for the two far north end sites are presented in Figure 2. Although the increased relative abundance of northern pike over time cannot be quantified, Figure 2 does show that northern pike are relatively more abundant in the north end (i.e., near Aishihik Village) compared to the lake as a whole.

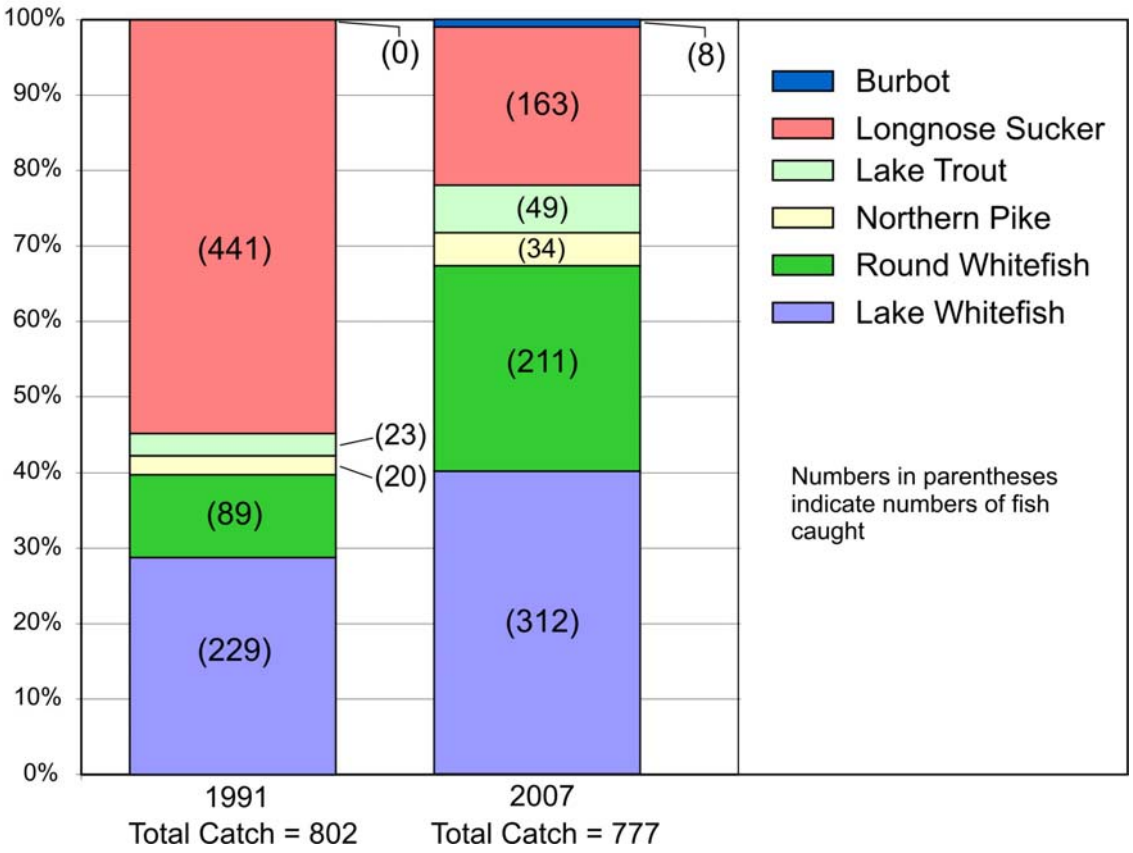
Figure 2 Relative Species Composition for North End Sites, 2007



Canyon Lake

The relative species composition (%) for Canyon Lake (1991 vs. 2007) is presented in Figure 3.

Figure 3 Canyon Lake: Species Composition 1991 vs. 2007



The data suggest that lake whitefish and round whitefish were relatively more abundant in 2007, while longnose sucker were substantially less abundant. Although it is likely that changed survey methodology accounts for some of these differences, it is difficult to conclude whether or not the data indicate that real changes have occurred in the species assemblage in Canyon Lake. Furthermore, since only two surveys have been conducted over a period 16 years, the role of natural variability is not understood.

3.2.2 Catch Per Unit Effort (CPUE)

Aishihik Lake

The CPUE for lake whitefish in Aishihik Lake (1991 vs. 2007) is presented in Table 1.

There has obviously been a substantial increase in CPUE, both by number and by weight, for lake whitefish in Aishihik Lake. Although much of this increase can likely be attributed to different methodology, primarily shorter net set durations, it seems reasonable to conclude that CPUE increased in 2007 compared to 1991. Table 1 also provides simplified CPUEs based on fish/set and kg/set only. This approach ignores the effect of altering the set durations, and therefore provides a very conservative estimate of increased fishing success in 2007 relative to 1991.

Table 1 Aishihik Lake: CPUE 1991 vs. 2007

	Aishihik Lake		
	1991 *	**2007**	**Difference**
No. of Sets	13	12	- 1
Mean duration	17.5	12.5	- 29%
Lake whitefish caught	551	613	+ 11%
fish/100m/24hr	38.75 ± 12.21	61.78 ± 33.90	+ 59%
kg/100m/24hr	45.74 ± 14.41	86.98 ± 50.81	+ 90%
fish/set	42.2	51.1	+ 21%
kg/set	50.0	71.9	+ 44%

* data from de Graff 1993

Canyon Lake

The CPUE for lake whitefish in Canyon Lake (1991 vs. 2007) is presented in Table 2. Similar comments can be made for Canyon Lake, as for Aishihik Lake (above).

Table 2 Canyon Lake: CPUE 1991 vs. 2007

	Canyon Lake		
	1991 *	**2007**	**Difference**
No. of Sets	8	12	+ 4
Mean duration	20.9	11.5	- 45%
Lake whitefish caught	230	312	+ 36%
fish/100m/24hr	20.75 ± 8.46	31.03 ± 16.89	+ 50%
kg/100m/24hr	13.46 ± 5.49	21.82 ± 6.18	+ 62%
fish/set	28.8	26.0	- 10%
kg/set	18.7	11.43	- 39%

* data from de Graff 1993

3.2.3 Length-Frequency Distribution

Aishihik Lake

The lake whitefish length-frequency distribution for Aishihik Lake (1991 vs. 2007) is presented in Figure 4. The length-frequency distributions were similar between years, the only real difference being that the 2007 fish were somewhat larger. The lack of smaller fish is a noteworthy feature for both years, suggesting that older juveniles (i.e., sub-adults that are vulnerable the mesh sizes used) were relatively scarce in Aishihik Lake in both years. This may be a feature of a stable population in both years, with respect to length distribution, for a relatively unexploited lake whitefish population at or near the carrying capacity for the lake.

Canyon Lake

The lake whitefish length-frequency distribution for Canyon Lake (1991 vs. 2007) is presented in Figure 5. There are some noteworthy differences between the two years that are difficult to explain (i.e., generally smaller fish and a more disbursed bimodal distribution), given the data that are available (i.e., only two surveys conducted 17 years apart).

Figure 4 Aishihik Lake: Lake Whitefish Length Distribution 1991 vs. 2007

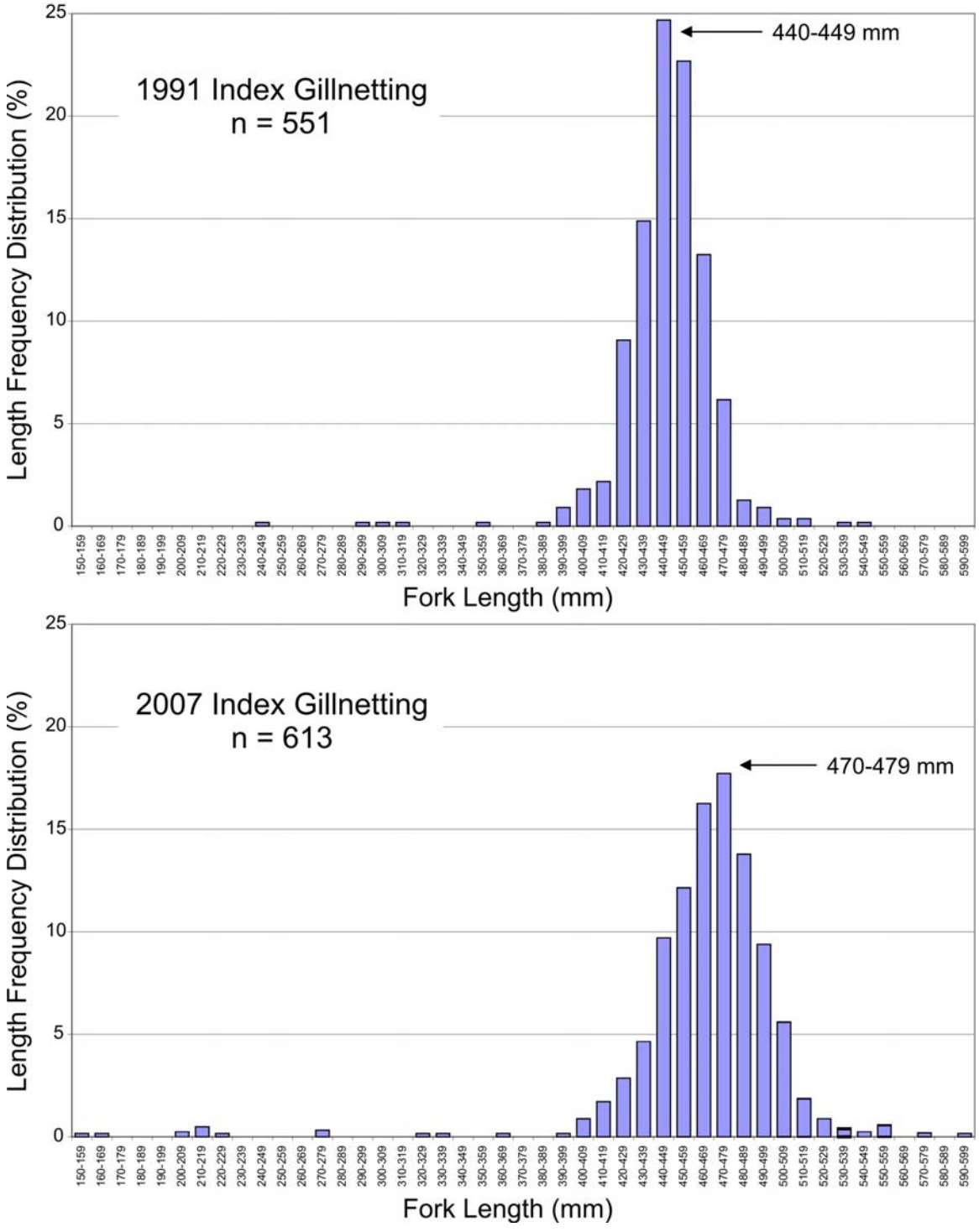
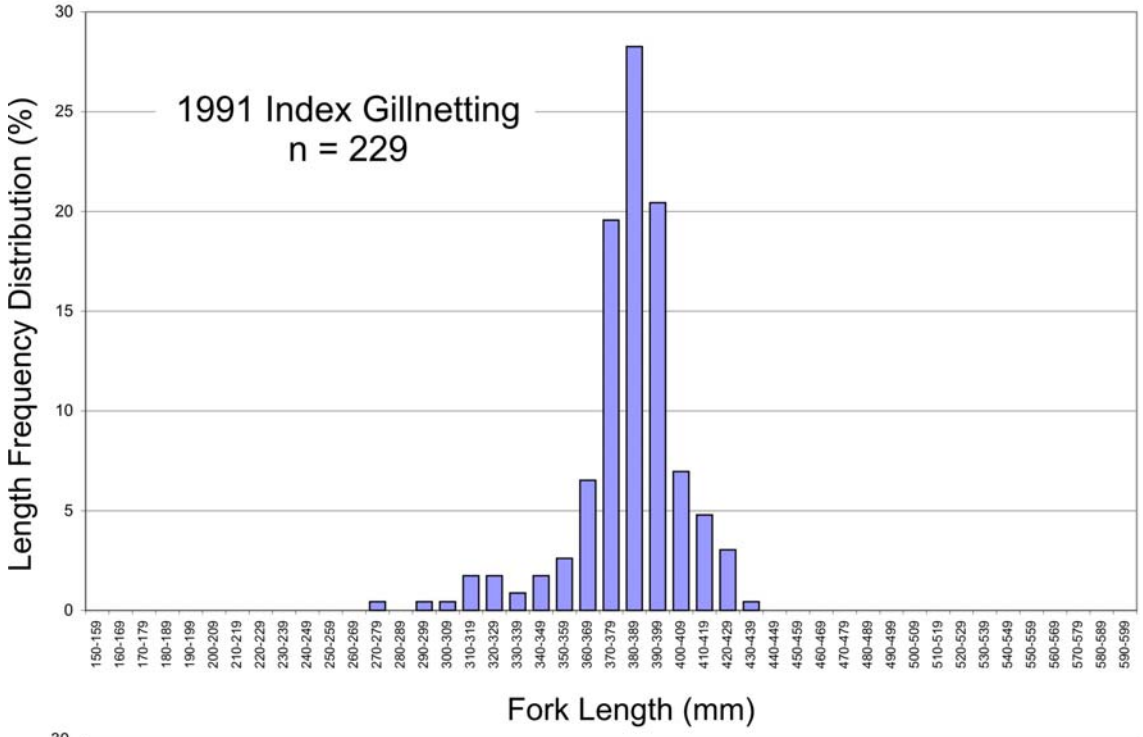
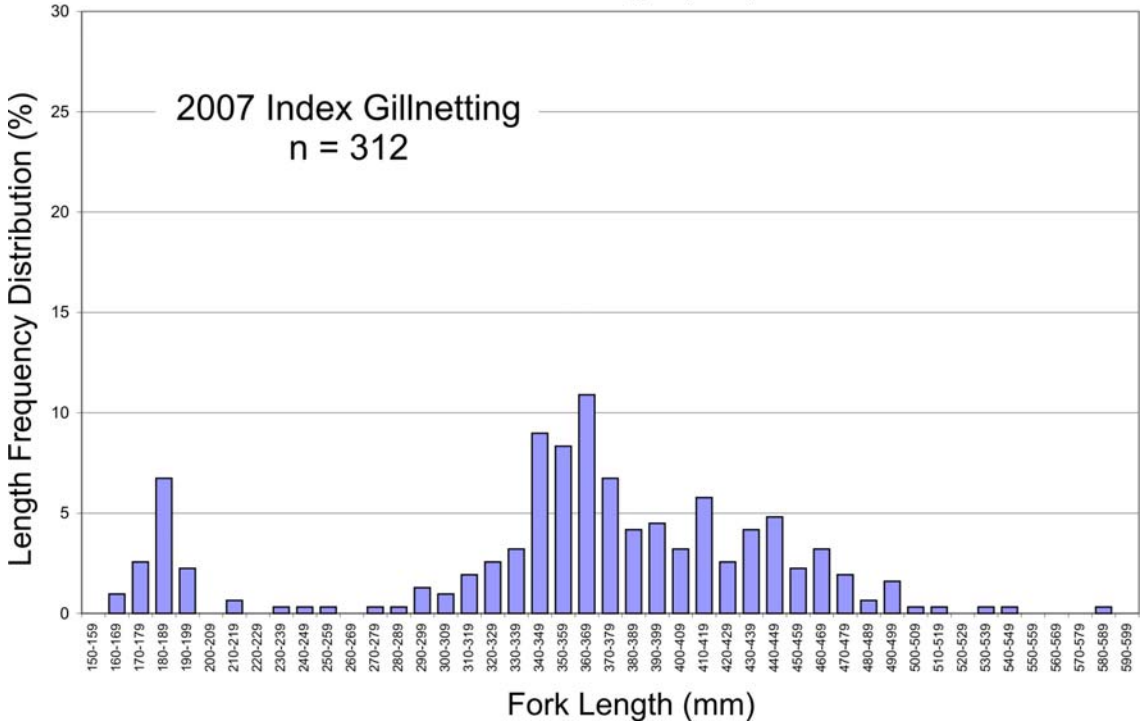


Figure 5 Canyon Lake: Lake Whitefish Length Distribution 1991 vs. 2007





3.2.4 Age-Frequency Distribution

Aishihik Lake

A multi-year comparison of age distributions for lake whitefish is provided in Figure 6. Although the four surveys illustrated (1991, 1994, 1999 and 2007) were not carried out with consistent methodology, and can therefore not be compared directly, the figure provides a useful temporal perspective and illustrates that the age data available for 1991 and 2007 are probably reliable. Consistent tracking of strong year-classes, weak early 1980s year-classes and the overall progression of age modes suggest a high level of consistency in aging between years.

Figure 7 shows the age-frequency/year-class distributions for Aishihik Lake based on the 1991 and 2007 gillnetting data. The 1991 histogram shows two adult modes; a primary mode at ages 16 and 17, and a secondary mode at age 25. This bi-modality is somewhat unusual and is not reflected in the corresponding length-frequency distribution (Figure 4). It may represent a period of low recruitment around 1970 (i.e., pre-project), but this can not be verified. The smaller third juvenile mode at age seven is an artefact resulting from the weak or missing year-classes in the early 1980s, as reported by de Graff (1993) and YEC (1998). These weak or missing year-classes have since moved on, and are represented by the relatively weak right-hand limb of the 2007 histogram.

The 2007 histogram in Figure 7 also shows an adult mode at age 16. Overall, the irregular profile of the 2007 histogram, highlighted by exceptionally strong year-classes in 1991 (age 16) and 1998 (age 9), suggests a recruitment response to vacancies left by the poor recruitment of the early 1980s year-classes. Since the 2007 length-frequency distribution is normal in appearance, this suggests that juveniles and sub-adults grew relatively quickly to assume their positions in the adult population.

Figure 8 relates the 2007 lake whitefish age-class distribution to historical lake elevations for Aishihik Lake. As illustrated, there were some very strong year classes produced in years when lake elevations dropped below the natural (i.e., established pre-1975) minimum (914.1 m) but above current low supply elevation (913.0 m). Monitoring conducted since 1999 has shown that lake elevations below the natural minimum result in an expansion of littoral zone in the north end of the lake as evidenced by the expansion of aquatic plant communities. This expansion of the littoral zone likely equates to increased productivity, which would explain, at least in part, the occurrence of strong year-classes despite the low lake elevations. At some point below 913 m increased productivity is likely offset by loss of north end spawning habitat, resulting in weak or failed year-class as observed in the early 1980s.

Figure 6 Multi-year Comparison of Age-Frequency Distributions for Aishihik Lake based on previous Gillnetting Surveys

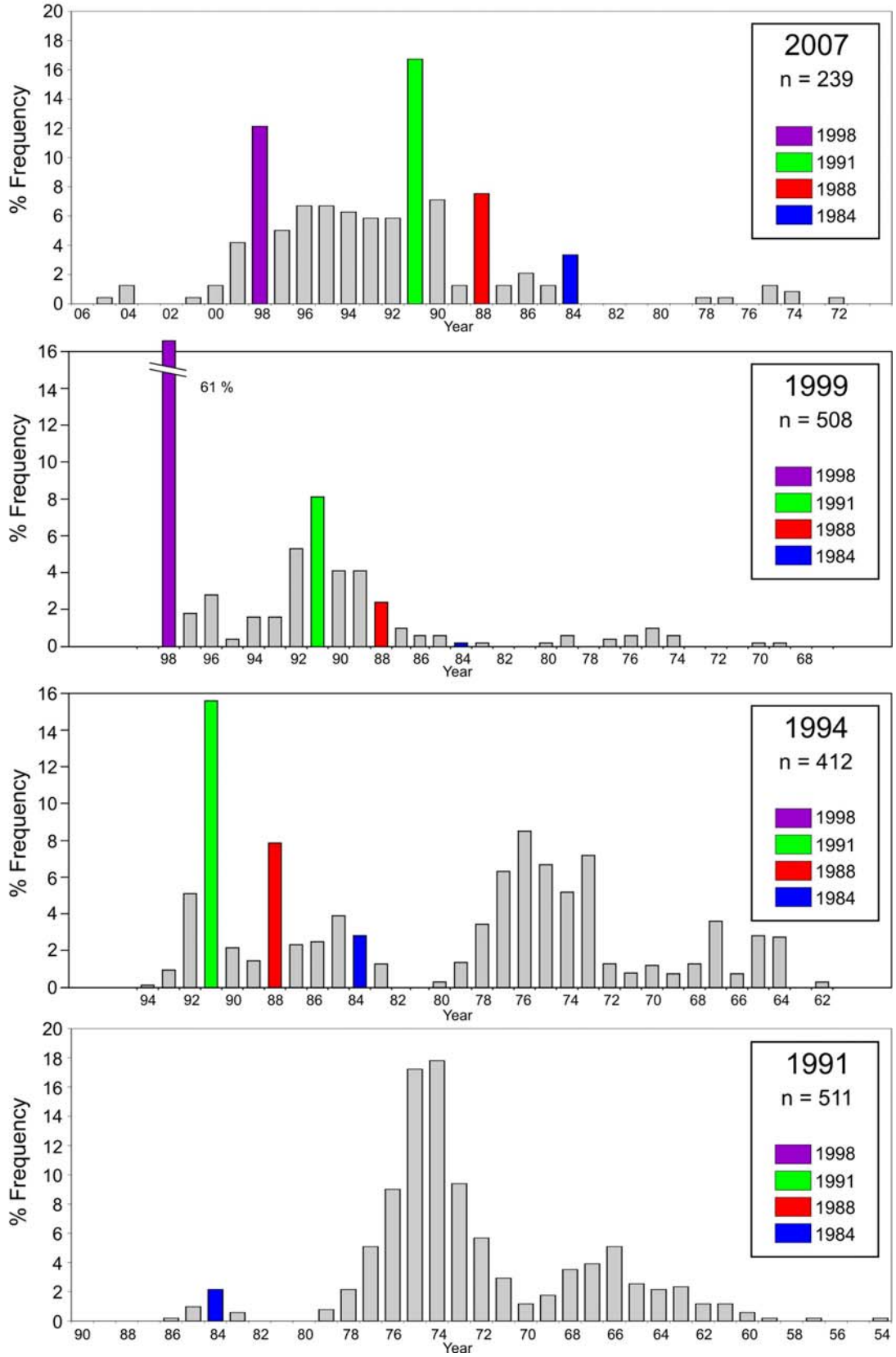


Figure 7 Aishihik Lake: Lake Whitefish Age Distribution 1991 vs. 2007

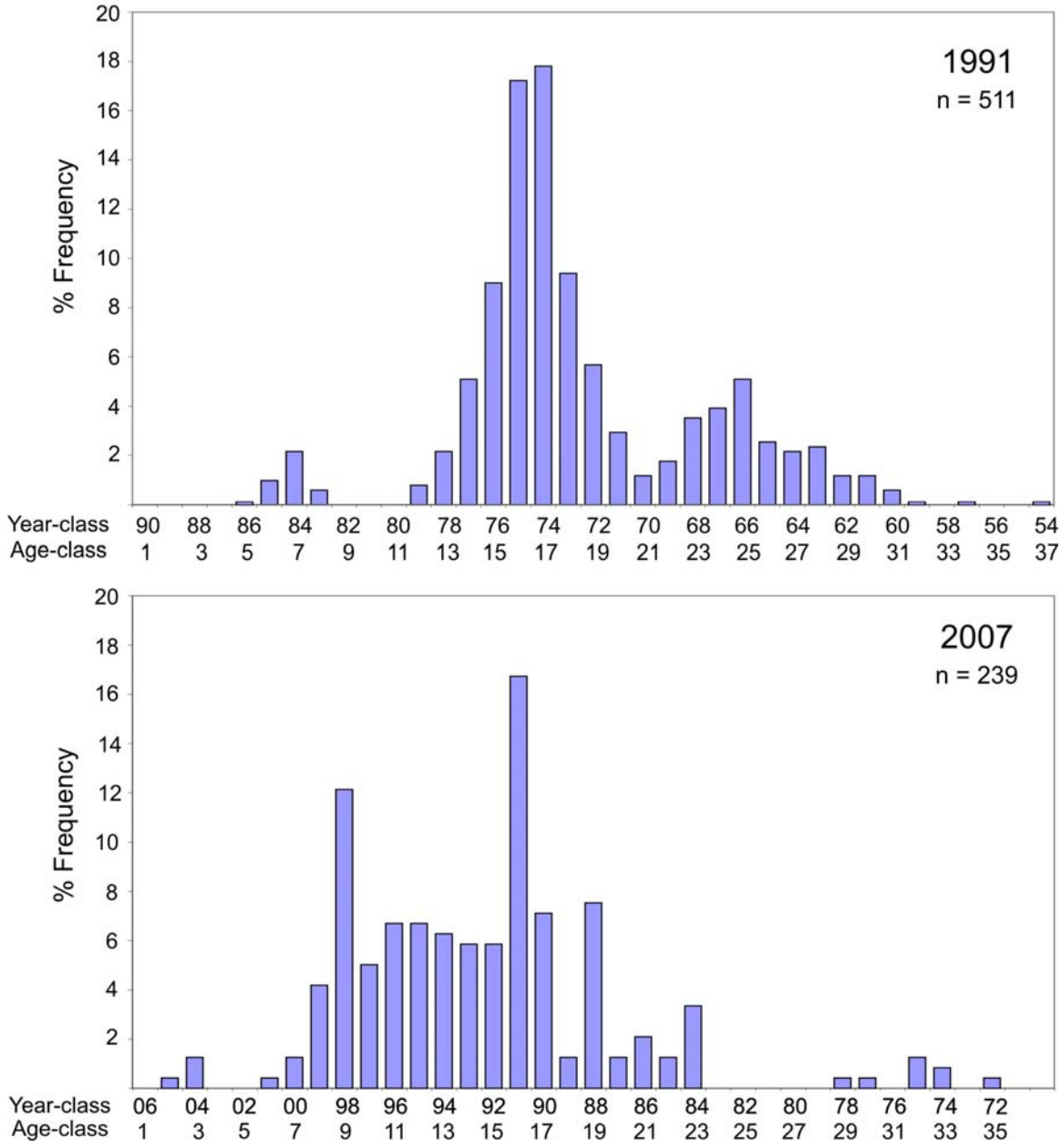
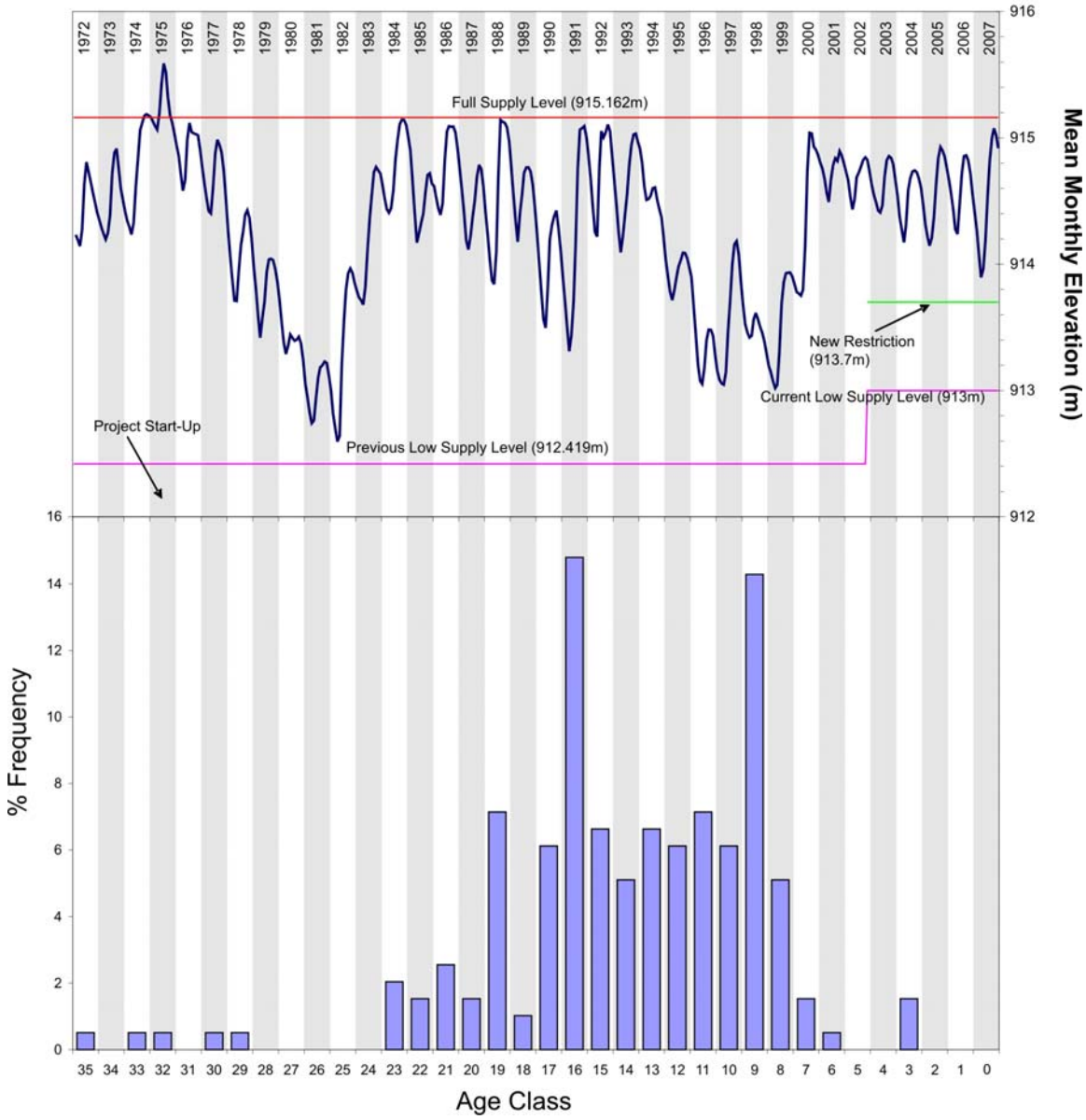


Figure 8 Aishihik Lake Mean Monthly Historical Elevations and Lake whitefish Age Distribution based on the 2007 Data

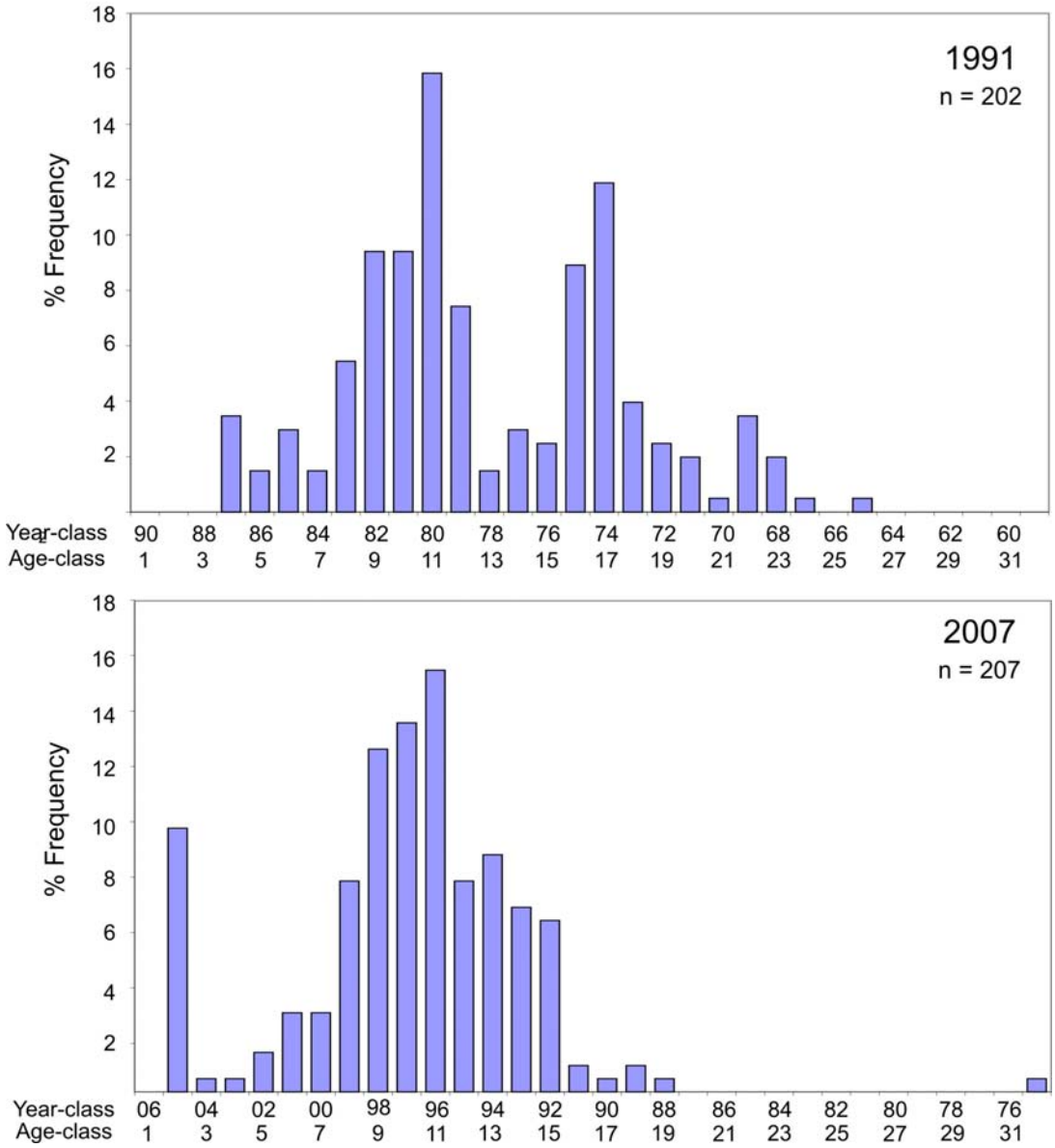


Canyon Lake

Figure 9 shows the age-frequency/year-class distributions for Canyon Lake based on the 1991 and 2007 gillnetting data. The 1991 histogram shows a primary age mode at age 11 (1980) and a secondary mode at age 17 (1974). The reason for this bi-modality can not be determined based on existing information, but suggest variable recruitment that may be either natural or related to human activity (i.e., related to the Project, fishing pressure or both).

The 2007 histogram shows a similar adult mode at age 11 (1996) but the previously strong 1980 year–class is no longer evident. The abundance of two year old fish in the 2007 catch suggests that this may develop as a strong year-class.

Figure 9 Canyon Lake: Lake Whitefish Age Distribution 1991 vs. 2007



3.2.5 Determination of Relative Year-Class Strength for Aishihik Lake

Mortality Adjusted Age Distribution

Paragraph 4(a) of the Authorization stipulates:

> *"In the event that the results from the 2007 adult lake whitefish monitoring program indicate adult recruitment for 1996 to 1999 year classes on average (i.e., the arithmetic mean) to be at or above normal year class strength (i.e., the average for year classes, mortality adjusted, when minimum daily spring elevations were 914.13 m ASL or higher) ("Normal Year Class Strength") then, subject to paragraph 4(d), the conditions set out in paragraph 3 shall no longer apply and no minimum Ten-Year Rolling Average shall be required to be maintained;"*

Paragraph 3 of the Authorization requires that a ten-year rolling average of minimum daily spring water elevations shall not be lower than 913.7 m (the current restriction elevation), and that the minimum daily spring elevation shall not be lower than 913.7 more than two years for the period 2003-2007 (Note: the second requirement was met). Paragraph 4(d) sets out several provisions that will remain in effect after 2007, regardless of the 2007 monitoring results and any subsequent modifications to YEC's operational requirements. The implications of Paragraph 4(d) are discussed further in Section 4.0 of this report.

The process of mortality adjustment assumes that a fish population is subject to a constant rate of annul mortality, and that a population's age distribution (e.g., as illustrated in Figure 7) can be standardized by adding the accumulated losses for each successive year beyond a selected starting point. In other words, the process results in an index of relative year-class strength.

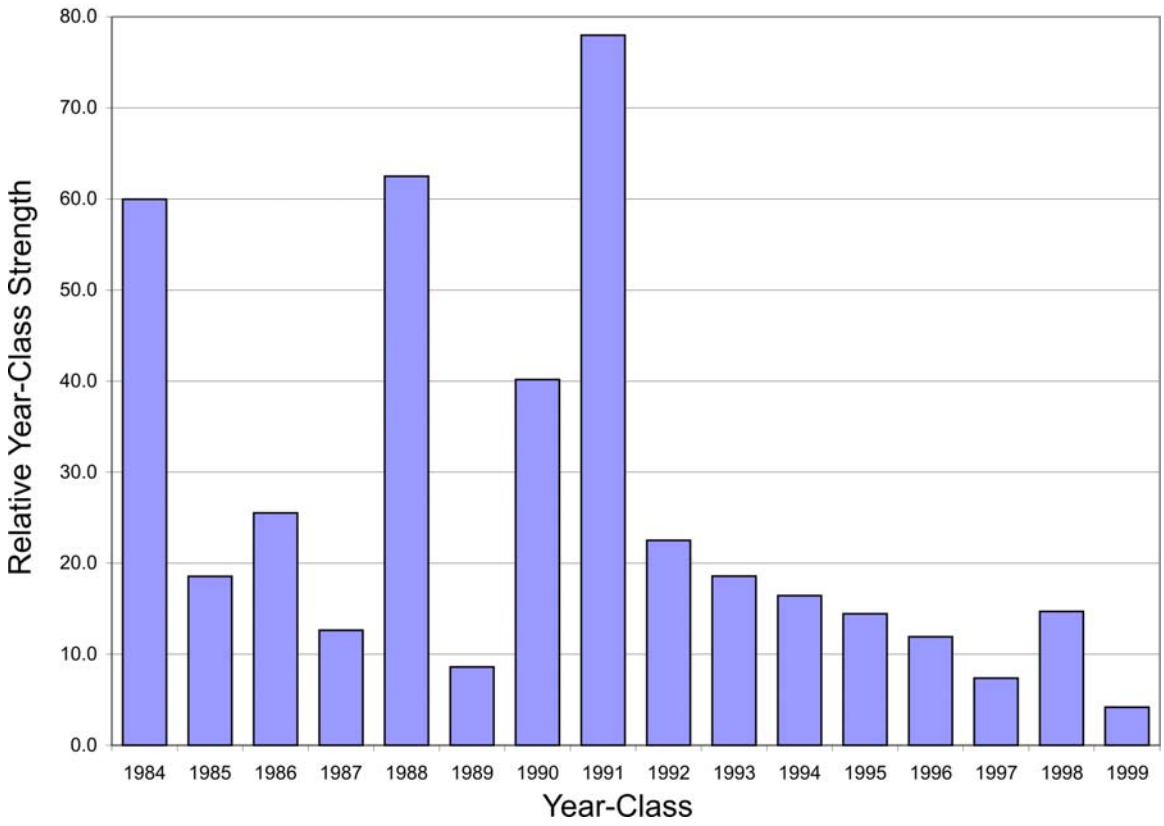
Since the age distribution data for Aishihik Lake whitefish are not reliable at the young end of the scale (i.e., young fish [< 9 or 10 years] are not fully recruited and are less vulnerable to the gill net mesh sizes used) and the older end (just not enough of them around any more), the mortality adjustment in Table 3 was based on ages 8-23 (1984 to 1999). Although it is unlikely that the age 8 and age 9 year-classes were fully recruited in 2007, the mortality adjustment included these years in compliance with the requirements of the Authorization. To complete the adjustment in Table 3, the Annual Mortality value calculated by de Graff (1993) for the 1991 survey was used (i.e., A = 0.175). The resulting distribution of Relative Year-Class Strength (RYCS) is illustrated in Figure 10.

Table 3 Derivation of Relative Year-Class Strength Based on Mortality Adjusted Age Distribution

Year	Unadjusted Values from Fig 7	Annual Mortality Adjustment (Annual Mortality [A] = 0.175 *)															Relative Year-Class Strength
1984	3.3	4.1	4.9	6.0	7.2	8.8	10.6	12.9	15.6	18.9	22.9	27.8	33.7	40.8	49.5	60.0	**60.0**
1985	1.3	1.5	1.8	2.2	2.7	3.3	4.0	4.8	5.8	7.1	8.6	10.4	12.6	15.3	18.6		**18.6**
1986	2.1	2.5	3.1	3.7	4.5	5.5	6.6	8.0	9.7	11.8	14.3	17.4	21.0	25.5			**25.5**
1987	1.3	1.5	1.8	2.2	2.7	3.3	4.0	4.8	5.8	7.1	8.6	10.4	12.6				**12.6**
1988	7.5	9.1	11.1	13.4	16.3	19.7	23.9	29.0	35.1	42.5	51.6	62.5					**62.5**
1989	1.3	1.5	1.8	2.2	2.7	3.3	4.0	4.8	5.8	7.1	8.6						**8.6**
1990	7.1	8.6	10.5	12.7	15.4	18.6	22.6	27.3	33.1	40.2							**40.2**
1991	16.7	20.3	24.6	29.8	36.1	43.8	53.1	64.3	78.0								**78.0**
1992	5.9	7.1	8.6	10.4	12.6	15.3	18.6	22.5									**22.5**
1993	5.9	7.1	8.6	10.4	12.6	15.3	18.6										**18.6**
1994	6.3	7.6	9.2	11.2	13.5	16.4											**16.4**
1995	6.7	8.1	9.8	11.9	14.5												**14.5**
1996	6.7	8.1	9.8	11.9													**11.9**
1997	5.0	6.1	7.4														**7.4**
1998	12.1	14.7															**14.7**
1999	4.2																**4.2**

* de Graff (1993)

Figure 10 Aishihik Lake 1984 - 1999 Lake Whitefish Mortality Adjusted Relative Year-Class Strength



The RYCS values in Table 3 were then tabulated and calculations performed to determine year-class performance relative to historical lake elevations. Table 4 presents this comparison as stipulated in the Authorization; i.e., the mean RYCS for the 1996-1999 period is compared to the mean for "normal" years; i.e., years with minimum late winter lake elevations above 914.1 m. The comparison indicates that the mean RYCS for 1996-1999 was below the mean RYCS for the normal years between 1984 and 1994.

Table 4 Aishihik Lake 1984 - 1999 Lake Whitefish Mortality Adjusted Relative Year-Class Strength, Comparing the 1996 - 1999 Period to Years When Minimum Lake Elevations Were Above 914.1 m asl

Minimum Lake Elevation: 914.1		
	Relative Year-Class Strength for Years Above and Below 914.1	
Year	**Above**	**Below**
1984	60.0	
1985	18.6	
1986	25.5	
1987	12.6	
1988		
1989	8.6	
1990		
1991		
1992	22.5	
1993	18.6	
1994	16.4	
1995		
1996		11.9
1997		7.4
1998		14.7
1999		4.2
Average	**22.8**	**9.5**
Difference		**-13.3**

Although the Authorization stipulates that the mean RYCS for 1996 to 1999 be compared to normal years, this approach excludes a number of years when lake elevations were below the 914.1 m benchmark elevation. Furthermore, the prescribed comparison includes only four

values (1996 – 1999), which includes two year-classes that were probably not fully recruited in 2007 (i.e., 1998 and 1999). To make the comparison more balanced and inclusive, therefore, comparisons were also made using all years in the 1984-1999 period (Table 5).

Table 5 compares the mean RYCS for those years when the minimum winter lake elevation was above or below the natural low of 914.1 m. The table also provides the same comparison for years when the minimum winter lake elevation was above and below the current restriction elevation of 913.7 m. Both comparisons indicate that mean RYCS was higher for the lower water years.

Table 5 Aishihik Lake 1984 - 1999 Lake Whitefish Mortality Adjusted Relative Year-Class Strength, Comparing Years When Minimum Lake Elevations Were Above and Below 914.1 and 913.7 m asl

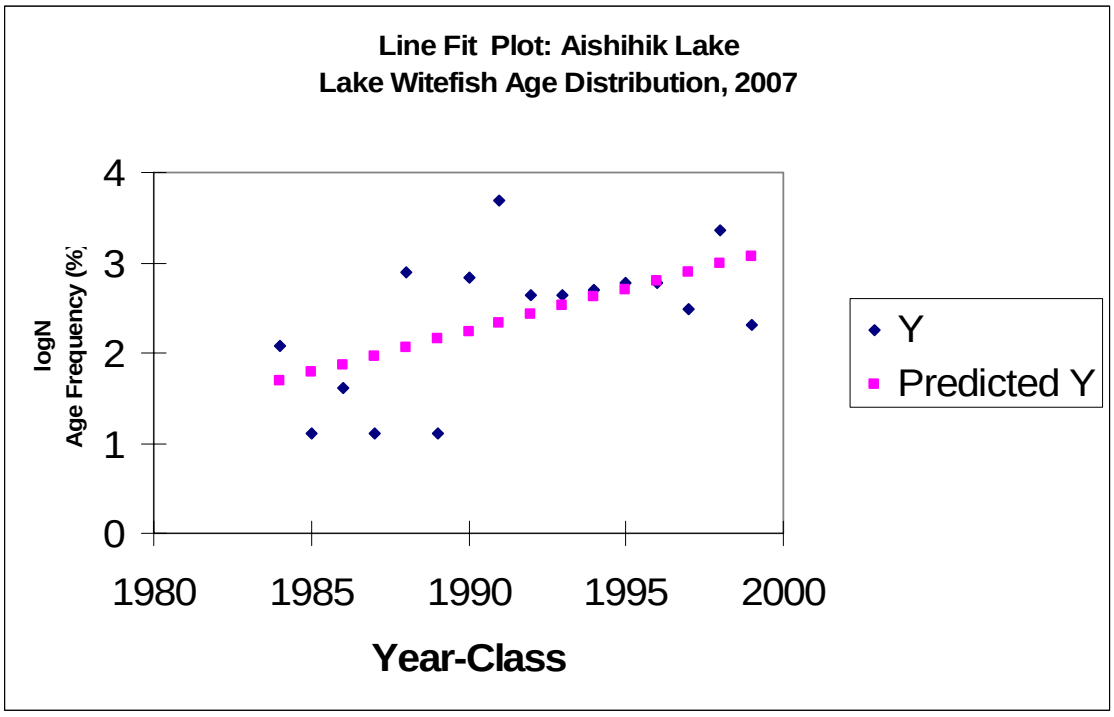
Minimum Lake Elevation: 914.1		
	Relative Year-Class Strength for Years Above and Below 914.1	
Year	**Above**	**Below**
1984	60.0	
1985	18.6	
1986	25.5	
1987	12.6	
1988		62.5
1989	8.6	
1990		40.2
1991		78.0
1992	22.5	
1993	18.6	
1994	16.4	
1995		14.5
1996		11.9
1997		7.4
1998		14.7
1999		4.2
Average	**21.8**	**29.2**
Difference		**+6.3**

Minimum Lake Elevation: 913.7		
	Relative Year-Class Strength for Years Above and Below 913.7	
Year	**Above**	**Below**
1984	60.0	
1985	18.6	
1986	25.5	
1987	12.6	
1988	62.5	
1989	8.6	
1990		40.2
1991		78.0
1992	22.5	
1993	18.6	
1994	16.4	
1995		14.5
1996		11.9
1997		7.4
1998		14.7
1999		4.2
Average	**26.0**	**26.1**
Difference		**+0.1**

Plotting Regression Residuals

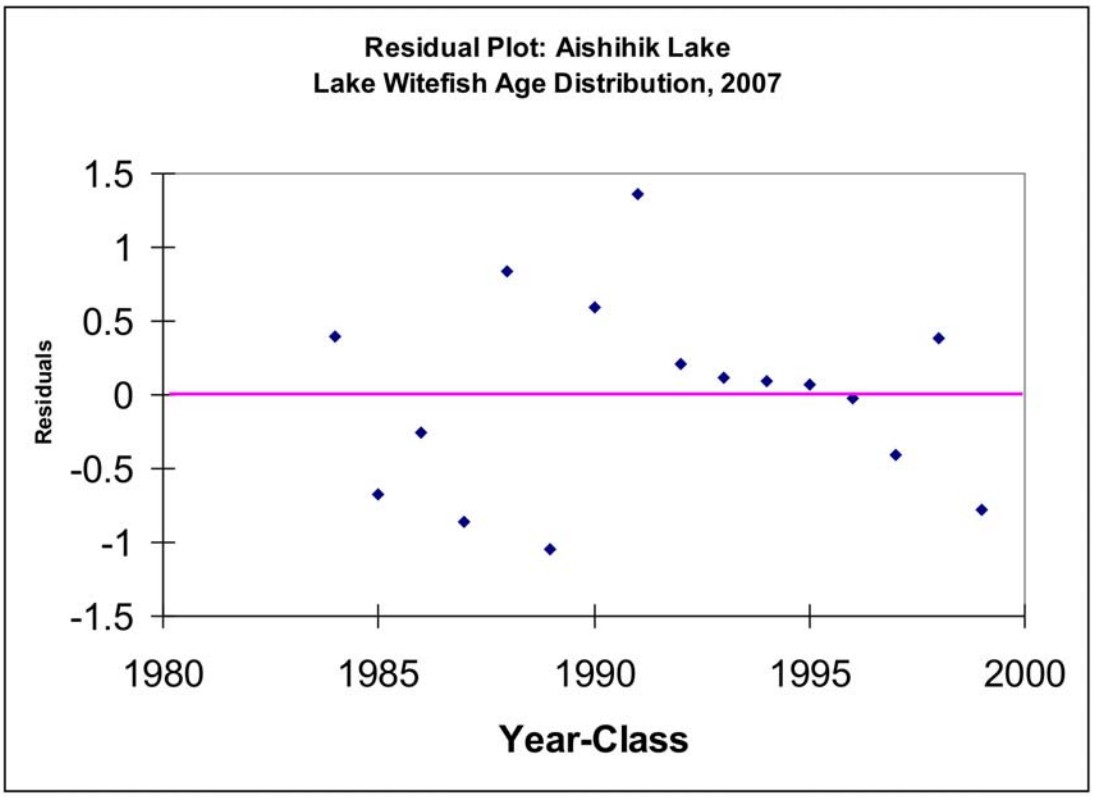
It is difficult to find examples of other cases where RYCS analyses are attempted, but one method that does get used more than others is an analysis of residuals (Maceina 1997). Simply put, this involves a regression analysis done on the descending limb of a normal catch curve, the same way that it is done when calculating mortality. However, unlike with mortality calculations, in which you typically exclude odd year-classes that throw off the accuracy of the line fit, an analysis of residuals aims to tease out and quantify the oddities (i.e., the variations from the normal). In this case, years that are substantially below or above the normal (i.e., predicted) value represent weak or strong year-classes, respectively. Also in contrast to the mortality adjustment method, analysis of residuals does not require assumptions about the data regarding mortality and does not involve manipulation of the data, other than converting catch numbers to natural log values. Two kinds of plots are generated. Figure 11 shows a Line Fit Plot that indicates the predicted age distribution (predicted Y) if annual recruitment and mortality are constant. The "Y" values, on the other hand, show the observed values and the variations above and below the line that indicate deviations from the prediction.

Figure 11 Line Fit Plot for Aishihik Lake Whitefish Age Distribution, 1984 – 1999, Based on 2007 Data



A Residual Plot (Figure 12) plots these variations as residuals which can be quantified.

Figure 12 Residual Plot for Aishihik Lake Whitefish Age Distribution, 1984 – 1999, Based on 2007 Data



If the residuals are tabulated and analyzed in the same manner as for the Adjusted Mortality method (above), the following results are obtained (Table 6 and Table 7).

Table 6 Aishihik Lake 1984 - 1999 Lake Whitefish Relative Year-Class Strength, Comparing the 1996 - 1999 Period to Years When Minimum Lake Elevations Were Above 914.1 m asl

Minimum Lake Elevation: 914.1		
	Relative Year-Class Strength for Years Above and Below 914.1	
	Above	**Below**
1984	0.395	
1985	-0.678	
1986	-0.260	
1987	-0.864	
1988		
1989	-1.050	
1990		
1991		
1992	0.212	
1993	0.120	
1994	0.096	
1995		
1996		-0.025
1997		-0.406
1998		0.384
1999		-0.774
Average	**-0.254**	**-0.205**
Difference		**+0.049**

Table 7 Aishihik Lake 1984 - 1999 Lake Whitefish Relative Year-Class Strength Calculated by Plotting Residuals, Comparing Years When Minimum Lake Elevations Were Above and Below 914.1 and 913.7 m asl

Minimum Lake Elevation: 914.1		
	Relative Year-Class Strength for Years Above and Below 914.1	
	Above	**Below**
1984	0.395	
1985	-0.678	
1986	-0.260	
1987	-0.864	
1988		0.835
1989	-1.050	
1990		0.592
1991		1.355
1992	0.212	
1993	0.120	
1994	0.096	
1995		0.067
1996		-0.025
1997		-0.406
1998		0.384
1999		-0.774
Average	**-0.254**	**0.254**
Difference		**+0.508**

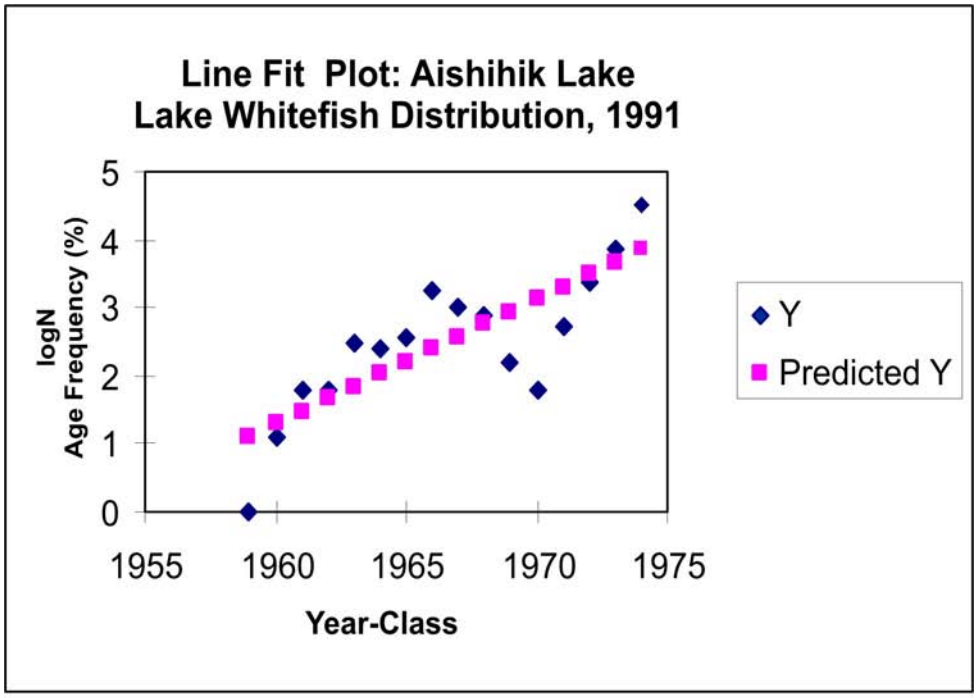
Minimum Lake Elevation: 913.7		
	Relative Year-Class Strength for Years Above and Below 913.7	
	Above	**Below**
1984	0.395	
1985	-0.678	
1986	-0.260	
1987	-0.864	
1988	0.835	
1989	-1.050	
1990		0.592
1991		1.355
1992	0.212	
1993	0.120	
1994	0.096	
1995		0.067
1996		-0.025
1997		-0.406
1998		0.384
1999		-0.774
Average	**-0.113**	**0.188**
Difference		**+0.301**

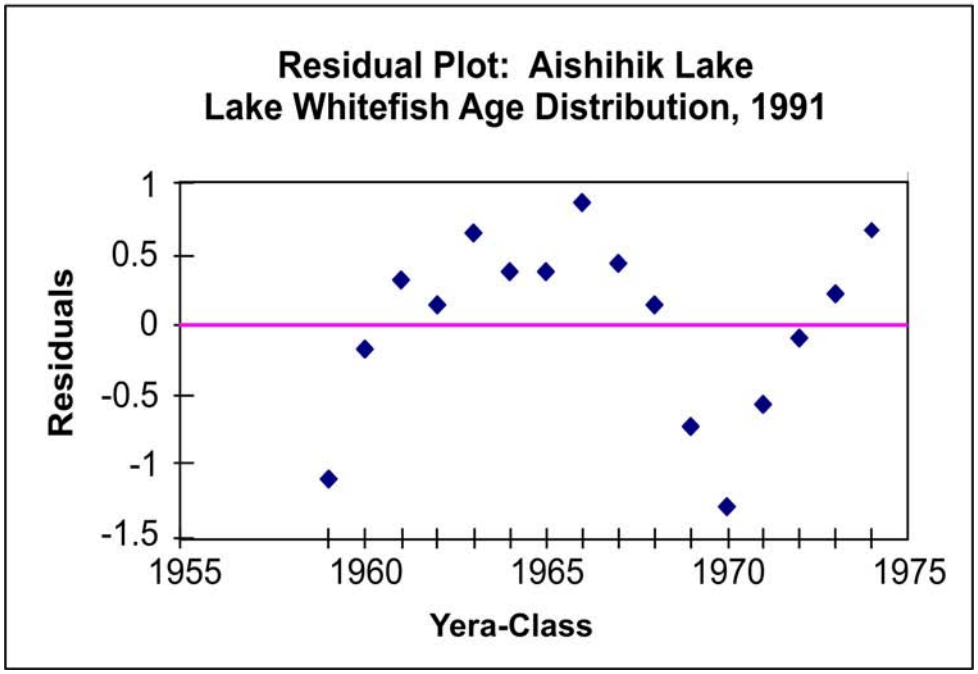
Using this approach the mean RYCS associated with low water years is higher in all three comparisons relative to the normal years.

As a final illustration, and to provide some context, one additional analysis was performed using the 1991 lake whitefish age distribution data (de Graff 1993). Figure 13 presents Line Fit and Residual plots for the 1959-1974 period (i.e., pre-project). The plots indicate a range of RYCS variability that is comparable to that observed for the 2007 data (Figures 11 and 12). In this case the variability is assumed to represent natural variability since the year-

classes in question were recruited prior to the completion of the Aishihik hydroelectric facilities in 1975.

Figure 13 Line Fit and Residual Plots for Aishihik Lake Whitefish Age Distribution, 1959 – 1974, Based on 1991 Data

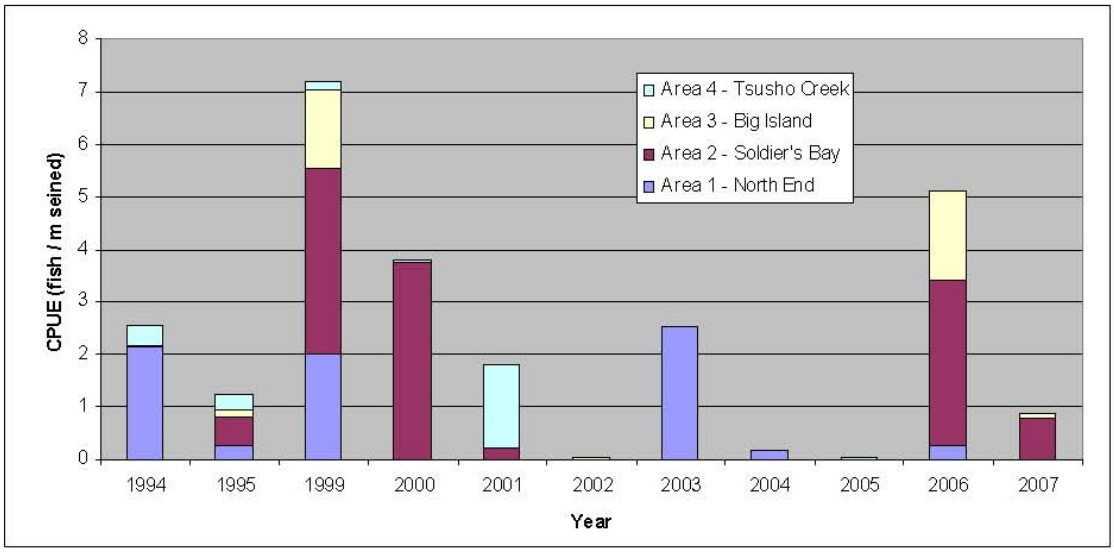




4.0 ANNUAL BEACH SEINING SURVEYS

A total of 11 beach seining surveys have been conducted since 1994 (Figure 13), including nine standardized monitoring surveys (1999-2007). The primary objective of the monitoring surveys was to determine if summer beach seining results could be used as an early predictor of adult recruitment. In other words, is the abundance of young-of the-year (YOY) lake whitefish in a given year, expressed as catch-per-unit-effort (CPU), a useful predictor of the strength of that year-class when it becomes recruited into the adult population?

Figure 13 Comparison of YOY lake whitefish capture rates based on beach seining CPUE (fish/m seined), 1994-2007 (from EDI 2007)



To date, no trend has been observed that relates beach seining success to minimum spring lake elevations. Catch numbers have varied widely between years with no apparent relationship to lake levels, and both high and low CPUE values have been reported for low and high water years. It is likely that other environmental factors (e.g., spring and summer weather, water temperatures at the time of the surveys) play a major role in catch success and, therefore, represent a significant confounding factor.

The principal question of whether the catch data correlate to eventual adult recruitment can not be answered conclusively since most of the year-classes represented in the annual beach seining surveys (i.e., 1999-2007) were not fully recruited at the time of the 2007 index gillnetting program. For the younger year-classes that are represented in the 2007 gillnetting catch, there appears to be a poor correlation to beach seining CPUE values. The 1999 year-class was strong in 1999 and is fairly well represented in the 2007 gillnetting catch. In contrast however, age-3 fish (2004) are better represented in the gillnetting catch data than

other juvenile year-classes (e.g., 2003 and 2006) even though beach seining CPUE was relatively low in 2004 compared to 2003 and 2006.

Based on existing information it is difficult to determine if annual beach seining is a useful predictor of adult recruitment. However, continued monitoring may eventually answer this question when the data are eventually compared to future index gillnetting surveys.

Paragraph 4(d) of the Authorization sets out several provisions that will remain in effect after 2007, regardless of the 2007 monitoring results and any subsequent modifications to YEC's operational requirements. Paragraph 4(d)(i) goes on to say:

> *"Should anytime after 2007 lake whitefish monitoring results in two of any five year period, demonstrate, for years when minimum daily spring elevations were below 913.7 m ASL, poor recruitment results (i.e., juvenile recruitment at or below 50% of Normal Year Class Strength), then, subject to 4(d)(ii), the Ten Year Rolling Average shall be re-instituted as soon as reasonably practicable and the minimum daily spring elevation shall not be lower than 913.7 m ASL more than two years in any five year period, or other mitigation measures acceptable to DFP and Yukon Energy shall be established."*

Paragraph 4(d)(ii) states:

> *"Should anytime after 2007 lake whitefish monitoring results in four out of any five year period demonstrate juvenile recruitment greater than 50% of Normal Year Class Strength, then, subject to paragraph 4(d)(i), the Ten Year Rolling Average Requirement and any requirement that the minimum daily spring elevation not be lower than 913.7 m ASL more than two years in any subsequent five year period both shall not apply."*

Given the uncertainties regarding the usefulness of the annual beach seining results to date, it is unlikely that the provisions in the two Authorization paragraphs above can be met at this time.

5.0 ANNUAL AQUATIC MACROPHYTE SURVEYS

Aquatic macrophyte (plant) surveys were conducted in the north end of Aishihik Lake in 1993 and annually since 2000 as part of the Aishihik Lake Monitoring Program. The annual surveys have been conducted in accordance with the Water Use Licence requirement to monitor habitat changes in that part of the lake, particularly as these changes relate to lake regulation.

Between 1995 and 2000, Aishihik Lake experienced relatively low lake elevations which resulted in the substantial expansion of littoral aquatic habitats in the north end of the lake. Since 2000, the elevation of Aishihik Lake has returned to the natural range (pre-project) and consequently littoral plant communities have been reverting to distribution patterns and composition observed and recorded prior to the low water period. Surveys completed in recent years (2003-2007) provide evidence that the aquatic macrophyte communities in the north end have become more stable with regard to distribution and community composition, although minor differences continue to occur between years. Some differences between years would be anticipated in any event, as plant communities respond to intra-annual differences in environmental conditions such as weather. It therefore appears that the aquatic macrophytes community in the north end of Aishihik Lake has attained a level of stability that it is likely to maintain unless significant environmental changes occur (e.g., a substantial change in lake elevation).

6.0 REFERENCES

de Graff, N.M. 1993. Fisheries assessment of Aishihik, Canyon and Sekulmun lakes, 1991-992. Fish and Wildlife Branch, Yukon Department of Renewable Resources. Technical Report TR-93-1. 68 pp + app.

Environmental Dynamics Inc. (EDI). 2007. Aishihik Lake Whitefish Monitoring Program 2007. Prepared for Yukon Energy Corp. 23 pp. + 2 App.

Maceina, M.J. 1997. Simple application of using residuals from catch curve regressions to assess year class strength in fish. Fisheries Research 32:115–121.

YEC 1998. Aishihik Relicensing Project Environmental Impact Assessment. Vol. 6: Aquatic Studies. Prepared for Yukon Energy Corporation by North/South Consultants Inc. 244 pp. + 1 App.

REFERENCE: Tab 5 Capital Projects; P 5-22, L 26

QUESTION:

a) The Mayo Lake dam was first built in the mid 1950s and extensively rebuilt in 1988 and 1989. Please describe in detail the portions of this dam needed to be assessed.

ANSWER:

(a)

All wooden portions of the dam will be assessed including the connections, spill boards, and the valve structure for their soundness and design. The location of the valves will also be assessed to determine if there is a more optimal design for its operation.

REFERENCE: **Tab 5 Capital Projects; P 5-23, L 1**

QUESTION:

a) Has the Alexco mine paid for this work in advance? If not what is the agreement between Yukon Energy and Alexco? Please provide a copy of any written agreements.

ANSWER:

(a)

No. As noted in response to LE-YEC-1-8, discussions with Alexco related to a Power Purchase Agreement are currently underway.

REFERENCE: **Tab 9 Audited Financial Statements; P 9-11, Amortization periods**

QUESTION:

a) The amortization of wind turbines in Europe is typically 20 years (sometimes 25 years in USA), and turbines typically have a design life of 20 years. This being the case it seems inappropriate to amortize them over 30 years, why does Yukon Energy do so?

ANSWER:

(a)

Yukon Energy adopted its current depreciation rates out of the Gannett Fleming depreciation study completed for the 2005 Required Revenues and Related Matters Application. That study recommended a 30 year amortization period for wind turbines.

PETER PERCIVAL / HAMLET OF MOUNT LORNE (PWP / HML)

REFERENCE:

QUESTION:

a) OIC 2008/149 was issued Oct. 3, 2008 and the GRA was filed with the YUB on Oct. 6, 2008. Based on the reasonable assumption that it takes a considerable length of time to prepare a GRA filing and therefore by Oct. 3, 2008 the GRA would have been virtually complete, did YEC during the three day (in reality a 2 day) interval find it necessary to make any changes to the filing so as to comply with OIC 2008/149? Please explain why or why not changes were required. Does YEC now plan to make any amendments to the existing GRA as filed so as to conform to OIC 2008/149?

ANSWER:

(a)

Please see response to YUB-YEC-1-20. YEC filed its Application on October 6, 2008 in compliance with the YUB and the directives in place at the time, including OIC 2008/149.

REFERENCE:

QUESTION:

a) Please explain why the on page 2 of the Over View it states that "Rate Policy Directive (OIC 1995/90) was amended prior to this Application…" but the Application does not provide the new OIC number in this reference nor was the new OIC 2008/149 included in the Application binder under TAB 10, ORDERS IN COUNCIL?

ANSWER:

(a)

The government OIC (2008/149) was not available for inclusion in the 2008/2009 General Rate Application when the Application was being finalized for printing.

REFERENCE:

QUESTION:

a) When exactly did YEC receive OIC 2008/149? At what point in time was YEC made aware that this OIC was being prepared? Did any YEC staff or Board members of YEC or its parent YDC have input or were they consulted during the preparation of this OIC? Please identify such staff or members. Please provide any YEC files, records, notes, letters or emails relating to the issuance and impacts of this OIC.

ANSWER:

(a)

Please see response to YUB-YEC-1-20.

REFERENCE:

QUESTION:

a) Please provide a list of the YEC Board Members and Corporation Officers with titles and appointment term expiry dates for each Board Member. Which of these YEC Board Members or Corporation Officers serve in similar capacities on the Board or within the corporate structure of YEC's parent Crown Corporation YDC?

ANSWER:

(a)

YEC Board Members are as follows:

	Date Appointed	Term
Willard Phelps, Chair	March 16, 2007	March 15, 2010
Paul Hunter	August 5, 2007	August 4, 2010
Paul Birckel	January 21, 2009	January 20, 2012
Barb Joe	August 5, 2007	August 4, 2010
Pat Irvin	December 9, 2007	December 8, 2010
Martin Allen	July 25, 2008	July 24, 2010
Greg Hakonson	October 15, 2008	October 14, 2011
Luke Johnson	January 21, 2009	January 20, 2012

The Officers of YEC are as follows:

David Morrison, President and CEO
Ed Mollard, CFO
David MacDonald, VP Operations
Shelley Dixon, Corporate Secretary

Issues relating to YDC and its corporate structure are not relevant to this Application.

REFERENCE:

QUESTION:

a) Assuming that YEC's proposed retail customer rates for all classes of retail customers are implemented on a Yukon wide basis (i.e. would apply to YECL's retail customers also), please provide, on a (YEC / YECL combined) Yukon wide basis, estimates for the amount of energy consumption and the amount of revenue collected from each of the first blocks and run out blocks for each retail customer class for each of the test years.

ANSWER:

(a)

Please see Table 4.10, Tab 4.

REFERENCE:

QUESTION:

a) As run out or second block rates, sales and revenues are in effect to be used to subsidize or lower the first block rates for the residential retail classes how does YEC propose to cover revenue short falls that may occur as a result of customer price resistance to the run out rates? What sensitivity analysis has YEC carried out with regards to this possible price resistance?

ANSWER:

(a)

Yukon Energy understands the question to be in regards to price elasticity of demand for second block rate power.

Yukon Energy does not anticipate price elasticity of demand leading to reduced second block use to be a material factor in the test years. This is because electricity as a commodity is typically not particularly elastic, and any consumer price elasticity is normally understood as a longer-term factor.

Beyond the test years, to the extent less purchases occur in the second block, the impacts of this development in terms of both revenues and reduced peaking diesel consumption will be reflected in future GRAs.

REFERENCE:

QUESTION:

a) If OIC 2008/149 requires that "rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers." why does the table on page 2 of the OVERVIEW Background show Overall Percentage Changes for first block rate decreases that vary between (17.8%) and (13.7%)? To conform to the OIC does YEC plan to amend the GRA filing to rebalance the % decreases so that the rate adjustments for retail customers apply equally?

ANSWER:

(a)

No. YEC's GRA filing is in compliance with the OIC. All classes of customers are proposed to receive a 3.48% rate reduction to the class.

This OIC directive has applied in the past to prevent rebalancing of revenues among retail rate classes. During the time that this directive was previously in effect, adjustments were approved to address runout rate requirements and other specific rate elements within each class in the same manner as proposed in the Application.

REFERENCE:

QUESTION:

a) Do the second block run out rate increases for retail customers apply equally, when measured as percentages, to all classes of retail customers?

ANSWER:

(a)

No. The requirement for rate changes to apply equally on a percentage basis is applied at the class level, not at the individual rate block charge level. Please also see response to PWP/HML-YEC-1-7.

REFERENCE:

QUESTION:

a) In the OVERVIEW, Summary of Requested Orders c. Depreciation and Amortization Expenses i. pages 4/5 the amortization period for the current GRA (Phase I) Application is proposed to be only over the 2 test years. Would it not be more appropriate to amortize these costs over the period ending December 31, 2012, the date on which OIC 2008/149 expires, and which is probably the earliest likely date by which YEC would file a new GRA?

ANSWER:

(a)

YEC has no specific plans as to when it would seek to file a next GRA. It is possible it will be for test years prior to 2012.

The practice in Yukon has been to amortize the costs of a GRA or rate hearing over the period covered by the test years. The only exception YEC is aware of was YEC's 2005 GRA, which was amortized over 3 years (2005-2007) based on the approval to make use of deferred revenues (de-watering funds) to plan to avoid the need for a GRA until test year 2008.

REFERENCE:

QUESTION:

a) In the OVERVIEW on page 6 under a. v. Lighting (Rate Schedules 61/66, 67, 75/76) please provide the actual reductions for each of the rate schedules in cents/kW.h?

ANSWER:

(a)

Lighting loads served under these rate schedules are not billed on a cents/kW.h basis, but rather a flat fee per month for each lamp or each watt of lighting capacity installed. For the Rider U reductions proposed for each lighting rate class, please see the table provided below.

Proposed reductions for Rate Schedules 61/66, 67, 75/76.

	Current base rate	Proposed reduction	Proposed base rate
Rate Schedule 61/66			
Customer Charge ($/lamp)	6.36	0.22	6.14
Demand Charge (c/Watt)	4.03	0.14	3.89
Surcharge for Highmast Fixtures ($/lamp)	1.03	0.04	0.99
Rate Schedule 67			
400 Watts Street Light ($/month)	23.66	0.82	22.84
250 Watts Street Light ($/month)	15.47	0.54	14.93
Rate Schedule 75/76			
Normal 12-month unmetered service			
100 Watt HPS ($/month)	11.64	0.40	11.24
A 175 Watt MV 7,000 Lumen ($/month)	14.18	0.49	13.69
A 250 Watt MV 11,000 Lumen ($/month)	17.34	0.60	16.74
A 400 Watt MV 20,000 Lumen ($/month)	23.03	0.80	22.23
400 Watt MV Flood-Light Unit ($/month)	25.44	0.88	24.56
Energy and maintenance only			
100 Watt HPS ($/month)	6.46	0.22	6.24
A 175 Watt MV 7,000 Lumen ($/month)	9.87	0.34	9.53
A 250 Watt MV 11,000 Lumen ($/month)	13.16	0.46	12.70
A 400 Watt MV 20,000 Lumen ($/month)	18.61	0.65	17.96
400 Watt MV Flood-Light Unit ($/month)	17.75	0.62	17.13
12-month service through customer meter			
100 Watt HPS ($/month)	7.34	0.26	7.08
A 175 Watt MV 7,000 Lumen ($/month)	7.97	0.28	7.69
A 250 Watt MV 11,000 Lumen ($/month)	8.23	0.29	7.94
A 400 Watt MV 20,000 Lumen ($/month)	7.84	0.27	7.57
400 Watt MV Flood-Light Unit ($/month)	10.26	0.36	9.90

REFERENCE:

QUESTION:

a) If OIC 2008/149 requires that "rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers." And other retail customers are receiving overall percentage changes in the range between (17.8%) and (13.7%) why do Rate Schedules 61/66, 67, 75/76 only receive negative 3.48% to all base rates.

ANSWER:

(a)

Each class of retail customer is receiving a rate reduction equal to 3.48%. This same percentage does not apply to each specific rate or charge within the class rate structure, but at a class level the percentage reductions are equal.

The reference to percentage changes in the range between (17.8%) and (13.7%) reflect only the overall impact (after all riders, rebates and subsidies) of changes to the first block energy charge. As reviewed in the Application, the overall rate change to each of the related retail classes remained an overall 3.48% reduction.

Due to the absence of any separate rate components, all space and street lighting base rates were simply reduced by 3.48%.

REFERENCE:

QUESTION:

a) As Lighting is un-metered what is the rational of having Lighting classed as a Retail Rate?

ANSWER:

(a)

The term “retail customer” is defined by OIC 1995/90, and includes lighting customers.

REFERENCE:

QUESTION:

a) Please provide in table form a summary of all planned or accidental power disruptions or power bumps (dates, durations, affected zone(s) / number of customers affected, causes, remediation / response procedures, etc.) attributable to YEC operations on the WAF and D-M grids from the period beginning when the D-M grid came on line up to date.

ANSWER:

(a)

Please see Attachment 1 provided to this response. These reports commenced in March 2004.

YUKON ENERGY

Outage / Disturbance Report
March 2004

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
March 11/04	***Faro*** - Little Salmon	2	Bird/animal	1 hour, 30 minutes	Customer not sure when power went off. Called at 14:15 hrs, power on at 15:45.
March 19/04	***Faro*** - Tintina subdivision	6	Planned	29 minutes	Planned outage to change out a switch.
March 26/04	***Mayo*** - Mayo and Elsa Line	350	Planned	8 minutes	Planned outage to test Mayo diesel load pickup.
March 26/04	***Mayo*** - Elsa Line	35	Planned	3 minutes	Planned outage to test Mayo diesel load pickup.
March 26/04	***Mayo*** - Mayo and Elsa Line	350	Planned	3 minutes	Planned outage to test Mayo diesel load pickup.
March 30/04	***Dawson*** - Part of Feeder 2	110	Planned	35 minutes	Express Feeder Alley Work.

YUKON ENERGY

Outage / Disturbance Report
April 2004

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
April 2/04	Part Feeder 2	110	Planned	29 min	Express Feeder Work
April 3/04	Dawson S7960 out to Dempster cutoff	161	Planned	92 min	Install gang switch S7964
April 3/04	Grid/Dawson City	Feeder 1- 389 Feeder 2- 474 Feeder 3- 306	Unknown	Feeder 1 8 min Feeder 2 11 min Feeder 3 37 min	Phase to ground fault on Hunker Creek feeder. During heavy icing, nothing found after line patrol. Relay coordination problem caused breaker CM-1 to trip.
April 17/04	Rock Creek	20	Isolation	20 min	Trouble call – tree felled on line by third party.
April 19/04	Dome Sub	1	Blown Transformer	12 hrs	Customer didn't call until next AM.
April 27/04	Henderson Corner	1	Damaged Transformer	2 hrs	Transformer failed after oil sample was taken.
April 27/04	L170 (S164 to Faro)	505 - 11 506 – 131 507 – 131 Drury Crk – 9 Braeburn– 10 Lt Fox – 2 Lt Salmon- 8 Deep Crk - 1 (YECL)	Tree Contact	505 – 7 min, 46 sec 506 – 8 min, 40 sec 507 – 8 min, 58 sec Drury Creek & Lt Salmon – 2 hrs, 28 min Braeburn, Lt Fox & Deep Creek – 1 hr, 24 min	Trees contacting the line near Little Salmon structure 1272. Faro placed on diesel and L170 was energized up to Carmacks, trees removed on April 28/04.

YUKON ENERGY

Outage / Disturbance Report
May 2004

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
May 4/04	Mayo	23	Unplanned - Nature	14 minutes	Tree was on Primary. Had to open line to remove
May 20/04	L250 line (Elsa Feeder)	5	Unplanned - Mechanical	2 minutes	Gang switch did not close properly, had to take outage to close.
May 26/04	Henderson's Corner (Dawson)	49	Planned	70 Minutes	Pole Changed
May 27/04	Callison Subdivision (Dawson)	78	Planned	55 Minutes	Pole Changed
May 28/04	Boutillier Road (Dawson)	4	Planned	60 Minutes	Move Pole for YTG
May 28/04	6th and York (Dawson)	75	Planned	15 Minutes	Set Pole to Remove Arial Transformer

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
June 2004

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
June 9/04	Mayo	2	Planned	25 min	Planned outage to remove PCB transformer.
June 22/04	Porter Creek & Riverdale	1- YECL	Equipment Failure	19 min, 41 sec	AH1 tripped off (guide bearing temperature) line while generating 10 MW, resulting in the under-frequency tripping of S6838 and S150 52-17
June 22/04	Mayo - Town site	296	Wind	1 hour, 1 min	Strong winds caused three separate tree contacts on the Mayo town feeder resulting in the over-current trip of OCR S7748.
June 22/04	Dawson - Rock Creek	2	Wind	Approx. 6 hours	Windstorm hit causing trees to fall on line, broke pole, 5 spans down.
June 22/04	Dawson - Rock Creek	1	Wind	Approx. 4 hours	Wind causing tree contact.
June 29/04	Dawson - Part of Feeder 1	49	Planned	37 min's	Move of RCMP building.
June 30/04	Downtown Whitehorse	1- YECL	Lightning	22 min's	Many lightning strikes in the Whitehorse area.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
July 2004

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
July 1/04	L170 (S164 to Faro)	505 - 11 506 – 131 507 – 131 Drury Crk – 9 Braeburn– 10 Lt Fox – 2 Lt Salmon- 8 Deep Crk - 1 (YECL)	Suspected Lightning	505 – 11 min, 18 sec 506 – 11 min, 18 sec 507 – 11 min, 18 sec Drury Creek & Lt Salmon – 5 min, 54 sec Braeburn, Lt Fox & Deep Creek 5 min, 54 sec	Lightning strike on L170 caused breaker S164 52-3 to trip on over-current. The breaker was successfully reclosed. Faro was not placed on diesel during this event. Carmacks and Ross River transferred to standby diesel (YECL) during this event.
July 2/04	Group Home Road, Mayo	10	Tree Contact	12 minutes	Had to remove a tree on the Primary
July 3/04	Whitehorse Feeders: 9L, 10L, 19L and S6838	1 (YECL)	Animal Contact	9L – 10 min 10L – 25 min 19L – 31 min S6838 - 17 min	A raven in the Shipyards substation caused a phase to ground fault which tripped off WH4 before the feeder breaker cleared the fault.
July 11/04	L170 (S164 to Faro)	505 - 11 506 – 131 507 – 131 Drury Crk – 9 Braeburn– 10 Lt Fox – 2 Lt Salmon- 8 Deep Crk - 1 (YECL)	Equipment Failure	505 – 12 min, 12 sec 506 – 17 min, 3 sec 507 – 19 min, 42 sec Drury Creek & Lt Salmon – 2 hrs est. Braeburn, Lt Fox – 4 hrs, 59 min, 46 sec Deep Creek – 4 hrs, 13 min, 46 sec	The cause of this outage was found to be a broken cross-arm on structure 262 near the south end of Fox Lake. Faro was placed on diesel during the repairs. Carmacks and Ross River transferred to standby diesel (YECL) during this event.
July 12/04	All of Feeder 3	304	Planned	55 minutes	Change faulty insulator on guy.
July 14/04	Elsa, & Keno, Mayo	4 – Elsa 245 - Mayo	Equipment Failure	4 minutes and 1 second (Elsa), 4 minutes and 28 seconds (Mayo)	Men were working on the Governors of MH2- SCC received incorrect readings on SCADA – Resulting in the operator tripping the feeder breakers.
July 19/04	L170 (S164 to Faro) & Whitehorse Feeders: 9L, 10L, 13L, 19L, S6837, S6838.	(L170) 505 - 11 506 – 131 507 – 131 Whse Feeders are YECL customers.	Suspected Lightning & Equipment Failure (WH4 Protection)	505 – 48 min, 47 sec 506 – 49 min, 15 sec 507 – 48 min, 47 sec Drury Creek & Lt Salmon – 5 min, 54 sec Braeburn, Lt Fox & Deep Creek 5 min, 54 sec 9L – 12 min, 41 sec 10L – 33 min, 42 min 13L – 8 min 19L – 43 min, 5 sec S6837 - 51 min, 29 sec S6838 – 45 min, 8 sec	The loss of WH4 resulted in a major system outage, WH3 remained on line energizing the sub buses and transmission line, Haines Junction remained on the grid. The protection at WH4 indicates a high current on A phase, which indicates a potential distribution or transmission fault, however nothing was reported in either case. The protection settings on WH4 were changed on July 19, 2004, these changes were made after the system was restored and stabilized.

YUKON ENERGY

Outage / Disturbance Report
August 2004

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Aug. 11/04	Village of Mayo	249	Planned Outage	3 hours, 40 minutes	Replacing Gang Switch at Diesel yard.
Aug. 12/04	Village of Mayo	249	Planned Outage	3 hours, 50 minutes	Replacing Gang Switch at Diesel yard.
Aug 13/04	Dawson - Feeders #2 and #3.	777	Equipment Failure	Feeder 3: 1 hour, 12 minutes Feeder 2: 1 hour, 42 minutes	At the time of this event MH2 was off line for repairs to the slip ring. MH1 and DD5 were on line supplying the grid demand. The investigation found two blown fuses on a bank of 37 kva's in Callison. The services are on but there is no consumption. The H1 bushings on both cans were flashed over (they had squirrel guards on them that were pushed all the way down to the top of the can, covering all the skirts of the glass.).
Aug 25/04	Town of Elsa	2	Planned Outage	2 hours, 15 minutes	Customer requested switch opened, to brush substation
Aug 27/04	S150 9L - Teslin and Carcross Loads	1- YECL 15 – Johnson's Crossing	Lightning	1 minute, 26 seconds	Lightning strike caused breaker S150 52-22 to trip, successfully re-closed by SCC
Aug 31/04	Village of Mayo	130	Planned Outage	2 hours, 45 minutes	Replace switch S7709
Aug 31/04	Village of Mayo	4	Improper installation	10 minutes	Polarity of Transformer in Bank incorrect.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
September 2004

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Sept 4/04	Mayo	27	Tree Contact	22 min	Tree contact at Wozinacs (Government subdivision)
Sept 24/04	Dawson	1166	Line Contact	Feeder #1 - 14 min Feeder #2 – 18 min Feeder #3 – 2 hrs 20 min (estimated)	Airplane flew through the L174 transmission line, cutting all three phases.
Sept 25/04	Dawson	1166	Loss of Generation	Feeder #1 - 44 min Feeder #2 – 46 min Feeder #3 – 1 hr (estimated)	Dawson fed from diesel while L174 was down for repairs. DD3 tripped off line on high jacket water temperature.
Sept 28/04	WAF – S150 52-17, S150 52-22 & S6838	1 – YECL 15 – YEC (Johnson's Crossing)	Tree Contacts & Loss of Generation	S150 52-17 – 33 min S150 52-22 – 34 min S6838 – 12 hrs, 1 min	High winds caused multiply tree contacts, specifically south of Whitehorse. WH4 tripped off line (over-current) causing additional outages in Riverdale and Porter Creek (under-frequency trips). WH4 was unable to be placed back on line, failed to sync.
Sept 29/04	WAF – S6838 and S150 52-17	1-YECL	Loss of Generation	S150 52-17 – 11 min S6838 – 17 min	WH4 was placed on line after being electrically tested from the Sept 28/04 outage, when the unit breaker closed an under-frequency condition occurred on the system resulting in the tripping of feeders S150 52-17 and S6838.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
October 2004

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Oct 2/04	Riverdale	1- YECL	Bad Insulators	3 hours, 45 minutes	Bad insulators on 19L (S150 52-17)
Oct 10/04	Mayo School	1	Unplanned - Customer Problem	1 hours, 10 minutes	Blown fuse in Cutout. Refused - OK
Oct 13/04	Carcross Line 9L	1- YECL	Tree Contacts (high Winds)	4 hours, 35 minutes	Extremely high winds gusting to 65km/hr, tripped line 9L (S150 52-22). Many trees on the line
Oct 19/04	Riverdale and Porter Creek	1- YECL	Loss of Generation	S150 52-17 – 3 minutes S6838 – 4 minutes	WH4 was off line for breaker repair when unit was put back on line it went unstable causing S6838 and S150 52-17 to trip on under frequency. Cause unknown at this time.
Oct 20/04	Dawson - Feeder #3	304	Over speed on DD5	2 minutes	See outage report.
Oct 20/04	Faro - Breaker 506	135	Animal Contact (Raven)	7 minutes	Raven blew 50 KVA transformer fuse. This caused feeder breaker 506to operate.
Oct 20/04	Faro RCMP Office	1	Animal Contact (Raven)	22 minutes	Refused 50 KVA transformer and restored power at 10:10

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
November 2004

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Nov 3/04	Johnson's Crossing	16	Tree Contact	1 hour, 42 minutes	Tree contacted the line.
Nov 17/04	Elsa Feeder	YECL customers -10 YEC customers-4	Planned Outage	3 hours, 15 minutes	Pole change out
Nov 18/04	Elsa Feeder	YECL customers- 10 YEC customers- 4	Planned Outage	2 hours, 24 minutes	Pole change out
Nov 18/04	Elsa Feeder	YECL customers- 10 YEC customers- 4	Weather	4 minutes, 48 seconds	Heavy snow at the time of this outage.
Nov 21/04	Johnson's Crossing	16	Weather	9 hours, 4 minutes	Snow and icing on the lines caused this outage.
Nov 24/04	Johnson's Crossing	16	Weather	1 hour, 31 minutes	Snow and icing on the lines caused this outage.
Nov 24/04	Johnson's Crossing	16	Weather	15 minutes	Snow and icing on the lines caused this outage.
Nov 28/04	Johnson's Crossing	16	Weather	6 hours, 14 minutes	Snow and icing on the lines caused this outage.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
January 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Jan 28/05	Johnson's Crossing	16	Loss of Supply - Heavy Snow	1 hour 15 min	YECL reported this outage, which was initiated at Marsh Lake OCR S9657.
Jan 28/05	Johnson's Crossing	16	Loss of Supply - Heavy Snow	1 hour 30 min	Second Outage - YECL reported this outage, which was initiated at Marsh Lake OCR S9657

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
February 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Feb 16, 2005	Dawson - All Feeders Elsa Feeder	Dawson - 1169 YECL customers- 10 YEC customers- 4	Human Error	Feeder 1 - 8 min Feeder 2 – 9 min Feeder 3 – 28 min L174 – 20 min MH0 52-F1 – 13 min	While installing new speed sensing equipment on the Mayo hydro units, the online unit was inadvertently tripped. At the time of this event only one hydro unit was on line, the remaining generation came from Mayo diesel.
Feb 28, 2005	Elsa Feeder	YECL customers- 10 YEC customers- 4	Melting Snow	1 min, 57 sec	The suspected cause of this outage is snow melting causing tracking on a bad insulator.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
March 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
March 30/05	Faro - Feeder 1 (Breaker 506)	152	Suspect Animal Contact	13 minutes	Cause of this event a suspected bird contacting the line. Phase to phase fault.
March 30/05	Mayo-Dawson	2	Planned	5 minutes	Switch In - Outage due to switching so crew could work on the Mayo Dawson line. Partridge & Moose Creek customers.
March 30/05	Mayo-Dawson	2	Planned	6 minutes	Return to Normal - Outage due to switching so crew could work on the Mayo Dawson line. Partridge & Moose Creek customers.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
April 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
April 28, 2005	Faro	284	Animal Contact	506 – 19 min, 11 sec 507 – 36 sec	At 07:42:08 Faro Breakers 506 and 507 tripped. SCC reclosed Faro 507, which closed and held. SCC unsuccessfully reclosed Faro 506. The Faro serviceman performed a line patrol. And reported a dead raven found near switch S7584. At 08:01:19 SCC reclosed Faro 506, which closed and held.
April 29, 2005	L174/Dawson	Dawson – 1166 L174 - 6	Animal Contact	Feeder 1 – 30 min, 57 sec Feeder 2 – 43 min, 42 sec Feeder 3 – 43 min, 6 sec L174 - 25 min, 14 sec	The cause of this outage was found to be a squirrel contacting the line at the Dawson airport; the contact was at a riser pole that feeds the pad mount transformer. During the Dawson restoration the fuel automatic shut off valve was tripped causing delays to the restoration. Suspected cause is dead batteries to the valve.
April 30, 2005	Johnson Crossing	15	Loss of supply – tree contact	2 hours, 35 min	Tree contacted the 9L line. YECL provided the restoration.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
May 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
May 3, 2005	Dawson Feeders 1 and 2	Feeder 1 – 389 Feeder 2 - 473	Human Error	Feeder 1 - 16 min, 11 sec Feeder 2 – 17 min, 1 sec	Dawson feeders 1 and 2 were being fed from diesel at the time of this event. An electrician was working on the fire system and unintentionally closed the fuel valve to the units.
May 12, 2005	Haines Junction Feeder	3 – YEC 1 – YECL (Haines Jct)	Animal Contact	S167 52-2 - 37 min, 51 sec	The cause of this outage was found to be a squirrel-contacting transformer S167 T2. Haines Junction went to diesel backup with 3 minutes.
May 14, 2005	Whitehorse S6838 S150 52-21 S150 52-22	1 - YECL	Loss of Generation	S6838 – 20 min 37 sec S150 52-21 – 18 min 36 sec S150 52-22 – 9 min 11 sec	Aishihik unit #1 tripped off line due to a "Lower Guide Bearing Temperature" trip. At the time of this event the unit was at 10.2 Mw, the loss of this generation caused an under frequency condition on the system.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
June 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
June 8/05	Mayo - Silver King Mine	1	Equipment Failure - Opened fuse	60 minutes	S7744 Fell open, not blown
June 10/05	Partridge Creek	5	High Winds - Tree hit line	2 hours, 45 minutes	T174P 89-2 Fuse operated
June 12/03	Dawson - All Feeders L174 (Partridge & Moose Creek)	1169 6 Total - 1175	Wind Storm	Feeder 1 10 minutes Feeder 2 10 minutes Feeder 3 2 hours, 51 minutes L174 – 1 hour, 5 minutes	Relay coordination problems caused L174 to trip resulting in a Dawson outage; the cause was multiple tree contacts on the Hunker Creek feeder. Rock Creek was isolated so that Hunker and Henderson could be reenergized while repairing the line and cutting trees.
June 14/05	Mayo - Gov Subdivision	29	High Winds - Tree hit line	1 hour, 15 minutes	S7727 Fuse operated
June 17/05	Mayo - Gov Subdivision	29	High Winds - Tree hit line	52 minutes	S7727 Fuse operated
June 17/05	Mayo - Group Home Road	12	High Winds - Tree hit line	1 hour, 43 minutes	S7702 Fuse operated
June 17/05	Mayo - Lot 5 Alder drive	1	High Winds - Tree hit line	45 minutes	Tree Broke Triplex
June 27/05	L170 (Takhini to Faro line)	331 – Includes Fox, Drury, Braeburn and Faro	Lightning Strike	L170 customers 4 min Faro customers 8 min	Suspected cause of this outage is lightning. YECL Carmacks and Ross River transferred to diesel at the onset of this disturbance.
June 30/05	Braeburn	1	Animal Contact – Raven	6 hours est.	Long time frame due to YEC serviceman traveling back from Faro and the lack of notification from the customer (fuse found open when meter reading).

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
July 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
July 1/05	Faro - 506	142	Animal Contact	9 min, 37 sec	Dead raven found on the feeder.
July 5/05	Elsa Transmission Line	5 – YEC 11-YECL	Lightning	1st – 1 min 2nd – 1 min 3rd - 2 min	Line tripped 3 separate times due to lightning strikes. A subsequent line patrol identified Halfway Lakes and Silver King Mine fuses had blown (see below).
July 5/05	Halfway Lakes	2	Lightning	1 hour, 48min	Found on patrol. Customer wasn't home
July 5/05	Silver King Mine	1	Lightning	2 hours, 23min	Found on patrol.
July 5/05	Dawson / L174	1172	Lightning	Feeder 1 – 15 min Feeder 2 – 16 min Feeder 3 – 34 min L174 – 41 min	The cause of this outage is a suspected lightning strike on L174, tripping S249 52-2.
July 14/05	Silver King	1	Unknown	2 hours, 16min	Fuse was burned off. Had problems with this fuse last month
July 14/05	Elsa Transmission Line	5 – YEC 11-YECL	Requested By Lineman in the field	5 min	Fuse was burned off at Silver King, Had to have Elsa line de-energized to safely remove fuse
July 16/05	Mayo Airport	1	Animal Contact	6 hours, 15 min	Fuse blue at 9am but customer had back up generator. Didn't call until 3pm and power was restored at 3:15pm
July 22/05	Faro - 507	142	Animal Contact	3 min	Raven contacted a transformer causing the feeder breaker to trip. A subsequent line patrol identified a 50 KVA transformer blown (see below).
July 22	Faro - 525 Douglass	6	Animal Contact	1 hour, 10 min	Raven caused 50 KVA transformer fuse to blow.
July 25/05	Elsa Line & Dawson Feeder 3	Elsa Line - 5 – YEC 11-YECL Dawson Feeder 3 - 304	Equipment Failure	Elsa/Keno – 14 min, 15 sec Dawson Feeder 3 – 28 min, 52 sec 21	MH1 slip ring was arcing badly; SCC was unable to replace the generation from this unit before it tripped. SCC tripped the Elsa line, Dawson feeder 3 tripped on U/F.
July 26/05	Mendenhall	33	Planned	5 min 0	Scheduled outage to place Mendenhall on mobile diesel in preparation for a line outage.
July 26/05	Champagne	30	Planned	4 min	Scheduled outage to place Champagne on mobile diesel in preparation for a line outage.

YUKON ENERGY

Outage / Disturbance Report
August 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Aug 15-16/05	Whitehorse L171	1 – YECL 65 – YEC	Equipment Failure	Champagne – 6 hours, 24 min Mendenhall – 6 hours, 19 min (YECL) Takhini River PT – 8 hours, 19 min	A faulty lightning arrestor at the Mendenhall PT sub was the cause of these disturbances. Note the outage durations are a summary of three separate events related to the same outage cause.
Aug 15/05	Faro – 505 & 506	505 – 142 506 - 142	Animal Contact	505 – 2 min 506 – 21 min	Raven contacted the line tripping both 505 and 506 breakers. SCC was unable to closed 506, which was successfully closed locally.
Aug 16/05	Mayo, Bill Leary's Garage	1	Equipment Failure - Connection failed at mast	30 min	Changed connections and replaced melted triplex
Aug 17/05	Dawson – S250 52-2	304	Lightning	24 min	Suspected cause of this outage is lightning tripping feeder 3 and the synchronous condenser off line.
Aug 18/05	Whitehorse	1 – YECL 15 - YEC	Equipment Failure	S6838 – 31 min 27 S150 52-17 – 21 min S150 52-18 – 27 min S150 52-22 – 19 min	Loss of WH4 due to a bus bar failure caused this outage. Diesel generation was required during the restoration.
Aug 19/05	Whitehorse – S150 52-22	1 – YECL 15 - YEC	Equipment Failure	5 min	YECL gang-switch failure caused S150 52-22 to operate.
Aug 20/05	WAF Total Outage	1 – YECL 444 - YEC	Equipment Failure	Faro 505 – 10 min Faro 506 – 11 min Faro 507 – 12 min S6837 – 25 min S6838 – 23 min S150 52-17 – 35 min S150 52-18 – 18 min S150 52-21 – 55 min S150 52-22 – 23 min L170 – 29 min L171 – 5 min L355 – 5 min	Exciter fault on WH4 caused the unit to trip off line resulting in a WAF outage.
Aug 22/05	Champagne	30	Planned	5 min	Champagne placed on mobile diesel in preparation for L171 line maintenance.
Aug 23/05	Mendenhall	33 – YEC	Planned	3 min	Outage required to open a line switch for the Safe Work Permit issued for L171 line maintenance.
Aug 25/05	Champagne Mendenhall	63 – YEC	Planned	Champagne – 5 min Mendenhall – 2 min	Outages required returning L171 to normal after line maintenance, Champagne off diesel.

YUKON ENERGY

Outage / Disturbance Report
September 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Sept 2/05	Whitehorse S6838	1 - YECL	Equipment Failure	23 min	WH4 tripped off line due to a burnt bus bar. Feeder breaker S6938 tripped on under frequency.
Sept 13/05	Faro - 505	12 – YEC 1 – YECL (Ross River)	Animal Contact (Raven)	17 sec	Cause of this outage was found to be a raven contacting the line.
Sept 24/05	Elsa line	16 – YEC 1 – YECL (Keno City)	Lightning	2 min	Lightning is the suspected cause of this outage as reported by the Mayo serviceman.
Sept 26/05	Whitehorse S150 52-17 S6838	1 - YECL	Equipment Failure	S6838 – 13 min S150 52-17 – 19 min	WH4 was placed on line after the bus bar repair; the unit began to motorize tripping feeder breakers S6838 and S150 52-17 on under frequency. WH4 tripped off line on reverse power.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
October 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Oct 12/05	Dawson - Hunker Feeder	304	Inadequate Generation	27 minutes	Dawson was islanded (L174 line maintenance) and on diesel at the time of this event. Due to suspected sequencer problems there was inadequate generation on line as the load started to increase.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
November 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Nov 17/05	Elsa line	16	Weather	1 min	Heavy snow at time, possible tree contacting the line due to snow loading.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
December 2005

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Dec 26/05	Elsa Transmission Line	5 – YEC 11-YECL	Snow	4 minutes	Suspected cause of this outage is snow buildup on the line.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
January 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Jan 10/06	Faro S870	264	Planned	7 minutes	Required to pickup the Faro mine site (power quality), L170 isolated for line maintenance. Switching as per ES 06-1
Jan 11/06	Faro – 505	12 – YEC 1 - YECL	Weather - Frost	42 minutes	Reports light snow and frost building on lines, breaker opened on an over-current condition. Long duration cause by lack of SCADA visibility.
Jan 16/06	Champagne	30	Weather - Frost	2 hours, 15 minutes	Fuse tripped due to frost build-up on the lines.
Jan 19/06	Champagne	30	Tree contact	1 hour, 48 minutes	Fuse tripped due to a tree contact.
Jan 22/06	Faro – 505	12 – YEC 1 - YECL	Weather - Frost	Less than 1 minute	Reports light snow and frost building on lines, breaker auto reclosed.
Jan 23/06	Faro S870	264	Planned	4 minutes	Required to pickup the Faro mine site (power quality), L170 isolated for line maintenance. Switching as per ES 06-15
Jan 29/06	WAF blackout	YEC – 446 YECL - 1	Loss of Generation	See table below	A cable failure at the Aishihik plant initiated this disturbance, for complete details of this event reference the outage report. ..\..\Outage Reports\2006\1st Quarter (January-March)\Jan 29 2006 W.A.F System Blackout.rtf

Feeder	Variance	
S6838	3:16	196
S6837	3:14	194
S150 52-17	2:19	139
S150 52-21	2:25	145
S150 52-22	3:39	219
S150 52-18	3:37	217
Faro 505	0:10	
Faro 507	0:10	
S164 52-3 (L170)	7:20:54	740
L171	2:26:56	146
L355	7:10	730
Mendenhall	15:09 est.	909

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
February 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Feb 12, 2006	WAF – Whitehorse	1 YECL	Loss of Generation	S6838 – 14 min S150 52- 17 - 16 min	WH4 tripped off line due to a bus bar failure. Feeders tripped on under-frequency as a result of the lost generation
Feb 13, 2006	WAF – Whitehorse	1 YECL	Loss of Generation	S6838 – 41 min S150 52- 17 - 37 min	WH4 was placed on line after the bus bar repairs, the unit reversed powered causing an under frequency condition on the system. WH1 and WH2 tripped on over speed closing the unit headgate, which delayed the restoration.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
March 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
March 6, 2006	Braeburn	1 - YTG	Animal	2 hours	Squirrel contacted the transformer.
March 14, 2006	NWTEL - Little Fox	1	Planned	30 min	PCB sample
March 22, 2006	Mayo – Government subdivision	26	Planned	55 min	Required to remove a transformer from service.
March 30, 2006	NWTEL – Mendenhall	1	Planned	1 hour	Required to take conductor measurements at the site.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
April 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
April 10, 2006	Dawson	1170	Animal Contact	Feeder 1 – 7 min Feeder 2 – 8 min Feeder 3 – 36 min L174 – 2 hrs, 3 min (123)	A squirrel contacted S250 RT-1 causing an over current condition tripping L174 feeder breaker S249 52-2. The three Dawson feeder breakers cleared on under-voltage. Dawson was restored with diesel; L174 restoration was delayed until crews working near the line could be contacted.
April 26, 2006	WAF	YECL YEC – 279	Animal Contact	YECL – 46 min YEC – 16 min	This outage originated in the YECL Lewes Blvd substation with a squirrel contacting and extensively damaging a breaker. Aishihik was split (S164 52-1) from the system and remained on line feeding the L170 and L171 customers, with the exception of Faro (U/V), which was restored with local diesel. System protection coordination between utilities may have caused this disturbance to escalate beyond the main Riverdale feeder.
April 27, 2006	Dawson	233	Planned	Feeder 1 – 4 hrs, 45 min	Planned late night outage on a section of feeder 1 to install an in-line pole and replace another.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
May 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
May 5-6, 2006	Dawson – Rock Creek	47	Flooding	27 hrs, 55 min	As a result of flooding in the Rock Creek area electrical supply to this section of Dawson was isolated. Once the levels had receded the power was restored.
May 19, 2006	Whitehorse S6838	1 (YECL)	Human Error	7 min	Contractor tripped AH2 off line resulting in a system under frequency condition tripping breaker S6838.
May 19, 2006	Whitehorse L171	67	Transmission Failure	Mendenhall – 4 hrs, 50 min Champagne – 5 hrs, 4 min L171 – 42 hrs, 44 min	A faulty insulator on L171 was the cause of this disturbance. At the time of this failure Aishihik was isolated to install new cables, which minimized the effect of the outage. Mendenhall was supplied by a mobile diesel initially with Champagne and Mendenhall later fed from P130 while repairs were being completed. With the loss of P130 generation backup diesel generation was required to meet peak.
May 25, 2006	Mayo	1	Animal Contact	1 hour	Squirrel contacted the line causing the fuse to blow.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
June 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
June 6, 2006	Mendenhall	39	Planned	2 hrs, 33 min	Planned outage required to replace transformer and install lightning arrestor.
June 7, 2006	Whitehorse	1 – YECL S6838 S150 52-17	Human Error	S6838 – 5 min, 13 sec S150 52-17 – 4 min, 20 sec (16)	Emergency stop inadvertently activated on WH4 during on line testing of the unit. Unit tripped with 12 Mw of load, resulting in breakers S6838 and S150 52-17 tripping on under-frequency.
June 10, 2006	Whitehorse	1 – YECL 15 - YEC S6837 S6838 S150 52-17 S150 52-18 S150 52-21 S150 52 -22	Line Contact	S6837 – 49 min, 33 sec S6838 – 15 min, 42 sec S150 52-17 – 14 min, 12 sec S150 52-18 – 17 min, 30 sec S150 52-21 – 39 min, 45 sec S150 52 -22 – 11 min, 25 sec	.S164 52-1 tripped on a distance relay de-energizing L172, WH4 was unable to supply the load at S150 and S170 by itself resulting in an under voltage condition tripping the feeder breakers at each substation L355, L170 and L171 remained energized and fed from AH1. YECL reports a possible high load contact over the weekend that may have caused this outage. They found a burnt primary conductor in the Marwell area fed from S7192 in the services substation. There may be problem with relay coordination between YEC and YECL; this fault should not have escalated past the YECL distribution protection.
June 13, 2006	Dawson	2	Unknown	57 min	Cause of this event is unknown, occurred at the Dome subdivision.
June 26, 2006	Dawson	1184	Line Fault Suspected Lightning	F1 – 9 min, 25 sec F2 – 12 min, 30 sec F3 – 16 min, 51 sec L174 – 13 min, 5 sec	A B phase fault on the Mayo-Dawson line caused this disturbance; to date the cause of the fault has not been determined. Dawson was restored with diesel and later synchronized back to mayo hydro.
June 28, 2006	Johnson Crossing	15	Insulation failure	4 hours, 10 min	An insulation failure on 9L resulted in this disturbance affecting both YEC and YECL customers. Extended duration due to the time to find the failure and its location.
June 29, 2006	Whitehorse	1 - YECL S6838	Generation Failure	10 min, 23 sec	While re-energizing S150 T2, WH1 tripped off line (phase 87 O/C) causing S6838 to trip on under frequency.
June 30, 2006	Mayo	26	Tree Contact	25 min	Tree contacted the line in the government subdivision.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
July 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
July 5/06	Braeburn	1	Animal Contact	1 hour, 22 min	Bird contacted the line resulting in a blown fuse.
July 8//06	Mayo	3	Animal Contact	10 hours est.	Power went out on the evening of July 8. Customer called SCC trouble line and reported, however when asked if she wanted her power restored she said it could wait until morning. An employee had his neighbor knock on his door at 7:30 next morning complaining his power was out. Employee then called serviceman. Total of 3 customers out.
July 12/06	Mayo	26	Tree Contact	1 hour, 21 min	High winds resulted in a tree contacting the line.
July 13/06	Mayo	16	Lightning	13 min, 33 sec	Lightning strike on the Elsa line caused an instantaneous over-current trip of the feeder.
July 14/06	WAF	443	Human Error	51 minutes Note: Feeders were closed at various times. The above duration indicates the last SCADA controlled feeder closed.	The cause of this disturbance was found to be an incorrect CT wiring on S150 52-15. The breaker had been replaced the week of July 10, 2006. On the return to normal switching one of the last steps was to close this breaker completing the circuit through S150 T7. However once the breaker was closed S150 T7 indicated a differential trip resulting in breakers S150 52-1, S150 52-15 and circuit switcher S150 52-23 opening. As a consequence of these switches opening the WAF system was split; WH2 and WH3 feed the S150 load and WH4 and AH1 feeding the remaining WAF system.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
August 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Aug 17/06	L174 - Dawson	1190	Lightning	Dawson F1 – 12 min Dawson F2 – 15 min Dawson F3 – 31 min L174 – 55 min Stewart – 1 hr, 9 min	Suspected cause of this event is lightning in the Stewart area. Delays restoring Stewart were a YECL issue.
Aug 21/06	Mayo	3	Animal Contact	1 hr, 30 min	A raven contacted the line on 2nd avenue.
Aug 27/06	WAF	1 - YECL 15 - YEC	Equipment Failure	S150 52-17 – 10 min S150 52-22 – 10 min S6837 – 37 min S6838 – 34 min	The loss of WH4 generation as a result of a bus-bar failure caused this event. Breakers tripped on under-voltage.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
September 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Sept 13/06	Elsa Line	16	Unknown	1 minute, 25 seconds	At the time of the event there were no adverse weather conditions.
Sept 13/06	Elsa Line	16	Unknown	1 minute	At the time of the event there were no adverse weather conditions.
Sept 20/06	Mayo	310	Planned	6 hours	Scheduled outage to accommodate the town feeder project.
Sept 20/06	Mayo	310	Planned	6 hours, 25 minutes	Scheduled outage to accommodate the town feeder project.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
October 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Oct 10/06	L170	Faro – 296 L170 - 29	Tree Contact	Dury Creek – 5 hours, 34 min Braeburn & Little Fox – 3 hours 12 min Faro – 18 min	Two separate tree contacts on the L170 transmission line between Carmacks and Faro were identified as the cause of this event. Faro and Dury Creek were placed on diesel. Total duration to return the system to normal was 35 hours and 5 minutes, due to darkness and the requirement to fly the line to locate the tree contacts.
Oct 11/06	L170 Braeburn & Little Fox	15	Scheduled	4 min	Planned outage to switch L170 back to normal from the Oct 10 outage.
Oct 25/06	L170 Braeburn & Little Fox	15	Scheduled	7 min	Planned outage to accommodate work on the L170 transmission line.
Oct 27/06	L170 Braeburn & Little Fox	15	Scheduled	4 min	Planned outage to accommodate work on the L170 transmission line.
Oct 31/06	L170 Braeburn & Little Fox	15	Scheduled	3 min	Planned outage to accommodate work on the L170 transmission line.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
November 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Nov 2/06	L170 Braeburn & Little Fox	29	Scheduled	2 min	Planned outage to accommodate work on the L170 transmission line.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
December 2006

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Dec 18/06	Dawson	1190	Adverse Weather (Snow)	F1 – 11 min F2- 11min F3 - 27 min L174 – 8 hours	The suspected cause of this outage is snow loading on the L174 transmission line, which resulted in the phase slapping when the snow released. Due to the time of this event and the failure of an attempted reclose the line remained de-energized for the night, with Dawson remaining on diesel.
Dec 18/06	Dawson (Feeder 3)	318	Loss of Supply (Generation)	F3 - 31 min	P158 was put in economic dispatch after a previous line outage. The economic dispatch didn't function properly resulting in two of the three generators coming off line resulting in under frequency condition tripping the Hunker Creek feeder S250 52-2. P158 left in manual until economic dispatch mode adjusted.
Dec 18/06	Dawson and Elsa Line (L250)	1208 (L250 22) (Dawson 1186)	Loss of Supply (Generation)	F1 – 29 min F2 – 25 min F3 – 46 min L250 - 1 hr, 3 min	MHO 52-F2 tripped on an ABC instantaneous over-current, however SCADA still indicated closed. Trouble calls were received from Elsa and Keno confirming L250 was down. SCC opened MHO 52-F2 in SCADA and MH2 52-1 opened tripping the unit on over-speed. P158 F1, P158 F2 and S250 52-2 opened on under frequency as a result of MH2 going offline. See this events outage report for recommendations and actions.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
January 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Jan 1/07	Elsa Line – L250	16	Weather – Heavy Snow	1 min	Outage caused by heavy snow conditions in the district, snow loading on the line.
Jan 10/07	Dawson	1198	Relay Failure	F1 – 8 min F2 – 10 min F3 – 20 min	A faulty protective relay (51V) on MH2 caused the unit to trip off line, resulting in an under-frequency condition initiating trips to the three Dawson feeders. Feeders were restored using P158 generation.
Jan 10/07	Dawson	318	Relay Failure	F3 – 5 min	The same relay mentioned above failed a second time, however with two P158 units on in base-load and MH2 running at a reduced load the outage was limited to the F3 feeder.
Jan 16/07	Dawson	880	Human Error	F1 – 17 min F2 – 18 min	This event took place during the plant automation commissioning. Outage caused by the shorting out a pressure switch on DD3 which caused the 24 volt system to trip. The feeder DC power supply is fed from same supply resulting in Feeder #1 and Feeder #2 tripping.
Jan 24/07	Dawson & L174	1198	Weather – Heavy Snow	F1 – 9 min F2 – 9 min F3 – 30 min L174 – 1, hr, 20 min	Suspected cause of this event is snow / frost loading on the L174 transmission line, which caused S249 52-2 to open and lock-out. Dawson Diesel started and the system was separated to aid in restoration.
Jan 24/07	L174	7	Weather – Heavy Snow	32 min	Suspected cause of this event is snow / frost loading on the L174 transmission line, which caused S249 52-2 to open and lock-out. Due to the extreme weather conditions (snow / frost) Dawson was islanded from Mayo hydro resulting in a lower customer impact.
Jan 24/07	L174	7	Weather – Heavy Snow	15 min	Suspected cause of this event is snow / frost loading on the L174 transmission line, which caused S249 52-2 to open and lock-out. Due to the extreme weather conditions (snow / frost) Dawson was islanded from Mayo hydro resulting in a lower customer impact. The line was flown the Jan 25/07 and re-energized.
Jan 29/07	Dawson	1198	Equipment Failure	F1 – 9 min F2 – 9 min F3 – 30 min	MH2 tripped off on 86 lock-out. Problem was failed power supply to governor. On restoration with diesels load was picked up with units in base load causing poor power quality. Diesels should be in sharing mode when picking up feeders.

YUKON ENERGY

Outage / Disturbance Report
February 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Feb 27, 2007	Mayo - NND Subdivision	5	Failed Connection	4 hours	A connection failed on an open wire secondary causing this outage. Delays in reporting of the failure resulted in the increased duration.
Feb 27, 2007	Dawson Feeder 2	483	Human Error	10 minutes	While working on the Dawson automation project the employee inadvertently hit the test/reset button on the 27/59T coil which tripped P158-52-F2. Power was restored using P158 diesel.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
March 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
					No outage to report for this month

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
April 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
April 16/07	Haines Junction Line (L355)	1 – YECL 2 - YEC	Protective Relaying	2 min, 35 sec	During the return to normal switching of transmission line L171 (Aishihik) the line was re-energized with AH2. The line breaker closed, however AH2 tripped off line due to a phase differential on the unit, resulting in an outage to the L355 customers. The cause of the loss of AH2 is still under review.
April 17/07	Faro - L356 (505)	1 - YECL 147 - YEC	Damaged Line Structure	7 hours 46 min (Tintina Subdivision)	Cause of this disturbance was a broken pole on the L356 transmission line to Ross Rive. The majority of the customers affected were restored within 42 min once the damage section of the line was isolated; however the Tintina Subdivision experienced an extended outage duration due to the requirement to transport a mobile diesel from Whitehorse to the site.
April 27/07	Dawson	7	Scheduled Outage	1 hour, 30 min	Planned outage to remove from service PCB transformers.
April 27/07	Faro - L356 (505)	1 - YECL 147 - YEC	Customer Equipment Failure	8 min	A problem with customer equipment (bad meter base) resulted in a failed transformer bank feeding the Faro pump-house initiated this outage.
April 27/07	Dawson	1198	MH1 Governor Tracking Error	16 min, 48 sec	P158 52-F1 Dawson Town Feeder #1, P158 52-F2 Dawson Town Feeder #2 and S250 52-2 Hunker Creek all tripped on U/F resulting from MH1 shedding its load, due to a unit governor tracking error. The restoration was performed using the remaining Mayo hydro unit and Dawson diesel.
April 28/07	Dawson	20	Unknown	30 min	Blown distribution fuse cause this outage. Serviceman checked the transformer for damage and for evidence of an animal contact, with nothing found the fuse was replaced and closed.
April 28/07	Mayo - Elsa Line	1 – YECL 18 - YEC	Customer Equipment Failure	1 hour, 39 min	The cause of this disturbance was found to be a broken pole on the Bell Keno line, which is owned by the mine. The serviceman found one fuse tripped, he opened the remaining two and the line was successfully energized. The feed to the line is currently de-energized, until Arctic Power can make repairs. Extended duration due to the operational procedure to sectionalize the line to define the problem area.
April 30/07	Faro Town-site	282	Scheduled Outage	5 min	Planned outage to allow for the safe switching (bypass) of the Faro voltage regulator. The regulator controller had previously failed.

YUKON ENERGY

Outage / Disturbance Report
May 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
May 3/07	Dawson - Klondike Highway near Callison	1	Animal Contact	1 hour, 25 min	Blown fuse caused by a bird contact.
May 14/07	Mayo – Airport Subdivision	26	Scheduled	1 hour , 20 min	Planned outage to install line jumpers.
May 21/07	Dawson - Airport	3	Tree Contact	1 hour, 15 min	Tree contacted the line resulting in a blown fuse.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
June 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
June 4/07	South Fox	6	Scheduled	12 minutes	Scheduled outage required to connect backup diesel for substation deficiency work.
June 5/07	South Fox	6	Scheduled	11 minutes	Scheduled outage required to disconnect backup diesel from the June 4/07 substation deficiency work.
June 5/07	Elsa Line	18	Lightning	1 hour, 32 minutes	MHO 52-F2 is tagged for fire rating (extreme). Outage duration long due to the requirement to patrol the line from Mayo to Keno in extreme fire hazard conditions. Nothing found and the line was successfully re-closed.
June 6/07	L355 – Haines Junction Line	5	Scheduled	2 hours, 41 minutes	Scheduled outage required to accommodate the installation of 2 poles for the new YECL subdivision.
June 13/07	Dawson F1	231	Scheduled	1 hour, 10 minutes	Scheduled outage required to install a new pole downtown Dawson.
June 13/07	Dawson F1	20	Scheduled	3 hours, 20 minutes	Scheduled outage required to install a new pole downtown Dawson. Majority of customers were restored earlier in the above scheduled outage.
June 13/07	L174	7	Scheduled	2 hours 12 minutes	Scheduled outage required to remove damaged lightning arrestors in S249 and S250 substations. Dawson islanded from Mayo hydro for this work.
June 16/07	Faro – Breaker 507	135	Animal Contact	8 minutes	Raven contacted the line resulting in blown fuses on transformer banks.
June 17/07	WAF – L170, S6838 and S150 52-17	1 - YECL 310 - YEC	Lightning	L170 – 2 hrs, 48 min S150 52-17 – 40 min S6838 – 53 min Faro – 5 min	The cause of this event has been determined to be a lightning strike on L170. . Due to the loss of load (U/F breakers) WH1 and WH2 tripped on over-speed, closing the head-gates and delaying the restoration process.
June 29/07	Dawson – Feeder 2 & 3	801	Lightning	F2 – 14 minutes F3 – 16 minutes	Lightning storm in the Dawson district cause this outage. Restoration was performed using both diesel and hydro. Due to the storm Dawson was islanded from Mayo to minimize any additional outages.

YUKON ENERGY

Outage / Disturbance Report
July 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
July 1/07	Faro – F1	135	Animal Contact	506 - 4 minutes	Dead raven found at a transformer.
July 3/07	Dawson	1205	Lightning	F1 – 8 minutes F2 – 9 minutes F3 - 17 minutes L174 - 21 minutes	A lightning strike on L174 tripped the line off resulting in an outage to the Dawson and L174 customers. Dawson was restored using diesel generation and L174 was re-energized up to Callison. Dawson remained islanded until the storm passed.
July 3/07	L174	7	Lightning	L174 – 20 minutes	A lightning strike on L174 tripped the line. Dawson was islanded (see above) at the time and was not affected.
July 3/07	Dawson	1	Lightning	4 hours, 20 minutes	Localized lightning strike on a distribution tap caused this outage.
July 3/07	Dawson	1	Lightning	23 hours, 40 minutes	Localized lightning strike on a distribution tap caused this outage (same outage as above). Customer was not on site, this drop was repaired the following day July 4/07.
July 4/07	Mayo	3	Animal Contact	45 minutes	Dead raven found at a transformer.
July 7/07	Dawson	1205	Lightning	F1 –37 minutes F2 – 36 minutes F3 - 55 minutes L174 - 59 minutes	A lightning strike on L174 tripped the line off resulting in an outage to the Dawson and L174 customers. Dawson was restored using diesel generation and L174 was re-energized up to Callison. There were delays in the restoration due to the P158 diesel units failing to pick up load (see outage report).
July 11/07	Dawson	11	Scheduled	1 hours, 30 minutes	Scheduled outage required to change out a PCB transformer.
July 11/07	Dawson	11	Unknown	1 hours, 30 minutes	Transformer fuse blown; cause unknown.

July 11/07	Dawson	11	Scheduled	3 hours	Scheduled outage required to install pole for Arctic Inland Sawmill.
July 12/07	Faro – F1	135	Animal Contact	506 - 7 minutes	Dead raven found at a transformer.
July 14/07	Dawson	1205	Lightning	F1 –8 minutes F2 – 9 minutes F3 - 18 minutes L174 - 19 minutes	A lightning strike on L174 tripped the line off resulting in an outage to the Dawson and L174 customers. Dawson was restored using diesel generation and L174 was re-energized up to Callison. Dawson remained islanded until the storm passed.
July 14/07	WAF	1- YECL 14 – YEC (9L)	Unknown	S6837 – 33min S6838 – 60 min S150 52-17 – 45 min S150 52-21 – 38 min S150 52-22 – 7 min	At the time of this disturbance YECL was trouble-shooting in the Cooper Ridge subdivision and picked up 1.74 Mw, which resulted AH1 tripping and causing a under-frequency and under voltage condition on the system tripping the feeders. There was no definitive cause identified for this outage, the YECL load pickup should not have tripped AH1 off.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
August 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Aug 1/07	WAF (66%)	354	Equipment Failure	S150 52-17 – 54 min S150 52-21 – 34 min S150 52-22 – 37 min S6838 – 59 min L170 - 1 hour, 53 min	A governor hydraulic valve failurecaused WH4 to trip offline, as a result the system collapsed due to lack of generation. Restoration was delayed as L171 the Aishihik line was isolated for maintenance prohibiting the use of Aishihik generation. Whitehorse hydro and diesel were utilized in the restoration.
Aug 6/07	L174	7	Lightning	33 minutes	Dawson had been islanded prior to the disturbance to minimize the potential outage impact, of the forecasted lighting in the area.
Aug 6/07	L355 Haines Junction Line	7	Equipment Failure	2 minutes	The cause of this and future outages on the L355 was later identified as a failed arrestor on the line side off the metering tank.
Aug 14/07	WAF (100%)	433	Equipment Failure	Total outage duration was 40 minutes (see outage report for feeder details)	A governor hydraulic valve failure caused WH4 to trip offline, as a result the system collapsed due to lack of generation.
Aug 18/07	Faro - 506	135	Unknown	1 minutes	No targets or flags on breaker 506, breaker was closed remotely.
Aug 20/07	L355 Haines Junction Line	7	Equipment Failure	3 hours, 37 minutes	The cause of this and future outages on the L355 was later identified as a failed arrestor on the line side off the metering tank. The line was flown during this event line fault detectors where installed to help locate the problem.
Aug 21/07	L355 Haines Junction Line	7	Equipment Failure	36 minutes	The cause of this and future outages on the L355 was later identified as a failed arrestor on the line side off the metering tank.
Aug 28/07	Faro - 506	135	Animal Contact	1 minutes	A dead raven was found near a transformer with a blown fuse.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
September 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Sept 2/07	L355 Haines Junction Line	7	Equipment Failure	52 minutes	The cause of this and future outages on the L355 was later identified as a failed arrestor on the line side off the metering tank.
Sept 3/07	L355 Haines Junction Line	7	Equipment Failure	15 minutes	The cause of this and future outages on the L355 was later identified as a failed arrestor on the line side off the metering tank. Repaired Sept 15/07.
Sept 11/07	Dawson	1205	Unknown	F1 – 7 minutes F2 – 7 minutes F3 – 29 minutes L174 - 48 minutes	Cause of this event is unknown (D-60 relays – Zone 1 ground operation – Phase under voltage on A-B-C). The line was successfully re-closed after Dawson was restored with diesel.
Sept 15/07	WAF (100%)	433	Equipment Failure	Total outage duration was 1 hour, 27 minutes (see outage report for feeder details)	The cause of this disturbance was found to be a failed coil in the WH4 creep detector resulting in a DC system fault taking the unit off line, with insufficient generation the system collapsed.
Sept 24/07	Faro - 505	12	YECL Equipment Failure	9 minutes	The cause of this disturbance was a failed YECL bypass switch on the metering tank in Ross River.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
October 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Oct 10/07	L355 Haines Junction Line	7	Equipment Failure	2 minutes	Line feeder breaker tripped and was remotely re-closed. The cause of this and future outages on the L355 was later identified as a failed arrestor on the line side off the metering tank.
Oct 17/07	Mayo / Dawson	1549	Human Error	L174 – 51 minutes Dawson F1 – 13 minutes Dawson F2 – 14 minutes Dawson F3 – 43 minutes Mayo TF – 9 minutes Elsa Feeder – 8 minutes	The system setup at the time of this event had MH1 out of service under a WAP for annual preventive maintenance with DD5 on line in base-load to supplement MH2 generation. Work was also taking place on the SCADA RTU, which involved replacing the old Pentium with a new Scout RTU. As part of the RTU work the employee was reconnecting the 4/20mA transducer loops to the RTU analog cards. The on line hydro unit MH2 received a "Gate Tracking Error" which shut the unit down. With insufficient generation on line the system collapsed, the Dawson feeders tripped on under-frequency, DD5 tripped on over-speed and S249 52-2 (L174) on under-voltage.
Oct 17/07	Mayo – NND Admin Building	1	Unknown	30 minutes	Blown transformer fuse, no dead animals found.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
November 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Nov 14/07	Whitehorse	1 - YECL	Loss of Supply	S6838 - 7 minutes	AH1 tripped off line resulting in the under-frequency tripping of breaker S6838. The cause of the AH1 trip was due to insulator problems on the slip rings.
Nov 17/07	Whitehorse	1- YECL 14 – YEC (9L)	Human Error	S150 52-17 – 16 minutes S150 52-18- 21 minutes S150 52-21- 27 minutes S150 52-22 – 37 minutes S170 S6838 – 24 minutes	Workers were commissioning the new RTU in S171 and reset the 94/L150 relay, this caused S171 52-3 S171 52-4 and S171 52-1 to open producing a split system. Haines Junction,, Faro, and S6837 stayed energized being fed from AH2 .
Nov 25/07	Dawson - Rock Creek	30	Unknown	1 hour, 42 minutes	A blown fuse was found, however there is no definitive cause for this outage. Recent heavy snow in the area may have caused the lines to slap. There were no calls to indicate the power was out until for approximately 1 hour after what we can determine is the start of this event.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
December 2007

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Dec 4/07	Dawson Feeder 2	483	Unknown	22 minutes	The system load and frequency where surging prior to the loss of feeder 2 in Dawson, indicating a possible line contact i.e. tree. The relay set point on feeder 2 caused it to trip before feeder 3. No definitive cause for this event was found.
Dec 11/07	Johnson Crossing	15	Animal Contact	59 minutes	The YECL breaker S9567 operated twice and held. The responding YEC servicemen found a blown transformer fuse and dead raven in the Johnson Crossing area.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
January 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Jan 4/08	Dawson	1205	Adverse Weather (Snow)	Dawson F1 – 18 minutes Dawson F2 – 18 minutes Hunker Creek – 30 minutes L174 - 42 minutes	Suspected phase slap on the L174 transmission line caused this outage. Dawson diesel was used to restore power in Dawson.
Jan 10/08	Faro – 506	142	Animal contact	31 minutes	Dead raven found on Faro feeder #2.
Jan 10/08	Faro RCMP Office	1	Animal contact	3 hours. 59 minutes	Part of a previous outage (see above) caused by a raven contacting the line the customer fuse was frozen and did not drop out as is usual. The customer did not inform YEC for quite some time their power was still out.
Jan 13/08	Johnson Crossing	15	Tree contact	5 hours, 39 minutes	The YECL owned sub transmission line south had multiple tree contacts, resulting in this outage.
Jan 13/08	Champagne	29	Improper fusing	5 hours, 58 minutes	The fuse feeding the Champagne area was too low, due to the cold temperatures to demand was high enough to burn the fuse. Delays in restoration due to the on call serviceman dealing with the Johnson Crossing outage (see above).
Jan 17/08	Elsa Line	16	Unknown	47 seconds	Line breaker tripped and was immediately re-closed. A line patrolled was performed, nothing obvious was found. Weather at the time was clear and calm.
Jan 18/08	Dawson school	1	Planned	25 minutes	The Dawson school was de-energized to allow for repairs to connections found in an infrared scan.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
February 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Feb 3,2008	Dawson F2	483	Unknown – Possible Line Contact	58 minutes	P158 52-F2 tripped (Ground Over current Relay) After P158 52-F2 reclose failed the system was sectionalized at S7942. P158 52-F2 then held but tripped again when S7942 was closed. Dave Wray recommended the Neutral current trip set point be set from Normal to High. P158 52-F2 was closed a third time and held when S7942 was later closed. All feeder operations took place with DD 2, 3 & 5 online in sharing.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
March 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
March 8,2008	Mayo – Mease Farms	1	Defective Equipment	1 hour	Fuse barrel dropped out. This piece of equipment is old and will be replaced this spring/summer.
March 26, 2008	Dawson – Airport Nav. Beacon	2	Scheduled Outage	1 hour	Outage required installing new switch and switching plate at the Dawson airport navigation beacon feeder. This site has diesel backup.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
April 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
April 2/08	Dawson F3 (Hunker Creek)	318	Planned Outage	2 hours, 38 minutes	Outage required for gang-switch maintenance.
April 2/08	Dawson F1	40	Planned Outage	1 hour, 12 minutes	Outage required to rebuild copper risers on feeder one.
April 2/08	Dawson F2	140	Planned Outage	47 minutes	Outage required to rebuild copper risers on feeder two.
April 3/08	Dawson F3 & L174	F3 -318 L174 -7	Planned Outage	F3 - 5 hours, 36 minutes L174 - 25 minutes	This outage was required to reframe a66kv pole and install an overhead guy on the 66kv. This section of the line is a double circuit and required the isolation of both L174 and F3 for the crew's safety.
April 4/08	Dawson F2	483	Planned Outage	3 hours, 35 minutes	Outage necessary for the removal of two gang switches, reframe structures and re-harness two transformer banks.
April 9/08	L250 ELSA	18	Planned Outage	37 minutes	Outage required for transmission line maintenance.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
May 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
May 1/08	Faro	296	Equipment Failure	13 min, 42 seconds	A failed lightning arrestor on 502T transformer was the cause of this event.
May 4/08	WAF	443	Vandalism	4 hours, 14 minutes	The cause of this disturbance was found to be shot insulators on L172 transmission line between S171 and S164 substations. At this critical juncture of the system, it produced a split system and without insufficient generation from the Aishihik plant the system collapsed.
May 6/08	WAF S6838 S150 52-21	1 (YECL)	Equipment Failure	S6838 – 17 min, 11 sec S150 52-21 – 21 min, 10 sec	The cause of this event was a failed insulator on the YECL owned distribution system. S150 52-21 tripped on over-current, the fault dropped the system frequency low enough to cause S6838 to trip.
May 10/08	Faro	12	Tree Contact	24 seconds	Breaker over-current tripped and was successfully re-closed. The cause was determined to be a tree contact.
May 16/08	WAF S6838 S150 52-17	1 (YECL)	Generation Failure	S6838 – 28 min, 40 sec S150 52-17 – 18 min, 54 sec	WH4 governor issues (proportional valve) resulted in the loss of this unit, SCC was able to reduce the output from the unit prior to the unit tripping reducing the outage impact. Feeder breakers S6938 and S150 52-17 tripped on under-frequency.
May 22/08	WAF S6838	1 (YECL)	Generation Failure	S6838 – 25 min, 18 sec	WH3 governor issues (LVDT), resulted in the unit shedding load causing an under-frequency condition that tripped breaker S6838.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
June 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
June 5/08	Elsa line	16	Scheduled	27 minutes, 10 seconds	Planned outage to remove danger trees from the line
June 8/08	Faro (Feeder 2)	142	Unknown	5 minutes	Breaker tripped on a ground fault, the line was patrolled no definitive cause was found.
June 9/08	L355 (Haines Junction)	2	Adverse Weather - Snow	5 minutes , 53 seconds	Haines Junction YECL serviceman reports the outage was caused by large amounts of snow on the lines at Canyon City.
June 9/08	L355 (Haines Junction)	2	Adverse Weather - Snow	26 minutes , 16 seconds	Second disturbance on L355 again caused by heavy snow near Canyon City. Delays in re-energizing the line due to servicemen working in the area removing snow from the line.
June 11/08	Faro (Feeder 2)	142	Foreign Interference (bird)	3 minutes	Cause of this outage was determined to be a bird contacting the line.
June 11/08	Dawson	40	Lightning	3 hours, 44 minutes	Significant storm activity near the Rock Creek subdivision caused this event, resulting blown fuses at the river crossing and 9 transformers.
June 19/08	Dawson	1	Unknown	3 hours, 30 minutes	Blown transformer fuse caused this outage, the fuse may have been damaged/weakened by the June 11/08 storm.
June 25/08	Faro (Feeder 2)	142	Foreign Interference (squirrel)	20 minutes	Cause of this outage was determined to be a squirrel contacting the line.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
July 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
July 1/08	Mayo – L250	16	Adverse Weather	2 hours, 6 minutes	The Elsa line tripped and was sectionalized to determine the location of the fault. Storm reported in the area.
July 4/08	Faro F2	142	Animal Contact	41 sec	Bird contacting the line caused the feeder to trip. Reclosed via SCC.
July 5/08	Mayo – L250	16	Adverse Weather	1 minute	The Elsa line tripped and was reclosed by SCC. Storm reported in the area.
July 6/08	Mayo – L250	16	Transmission Failure	2 hours, 2 minutes	The Elsa line tripped and was sectionalized to determine the location of the fault. Broken conductor was found on the transmission line near Keno. Keno placed on mobile diesel during the repairs.
July 15/08	Faro - L356	3	Transmission Failure	7 hours, 13 minutes	Ross River line tripped, SCC was unable to reclose the line. Serviceman dispatched from Whitehorse, the line was sectionalized and flown. Cause was a failed structure. Ross River and the YEC customers on diesel while repairs took place.
July 15/08	Faro F2	142	Unknown	7 minutes	Cause unknown for this event. Breaker was locally closed in.
July 7-16/08	Dawson	1	Flood – Eroded river bank	208 hours	Flooding of the Klondike River near Rock Creek caused bank erosion resulting in the loss of the river crossing feeding one customer. Limited access required the use of a helicopter to reconstruct the crossing.
July 16/08	Dawson	30	Scheduled	30 minutes	Planned outage required to cut in the river crossing noted above.
July 19/08	WAF – 9L	15 YEC 1 -YECL	Tree Contact	5 minutes	Bump S6839 (9L) tripped loss of 0.90 Mw. On the attempt to re-close S150 52-22 tripped. A tree was later found on the line.

July 25/08	Mayo	1	Animal Contact	30 minutes	Bird contacted line causing blown fuse. (Airport)
July 25/08	Mayo	1	Defective Equipment	15 minutes	Blown fuse in customers panel. (Airport)
July 26/08	Mayo	2	Animal Contact	30 minutes	Squirrel contacted line causing blown fuse. (Band Office)
July 28/08	Mayo	1	Animal Contact	30 minutes	Squirrel contacted line causing blown fuse on one phase of a three phase bank. (Dick Ewing Shop)
July 30/08	Mayo	3	Animal Contact	40 minutes	Squirrel contacted line causing blown fuse.
July 30/08	WAF – L355 KJ.	6	Loss of Supply	44 minutes	The SCADA communication with Aishihik was down at the time of this event, YECL informed SCC that Haines Junction was on diesel. The feeder breaker was reclosed locally from the plant.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
August 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Aug 4/08	Faro - F2	142	Unknown	3 minutes	Cause unknown, closed locally (506).
Aug 4/08	WAF – 9L	15 YEC 1 -YECL	Tree Contact	36 minutes	S150 52-22 tripped, reclosed after YECL sectionalized the line.
Aug 6/08	Mayo – L250	16	Adverse Weather	2 hours, 30 minutes	The Elsa line tripped and was reclosed by SCC after the line was sectionalized. Heavy rain reported in the area.
Aug 8/08	Dawson & L174	1190	Lightning	Dawson: F1 – 5 min F2 – 4 min F3 – 17 min L174 -26 min	Heavy lightning in the Mayo district is the suspected cause of this disturbance. Dawson was restored with P158 diesel.
Aug 20/08	Faro – F2	142	Unknown	13 minutes	Cause unknown, closed locally (506).
Aug 28/08	WAF - L355 H.T	6	Unknown	44 secs	Cause unknown, closed by SCC.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
September 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Sept 2/08	WAF L355 HT	6	Flooding	17 hours, 5 minutes	As a result of heavy rain and plant flow from Aishihik the river bank eroded taking out a river crossing near Canyon Creek. The YECL diesel back-fed the line to a temporary open point and a mobile unit fed Dimock timber until repairs were completed. Required the use of a helicopter to pull the damaged structure from the river and re-string the crossing.
Sept 21/08	Faro F2	142	Human Error	5 minutes	YEC employee working on the 502T transformer protection inadvertently caused a differential trip of feeder breaker 507.
Sept 29/08	WAF – S6838	1 - YECL	Transmission Failure - YECL	16 minutes	Breaker S6838 tripped while YECL was restoring a power outage in the Lake Labarge area. When YECL called for a close on breaker S8306 it was a hard hit to the WAF grid and caused S6838 to trip. The cause was found to be a span off of S8306 was lying on the ground.
Sept 30/08	WAF – S6838	1 - YECL	Transmission Failure - YECL	19 minutes	Breaker S6838 tripped while YECL was restoring a power outage in the Lake Labarge area. When YECL called for a close on breaker S8306 it was a hard hit to the WAF grid and caused S6838 to trip. Cause was found to be a vehicle hitting a guy wire taking down two poles.

File #2700-05-04

YUKON ENERGY

Outage / Disturbance Report
October 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Oct 5/08	WAF	448	Loss of Generation	50 minutes	Loss of WH4 generation resulted in a complete system outage. WH4 failure is suspected to be a governor issue, possibly a stuck proportional valve. The SCC operator received a WH4 governor status alarm prior to the trip which indicates a governor related issue. Update: The cause of this and the following outages related to WH4 was investigated by L&S (governor specialists); the failure was a cartridge valve in the governor manifold. The new manifold does not use these types of valves.
Oct 5/08	Dawson	5	Unknown	20 minutes	A customer called reporting the outage; the line tech was unable to determine the cause of event and re-fused the tap.
Oct 7/08	Mayo	2	Unknown	30 minutes	A customer called reporting the outage; the line tech was unable to determine the cause of event and re-fused the tap.
Oct 9/08	Elsa Line	16	Unknown	1 minute	The line feeder breaker tripped, SCC successfully re-closed the breaker. No definitive cause found for this event. Weather was clear and -3 C at the time.
Oct 9/08	Elsa Line	16	Unknown	>1 minute	The line feeder breaker tripped, SCC successfully re-closed the breaker. No definitive cause found for this event. Weather was clear and -5 C at the time.
Oct 12/08	WAF	448	Loss of Generation	1 hour, 7 minutes	Loss of WH4 generation resulted in a complete system outage. WH4 failure is suspected to be a governor issue, possibly a stuck proportional valve. The SCC operator received a WH4 governor status alarm prior to the trip which indicates a governor related issue. Update: The cause of this and the following outages related to WH4 was investigated by L&S (governor specialists); the failure was a valve in the governor manifold. The new manifold does not use these types of valves.
Oct 13/08	WAF	448	Loss of Generation	2 hours, 35 minutes	The WH3 digital governor lost its gate position indication causing the unit to shutdown, the unit breaker tripped on reverse power (timed). In combination with the loss of generation from WH3 and the reverse power (> 9 Mw) the unit absorbed, the system frequency dropped enough to initiate the under-frequency protected breakers to trip. This load loss was not enough to recover the system frequency, both Aishihik units tripped off line. The system restoration was longer than normal due to WH4

					being out of service from the Oct 12/08 failure and the initial assumption that the cause of the event was distribution related.
Oct 16/08	Elsa Line	16	Unknown	>1 minute	The line feeder breaker tripped, SCC successfully re-closed the breaker. No definitive cause found for this event. Weather was clear and -3 C at the time. This and the previous Elsa line outages may be related to failed insulation on the line.
Oct 20/08	WAF – S6838	1 - YECL	Loss of Generation	4 minutes	The second outage caused by the WH3 gate position feedback to the PLC, resulting in feeder breaker S6838 to trip on under frequency.
Oct 29/08	WAF - Faro	282	Equipment Failure	8 minutes	The initial cause of this outage was thought to be a 701T transformer issue as the protective flags indicated a neutral over-current. Faro was restored with local diesel. Further investigation found the vacuum interrupter on B phase of circuit switcher S255 52-2 was improperly setup during commissioning of the new Carmacks substation equipment.

YUKON ENERGY

Outage / Disturbance Report
November 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Nov 12/08	WAF	448	Loss of Generation	47 minutes	Loss of WH4 generation resulted in a complete system outage. One of the output cards in the PLC used by the governor failed. The specific card that failed provides the run indication for the unit. The vendor was aware of these card failures, however did not send YEC the notification of the required upgrade. A non essential card was switched over to return this unit to service.

YUKON ENERGY

Outage / Disturbance Report
December 2008

Date	Location	Number of Customers Affected	Cause	Duration (Outage to Restoration)	Comments
Dec 1/08	WAF	448	Equipment Failure	1 hour, 12 minutes	The cause of this disturbance was found to be a failed pot-head from the bus work to the S167 reactor gang-switch, causing S167 52-1 and P130 52-F2 to trip separating the P130 generation from the rest of the grid. At the time of the event WH4 was off line under a permit for hydro testing. WH4, P126 and eventually P125 units were used for the system restoration.
Dec 9/08	Dawson	1166	Extreme Weather	27 minutes	The suspected cause of this outage is the release of frost build up on the L174 (Mayo-Dawson) transmission line.

REFERENCE:

QUESTION:

a) Was the power outage on the WAF system that occurred near mid October 2008 in any way associated with trials or inadvertent switching / hookup operations related to feeding power to or from the Minto Mine?

ANSWER:

(a)

No.

REFERENCE:

QUESTION:

a) When will the SCADA system be operational at the Minto diesel facility so as to allow this plant to be integrated into the WAF grid? Please explain why this SCADA equipment was not installed by the time that the Minto mine began receiving power from the WAF grid.

ANSWER:

(a)

It is expected that the Minto Diesel facility will be connected to the WAF SCADA system by year end 2009. The SCADA connection for the substation at the Minto Mine will be complete by August 2009.

The diesel connection was not part of the Carmacks Stewart Transmission Line project. The substation control was delayed due to other project priorities, and with the knowledge that Minto Mine personnel would be available to operate some YEC equipment under instruction from YEC.

REFERENCE:

QUESTION:

a) Please provide, on a monthly basis, the actual amount of electrical energy supplied by YEC to the Minto mine at the Industrial Primary Rate from the time of hook up to at least the end of January 2009.

ANSWER:

(a)

Minto Mine billing from the time of hook up to the end of January 2009 is as follows:

Month	KWh	KVA (billed demand)
November	784,980	1,315
December	2,415,504	4,383
January	2,459,856	4,383

REFERENCE:

QUESTION:

a) Please provide, on a monthly basis, the actual separate amounts of YEC electrical energy generated by diesel, hydro and wind on the WAF system from the time of hook up of Minto to at least the end of January 2009.

ANSWER:

(a)

Please see table provided below for actual separate amounts of YEC electrical energy generated by diesel, hydro and wind on the WAF system from the time of Minto hook up until end of January.

	November	December	January
Total Hydro (kWh)	31,469,430	35,346,068	35,059,529
Total Diesel (kWh)	31,256	663,618	700,879
Total Wind (kWh)	101,390	6,450	0
Total Generation (kWh)	31,602,076	36,016,136	35,760,408

REFERENCE:

QUESTION:

a) On a monthly basis, during the period from the time of hook up of Minto to at least the end of January 2009, what were the estimated or actual average all in costs on the WAF for YEC to generate a kWh from each of wind, diesel and hydro sources? What was the blended hydro/diesel actual all in costs per kWh on the WAF on the same basis over the same period?

ANSWER:

(a)

Yukon Energy cannot calculate "estimated or actual average all in costs" on a monthly basis, or by generation type. Even a full Cost of Service analysis, including significant analysis on the classification and allocation of all of YEC's and YECL's costs, would not yield this type of information on a monthly basis, nor typically by generation type.

Short-term incremental costs of WAF diesel generation (ignoring capital-related fixed costs, but including fuel, variable O&M and assumed 10% line loss to supply the customer), based on GRA prices (117 c/litre), are 37.37 cents/kW.h for 2009, as set out at the top of page 4-12. Monthly variations in such costs have not been forecast. Actual costs for fuel during November to January were below GRA forecasts.[1]

In contrast, short-term incremental costs for established WAF hydro generation and wind generation are typically very low, and hard to measure. For hydraulic generation, this has been estimated in the past at 0.5 cents/kW.h. Such costs are not assessed or forecast to vary on a monthly basis.

[1] UCG-YEC-1-62(a) indicates that, based on January 2009 fuel prices, WAF short-term incremental costs of diesel generation were 24.8 c/kWh. Actual average inventory costs charged for fuel use might be lower or higher, depending on average blended costs of inventory at that time.

REFERENCE:

QUESTION:

a) On a monthly basis, during the period from the time of hook up of Minto to at least the end of January 2009, how much energy generated on the WAF system was subject to Rider F fuel adjustments? On a monthly basis over this period how much revenue was collected via Rider F on the WAF?

ANSWER:

(a)

Diesel generation on WAF and total Rider F collections in the Yukon since commencement of service to Minto (November 22, 2008) are as follows:

WAF	**YEC Diesel Generation**			**Rider F Collections**
From Nov 22-08	**kWh**	**Litres**	**Price Variance**	**(All Yukon)**
Nov-08	-	-	-	
Dec-08	663,618	179,465	$ (80,696)	$ 521,703
Jan-09	700,879	187,289	$ (84,546)	$ 693,220
	1,364,497	366,754	$ (165,243)	$ 1,214,923

YEC diesel generation on WAF for the period from mine in service date of November 22, 2008 to January 31, 2009 was 1,364 MWh. This resulted in 366,754 litres of fuel that would have been subject to Rider F fuel adjustment in the amount of $165,243.[1]

YEC is not able to report the Rider F revenues collected specifically for the WAF for the corresponding period as YECL, the primary distribution company serving the WAF, does not share its community level data with YEC.

YEC is able to report that Rider F collections for all communities in Yukon during the corresponding period were $1,214,923.

[1] The fuel adjustment is the amount that the actual average inventory price for fuel used is in excess of the 2005 GRA fuel price forecast price.

REFERENCE:

QUESTION:

a) On a monthly basis, during the period from the time of hook up of Minto to at least the end of January 2009, how much energy generated on the WAF system and supplied by YEC to the Minto mine was subject to Rider F fuel adjustments? On a monthly basis over this period how much revenue was collected via Rider F from the Minto mine?

ANSWER:

(a)

It is not practical to estimate "how much energy generated on the WAF system and supplied by YEC to the Minto mine was subject to Rider F fuel adjustments." As provided in response to PWP/HML-YEC-1-19, total YEC diesel fuel consumed on WAF, in kW.h and litres, and amount of fuel price variance charged to the diesel fuel price variance account (Rider F account) since hook of the Minto mine until the end of January 2009 is as follows:

WAF	YEC Diesel Generation		
	kWh	Litres	Price Variance
Nov-08	-	-	
Dec-08	663,618	179,465	$ (80,696)
Jan-09	700,879	187,289	$ (84,546)
Total	**1,364,497**	**366,754**	**$ (165,243)**

Total Rider F collections from Minto

Minto Rider F collections		
	kWh	Rider F
Nov-08	784,980	$ 5,267
Dec-08	2,415,504	$ 16,208
Jan-09	2,459,856	$ 16,506
	5,660,340	**$ 37,981**

REFERENCE:

QUESTION:

a) Has YEC completed in depth independent or internal inspection condition reports on the Minto diesel engines and electrical generators? If so please provide the inspection assessment reports on each of these three units. Have any of these units recently had or will they require a minor or major overhaul as contemplated or provided for under the PPA?

ANSWER:

(a)

No independent assessment was completed for the Minto diesel units. The Power Purchase Agreement with Minto (section 10.2(f)) provides that YEC's obligation to take an assignment of the Cat Leases is conditional upon (among other factors) Minto performing prior to purchase by YEC.

(i) A minor or top end overhaul on each of the Diesel Units, in accordance with manufacturer recommendations for an overall on such a Diesel Unit with approximately 8,000 hours of operations; and

(ii) For each of the Diesel Units with 16,000 hours of operation or more, a major overhaul in accordance with manufacturer recommendations for an overhaul of such a Diesel Unit with approximately 16,000 hours of operation.

Three of four units have had the required minor, top end overhauls completed. None of the units is approaching the 16,000 operating hour threshold for the major overhaul.

REFERENCE:

QUESTION:

a) Has a reduction in price for these units been determined as a result of their current condition and based on related depreciation and maintenance expenses related to actual use in excess of stipulated hours of operation? If so please provide the new estimated or actual purchase price for each unit and the costs estimates (or actual costs) to restore them to acceptable levels of service.

ANSWER:

(a)

The purchase price of the Minto Diesel Units is determined in accordance with the terms of the Power Purchase Agreement. This price is to be determined at the time when Yukon Energy is assigned the Cat leases. To date, Yukon Energy has not been assigned the relevant Cat leases for these diesel units and therefore has yet to actually purchase the units. Accordingly, no final price is yet available, as discussions are ongoing.

REFERENCE:

QUESTION:

a) Please provide, in Excel format (with explanations for all assumptions i.e. interest / discount rates, current purchase prices, rehabilitation costs, service lives, repositioning schedules with costs, annual O&M (hours of use, fuel efficiencies, etc.), security/insurance costs, depreciation, periodic upgrades, salvage / reclamation / remediation / retirement costs, etc.), the detailed life cycle net present value (in this case cost) engineering economy comparison studies for the business case justification of the purchase of the Minto diesel units as compared to the refurbishment and similar O & M costs for the Mirrlees.

ANSWER:

(a)

The business case analysis for the Minto diesels or any other form of peaking capacity is driven almost entirely by the capital costs per MW. Over the life of the units, operating costs, including fuel efficiency, insurance costs, etc. for units that are basically emergency stand-by units operating very few hours in any given year are very low compared to the capital costs incurred. For this reason, the business case analysis on new sources of capacity hinge almost entirely on the comparative capital cost estimates provided in YUB-YEC-1-34(e).

The other factor that is supportive of the Minto diesels is portability. These units offer significant flexibility compared to a Mirrlees life extension project or other baseload permanent installation diesel unit, as they can be moved as necessary and ultimately disposed of (sold) at market prices if determined to be no longer required.

REFERENCE:

QUESTION:

a) Did Minto confirm by Dec. 31, 2008 its ability and commitment to process Additional Reserves at the Mine prior to Dec. 31, 2017? Has Minto provided YEC with documentation as to an Adjusted Mine Life due to increases in processing rates or increased reserves as per the May 25, 2007 PPA Agreement?

ANSWER:

(a)

Minto did not confirm by Dec. 31, 2008 its ability to process Additional Reserves prior to December 31, 2017. As provided for in the May 25, 2007 PPA Amendment, Minto has provided YEC with access to its public documentation as to its reserves and processing to date as required to determine an Adjusted Mine Life due to increases in its licensed mill processing rate. During 2009, Minto plans to confirm material additional reserves.

Yukon Energy is currently in discussions with Minto regarding these matters.

REFERENCE:

QUESTION:

a) Is Minto currently disputing or in arrears in payments for any of its financial obligations under the PPA? If so please provide details.

ANSWER:

(a)

Minto is not currently in arrears on their payments, and is not disputing its financial obligations under the PPA.

REFERENCE:

QUESTION:

a) Could any of the capital projects proposed in the GRA be eligible for and take advantage of the recently announced Federally funded infrastructure program? If so which ones and if approved what impact would such cash infusions have on YEC' revenue requirements for the test years?

ANSWER:

(a)

The only projects in YEC's capital spending plans (Tab 5) that are anticipated to qualify and be put forward for federal funding support are Carmacks-Stewart Stage 2, and Mayo B. Funding for these project will have no effect on YEC's revenue requirement in the test years as the projects are not in service in the test years, and remain in Work in Progress.

REFERENCE:

QUESTION:

a) In light of current economic conditions and low metal prices it seems unlikely that the CSTP Stage Two extension would be required to meet new mine loads by 2010 or 2011. Could the $1 million allocated for this project in 2009 not be "safely" deferred to some future test years?

ANSWER:

(a)

Yukon Energy project budgets are reassessed on a regular basis in light of current conditions and forecasts. With regard to planning related to the CSTP Stage 2, the following relevant factors continue to be considerations:

- **Alexco Resources Corp. Connection** – With potential connection of Alexco in 2010, there remains a need to ensure ability to reduce potential diesel usage due to that mine load connecting to the grid in that year.

- **Available Government Infrastructure Funding** – To the extent government infrastructure funds become available, the ability to be ready to advance and proceed with the project in the near term is critical.

REFERENCE:

QUESTION:

a) In light of current economic conditions is it realistic to expect that customer extensions will cost YEC $150,000 over the test years?

ANSWER:

(a)

Yes.

As it does only a small degree of distribution, Yukon Energy has limited customer connections in any given year, typically small customers. The standard annual budget for this has been $475,000, offset by an estimated $400,000 in customer contributions.

There is no evidence current economic conditions will materially affect the rate of residential and small commercial customer connections in the communities YEC serves directly. The best estimate YEC can provide of the rate of customer connections is as set out in the GRA.

REFERENCE:

QUESTION:

a) As a consequence of the present and projected economic down turn has YEC, in conjunction with YECL, revised its estimate that non-industrial growth on the WAF will continue at the approximate 1MW per year?

ANSWER:

(a)

The forecasts included in the GRA remain the best estimates for the test years. There is no evidence to suggest a specific revision to the test year forecasts, or that current economic conditions will materially affect non-industrial growth in the test years.

REFERENCE:

QUESTION:

a) Do YEC and YDC share the same office space, administrative staff, corporate officers and Board meeting rooms all of which are located at #2 Miles Canyon Road and even the same P. O. Box 5920 mailing address plus a common Board of Directors?

ANSWER:

(a)

YDC rents office space in YEC's Whitehorse corporate offices. Administrative services are provided on a cost recovery basis. Corporate officers are not all the same. Mail can be received by YDC via P.O. Box 5920 or via Yukon Government central mail (P.O. Box 2703 (D-1)).

REFERENCE:

QUESTION:

a) What problems are there with the J. D. Edwards financial software package (page 5-17) that require its replacement? Will the replacement system if approved by the Board of Directors will this be for the exclusive use of YEC or will this system also be used by YDC?

ANSWER:

(a)

The JDEdwards Financial software package was originally installed in 1999 and has been deemed to be at its end-of-life. The supplier has stopped support for this version of this software.

The current system is owned by YDC, and YEC pays a lease fee to be able to use the product. The replacement system will be owned by YEC. Yukon Energy provides YDC with accounting services on a cost recovery basis, including use of the replacement financial software package.

REFERENCE:

QUESTION:

a) Will the Electronic Document Management system (page 5-17) be for the exclusive use of YEC or will this system also be used by YDC?

ANSWER:

(a)

The Electric Document Management System is software for use by YEC.

The software is not being designed for YDC's purposes. In the event it could serve YDC, it is likely that the software would be used for YDC's purpose as well, on a cost recovery basis.

REFERENCE:

QUESTION:

a) What are the annual direct and indirect costs for YEC to be registered under the Yukon Business Corporations Act as a private corporation? What administrative, operational, tax, legal, etc. cost advantages or savings does YEC benefit from by being a private corporation versus being a Yukon Crown Corporation?

ANSWER:

(a)

Business Corporations Act (BCA) incorporation requires YEC to pay $150 per year for corporate address registration, plus $15 per year to file our annual report. In addition, there is a $15 cost to file changes to Directors and Officers.

The comparison question is not relevant as Yukon Energy has no option; it must be a BCA Corporation. Only the Yukon Government can create legislated Corporations.

REFERENCE:

QUESTION:

a) Does the President and Chief Executive Officer of YEC also hold the same or similar position with YDC? Does the President and Chief Executive Officer of YEC report only to and hold office at the pleasure of the YEC' Board of Directors? Does the YEC' President and Chief Executive Officer position have, through its connection to YDC, de facto Deputy Minister status and access to the Yukon Minister Responsible for YDC and thus to the Yukon Cabinet?

ANSWER:

(a)

The President and Chief Executive Officer of YEC also holds the position of Chief Executive Officer for YDC. The President and Chief Executive Officer of YEC reports to and holds office at the pleasure of the YEC's Board of Directors. The President and Chief Executive Officer does not have de facto Deputy Minister status as described above.

REFERENCE:

QUESTION:

a) In RATE SCHEDULE – 42, what is the 37.37 cents per kW.h based upon? Is this the actual (or estimated) cost to generate a kW.h of electrical energy by diesel alone on the WAF system?

ANSWER:

(a)

The Energy Reconciliation Adjustment (ERA) in Rate Schedule 42 is to reconcile wholesale purchases to test year forecast purchases; it is applied only when diesel generation is on the margin[1], and per the 1996/97 GRA approved rate, was set at the approved run out rate for non-government residential service for the Hydro Zone. Based on OIC 1995/90 and the related implementation principles approved in the 1996/97 joint YEC/YECL GRA, the Hydro Zone non-government residential run out rate was determined based on short-term incremental diesel generation costs (fuel plus variable O&M and 10% for line losses from the generator to customer meter).

As per the 1996/97 GRA determination of the non-government residential run out rate, the 37.37 cents per kWh is based on the Application's forecast cost of diesel generation on the WAF system as used in the Application for 2009 (see Page 4-18 of the Application). Footnote 11, at page 4-12 of the Application, provides the following explanation of the calculation of 37.37 cents/kWh noting it is based on:

> Average 2009 YEC fuel price for hydro systems of $1.170/litre, average efficiency of 3.60 kW.h/litre, 10% system-wide losses and assuming retention of the 1.6 cents/kW.h variable O&M estimates from 1996/97.

Overall, the proposed Rate Schedule 42 addressed the need to ensure that, regardless of the Hydro Zone non-government residential run out rate approved at this time (i.e., YEC has sought only a modest increase in this rate to start moving to the levels required per OIC 1995/90), the ERA will provide that YEC is compensated for its GRA-approved

[1] Order 1999-4 approved a Settlement between YEC and YECL on Rate Schedule 42 which, among other provisions, confirmed that "the ERA mechanism will apply only during months when diesel is on the margin for the WAF system."

forecast cost of diesel generation in the event that such generation is required to supply YECL with wholesales greater than the GRA forecast wholesale purchases.

Please see also response to YUB-YEC-1-22.

REFERENCE:

QUESTION:

a) If there is a very cold winter and YECL's actual wholesale purchases substantially exceed forecasts won't the provisions of Schedule 42 effectively require YECL to establish a form of Diesel Energy Surcharge Rider to recover the YEC adjustment costs from YECL' retail customers? Will YEC' industrial customer(s) be subject to the same Schedule-42 adjustment rate?

ANSWER:

(a)

The Energy Reconciliation Adjustment (ERA) provisions of Rate Schedule 42 occur only after the fact, when diesel generation is on the margin for WAF operations of YEC, and do not provide under a very cold winter any basis for changes to retail or industrial rates or for any form of Diesel Energy Surcharge Rider to be sought by YECL. Please see PWP/HML-YEC-1-35.

The triggering of the ERA does not create any new costs, it only addresses the distribution of costs between Yukon Energy and YECL. In the event diesel generation is on the margin for YEC, and YECL's load grows beyond the forecast levels reflected in Rate Schedule 42 rates, there will be an actual cost to the system of 37.37 cents/kW.h of added retail load growth to generate the power to serve this added load growth. The presence of the ERA does not create this cost, it only ensures that this cost is appropriately recovered by YEC from YECL, consistent with the terms of OIC 1995/90, section 7(b).

The effect is exactly analogous to the situation if YECL's load grows in Watson Lake beyond what was forecast in the GRA – in that case there is a need for YECL to incur the costs of diesel generation to serve the load growth, without any resort to rate changes or a Diesel Energy Surcharge Rider. There has not been, nor is there expected to be, any "Diesel Energy Surcharge Rider" related to such diesel generation costs on any system in Yukon.

The industrial rate schedule currently does not include a provision for an Energy Reconciliation Adjustment. However, Rate Schedule 39 continues to provide for a Base Load Energy Amount to be established at any time for a customer of 90% of forecast use when YEC expects to require diesel fuel generation to service use in excess of such a Base Load Energy amount. At such time, Rate Schedule 39 provides that YEC will submit this rate schedule to the YUB for amendment to adjust the Energy rate as required for a two part rate that yields the same overall energy charge at forecast energy use, with all energy consumed in excess of the Base Load being charged at a rate reflecting the incremental cost of using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use. This concept has been included in previous industrial rate schedules in Yukon applicable to the Faro mine.

REFERENCE:

QUESTION:

a) At my request, on February 6, 2008 I met with YEC staff members (David Morrison and Hector Campbell among others) to discuss rate design issues and concerns that I suggested could possibly be addressed in the upcoming GRA process. At that meeting I asked if YEC would consider studying the re-introduction of the Diesel Energy Surcharge which would include automatic fuel adjustment provisions so as to eliminate blended diesel/hydro rates and to more fairly distribute the actual costs of generating diesel electric energy on each of the WAF and M-D hydro zones to all classes of customers through all rate blocks whenever diesel generation was required on these systems. Sorry for the preamble. My questions are did YEC undertake such a study and if so can YEC please provide copies? If this study was not carried out can YEC please explain the reasons why not?

ANSWER:

(a)

YEC has not undertaken the suggested study. Yukon Energy did not attempt to undertake any fundamental redesign of base rates for this Application, and as a result no such study was undertaken.

YEC is unclear of the extent to which the overall proposal as outlined above and in the meeting with YEC would be consistent with current rate directives. Any such proposal for a Diesel Energy Surcharge would, by necessity, be constrained by OIC 1995/90 which requires equalized rates throughout Yukon within each retail rate class subject only to adjusted run off rates (applicable above the stipulated energy use levels per month) to reflect economy and efficiency (which the YUB has implemented previously on the basis for forecast short-term incremental diesel generation costs). Rider F adjustments, applicable to all retail energy use throughout Yukon, have then addressed variances from GRA forecast fuel prices.

REFERENCE:

QUESTION:

a) Has YEC undertaken any new studies or steps to reduce ice damming problems on the Yukon River near the Marwell area?

ANSWER:

(a)

YEC conducted investigations in 2006-2008 to ensure that the Whitehorse Rapids hydro plant could be operated to the planned output level in winter (as set out in the Resource Plan at a firm 24 MW capacity) without causing icing or other winter water-related issues. The studies were not oriented specifically at new steps to “reduce ice damming” near Marwell, but did provide Yukon Energy with forecasts of flow adjustments that may be required under certain conditions to minimize ice damming problems during an extreme icing event.

REFERENCE:

QUESTION:

a) In Table 2-5 page 2-19, why did the diesel generation in 2007 at Mayo rise to 21 MWh and in Dawson to 757 MWh? Why are there 0 MWh forecast for Mayo in 2008 and 2009?

ANSWER:

(a)

The 21 MWh of diesel generation in 2007 at Mayo was mainly due to maintenance run ups of diesels or to provide generation when the Mayo hydro plant was down for preventative maintenance.

The 757 MWh of generation in 2007 at Dawson City was due to the following activities (at the approximate generation amounts):

Islanding due to lightning risk in June/July	342 MWh
Loss of L174 or Mayo hydro outages	176 MWh
Scheduled outages / maintenance	239 MWh

YEC does not forecast diesel generation for Mayo in 2008 and 2009 because the minimal amount of diesel typically required for Mayo has historically been included in the general provision for diesel generation on the Mayo Dawson system which is forecast in 2009 as 2% of the overall generation required for Dawson City.

REFERENCE:

QUESTION:

a) In light of the resistance from Marsh Lake residents when YEC last suggested greater storage on Marsh Lake, what has changed that would indicate that YEC's new study and proposal to increase winter storage on the lake would be acceptable to local residents? Please provide the record of the public meeting that YEC and its consultants had previously with Marsh Lake residents on this issue.

ANSWER:

(a)

YEC has been working with the residents of Marsh Lake over the past two summers to further their understanding of the natural causes of high water levels on Marsh Lake and to provide assistance and public notice of potential high water levels. Local residents of Marsh Lake have also indicated what bio-physical aspects of Marsh Lake may need to be studied in order to assess the environmental and socio-economic effects of storing more water in the fall of each year after the peak water levels start to drop. A copy of the record of the Sept 11, 2006 public meeting is provided as Attachment 1 to this response.

During the same period, the Yukon Government has also been working with the residents of Marsh Lake, towards addressing issues related to fall flooding at the Lake.

YUKON ENERGY CORPORATION MEMORANDUM

DATE: September 21, 2006
File: 1700-02-04

TO: H. Campbell / D. Morrison / J. Patterson (via email)

FROM: Ron Gee

RE: Marsh Lake Public Meeting

Meeting Date: September 11, 2006
Time: 7 PM
Location: Marsh Lake Recreation Centre
Company Representation: D. Morrison, W. Phelps, J. Duke, E. McKennirey, M. Guilbeault, N. Steffen, L. Turney, A. Ball, R. Gee

Approximately 50 members of the public attended meeting.

Meeting format:

1. Introduction and opening statements by D. Morrison
2. Context and rationale of project, review of water level issues, review of operations, potential impacts by W. Phelps
3. Introduction of GLL and NHC consultants by J. Duke
4. Open forum

Issues or comments raised in the open forum:

1. If the Corporation is allowed a greater license range, they will attempt to use the water to the greatest extent possible and this will negatively effect the residents
2. Muskrats used to be plentiful, but now they experience freeze out during the draw down period
3. Fish habitat and other wildlife concerns should be looked at as well
4. Request was made to know when the last increase in storage range was granted
5. Question was asked if the Corporation has applied to any regulatory bodies for permits for this project
6. In this current year, would the 1 foot proposal have resulted in higher water?
7. Question as to why the Corporation is not building wind turbines instead of this project
8. What is the Corporations low water target and how close to the low supply level can be achieved?
9. Marsh Lake Advisory Committee would like a copy of all reports produced by the consultant
10. Wave action is the key factor to erosion, it must be considered both from the predominate direction, the south, as well as when it changes to a north wind

11. Mike Larson is the contact person for the MLAC
12. Corporation should come back to the group when it has a methodology for the studies
13. The Corporation is considering other means of increasing generation that provide a greater annual benefit than increasing the license range on Marsh Lake. The Corporation should pursue those alternatives and leave Marsh Lake levels alone because the benefit is small and the opposition will be great
14. Concerns ranged from open water erosion, groundwater in basements, effects on septic fields, and water levels in low lying areas behind the property freezing

\documents\memo\rg3110

REFERENCE:

QUESTION:

a) As I recall there was in the past opposition from Atlin residents regarding a previous proposal by YEC to increase storage on Atlin Lake and there was little or no support for this proposal from BC Hydro. What has changed that would indicate that it would be wise for YEC' to undertake a new study and proposal to increase storage on the lake that would be acceptable to local residents and would receive BC Hydro' blessing?

ANSWER:

(a)

In the early 1980's Northern Canada Power Commission studied the potential to store water in Atlin Lake in the fall and use it in the winter, utilizing top storage to raise the lake level well above its natural high.

Yukon Energy is considering a much smaller development that would store water in Atlin Lake within its natural high water levels and release it over the winter, very similar to what is currently undertaken with regard to Marsh Lake.

REFERENCE:

QUESTION:

a) What policies and procedures are in place that govern YEC' contract tendering and procurement processes. In particular, how are sole source, standing offer and invitational tendering procedures protected and monitored to ensure fairness and prevent preferential treatment?

ANSWER:

(a)

YEC has numerous corporate policies in place which govern procurement processes. The following policies and procedures are provided as Attachment 1 to this response:

- GS-001 Goods and Services Definitions
- GS-002 Signing Authority Guideline
- GS-003 Purchasing Agreements Guideline
- GS-004 Competitive Bid Guideline
- GS-005 Competitive Bid Threshold Guideline
- GS-006 contracts for Service Guideline
- GS-007 Evaluation Criteria Guideline
- GS-008 Bid Security Guideline
- GS-009 Emergency Purchases Guideline
- GS-010 Non-Competitive Purchases Guideline
- GS-011 Purchase Order Guideline
- GS-012 Standing Agreements Guideline
- GS-013 Vendor Registration Guideline
- GS-014 Pre-Qualified Vendor Guideline
- GS-015 Goods and Services Guidelines
- GS-016 Local Purchase Order Guideline
- GS-017 Invoice Approval Guideline
- GS-018 Incoming Shipping Negotiation Guideline
- GS-019 Shipping Invoice Approval and Payment guideline

Yukon Energy has a procurement group which monitors purchasing in the Corporation and ensures appropriate purchasing practices are respected.

YUKON ENERGY	Goods & Services Guidelines GS-001	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Definitions
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

Award The notification to a bidder that their bid has been accepted and that Yukon Energy will be issuing a legal binding agreement to that bidder.

Best Value Means overall best choice, as defined by the evaluation criteria (i.e. quality, availability, price, compatibility, qualifications, proposal process, innovation, etc.)

Bid An offer, as a price, whether for payment or acceptance. Usually a proposal submitted to the corporation in response to a request for bids to supply goods or services.

Bid Close The time and date indicated in the bid document after which bids/responses will not be accepted.

Bid Deposit/ Surety Bond
A guarantee, in the form of a bond or deposit, that the bidder, if selected, will sign the contract as bid: otherwise, the bidder (in case of a deposit) or the bidder or their guarantor (in the case of a bond) will be liable for the amount of the bond or deposit.

Bid— Formal
A bid/tender that is requested and responded to in writing.

Bid – Invitational
A bid that is extended to a selected number of firms by invitation. An invitational bid may be restricted (only those invited may bid) or non-restricted (other firms may bid if they wish).

Bid Shopping
The act of asking a vendor(s) if they can better an acceptable low bid (price) from another vendor on a commodity or service. The action allows other vendors to provide a better priced bid or some other aspect that would better the lowest acceptable bid that the corporation received. Such action is unethical, illegal and if done under a competitive bid process is, in fact, an attempt at bid manipulation.

Bidder A person, proprietorship, partnership or corporation that submits a proposal.

Bond – Payment/Labour
Protection for the buyer against liens which may be granted to vendors of material and labor to the bidder, in the event the bidder does not make proper payments to its vendors.

Bond – Performance

A guarantee that the work done will be done according to specifications and in the time specified. If the Yukon Energy has to go to another vendor for rework or to get the order completed, Yukon Energy is indemnified for these extra costs.

Competitive Bid

A process where all bidders compete with one another when bidding upon the same bid.

Construction

Work to build, repair, renovate, restore, maintain or demolish a structure and includes the hiring of equipment and services necessary for that work.

Consultant

A person, proprietorship, partnership or corporation with qualifications, by education (credentials) or by experience, in scientific, technical, managerial, accounting or any other field that is required to perform specialized services.

Contract A deliberate verbal or written agreement between two or more competent persons to purchase goods and or services and perform construction or services.

Contracting Authority

Any employee having authority to enter into a contract on behalf of Yukon Energy.

Contractor Any person, proprietorship, partnership or corporation which contracts to perform work or supply goods or services in accordance with a Purchasing Agreement.

Delegated Financial Authority

A person who has been designated and approved to purchase goods or supplies within stated financial parameters.

Emergency Purchase

An emergency purchase is classified as a procurement which is needed to "protect life and property, prevent substantial economic loss, and/or prevent the interruption of essential services."

Evaluation Criteria

Criteria against which bids are evaluated for determining qualified bids and for the selection of the winning bid.

Letter of Acceptance

A letter pursuant to a bid provided to the successful bidder, approved and signed by Corporate Services which indicates that the submitted bid has been accepted and that Yukon Energy will be issuing a legal binding contract to that bidder.

Letter of Intent

A letter indicating a preliminary contractual arrangement customarily used in situations where the items, quantities, price and delivery dates are known, but where the principal contract provisions require additional time-consuming negotiations. It is used to enter into an interim agreement, pending a definitive contract, so as to permit that start of construction, production, or delivery of the vendors or materials

Local Contractor

A person, proprietorship, partnership or corporation whose main place of business is the community in which the work is to be performed.

Lump Sum Price

A price agreed upon between the vendor and purchaser for a group of items without breakdown of individual values: a lot price. In construction, "lump sum" means a fixed total price for the complete project, as specified. Further, the price is the total amount and the total price will not decrease or increase except by the approval of a change to the work approved by Corporate Services.

Pre-Qualify Vendor

A formal process undertaken either on a project specific basis or on a regular operational basis to qualify vendors who are able to bid, undertake and complete specific types of work (contracts) for Yukon Energy in a safe and competent manner.

Price-Driven Contract

A contract entered into as the result of a bid that has price as its' primary criteria (greater than 51%) of the award.

Proposal A written form of bid or submission from a person, proprietorship, partnership or corporation.

Public Tender

An invitation to tender that is advertised publicly and to which any interested firm may submit a tender bid.

Purchasing Agreements

Purchasing Agreements can be initiated by Corporate Services or by an outside party, usually the vendor. Purchasing Agreements generated by Corporate Services may include, without limitation, purchase orders, standing agreements, contracts, letter of intent (for purchase), partnership agreements and other written purchase documents.

Purchasing Agreements initiated by an outside party may cover the purchase of materials, equipment, professional services, construction and lease/rental agreements.

Quotation – (Informal)

A statement of price, terms of sale and a description of goods or services offered by a vendor; a bid that is requested and responded to orally or in writing. When given in response to an inquiry, is usually considered an offer to sell.

Request for Bid (RFB)

A competitive bid process that is undertaken typically for transactions where price is the key factor in the purchasing decision.

Request for Proposals (RFP)

A competitive bid process that is undertaken typically for higher dollar value and/or complex transactions. Factors other than price will be used to make the final purchasing decision. An invitation to perform or provide a function, service or product that cannot be fully defined or specified.

Scope The technical conditions and specifications of a job; the overall requirements or deliverables of a specific project.

Signing Authority

Authority delegated to specific employees of Yukon Energy, empowering them to financially commit the Corporation to legally binding obligations, but which are limited by dollar amounts and may be limited to certain types of obligations. Exercising of an individual Signing Authority is typically limited to the area of the employee's functional role and responsibility, unless otherwise stated within their job responsibilities.

Single Source

A method of purchase where the purchase in made from one single vendor or source even though other vendors exist that can bid or supply the goods/materials or services.

Sole Source

A method of purchase where there is only one source of supply for the requirements of the corporation. This type of purchase is done because of the commodity's technological, specialized or unique character that only a sole vendor can provide.

Standing Agreement

A purchase agreement or contract used to provide direct access to a pre-determined vendor for the supply of specific goods and/or services, on an as-required basis, for specific periods of time, at prearranged prices and delivery conditions.

Subcontractor

A person, proprietorship, partnership or corporation who contracts with a prime contractor of Yukon Energy to perform all or any part of the prime contractor's obligations in a particular prime contract.

Tender

A document defining the minimum standards or specifications to be met by bidders and the requested terms and conditions of the contract so as to permit the evaluation of bids on the basis of price.

Value-Driven Contract

A contract entered into as the result of a "Request" that uses indicators other than price alone for evaluation.

YUKON ENERGY	Goods & Services Guidelines GS-002	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Purchasing Agreements Signing Authority Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	President & CEO

1.00 Purpose

1.01 To clearly identify, control and provide guidance so that Purchasing Agreements are signed/approved in accordance with Yukon Energy's Signing Authority Guideline (FG-001).

2.00 Purchasing Signing Authority Matrix

2.01 All purchasing agreements for Yukon Energy are to be signed in accordance with the following signing authority matrix:

Required Approval	Category	O & M Limit	Capital Limit
Board approval - signed by 1 Board Director and 1 Officer*	• Inventory Stock • Non-stock goods & Services	Over $500,000	Over $1 million
President & CEO	• Inventory Stock • Non-Stock goods & Services	Up to $500,000	Up to $1 million
Director, Corporate Services	• Non-stock Goods & Services	Up to $250,000	Up to $500,000
Director, Operations	• Inventory Stock	Up to $250,000	Up to $500,000
Leadhand, SCC & Materials Management	• Inventory Stock	Up to $50,000	Up to $100,000
Buyer	• Non-stock goods & Services	Up to $50,000	Up to $100,000
Assistant Buyer	• Non-stock goods & Services	Up to $50,000	Up to $100,000
Industrial Warehouseperson	• Inventory Stock	Up to $10,000	Up to $10,000

***Note:** As of January 1, 2005, Yukon Energy Officers are the: Chair, Board of Directors, President & CEO, Chief Financial Officer and the Corporate Secretary.

2.02 From time to time the Board may delegate signing authority for major purchasing agreements, by resolution of the Board, to the President & CEO and/or Chief Financial Officer or Director of Corporate Services.

2.03 All leases and licenses or conditional Sale Agreements (i.e. lease to purchase – operating or capital), regardless of the amount, will require the signature of the Director Corporate Services and the Chief Financial Officer.

YUKON ENERGY	Goods & Services Guidelines GS-003	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Purchasing Agreements Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 To define and establish parameters for the use of various purchasing agreements for consistent application and due process. Such guidelines will ensure standards are established that will be applied to the daily processing and preparation of the various purchasing agreements.

1.02 Corporate Services can provide advice on the procedures to follow and the purchasing agreement to use depending upon the particular circumstance.

1.03 Corporate Services issues all contracts, purchase orders for non-stock items and standing agreements to ensure that all bidding and mandatory elements of the purchase have been completed correctly and within established signing authorities.

1.04 All purchasing agreements will be executed in a confidential and timely manner with all legal, safety and risk management issues addressed.

2.00 Minor Works Contracts

2.01 Minor Works Contracts are used primarily for service and construction requirements of a minor financial value for the corporation. Yukon Energy considers minor works to be purchases for a financial value not to exceed $250,000.00.

3.00 Construction Contracts

3.01 Construction Contracts are used primarily for work to build, repair, renovate, restore, maintain or demolish a structure and includes the hiring of equipment and services necessary for that work or when performance bonding/protection is required. Any purchase requisition that has a total estimated financial value greater than $250,000.00 shall be reviewed as to whether a bid security is required.

4.00 Consulting Contracts

4.01 Consulting Contracts are to be used to secure professional and consulting services. Usually, these consulting services are for 'soft' services such as audits, managerial reviews, operational reviews, engineering, architectural and other services which are more conceptual and theoretical in nature.

4.02 Consulting Contracts specify the specialty in which the consultant is to provide services, and details carefully the obligation of the consultant. Consulting Contracts shall specify

the nature of the work/service, a list of deliverables, timeframes/milestones, confidentiality, name of project manager and information on invoice processing, etc.

4.03 Consulting Contracts shall comply with Yukon Energy's Contracts for Service Guideline (GS-006).

5.00 Purchase Orders

5.01 Purchase Orders are used for the purchase of goods, equipment, materials or services primarily with a financial value greater than $5,000.00.

5.02 Purchase Orders shall comply with Yukon Energy's Purchase Order Guideline (GS-011).

6.00 Local Purchase Orders (LPO's)

6.01 Local Purchase Orders (LPO's) are used for the purchase of local goods, equipment, materials or services with a financial value not to exceed $5,000.00.

6.02 Local Purchase Orders allows end-users, owner's designate or authorized field personnel to purchase small value items or services and expedite the acquisition of the requirements and needs of these individuals. There is no need to obtain competitive bids but it is expected that the issuer will obtain the best value available in the area.

6.03 Local Purchase Orders shall comply with Yukon Energy's Local Purchase Order Guideline (GS-015).

7.00 Standing Agreements

7.01 Standing Agreements are used for the purchase of repetitively purchased, lower dollar value goods, equipment, materials or services during a specified period.

7.02 Standing Agreements shall comply with Yukon Energy's Standing Agreements Guideline (GS-012).

8.00 Corporate Purchasing Cards

8.01 Corporate Purchasing Cards are used as a convenient cost efficient method for the purchase of goods, equipment, materials or services with a financial value not to exceed $5,000.00.

8.02 Corporate Purchasing Cards shall comply with Yukon Energy's Corporate Purchasing Card Guideline (GS-014).

YUKON ENERGY	Goods & Services Guidelines GS-004	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Competitive Bid Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 Yukon Energy is committed to a fair and transparent process for all purchases made on behalf of the Corporation. The competitive bid process ensures that the Corporation receives the best overall value for the all purchases.

1.02 All purchases are subject to the competitive bid thresholds set out in the Purchasing Policy (HR-021) and the Competitive Bid Threshold Guideline (GS-005). In addition, proposed purchases below the thresholds may be subject to a competitive bid process at the discretion of Corporate Services, in consultation with the requestor.

1.03 Corporate Services oversees the acquisition of services and non-stock goods and ensures that all applicable policies and procedures, as well as all applicable federal and provincial legislation and regulations governing the acquisition of goods and services are adhered to.

2.00 Overview

2.01 Corporate Service has clearly defined methods of soliciting competitive bids from vendors based on the dollar value and complexity of the proposed purchase.

2.02 Corporate Services requests pricing, product and market information through various solicitation requests (RFP, RFQ, RFI, etc).

2.03 Solicitation requests should not be construed as an agreement to procure services. The Corporation may elect to cancel or reject all bids/responses received and will not be liable to any respondent for any claims, whether for costs or damages incurred by a respondent in preparing its bid, loss of anticipated profits in connection with any final contract, or any other matter whatsoever.

3.00 Procedure

The following is the procedure to initiate a competitive bid:

3.01 Requestor submits a completed and properly signed Purchase Requisition to Corporate Services clearly indicating the goods and services to be purchased and the estimated purchase price.

3.02 Requestor identifies the potential sources of supply (if known). Corporate Services may add other potential sources of supply.

3.03 Requestor and Corporate Services establish appropriate evaluation criteria and weighting which will be used to evaluate responses (if other than price), prior to Corporate Services preparing solicitation request documents.

3.04 Corporate Services prepares the appropriate solicitation request documents for distribution.

3.05 Solicitation requests may be posted on Yukon Energy's electronic website for the vendor community at large.

3.06 Responders are to be given a reasonable period of time (based on the size, complexity and urgency of the proposed purchase) to provide a response to the solicitation request.

3.07 Corporate Services reviews all responses received by the designated closing date and time to ensure commercial compliance with the mandatory requirements of the solicitation request document.

3.08 Evaluators document the methodology for awarding/deducting points and use this methodology consistently in evaluating all responses received.

3.09 Corporate Services prepares and distributes score sheets to evaluators for each bid.

3.10 An evaluation committee of at least three employees, consisting of Corporate Services, the requestor and one other employee, shall evaluate all responses.

3.11 All evaluators must provide a signed and completed evaluation score sheet clearly showing the point scores awarded, and the reasons for the allocation of points for each response. If evaluation criteria are being used, all responses must be evaluated as per the stated criteria. Evaluators shall keep all information and pricing confidential and handle responses in such a manner as not to disclose any information to a competing vendor.

3.12 If a response is of such a highly competitive or strategic nature to the corporation, the responses can be held in the offices of Corporate Services. All reviews will be conducted at the Corporation's premises, to ensure proper handling of sensitive information and the release of information in an orderly and diligent manner.

3.13 The successful vendor is selected based solely on the evaluation criteria. All documentation is to be returned to Corporate Services and should clearly indicate the successful vendor as well as the items to be purchased.

3.14 Corporate Services will notify the successful vendor and issues the appropriate Purchasing Agreement.

3.15 No goods and services are to be provided to the Corporation until a fully executed Purchasing Agreement is in place.

3.16 Any revisions/corrections to a Purchasing Agreement must be done by Corporate Services by way of a Change Order request.

4.00 Public Openings

4.01 The following information will be released for public openings: Name and address of the bidder; price, and if required, whether bid security has been included and the form of that security.

5.00 Bid Security Requirements

5.01 Purchase Requisitions that has a total estimated value over $250,000 shall be reviewed as to whether a bid security is required and if not required, justification provided as to that decision. Bid security requirements will be in accordance with the Corporation's Bid Security Guideline (GS-008).

5.00 Signing Authority

5.01 All purchase transactions are to be requested only by authorized employees in accordance with the Corporation's Signing Authority Guideline.

6.00 Document Retention

6.01 Corporate Services will retain all original documents complete with supporting documentation for a period of six years plus current year for audit purposes.

YUKON ENERGY	Goods & Services Guidelines GS-005	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Competitive Bid Threshold Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 To clearly identify and provide guidance to the various departments of the corporation in determining when competitive bids are required and the financial thresholds that determine the use of various competitive bids.

2.00 Competitive Bid Thresholds

2.01 Competitive Bid Thresholds are provided to identify when certain competitive bids are required in the procurement of goods, services and equipment for the Corporation.

2.02 a) The President & CEO may waive any provision of this policy when it would be in the best interest of Yukon Energy to do so.

b) Directors may award non-competitive contracts up to a maximum value of $25,000.00. The President & CEO must approve all other non-competitive contracts. The criteria as set out in the Non-Competitive Purchases Guideline (GS-010) shall be adhered to.

c) In all other cases, competitive bidding will be applied as follows:

Purchase Value Threshold	***Competitive Bid Application***
Up to $5,000	Competitive bids **not** required; delegated purchasing/ contracting authorities may enter into a Purchasing Agreement (minor works contract, Consulting Contract, Purchase Order, LPO, VISA, Standing Agreement, etc.)
$5,001 to $25,000	Competitive bids required – a minimum of two (2) phone vendor quotations are required.
$25,001 to $50,000	Competitive bids required – a minimum of three (3) written vendor quotations are required
$50,001 to $100,000	Competitive bids required – Corporate Services solicits bids from a minimum of three vendors.
More than $100,000	Competitive bids required – Corporate Services releases a Public bid where any number of vendors can compete. A minimum of three vendors should be invited.

YUKON ENERGY	Goods & Services Guidelines GS-006	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Contracts for Service Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 Contracts for Service are required to ensure that the successful vendor:

- Is informed of its obligations including the services to be provided;
- Is provided the scope of work or work requirements and a schedule for services;
- Provides the required WCB and insurance coverage; and
- Complies with other terms and conditions of the contract, including cancellation.

2.00 Procedure

The following is the procedure for implementing a Contract for Service and/or Purchase Order for services:

2.01 Submit a completed Purchase Requisition to Corporate Services clearly indicating the nature of the service to be provided, along with any pertinent terms and conditions for the provision of service. The Purchase Requisition is the authorization to initiate the procurement process and enables a Purchase Agreement to be generated.

2.02 When initiating a request for a Contract for Services, the requisition must clearly define the scope of work, the term of the project and an estimated value for the work which will be completed.

2.03 A fully executed Purchase Agreement must be in place prior to commencement of any work or services. To be considered fully executed, the agreement must be signed by an authorized representative of Corporate Services, an authorized representative of Yukon Energy and the Contractor.

2.04 Any revisions/corrections to Purchasing Agreements must be done by way of Change Order request issued by Corporate Services.

3.00 Contracts for Service Signing Authority

3.01 All Contracts for Services are to be requested only by authorized employees in accordance with Yukon Energy's Signing Authority Guideline (FG-001).

4.00 Document Retention

4.01 Corporate Services will retain all original documents complete with supporting documentation for a period of six years plus current year for audit purposes.

YUKON ENERGY	Goods & Services Guidelines GS-007	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Evaluation Criteria Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 The purpose of this guideline is to identify the procedure for developing relevant evaluation criteria and methods to weight the criteria to score a vendor response.

2.00 Procedure

2.01 Corporate Services, the requestor and/or the evaluation committee identifies criteria that are relevant to properly evaluate a vendor response. The number of evaluation criteria should not be so numerous so as to make it impossible for the evaluators to determine whether a vendor has satisfied them all.

2.02 The following are some examples of evaluation criteria that may be considered:

Technical: Include the vendor's understanding of the procurement; their management plan; the quality of the proposed design for certain goods; the experience and qualifications of key personnel; and vendor resources.

Qualifications of the vendor: The qualifications and experience of the vendor and, in particular, the project team members, including the consultants, proposed to be assigned to the project.

Experience/familiarity with similar projects: The vendor's performance record and/or familiarity with similar projects/scope with respect to such factors as control of costs, quality of the work, and the ability to meet schedules.

Availability of the vendor: The availability of key personnel, equipment, and facilities assigned to provide the goods and/or perform the services.

Cost: For the procurement of goods and nonprofessional services only, cost criteria include the vendor's proposed price (for fixed-price contracts); the realistic expected cost of performance, plus any proposed fixed fee (for cost-reimbursement contracts); and other costs, such as that of ownership, including transportation costs, and life-cycle costs (installation, operation, maintenance, security and disposal).

Financial strength: The financial strengths and weaknesses of a vendor affect its capability to respond to the needs of the corporation. Individual financial measures that may be examined include, but are not limited to, credit rating, capital structure, profitability, ability to meet interest and dividend obligations, working capital, inventory turnover, current ratio and return on investment.

Remote Geographic Support: With certain requirements of the corporation for remote geographical areas, support for local suppliers may need to be considered and given a weighting depending on a number of factors (size of award, type of service, etc.).

Ability To Satisfy The Corporation's Requirements: Includes but are not limited to following elements: quality, safety, price, continuity of supply, capacity, reliability, environmental profile and ethical compliance.

3.00 Ranking of Evaluative Criteria

3.01 The evaluation criteria should be properly weighted in accordance with its importance.

3.02 The evaluation criteria should be ranked prior to issuing any bids for the procurement of goods and/or services.

3.03 The evaluators may determine a minimum threshold score that a potential vendor will have to attain in order to be accepted or considered for pre-qualification.

4.00 Evaluation Assessments

4.01 The following types of evaluation assessments can be conducted at the Corporation's discretion:

- Formal assessments – Where an evaluation committee evaluates responses.
- Semi-formal assessments – Where the requestor evaluates responses.
- Other assessments tools – Other assessment tools can be used as mutually agreed and upon the discretion of Corporate Services and the requestor.

5.00 Scoring Responses

5.01 Corporate Services and the requestor use their discretion in determining how to score responses provided that it is not arbitrary.

5.02 The following are some methods for scoring responses:

- By adjective (excellent, good, fair . . .);
- Numerical (10, 9, 8 . . .); or
- Narrative and ranking. A narrative evaluation may be the most effective scoring procedure in situations where the evaluation committee must present its results to the board of supervisors. Narratives can communicate specific information that adjectives and numbers cannot.

YUKON ENERGY	Goods & Services Guidelines GS-008	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Bid Security Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 To define requirements for bid security, performance and payment bonds.

1.02 Purchase Requisitions that have a total estimated value over $250,000 shall be reviewed as to whether bid security is required and if not required, justification provided as to that decision.

1.03 Bid security submitted by the bidder guarantees that the bidder will execute a contract with the Corporation at the bid price upon award of the bid. If the successful bidder refuses to enter into a contract, the bid security will be forfeited to the Corporation.

2.00 Procedure

2.01 Bid security is normally required for a Purchase with an estimated value of $250,000 or more for construction and or building requirements. The security may take the form of a bid bond or a certified cheque in the amount identified in the bid document. Performance bond and/or a labour and materials payment bond may be required.

2.02 Bid security in the amount of ten percent (10%) of the bid price is normally required with all bids for construction projects when the construction cost is estimated value over $250,000.00. The Corporation may authorize bid security for procurements if such a requirement is advantageous to the Corporation.

2.03 Corporate Services should use their discretion as to whether or not performance bonds are required as the costs associated with bonds may outweigh the advantages. If performance bonds and labour and material bonds are required, the bond shall be in effect until twelve months after the certificate of final completion.

2.04 Corporate Services may authorize certified cheques in lieu of a bid bond for the purpose of bid security if the project can be best served and competitiveness can be enhanced.

2.05 A bid submitted without proper bid security when requested shall be disqualified unless the Director, Corporate Services determines in writing that the bid substantially complies with the security requirements.

2.06 No payment shall be made on a contract where surety is required until the requested form of surety has been furnished.

4.00 Performance and Payment Bonds

4.01 Performance and/or payment bonds may be required for all construction contracts. Corporate Services and the requestor shall determine the percentage of the contract price required for performance and/or payment bonds.

4.02 Performance and/or payment bonds submitted by the successful bidder upon award of the contract guarantee faithful performance of the contract and payment of materials and labour by the contractor to all subcontractors, material suppliers and employees

4.03 Performance bonds for service contracts may be required to protect the interests of the Corporation. The amount of the bond shall be determined by the Corporation.

5.00 Bid Withdrawal

5.04 Before Bid Closing: If a bid is withdrawn at any time before bid closing, the bid security shall be returned to the bidder.

5.05 After Bid Closing: A successful bidder may not withdraw the bid after bid closing without forfeiture of bid security unless the bidder can establish by clear and convincing evidence that a nonjudgmental mistake was made in the bid. If withdrawal of a bid after bid closing is permitted by the Director, Corporate Services, no action may be taken against the bidder or bid security.

YUKON ENERGY	Goods & Services Guidelines GS-009	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Emergency Purchases Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 Situations arise whereby an exception to Yukon Energy's Purchasing Policy and related Guidelines may be required. Emergency purchases represent one of these potential situations. Typically, emergency purchases result when an unforeseeable situation or urgency exists. Failure to anticipate a need or lack of planning is not of itself considered a bona fide emergency. Proper planning will eliminate most "emergency" purchases.

2.00 Procedure

The following is the procedure for requesting an emergency purchase:

2.01 Submit a completed Purchase Requisition to Corporate Services clearly indicating the goods and services to be purchased. Any associated documents (e.g. Vendor quote, drawings, etc.) must be included with the Purchase Requisition.

2.02 Clearly mark "Emergency Purchase" on the Purchase Requisition and state the nature of the emergency to qualify for processing under the guidelines.

2.03 Proposed emergency purchases will be processed in the most expeditious manner to secure the goods or services in a timely manner to satisfy the emergency situation. The appropriate processing action will be taken by Corporate Services and can include a non-competitive purchase. The authorized employee will need to complete a Non-competitive request form.

2.04 Corporate Services will issue a Purchase Order and/or Contract to the Supplier.

2.05 Any revisions/corrections to an emergency purchase must be done by way of Change Order request. Corporate Services will issue all Change Orders.

3.00 Emergency Purchase Signing Authority

3.01 All emergency purchase transactions are to be requested only by authorized employees in accordance with Yukon Energy's Signing Authority Policy.

4.00 Document Retention

4.01 Corporate Services will retain all original documents, including bids complete with supporting documentation for a period of six years plus current year for audit purposes.

YUKON ENERGY	Goods & Services Guidelines GS-010	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Non-Competitive Purchases Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 The purpose of the Non-Competitive Purchases Guideline is to identify and provide guidance and justification to wave the competitive bid process and proceeding directly to acquisition by means of a single or sole source purchasing process.

2.00 Procedure

The following procedure outlines the steps involved in initiating a purchase involving a Non-Competitive Purchases request:

2.01 Requestor submits a completed Non-Competitive Purchases request to Corporate Services (attach to the Purchase Requisition) clearly stating the reasons for the non-competitive purchase.

2.02 Requestor submits a completed and properly signed Purchase Requisition to Corporate Services clearly indicating the goods and services to be purchased and the estimated purchase price.

2.03 Requestor identifies the potential source of supply (if known).

2.04 Exception requests will be reviewed and evaluated by Corporate Services and where applicable, the department head and/or the President & CEO.

2.05 Approved Non-Competitive Purchases will be processed by Corporate Services.

2.06 Any revisions/corrections to a Non-Competitive Purchase must be done by way of Change Order request. Corporate Services will issue all Change Orders.

3.00 Non-Competitive Purchases

3.01 Non-Competitive Purchases may be requested if the following conditions are identified:

- **Sole Source:** There is only one source of supply: or
- **Single Source:** There are other suppliers, but Yukon Energy elects to purchase from one single supplier due to one of the following:
  1. The work is of a proprietary nature and only one supplier can do the work within timeline;
  2. The work to be undertaken is an emergency;

3. For purposes of community support, the purchase will be awarded to a specific supplier; or
4. The President & CEO or Directors authorizes that work be given to a specific company.

3.02 Directors may award Non-Competitive Purchases up to a maximum value of $25,000.00. The President & CEO must approve all other Non-Competitive Purchases contracts.

4.00 Signing Authority

4.01 All Non-Competitive Purchases are to be requested only by authorized employees in accordance with Yukon Energy's Signing Authority Policy.

5.00 Document Retention

5.01 Corporate Services will retain all original documents complete with supporting documentation for a period of six years plus current year for audit purposes.

YUKON ENERGY	Goods & Services Guidelines GS-011	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Purchase Order Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 The purpose of a Purchase Order is to:

- Provide a basic instrument that describes the item(s) purchased and the circumstances under which it is to be produced and delivered, as well as the legal consideration under which the contract is to be performed and paid for; and
- Identify the total dollar value authorized to be paid for the items identified to be purchased.

2.00 Procedure

The following is the procedure for ordering goods, services and equipment:

2.01 Submit a completed Purchase Requisition to Corporate Services clearly indicating the goods, services and/or equipment to be purchased. Any associated documentation (e.g. specifications, quotes, drawings, etc.) must be included with the Purchase Requisition. The Purchase Requisition must be properly authorized to initiate the procurement process and provide valid coding.

2.02 Purchase requisitions will be processed and subject to the competitive bid process except where the non-competitive purchase guidelines are justified.

2.03 Corporate Services will issue a Purchase Order to the successful vendor on behalf of the Corporation (and requestor).

2.04 Any revisions/corrections to a Purchase Order must be done by way of Change Order request. Corporate Services will issue all Change Orders.

3.00 Signing Authority

3.01 All purchase requisitions or transactions are to be requested only by authorized employees in accordance with Yukon Energy's Signing Authority Policy.

4.00 Purchase Document Retention

4.01 Corporate Services will retain all original documents complete with supporting documentation for a period of six years plus current year for audit purposes.

YUKON ENERGY	Goods & Services Guidelines GS-012	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Standing Agreements Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 The purpose of Standing Agreements is to provide a procurement method for repetitively purchased, lower dollar value goods and services for a specified period.

1.02 Standing Agreements are a method of purchase used to provide direct access to a pre-qualified vendor for the supply of specific goods and/or services, on an as-required basis, for specific periods of time, at prearranged prices and delivery conditions.

1.03 Standing Agreements shall only be awarded as a result of a competitive bid process undertaken by Corporate Services and approved by the Director of Corporate Services or President, when appropriate.

1.04 Standing Agreements may be requested if:

- Yukon Energy is purchasing a large number of units of goods or services over time and the total volume of purchases is relatively predictable and consistent over time;
- The specification of each unit varies very little from unit to unit; and
- There are other value add services or elements that could be achieved by a long-term agreement.

2.00 Procedure

The following is the procedure for implementing Standing Agreements:

2.01 Submit a completed Purchase Requisition to Corporate Services clearly indicating the goods and/or services to be purchased, and the estimated annual usage (both in quantity and estimated dollar amount).

2.02 All Purchase Requisitions requesting a Standing Agreement will be subject to the Competitive Bid or Non-Competitive Purchases Guidelines where appropriate to that particular potential purchase.

2.03 The award of Standing Agreements will be made by Corporate Services, once proper processing and if necessary proper bidding procedures have been completed.

2.04 Standing Agreements will normally be issued on a yearly basis and are subject to review (renewal or cancellation) annually coordinated by Corporate Services and with input from the user departments.

2.05 Any revisions/corrections to a Standing Agreements must be done by way of a Change Order request. Corporate Services will issue all Change Orders.

3.00 Signing Authority

3.01 Standing Agreements and all associated acquisitions/ transactions are to be accessed only by authorized employees in accordance with Yukon Energy's Signing Authority Policy.

4.00 Accessing Standing Agreements

4.01 Authorized employee can access or use a Standing Agreements by:

a) Checking Standing Agreements log to ensure Standing Agreement exists with vendor;
b) Checking to ensure valid proof of Insurance and WCB;
c) Purchasing goods and/or services where there is compliance with (a) and (b);
d) Requesting vendor to put Standing Agreement number on all invoices;
d) Coding purchases;
e) Obtaining second authorized signature for purchase; and
f) Forwarding purchasing documents to Accounts Payable for processing.

5.00 Standing Agreements Document Retention

5.01 Corporate Services will retain all original documents, complete with supporting documentation for a period of six years plus current year for audit purposes.

YUKON ENERGY	Goods & Services Guidelines GS-013	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Vendor Registration Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 Yukon Energy's Vendor Registration List is a directory of vendors who want to conduct business with the Corporation.

1.02 Vendor Registration is a procurement tool that allows vendors to register the goods and/or services that they are qualified and able to provide to the Corporation.

2.00 Procedure

2.01 Interested vendors complete and submit the Vendor Registration form that provides information and identifies the type of goods and/or services that the vendor is qualified and able to provide.

2.02 Vendors are responsible for providing any required licenses, tickets or levels of expertise.

2.03 Registered vendors may be given the opportunity to bid on competitive purchases made on behalf of the Corporation.

2.04 Registration on Yukon Energy's Registration List does not mean a vendor will automatically receive copies of all tenders. Vendors may contact Corporate Services to receive copies of tender packages.

2.05 Corporate Services is responsible for the on-going maintenance of the Vendor Registration list.

3.00 Document Retention

3.01 Corporate Services will retain all original documents complete with supporting documentation for a period of six years plus current year for audit purposes.

YUKON ENERGY

YUKON ENERGY CORPORATION
VENDOR REGISTRATION

Vendor Name:	**Phone Number:**
Mailing Address:	**Fax Number:**
City, Territory/Province	**Postal Code:**
Contact Name(s):	**Phone Number(s):**
Email Address:	
Please provide a short description of your services/goods/expertise:	

WEB SITE **www.yukonenergy.ca**

confirm that this is a Yukon Business as defined below ☐ **YES** ☐ **NO**

Must meet at least two (2) of the following:

- The business employs Yukon residents
- The business operates a permanently staffed office in the Yukon
- The business owns, for purposes directly related to the operation of the business, real property in the Yukon
- The business is owned, or is a corporation that is owned, 50% or more by Yukon residents

Vendor's Authorized Signature _____ Date _____

Vendor's Authorized Name-please print _____

Note: Please select the fields (with an **X**) on the attached Products and Service List that identifies that type of goods/services that you are qualified to provide to Yukon Energy.

Corporate Services Use Only

The above vendor has been added to Yukon Energy's Vendor Registration List Yes ☐

Corporate Services Signature _____ Date _____

YUKON ENERGY CORPORATION
Purchasing (Corporate Services)
PRODUCTS AND SERVICES LISTING

"A"	
Advertising	
Air Purification Equipment	
Air Conditioning Equipment	
Audio Equipment	
Audio Visual Supplies	
Automotive Equipment	
Automotive Equipment/Repair Shop	
"B"	
Bags and Sacks	
Banking Services	
Batteries, Dry	
Batteries, Wet	
Bearing, Mounted	
Bearing, other	
Bearing, Unmounted	
Binders	
Boilers	
Bolts	
Books & Pamphlets	
Boring Machines	
Boxes, Cartons	
Brokerage	
Brushing	
Brush & Weed Control	
Buoys	
"C"	
Cabinets, Lockers, Shelving	
Cable and Wire	
Calculator	
Cameras, Still Picture	
Cameras, Motion Picture	
Capacitors	
Chain Link Fencing	
Chemical, Janitorial	
Chemical Analysis Instrument	
Chemicals	
Circuit Boards	
Circuit Breakers	
Cleaning & Polishing Compounds	
Clothing	
Communication Equipment	
Compressors and Pumps	
Computer, terminal	
Computer forms	

Computer, disk drive	
Computer, floppy drive	
Computer, hard drive	
Computer, mainframe	
Computer, Microsoft Windows	
Computer, modem	
Computer, monitor	
Computer, plotter	
Computer, server	
Computer, software	
Computer, Windows NT	
Computer, workstations	
Computer/Printer supplies	
Computers	
Concrete	
Connectors	
Construction Equipment	
Construction Material, other	
Consulting Services	
Containers, other	
Contract Administration	
Converters	
Copiers	
Copying & Blueprinting	
Cranes	
Crates	
Crushing	
Cultural, Heritage, History	
Cutting Tools for Machine Tools	
Cylinder	
"D"	
Data Collection	
Demolition	
Desktop Publishing	
Distance Measuring Device	
Drafting Supplies	
Drafting Equipment	
Drafting and Surveying	
Drawings	
Driers, Dehydrators,	
Drill Bits	
Drilling and Tapping Machines	
Drilling-Wells and Core Smaples	
Drywall	
Drums and Cans	

YUKON ENERGY CORPORATION
Purchasing (Corporate Services)
PRODUCTS AND SERVICES LISTING

"E"	
Earth Moving/Excavating Equipment	
Electric Arc Welding Equipment	
Electric Control Equipment	
Electrical Components, other	
Electrical Systems Components	
Electronic Measuring Instruments	
Elevator Parts	
Engine Accessories	
Engineering Services	
Engines Gas, Auto, Truck	
Engines, Diesel	
Engines, Jet	
Engines, other	
Equipment Rentals	
Explosives	
"F"	
Facilitator	
Facsimile Equipment	
Fan and Blower Equipment	
Fastening Devices	
Feasibility Studies	
Fences and Gates, Metal	
Fences and Gates, Wood	
Fences and Gates, other	
Fertilizers	
Fiber Optic Cables	
Fiber Rope, Cordage and Twine	
Fiber Optic Conductors	
Fiber Optic Devices	
Fiber Optic Kits, other	
Film, Processed	
Film Processing	
Filters, heating, other	
Fire Fighting & Safety Equipment	
Fire Fighting Equipment	
Fire Extinguishers	
Fire Protection Services	
First Aid Kits and Supplies	
First Aid Training	
Fittings for Rope, Cable and Chain	
Fittings, other	
Flag or Pennant	
Floor Polishers & Vacuum Cleaner	
Floor Coverings	
Footwear	

Forging Machines & Hammers	
Forms	
Framing, mats	
Framing equipment, other	
Framing material	
Framings, tapes	
Framing, tools	
Freezer	
Freight services	
Fuel Delivery	
Fuel System Components	
Fuels Bulk Petroleum	
Furnaces	
Furnishings, draperies & blinds	
Furnishings, other	
Furnishings, floor coverings	
Furniture, mailroom	
Furniture, other	
Furniture, office	
Furniture, library	
Fuses	
"G"	
Gardening Equipment, Mowers	
Gardening Tools	
Gas Welding & Heat Cutting	
Gases, Compressed & Liquefied	
Gear Cutting & Finishing Machines	
Generators, Electrical	
Geology	
Glass Materials	
Glass, Tile, Brick, Block	
Graphic, Visual Arts	
Grinding machines	
Groceries	
"H"	
Handyman	
Hardware Supplies, other	
Hazard Sampling Supplies	
Hazard Detecting Instrument	
Health Services	
Heat Exchanger & Steam Condensers	
Heating Equipment & Supplies	
Historical Items	
Hose & Tubing, Flexible	

YUKON ENERGY CORPORATION
Purchasing (Corporate Services)
PRODUCTS AND SERVICES LISTING

"I"	
Inspection Services	
Instruction Services	
Insulating Equip., protective covering	
Insulating Supplies, other	
Insulation Fasteners/Adhesives/Mastics	
Insulators	
Insurance, Risk Management	
Insurance Adjusters, Customs Broker	
Intercommunication & Public Address	
Iron & Steel, bars & rods	
Iron & Steel, structural shapes	
Iron & Steel, plates	
Iron, Steel, Wire	
IT Development and Support	
"J"	
Janitorial Services	
Janitorial Supplies, Brooms, Brushes	
Job Description, Qualifications Writing	
"K"	
Kitchen Equipment	
Kitchen, cutlery and flatware	
Kitchen Equipment & Supplies, other	
Kitchen, tableware	
Kitchen Utensils	
"L"	
Lamps	
Land Use Planning	
Lathes, Metal	
Leasing	
Legal Services	
Level	
Licenses & Permits	
Life Saving and Diving Equipment	
Life Skills Training	
Lighting Equipment	
Lighting Controls, other	
Lighting Fixtures, Outdoor	
Lighting Fixtures, Indoor	
Locksmith Services	
Lubricants	
Lubrication Equipment & Accessories	
Lugs Terminals	
Lumber and Related Wood Material	

"M"	
Machine and Tools, other	
Machine Tools	
Magazine	
Mailing Machines	
Maintenance & Repairs	
Manuals	
Mapping Station	
Maps, Charts. Topography	
Material Handling Equipment/Supplies	
Meals, Catering Services	
Media Services	
Metal Finishing Equipment	
Metal Shapes, other	
Microcomputer	
Microfilm	
Microphones and Speakers, Headsets	
Milling Machines	
Motors	
"N"	
Nails	
Newspaper and Periodicals	
Nuts and Washers	
"O"	
Occupational Health & Safety Services	
Office Equipment	
Offices Supplies	
Oils, other	
"P"	
Packaging & Storage, other	
Paint Brushes, Rollers	
Paint Supplies	
Panting Services	
Paint & Varnishes	
Paper Goods	
Paper	
Paperboard	
Pest Control Agents	
Pest Control Services	
Photographic Development & Finishing	

YUKON ENERGY CORPORATION
Purchasing (Corporate Services)
PRODUCTS AND SERVICES LISTING

Photographic Equip. & Supplies, other	
Photographic Equipment	
Photographic Supplies	
Pipe and Conduit, Nonmetallic	
Pipe and Tube	
Pipe Fittings	
Plant Material	
Plastic Laminating Presses	
Plastic Materials	
Plumbing Fixtures & Supplies	
Plumbing, Heating, Ventilation	
Plywood and Veneer	
Postal Scales	
Postal Services	
Power & Hand Pumps	
Power Plant Equipment, other	
Power Supply	
Prefabricated Structures, other	
Prefabricated towers	
Printer	
Printer, dot matrix	
Printer, laser	
Printing Equipment, other	
Printing Services	
Printing supplies	
Printing Supplies Paper	
Printing, Duplicating, Bookbinding	
Professional Services	
Project Management Services	
Projector	
Promotional Items	
Propane Gas	
Public Relation Services	
"R"	
Radio & T.V. Communication Equip.	
Reclamation, Remediation, Environ Clean-up	
Recycling	
Records Management Services	
Recreational Services, Supply	
Refrigeration Equipment	
Refrigerator	
Registration fees	
Relays and Solenoids	
Rental Service	
Repairs, Services, Maintenance	
Research	

Resistors	
Rivets	
Road Clearing & Cleaning	
Roofing, Siding	
Rope, other	
Rubber Materials	
"S"	
Safety Supplies	
Safety & Rescue Equipment	
Sand Blasting	
Sand, Gravel, Rock	
Satellite Receiver	
Saws and Filing Machines	
Scales and Balances	
Screws	
Sealing Compounds	
Security Equipment Systems	
Security Devices & Accessories	
Security Services	
Semiconductors	
Signs and Displays	
Snow Removal	
Snow Removal Equipment	
Soldering & Supplies	
Sound Equipment, Underwater	
Sound Recording/Reproducing Equip.	
Special Events Management	
Stationery	
Steelworks	
Stereoscope	
Stop Watches	
Storage Tanks	
Storage, Warehouse	
Strategic Planning	
Stretchers	
Structures and Scaffolding	
Subscription	
Surveyor-Engineering	
Surveyor-Legal	
Surveyor-Quantity	
Surveying & Mapping Equipment	
Surveys	
Switches, Electronic	
"T"	
Taps, Ties and Collets	
Taxi Services	

YUKON ENERGY CORPORATION
Purchasing (Corporate Services)
PRODUCTS AND SERVICES LISTING

Telecommunication Services	
Telemarketing	
Telephone & Telegraph Equipment	
Temporary Help Services	
Testing Equipment, meter	
Testing Instrument, other	
Testing Equipment, generator	
Testing Instrument, pressure, temp	
Testing Instrument, signal	
Tires and Tubes Repair Material	
Tires and Tubes, other	
Tires and Tubes Solid & Cushion	
Toiletry Paper Products	
Toner Cartridges	
Tool Boxes	
Tools, other	
Tools, hand, non-powered	
Tools, hand, powered	
Track Material	
Trailers	
Training Aids	
Training & Development	
Transcribing, Reporting Services	
Transformers, Electronic	
Transformers, Electrical	
Transport Services	
Travel Services	
Trucking	
"U"	
Uniforms	
Upholstery Services	
"V"	
Valves, other	
Valves, powered	
Valves, non-powered	
Vehicles Auto, Vans, Light Trucks	
Vehicles, Chrysler	
Vehicles, Medium & Heavy duty	
Vehicles, Toyota	
Vehicles, Medium & Heavy Duty	
Vehicles, Ford	
Vehicles, other	
Vehicular parts and Supplies	
Vehicular Accessories	
Vehicular Brake, Steering, Axle	
Vehicular Detailing	
Vehicular Power Transmission	
Vehicular Cab, Body & Frame	
Vocational Training	
"W"	
Warehouse Trucks	
Waste Removal Management Services	
Water Purification Equipment	
Water Delivery	
Welding Equipment	
Winches, Hoists, Cranes	
Window Coverings	
Windows and Doors	
Windows and Doors, Metal	
Window and Doors, Wood	
Wire Rope and Chain	
Wire and Cable, Electrical	
Wood Material, other	
Wrapping & Packaging Equipment	
Writing Services	

YUKON ENERGY	Goods & Services Guidelines GS-014	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Pre-Qualified Vendor Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.00 A Pre-Qualified Vendor list is a procurement tool that allows pre-qualified vendors to participate in competitive and non-competitive procurement of goods and/or services for Yukon Energy.

2.00 Procedure

2.01 Corporate Services and/or requestor identify the types of goods and/or services required in conducting business on behalf of the Corporation.

2.02 Corporate Services publicly advertises and promotes interested vendors to submit application form(s) for consideration for pre-qualification. The pre-qualification of vendors may be done on a project specific basis.

2.03 Corporate Services forwards the applicable application form(s) to potential vendors for consideration for pre-qualification.

a) **General Pre-Qualification Application** - This form requests such information as name, address, name of principles, name of insurance coverage, WCB information, business license, OH&S compliances and policies, management policies and other forms of general information important to the corporation.

b) **Technical Pre-Qualification Application Form** – This form requests information to ascertain technical or engineering qualification, list of past projects or work, distribution capabilities and other required information as to ascertain the suppliers' ability to meet the Corporation's standards.

2.04 Interested vendors complete and submit the appropriate application form(s) that provides information and identifies qualifications.

2.05 Selection of pre-qualified vendors will be assessed based fully on information disclosed in the completed application form(s) regarding the vendor's qualifications and their ability to meet the Corporation's requirements and standards.

2.08 Corporate Services will notify interested vendors in writing as to the status of their application once the pre-qualification process is complete.

2.09 Pre-Qualified vendors will be added to Yukon Energy's Pre-Qualified Vendors list.

2.10 Pre-qualified vendors shall be given the opportunity to bid on Purchasing Agreements (contracts, purchase orders, standing agreements, etc).

2.11 Corporate Services maintains the Pre-Qualified Vendor list to ensure that qualified vendors are provided with the opportunity to bid on goods and/or services.

3.00 Tenure of Vendor Pre-Qualification

3.01 The evaluation team determines the appropriate period of qualification for a pre-qualified vendor. The tenure should be for a minimum of three years subject or at the discretion of the Corporation.

4.00 Responsibilities

4.01 Each representative is responsible for their respective area of expertise and due diligence is required in completing these responsibilities. All assessments will be documented to ensure accountability and transparency of the decisions made and the actions taken in the pre-qualification process.

5.02 Corporate Services is responsible for: the operation and on-going maintenance of system; assessing potential vendors; repository of information gathered and release of assessment decisions.

5.03 Major users of the goods and/or services participate in the assessment of potential suppliers through review of application form(s) for technical, engineering and safety requirements.

6.00 Post Evaluation of Pre-Qualified Vendors

6.01 For the purposes of simplicity and to ensure the vendor pre-qualification system is as efficient as possible, post evaluation of pre-qualified vendor's performance is required.

7.00 Document Retention

7.01 Corporate Services will retain all original documents complete with supporting documentation for a period of six years plus current year for audit purposes.

YUKON ENERGY	Goods & Services Guidelines GS-015	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Corporate Purchasing Card Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 The purpose of the Corporate Purchasing card is to provide a convenient, cost-effective and efficient method of procuring and paying for lower dollar value goods by:

- Simplifying the procurement and payment process;
- Reducing the use of small dollar purchase orders (LPO's);
- Decreasing the use of petty cash in departments;
- Reducing personal credit card reimbursement for goods and services;
- Improving order cycle time;
- Enabling both user and support areas to make more effective use of their resources;
- Reducing paperwork; and
- Expediting supplier payments.

1.02 Employees are encouraged to use Corporate Purchasing cards for the purchase of goods where it is efficient, economical and operationally feasible to do so and within stated parameters.

2.00 Procedure

2.01 Requests for a Corporate Purchasing card are triggered by completion of the "Signing Authorities" form by the requestor's immediate supervisor. The form shall be forwarded to Finance. Finance shall forward a copy of the form to Corporate Services for processing and retention.

2.02 Corporate Purchasing cards are issued and controlled by Corporate Services. Employees must sign an "Employee acknowledgement of Responsibilities and Obligations" form prior the issue of the purchasing card.

2.03 Card limits are set for each position in accordance with Yukon Energy's Signing Authority Guideline.

2.04 Corporate Purchasing cards must be used only to make legitimate purchases for Yukon Energy within the limitations established for the card. Only the employee whose name appears on the card is authorized to use the card.

2.05 An "Expenditure Statutory Declaration" form must be completed for all lost receipts.

3.00 Responsibilities

3.01 Cardholders are responsible for:

- Signing the Employee Acknowledgement of Responsibilities and Obligations form;
- Following established procedures for the usage and safeguarding of the Corporate Purchasing card;
- Keeping adequate records of transactions for audit scrutiny;
- Matching receipts to monthly statements;
- Coding and signing monthly statements;
- Forwarding individual statements and receipts to your immediate supervisor and budget owner for review and approval;
- Reporting loss or suspected fraudulent or misuse of the card immediately to VISA and Corporate Services; and
- Returning the Corporate Purchasing card prior to leaving Yukon Energy's employ.

3.02 Corporate Services is responsible for:

- Controlling, distributing and canceling Corporate Purchasing Cards;
- Monitoring compliance with established policies and procedures; and
- Analyzing purchases.

4.00 Restricted items

a) Cash advances;
b) Personal purchases;
c) Goods stocked in Yukon Energy's warehouse;
d) **Meals;
e) Services;
f) **Airline tickets;
g) **Tuition and professional fees;
h) Charges incurred by independent contractors;
i) Capital budget purchases;
j) Furniture purchase;
k) Goods and materials covered by master agreements or standing purchase orders.

**Senior Management may waive any provisions of this guideline when it is in the best interest of Yukon Energy to do so.

5.00 Cancellation of Corporate Purchasing Card

5.01 Any breach of this guideline may result in the cancellation of the cardholder's corporate purchasing card.

YUKON ENERGY	Goods & Services Guidelines GS-016	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Local Purchase Order Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 The purpose of a Local Purchase Order (LPO) is to provide a basic instrument for purchases up to a value of $5,000.00.

1.02 Employees are encouraged to use LPO's for the purchase of goods where it is efficient, economical and operationally feasible to do so and within stated parameters.

1.03 Local Purchase Orders are to be used only if the Corporate Purchasing card is not accepted.

2.00 Procedure

2.01 LPOs must be used only to make legitimate purchases for Yukon Energy within established limitations.

2.02 The Local Purchase Order is a three part form and is to be distributed as follows:

Page Colour	Receiver	Action/Rationale
White	Supplier	• given at time of purchase for their records, after the signature is affixed at the bottom of the form, • if the LPO is faxed to the supplier then the Terms and Conditions on the reverse side of the document must be faxed as well
Pink	Accounts Payable	• forwarded to AP for payment to the vendor after the supervisor's signature is affixed at the bottom of the page or held in the LPO book until requested by AP
Green	Originator	• retained in the LPO book

2.03 All relevant fields of the LPO shall be completed by the issuer (e.g. vendor name and address, type of purchase; date; item; quantity; part number; item description/scope of work/ unit cost; extension; remarks/special conditions; sub-total; GST and total).

2.04 The issuer must request the vendor to provide proof of valid insurance and WCB coverage for services performed on Yukon Energy premises/sites.

2.05 Fully used LPO books shall be returned to Corporate Services which will trigger the issue of a new LPO book.

3.00 Signing Authority

3.01 All LPO's shall be issued by authorized employees in accordance with Yukon Energy's Signing Authority Guideline.

4.00 Document Retention

4.01 Corporate Services will retain all completed LPO books for a period of six years plus current year for audit purposes.

YUKON ENERGY	Goods & Services Guidelines GS-017	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Invoice Approval Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 The process for approving invoices or 'signing off' a purchasing agreement invoices requires the attention, diligence and cooperation of three areas:

- Owner's Designate (Owner Department);
- Corporate Services; and
- Accounts Payable

2.00 Responsibilities

2.01 **Owner's Designate** is responsible for ensuring that that the work being billed for has in fact been completed and to the satisfaction of the owner department.

- Audit invoice and verify that the scope of work or deliverables invoiced for is identified within the contract;
- Audit invoice to verify that the invoice has correct pricing and is according to any specified billing schedule;
- Attach all back-up documentation;
- Verify the coding is correct;
- Affix authorized signatory to invoice confirming goods and/or services have been completed to the satisfaction as identified within the scope of the contract;
- Obtain budget owner's signature and
- Once the invoice is signed, forward the invoice to the Corporate Services for their review, recording and approval.

2.02 **Corporate Services** is responsible for ensuring that the commercial terms and conditions of the contract have been adhered to and to track the progress of the contract in terms of the financial encumbrance and the release of funds through the approval process.

- Verify that the owner's designate and the budget owner has authorized the invoice within their financial authority. If either signature is absent, the invoice should be returned to the owner's designate;
- Verify that the vendor has satisfied all regulatory and statutory obligations (e.g. insurance, WCB, guarantees, warrantees, etc.);
- Verify that all commercial terms and conditions have been satisfied by the contractor;
- Verify proper purchasing agreement reference number;
- Ensure that invoice has not exceeded the financial limit or the timeframe stipulated in the contract and/or change orders;
- Verify that the invoice has not already been paid;
- Verify there are sufficient funds remaining on the purchasing agreement;
- Record invoices accordingly (files, logs, etc); and

- When the invoice has met the criteria, sign and forward the invoice to Accounts Payable for processing.

2.03 **Accounts Payable** is responsible for ensuring that there are two authorized signatures and that they have the accountability for the level of expenditure as per FA-004 Signing Authority Guidelines.

- Forward invoice to owner's designate for approval or disapproval;
- Upon return of the invoice from the Corporate Services, verify that there are three authorized signatures on the invoice, owner's designate, budget owner and Corporate Services. If any invoice fails to have the authorized signatures, accounts payable should return the invoice to the area(s) requiring a signature;
- When accounts payable receives an invoice with three correct signatures, this is notification of, and satisfies the requirement for due diligence and they may proceed to make payment; and
- Accounts payable to perform final check for accuracy, record and process invoice for payment.

3.00 Signing Authority

3.01 All invoices are to be approved only by authorized employees in accordance with the Corporation's Signing Authority Guideline.

YUKON ENERGY	Goods & Services Guidelines GS-018	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Incoming Shipping Negotiation Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 To ensure incoming material requirements are shipped in the most cost effective manner.

2.00 Procedure

The following is the procedure for securing the most economic and safe shipping service for incoming shipments.

2.01 Shipping instructions should be done in conjunction with establishing the F.O.B. point. Corporate Services should clearly define the routing and mode of transportation, if the corporation is to pay the freight charges or have ownership of the goods in transit. Terms such as 'Best Way' and 'Fastest Way' are too ambiguous and indefinite and provide no control or means of tracing shipments and are to be avoided.

2.02 When the corporation bears the shipping costs and ownership of goods in transit, the following factors need to be considered in determining the best mode of transportation, selection of carrier and in establishing the routing of the shipment.

a) Determine the type of transportation service which will best meet the delivery requirements.

b) Review the shipment needs in terms of:
- The required delivery date and the type of service that best meets those transit time requirements;
- Size of the shipment;
- Susceptibility of the commodity to damage;
- Cost of the transit service;
- Carrier accessorial services; and
- Selection of adequate and safe equipment – special equipment is often needed for shipments of excessive height, width, length or weight measurements.

c) Select a specific carrier or carriers. The factors to consider are:
- Financial condition of the carrier;
- Quality of service;
- Service at supplier's point of shipment;
- Dependability;
- Over–the-road service;
- Tracing and expediting shipments;

- Loss and damage claims;
- Overcharge claims;
- Insurance capabilities; and
- Miscellaneous services – i.e. handling complaints, remittance of COD's, rate notifications, document handling.

d) Perform a periodic check of the transportation service once the shipment(s) are moving.

2.03 Shippers will be requested to provide a 'Bill of Lading' with the shipment clearly identifying the carrier, a description of the goods and the terms for the freight charges.

2.04 Shippers will be instructed to provide information to the Corporation's Custom Broker so they may prepare certified invoices for customs clearance for shipments originating outside Canada.

2.05 Corporate Services will negotiate critical delivery of good/equipment when required.

2.06 Yukon Energy reserves the right to cancel the order if goods are not shipped within the period specified, at no cost to the purchaser. (This must be clearly stated on the PO and must be accepted in writing by the supplier to be enforceable and without penalty to Yukon Energy).

YUKON ENERGY	Goods & Services Guidelines GS-019	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Corporate Services	Shipping Invoice Approval & Payment Guideline
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2006	February 2009	Director, Corporate Services

1.00 Purpose

1.01 The process for approving and processing payment for shipping invoices requires the attention, diligence and cooperation of all relevant parties.

2.00 Procedure

The following is the procedure for the payment of incoming shipping invoices:

2.01 Payment of incoming shipping invoices will be made provided:

- Terms of the purchase order have been fulfilled, if shipping is stated as a critical item of importance on the face of the purchase order (agreement).
- Freight or transportation invoices must be supported by a corresponding Bill of Lading from the shipper.

2.02 Any claims, which are the supplier's responsibility, will be subject of adjustment after goods have arrived at the point of final destination.

2.03 Freight invoices which relate to a Purchasing Agreement will be paid according to the negotiated freight terms and FOB point as stated on the purchase document. Exceptions are to be referred to Corporate Services for further handling and action.

2.04 Only those specific shipping costs identified on the Purchasing Agreement will be paid. No other costs will be paid without the specific approval from Corporate Services.

2.05 All incoming international shipments (outside of Canada) must be supported by certified Customs Invoices prepared by Yukon Energy's custom brokers.

2.06 Supplier invoices which include items relating to shipping charges beyond the agreed to terms stated by the FOB point, must be forwarded to Corporate Services for investigation and, if necessary, approval.

2.07 Shipping invoices which identify boxing or packing charges will not be paid, unless stated on the corresponding Purchasing Agreement.

2.08 Prior to payment of a shipping invoice, efforts must ensure there is compliance with all terms, conditions and special requirements outlined on the Purchasing Agreement.

REFERENCE:

QUESTION:

a) Please explain why YEC, which is a relative small primarily energy generating utility with only one primary wholesale and only one industrial and relatively few retail customers, requires the services of a full time Communications position.

ANSWER:

(a)

Yukon Energy's Communications Supervisor carries out the following functions:

- **Corporate Communications:** Responsible for creating, implementing and overseeing communications programs that effectively describe and promote the organization and its products. Duties are wide ranging and include development of communication strategies, writing/producing various documents including annual reports and business plans, coordination/writing of ad campaigns, promotional material, and speeches.

- **Media Relations:** The Communications Supervisor is Yukon Energy's primary contact for media outlets, and along with Yukon Energy's president, is the primary spokesperson for the Corporation. Duties include researching and answering media questions, writing and distributing news releases and media FYIs, organizing news conferences and media briefings and monitoring media coverage of Yukon Energy.

- **Community Relations:** The Communications Supervisor is a primary contact for members of the public who have questions about Yukon Energy. Duties include answering questions through written or oral means, helping to select Yukon Energy scholarship recipients, helping to select non-profit groups that are to receive Yukon Energy corporate sponsorship funding, attending public functions/speaking engagements on behalf of Yukon Energy.

- **Public Consultation Coordinator:** Developing and executing public consultation plans for various projects/initiatives, organizing public meetings, and preparing all communication materials for each meeting.

- **Webmaster:** Duties include writing for and maintaining public web site and public blog.

- **Internal Communications:** Responsible for overseeing and implementing communications among Yukon Energy staff, including a monthly employee newsletter, and for helping to organize staff events.

- **Whitehorse Rapids Generation Station Fish Ladder:** Responsible for overseeing the operations at the fish ladder and for the production of all the educational/display materials at the fish ladder. Involved in the hiring/training of the fishladder staff.

- **Education Coordinator:** Responsible for organizing school tours of Yukon Energy's facilities and for giving some of the tours.

REFERENCE:

QUESTION:

a) What is YEC' policy on the customer contribution for the installation of a new pole required as a result of a customer requested pole relocation? For example, if the existing pole is at the end of its useful life and a new pole is installed at the relocation site, does the customer just pay for the labour, supplies and equipment installation costs with the new pole provide by YEC at no cost as the old pole would have required immanent replacement because of its age and condition?

ANSWER:

(a)

Generally, the cost of a customer-requested relocation would be the responsibility of the customer. YEC does not have a policy dealing with the specific scenario raised; however, if the pole was deemed to be at end of life, the customer would be responsible for any incremental costs associated with the relocation, i.e., any additional labour or materials (e.g. different pole height due to different terrain, adjacent pole relocations, conductor changes due to customer's request) would be the responsibility of the customer.

UTILITIES CONSUMER GROUP
(UCG)

REFERENCE: **Yukon Energy Corporation Profile (YEC Web Site), Mission Statement**

QUESTION:

According to its Mission statement, YEC undertakes a number of things including:

- "to be responsive to our customers and their changing needs and expectations"; and

- "to place priority on the fundamentals; that is, safe and reliable electrical services"

a) Please provide YEC's understanding of the expectations of its customers with respect to the affordability of electricity and customer expectations of what YEC should be doing to reduce electricity bills paid by Yukon ratepayers.

b) Please provide an analysis of YEC's 2005, 2006, 2007, 2008 and 2009 (forecast) operating and capital expenditures which identifies the amount and percentage of overall expenditures made on safety and reliability of service.

c) Please provide details of the planned and unplanned outages that have occurred in the Yukon in 2005, 2006, 2007 and 2008. This analysis should include but not be limited to duration of outages, the number of electricity consumers impacted and specifics on how much diesel generation (and its cost) was required to be provided to make up for lost hydro generated electricity.

d) Please provide details of any service reliability criteria that YEC uses as a policy guideline.

ANSWER:

(a)

Although Yukon Energy does not have direct survey information on overall "customer expectations" Yukon Energy's mission is to "provide a sufficient supply of safe, reliable electricity and related energy services to customers throughout the Yukon, while

following sound business practices and demonstrating leadership in protecting the environment".[1] To achieve these goals Yukon Energy must balance varying interests and concerns including the following points noted in Yukon Energy's mission statement:

- Be responsive to our customers and their changing needs and expectations;
- Commit to the safety and development of our employees;
- Be cost-effective in the utilization and investment of resources, always remembering that we are spending the customer's money and making long-term decisions;
- Place priority on the fundamentals; that is, safe and reliable electrical services;
- Demonstrate the value of Yukon-based public ownership and management;
- Act ethically and honestly treating employees, customers and others with fairness, dignity and respect; and
- Build enduring relations with Yukon First Nations.

In the current Application, Yukon Energy is returning benefits to ratepayers achieved through the successful completion of Stage 1 of the Carmacks-Stewart Transmission Project. Due to the provision of service to Minto mine through the negotiated Power Purchase Agreement, Yukon Energy has been able to provide for overall rate reductions. In addition long term infrastructure benefits are also being realized with the provision of service to Pelly Crossing (formerly served by diesel) and the completion of the first stage of the connection of the MD and WAF grids systems, allowing surplus energy available from either system to be utilized where the energy is needed.

(b)

Maintenance expenditures are by their nature, focused on ensuring the reliability of our assets. Section 3.3 of the application, beginning on page 3-5, defines the amount of maintenance dollars spent on production, distribution, transmission, etc matters. Safety

[1] http://www.yukonenergy.ca/about/profile/

spending is included in the application as part of Administration in section 3.3.5 beginning on page 3-10.

The table below categorizes safety and reliability capital projects for all projects over $50,000 (as set out in Table 5.2) by major category and year ($000s).

	2005	2006	2007	2008	2009
Major Projects					
Safety					
Reliability			407	4,698	750
Remainder			5,502	33,631	3,500
Total	0	0	5,909	38,329	4,250
Transmission					
Safety					
Reliability	1,120	689	340	50	870
Remainder					
Total	1,120	689	340	50	870
Distribution					
Safety		92			
Reliability			71	50	100
Remainder	1,167	486	236	575	575
Total	1,167	578	307	625	675
Generation					
Safety					
Reliability	440	1,743	1,430	823	639
Remainder					100
Total	440	1,743	1,430	823	739
General Plant & Equipment					
Safety	66	100	76	50	165
Reliability	779	962	763	909	902
Remainder	282	429	595	569	856
Total	1,127	1,491	1,434	1,528	1,923
Overall					
Safety %	2%	4%	1%	0%	2%
Reliability %	61%	75%	32%	16%	39%

(c)

Please see response to PWP/HML-YEC-1-13.

(d)

YEC does not use service reliability criteria as a policy guideline.

REFERENCE: October 6, 2008 Application Cover Letter, Page 1

YEC states "This GRA deals primarily with 'Phase 1' Yukon Energy revenue requirement matters for the test years of 2008 and 2009, and does not address 'Phase 2' cost of service and general rate design matters that would require joint work by Yukon Energy and the Yukon Electrical Company Limited".

REFERENCE: Yukon Utilities Board Report on Yukon Energy Corporation 20-Year Resource Plan, January 15, 2007, Page 51

The YUB states "Now is an appropriate time for YEC and YECL to have a complete review of all GRA Phase I and Phase II matters. The Board recommends that YEC and YECL file a full GRA application before October 31, 2007. The application should include a full cost of service, rate design and an update of the Electric Service Regulations. The Board also suggests that YEC and YECL consider a performance-based regulation mechanism. As well, the Board recommends that evidence be provided as to what other utilities provide for Maximum Company Investment and model theirs accordingly".

REFERENCE: Order in Council 2008/149 – Directive to Amend the Rate Policy Directive (1995)

REFERENCE: December 8, 2008 Hansard, Yukon Legislative Assembly

Mr. McRobb: Let's talk about some consumer issues. I have a question starting with the general rate application. We know there was a separate filing by Yukon Electrical and Yukon Energy and it seems this is becoming normal in recent years. Does this speak to a somewhat less-than-amicable relationship between the two companies? Why don't they file an application jointly as in years past?

Mr. Morrison: Perhaps in years past, their interests were common. What I suggest by that doesn't mean that we have anything less than a good working relationship with Yukon Electrical. Our interests are different. We have the benefit of a new industrial customer which has created additional revenue for the corporation and following the Yukon Utilities Board practices, rules or regulation, we would earn more than our rate of return; therefore, when you do that, you would normally come in and return those additional funds to the ratepayers. Our interest was to file a rate application that would reduce rates. For whatever their own internal reasons are, Yukon Electrical's interest

was to file a rate application that increased rates. **I don't know how you would do that together**. We have some very different interests and we have different approaches to rates and consumers, just in general.

QUESTION:

a) Please provide specific details of efforts made by YEC to comply with the Board's recommendation to prepare and file materials to allow for a review of all GRA Phase 1 and Phase 2 matters. Please include details of when the decision was made to proceed with a Phase 1 GRA with rate components not supported by Phase 2 analysis and the reasons why YEC believed that to be the best approach.

b) Please provide all internally generated reports or documents prepared for or by senior management or otherwise in 2007 and 2008 which discuss in any way how YEC should proceed with respect to an application to the YUB regarding 2008 and 2009 rates.

c) Please explain how YEC's current application could be considered a General Rate Application when YEC is not proposing to review rate design and terms and conditions of service nor provide cost of service data.

d) Please provide details of any discussions that YEC participated in and the input that YEC made regarding the development of OIC 2008/149.

e) Please identify the parts of OIC 2008/149 that YEC feels prohibit the YUB and other parties from reviewing the cost allocation and rate design of YEC.

f) Please confirm YEC's understanding that none of the Orders-in-Council issued to amend the Rate Policy Directive (OIC 1995/90) have affected the YUB's over-arching jurisdiction to determine electricity rates that are just and reasonable for all Yukon electricity ratepayers.

g) To YEC's knowledge, have there ever been any discussions related to changing any of the provisions in the rate policy directive to allow for greater flexibility in revenue-to-cost ratios incorporated in rates? For example, charging industrial customers something different than 100% of costs in order to ease the burden on

residential customers, to allow for the development of commodity-based industrial rates, etc.

h) Please explain how YEC's proposal ensures that "rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers" especially when combined with rate adjustments proposed by YECL.

i) Please explain whether the impacts of the fuel adjustment rider have been incorporated into YEC's proposal regarding equal rate adjustments.

j) Please provide an indication of the anticipated timing of YEC's next general rate application and timing of YEC's discussions in this regard with Yukon Electrical Company Limited.

k) Please confirm YEC's President's position on December 8, 2008 that YEC does not know how it would prepare and submit a consolidated general rates application to the YUB that would incorporate a net revenue increase from YEC's operations and a net cost increase from YECL's operations.

ANSWER:

(a)

Please see response to YUB-YEC-1-20.

(b)

Documents were prepared to seek Board of Directors approval of the Application and are Board documents and are therefore confidential.

(c)

Please see response to YUB-YEC-1-20. The Application as-filed addresses both revenue requirement and the rate issues that can be addressed in light of OIC both past and recent directions provided by the Yukon Government. Given the constraints on any inter-class rebalancing prior to 2013 due to the issuance of OIC 2008/149, Yukon Energy has focused on producing a GRA that was as comprehensive as possible within

the current regulatory framework. Yukon Energy has also sought to make some progress towards adjusting second block rates to ensure second block rates are based on rate design principles that promote economy and efficiency as required by OIC 1995/90.

In this vein, the Application includes requested approvals for changes to the following rate schedules, as well as provision in rate schedules to include Pelly Crossing in the Hydro rate zone rate schedules:

- Rate Schedule 32 Secondary Energy
- Rate Schedule 39 (re: fixed Rider F component applicable to Rate Schedule 39 Major Industrial Customers
- New Rider U - Yukon Energy Revenue Reduction Rider
- Rate Schedules for Residential Non-Government (1160,1260, 1360, 1460) and Residential Government (1180, 1280,1380,1480)
- Rate Schedule 42 (re: Energy Reconciliation Adjustment provision, and a small adjustment to the base energy rate).

(d)

Please see responses to LE-YEC-1-2 and LE-YEC-1-3.

(e)

Please see response to YUB-YEC-1-20.

(f)

The Yukon Utilities Board must approve rates that are just and reasonable within the regulatory framework provided by the Yukon Utilities Act and all OIC directions including Rate Policy Directive OIC 1995/90 and any subsequent OIC directions.

(g)

To YEC's knowledge no such discussions have taken place.

(h)

As noted at page 1 of the Application, Yukon Energy's proposal applies all proposed rate adjustments for retail customers equally, when measured as percentages, to all classes of retail customers, and therefore prevents rate revenue rebalancing among retail customer classes. YECL's rate proposals to date would not create rate revenue rebalancing among retail customer classes.

(i)

Fuel adjustment rider impacts are considered in YEC's Application. YEC's revenue requirement reflects the full forecast price of fuel and the full forecast revenues from secondary sales for each test year. If approved, the YEC elements of the fuel adjustment rider would be reset to reflect these new GRA fuel prices, and the rider would going forward would address only the extent that fuel prices or secondary sales prices vary from the 2009 GRA forecasts.

(j)

Please see YUB-YEC-1-20.

(k)

Not confirmed. The comments referred to a YEC application that would reduce rates, not an application seeking a net revenue increase from YEC's operations. The comments overall were in regards to the different objectives in the YECL application (seeking a material increase to its rate revenues) and the YEC application (seeking a decrease to its rate revenues), and how to ensure customers saw the benefit of the YEC rate decrease when it occurs at the same time as a substantial rate increase by YECL.

REFERENCE: October 6, 2008 Application Cover Letter, Page 2

YEC states "Yukon Energy previously committed to apply the benefits that accrue from providing grid service to Minto towards overall rate reductions".

REFERENCE: Yukon Utilities Board Report on Yukon Energy Corporation 20-Year Resource Plan, January 15, 2007, Page 31

The YUB states "YEC submitted that the Minto PPA would result in material benefits, over and above the cost of the line, so that ratepayers will not be adversely affected by the expenditures required to implement this project".

QUESTION:

a) Please provide evidence of when YEC made its commitment regarding applying benefits from serving Minto (Capstone Mining) towards overall rate reductions.

b) Please provide quantified details of all the benefits and costs to ratepayers of the Minto connection and explanations of where the net benefits have been incorporated in the Application material.

c) Please confirm that YEC's commitment to "overall rate reductions" does not mean the same as a commitment to "overall bill reductions".

d) Please provide calculations of the total bill (including all riders, rate relief, and taxes) for a residential customer living in Whitehorse using 1000 kWh, 1200 kWh and 1400 kWh per month in January 2005, January 2006, January 2007, January 2008, January 2009 and August 2009 assuming that the Rate Stabilization Fund expires in July 2009 and the rate adjustments proposed by YEC and YECL are approved. Please provide details of the bill calculations.

e) Given YEC's proposed bill increases for Yukon electricity ratepayers that consume higher amounts of electricity (especially those using electricity as a primary source for space heating), please explain how Yukon ratepayers have not been adversely impacted by the capital and O&M expenditures decisions made by YEC.

ANSWER:

(a)

Ratepayer benefits from the Carmacks-Stewart project and connection of Minto mine to the WAF system were noted in the 20 Year Resource Plan Supplementary Materials May 2006 (filed in conjunction with the main Resource Plan), in the Resource Plan Update November 2006 (Exhibit B-16 from the 20 Year Resource Plan proceeding) and in the PPA proceeding. At the time of the PPA proceeding, Yukon Energy was proposing that ratepayer benefits be accrued in a Mine Net Revenue Account (to address capital costs of the CSTP project and focus benefits of the Minto mine net revenues on capital investment), and not be used for immediate rate reductions at the time of the Minto connection. The Mine Net Revenue Account was rejected by the Board in Order 2007-5 on April 30, 2007.

The revised PPA was filed with the Board on May 14, 2007, which no longer included the Mine Net Revenue Account. Consequently, with this revision, the rate benefits from Minto would accrue to ratepayers from the date of connection, rather than be deferred towards long-term infrastructure benefits. Also note the following government press release provided May 14, 2007, which indicates that the benefits arising from the provision of service to Minto mine will be applied to ratepayers via a 2008 rate reduction.

http://www.gov.yk.ca/news/2007/07-091.html

(b)

Please see YUB-YEC-1-36(a).

(c)

Yukon Energy can only directly control its own revenue requirement and consequently the rates required to meet that Revenue Requirement, plus propose specific rate change adjustments to address specific issues that Yukon Energy is able to address. Yukon Energy can not commit to control all factors affecting overall bills, which include separate YECL rate increase applications, ongoing Rider F changes to reflect ongoing fuel price changes, and Yukon Government subsidies such as the RSF.

YEC has, through the timely completion of the CSTP and the negotiation of a Power Purchase Agreement with Minto mine, secured rate benefits for all Yukon retail ratepayers through the provision of grid service to the mine site. In addition, Yukon

Energy has proposed specific overall rate adjustments for first block residential and general service retail customer use that would, if adopted, more than offset the impact of removal of the remaining RSF subsidies.

The rate benefits provided in Yukon Energy's current Application may be muted on the bills to be paid by ratepayers through either significant rate increases, as applied for by YECL in its 2008/2009 GRA, or through any subsequent reduction in RSF subsidies provided by the government, or through deferral or rejection by the YUB of the specific rate adjustments proposed by YEC for first block energy rates. Such impacts are matters beyond the control of YEC, other than to the extent that. Yukon Energy can affect the revenue requirement or rates set for YECL through participation in the regulatory review of such rates as an intervenor in YECL's separate process.

(d)

For a bill calculation that includes all riders, rate relief, and taxes for residential customers please see Table 4.7 at Tab 4 of the Application which shows the situation with and without the Yukon Energy proposed changes, and with and without the RSF. Yukon Energy cannot hypothesize about the size of YECL's rate increase that will arise from the recently released Board Order on YECL's GRA.

There were no rate changes between 2005 and 2007 other than for Rider F, the diesel fuel rider.

For further clarification, based on Table 4.7, the detailed bill calculation allows determination of the following for a customer in Whitehorse:

- For 1000 kW.h use per month, the bill (before GST) is as follows:
  - Existing bill at time Application filed (October 2008) of $132.00 (consisting of $13.02 fixed monthly customer charge plus first block energy rate of $0.11898 per kWh times 1000 kWh) – the details as to how each billing component are calculated is set out in the table.
  - YEC's proposed bill provides a saving of $21.20 relative to the above existing bill, or $110.80 (through reduction of the energy charge as shown in the table).

- For 1200 kWh use per month, the bill (before GST) is as follows:
  - Existing bill at time Application filed (October 2008) of $160.68, including $132.00 for the first 1000 kWh (consisting of $13.02 fixed monthly customer charge plus first block energy rate of $0.11898 per kWh times 1000 kWh)

plus $28.68 for the balance of the energy (200 kWh second block energy in hydro zone times energy rate of $0.1434 per kWh) – the detail as to how each billing component is calculated is set out in the table.

- YEC proposed bill of $152.68 provides a saving of $8.00 relative to the above existing bill, composed of the $21.20 saving for the first 1000 kWh less the $13.40 added cost for the 200 kWh second block energy use (through increase of the energy charge as shown in the table).

- The same process as used for 1200 kWh would be used to determine the bill for 1400 kWh.

- Final bill totals (after GST) for existing bills and proposed non-government residential customers are set out in Table 4.11, including calculations for 1000, 1250 and 1500 kWh use in the hydro zone.

As noted, there were no rate changes between 2005 and 2007 other than for Rider F, the diesel fuel rider. For information on Rider F please see response to UCG-YEC-1-56(a) which attaches Rider F filings from February 7, 2006 to present. The following is noted with regard to the effect of Rider F on bills:

- Filing dated February 7, 2006 notified the Board of an increase in the automatic fuel price adjustment rider (Rider F) from 0.7909 cents per kW.h to 1.2799 cents per kW.h, with the increase effective for bills rendered on or after March 1, 2006.

- Filing dated November 20, 2006 notified the Board of a decrease in the automatic fuel price adjustment rider from 1.2799 cents/kWh to .9639 cents/kWh, effective for bills rendered on or after December 1, 2006.

- Filing dated April 16, 2008 notified the Board of a increase in the automatic fuel price adjustment rider from .9638 cents/kWh to 1.233 cents/kWh, effective for bills rendered on or after May 1, 2008.

- Filing dated July 10, 2008 notified the Board of a increase in the automatic fuel price adjustment rider from 1.233 cents/kWh to 1.860 cents/kWh, effective for bills rendered on or after August 1, 2008.

- Filing dated February 9, 2009 notified the Board of a decrease in the automatic fuel price adjustment rider from 1.860 cents/kWh to 0.0 cents/kWh, effective for bills rendered on or after March 1, 2009.

Impact of Rider F on bills prior to GST for each reference periods would be determined by multiplying the Rider F rate in place by energy use.

To provide bills as at January 2009, the only change from Table 4.7 calculations is the interim rider for YEC of 3.48% rate reduction replacing all of YEC's other proposed rate changes:

- For 1000 kWh use, the bill before GST is $128.15 or $17.35 higher than YEC's proposed bill of $110.80 as assessed in Table 4.7.

- For 1200 kWh use, the bill before GST is $156.11, or $3.43 higher than YEC's proposed bill of $152.68 as assessed in Table 4.7.

UCG requests that YEC calculate the same bills as at August 2009, assuming the RSF expires in July 2009 and that "the rate adjustments proposed by YEC and YECL are approved." These assumptions can be easily implemented for the YEC and the RSF change and for YEC's rate adjustment proposal (which fully included changes as needed to set Rider F to zero as it is affected by YEC). YECL's GRA in effect proposed an 11% final across the board rate rider for non-fuel revenue requirement components – when fuel cost changes as forecast in this GRA are considered, the effective rider requirement approximates a 19% increase.[1]

While the information requested can be derived from Table 4.7, in order to be as responsive as possible additional tables are provided as Attachment 1, Attachment 2 and Attachment 3 to this response, and set out specific bill calculations for 1,000 kWh per month, 1,200 kWh per month and 1,400 kWh per month for a non-government residential customer in Whitehorse for each January 1 from 2006 to 2009. Each table also provides bill calculations for August 2008 (reflecting YECL interim rate rider and Rider F increases) and for August 2009 without the RSF and separately with only the YEC proposed rate changes and then also with YECL's effective proposed rate change (including full consideration of forecast fuel costs in the YECL GRA).

(e)

The 2008/2009 Yukon Energy General Rate Application contains an overall rate reduction for Yukon ratepayers.

[1] See from YECL 2008/2009 Hearing Ex. C1-13, as reviewed at Transcript pages 49-50 and page 58, lines 15-24.

The second block run out rate is not based on revenue requirement or cost of service considerations. Rate Policy OIC 1995/90 (section 4(3)) provides that the Board must fix rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency. The Board has established rate design principles for runout block rates (initially in its 1992 Report to the Commissioner in Executive Council provided as Attachment 1 to YUB-YEC-1-21(d), and subsequently affirmed in Board Order 1993-8 at page 99, and Order 1996-7).

The underlying rationale as directed by government OIC and Board Order is that runout rate must promote economy and efficiency. Current board-approved rate design for runout rates provides that to promote economy and efficiency such rates must be adjusted to reflect short-run incremental costs. Capital and O&M expenditures included in the Revenue Requirement have no impact on either the requirement for the modest increase in runoff rate nor the quantum of the rate applied.

Table 1 -Bill Calculations for a Residential - Non Government Customer in Whitehorse (Hydro Zone)

Energy Consumption = 1,000 kW.h per month

Items	Units	Jan-06	Jan-07	Jan-08	Aug 08 (After YECL Interim Increase)	Jan 09 (After YEC Interim Rate Decrease)	Aug 2009 (After Proposed YEC Rate Changes and RSF expires)	Aug 2009 (After Proposed YEC & YECL Rate Changes and RSF expires)
1st block Energy Charge	$0.0986/kW.h	98.60	98.60	98.60	98.60	98.60	98.60	98.60
YEC Proposed Energy Charge Decrease	**-$0.0136/kW.h**						**-13.60**	**-13.60**
Customer Charge	$11.90/Cust.	11.90	11.90	11.90	11.90	11.90	11.90	11.90
Base Billing		110.50	110.50	110.50	110.50	110.50	96.90	96.90
YEC Rev Shortfall Rider J	14.93%	16.50	16.50	16.50	16.50	16.50	14.47	14.47
Fuel Adjustment Rider F	varies -see notes	7.91	9.64	9.64	18.60	18.60	0.00	0.00
YECL Interim Rider R	5.00%	-	-	-	5.53	5.53	4.85	0.00
YECL Proposed Final Rider R	19.00%							18.41
YEC Interim Rider J	**-3.48%**					**-3.85**		
YEC Proposed Rider U	**$0.00496/kW.h**	**-**	**-**	**-**	**-**		**-4.96**	**-4.96**
Income Tax Rebate	-0.50%	-0.55	-0.55	-0.55	-0.55	-0.55	-0.48	-0.48
Rate Stabilization Fund	-$1.19 Cust. Chrg -$0.01738/kW.h	-18.57	-18.57	-18.57	-18.57	-18.57	0.00	0.00
Billing Before GST		115.78	117.51	117.51	132.00	128.15	110.77	124.33
GST	varies - see note	8.10	7.05	5.88	6.60	6.41	5.54	6.22
Total Billing		123.89	124.56	123.39	138.60	134.56	116.31	130.55

Notes re: Fuel Adjustment Rider F:	$/kW.h
As at March 09	0
As at Aug 08	0.0186
As at May-08	0.0123
As at Dec-06	0.009639
As at Mar-06	0.012799
At Jan-06	0.007909

Note Re: GST	
7%	prior to July 2006
6%	As at July 2006
5%	As at Jan 2008

Table 2 -Bill Calculations for a Residential - Non Government Customer in Whitehorse (Hydro Zone)

Energy Consumption = 1,200 kW.h per mont

Items	Units	Jan-06	Jan-07	Jan-08	Aug 08 (After YECL Interim Increase)	Jan 09 (After YEC Interim Rate Decrease)	Aug 2009 (After Proposed YEC Rate Changes and RSF expires)	Aug 2009 (After Proposed YEC & YECL Rate Changes and RSF expires)
1st block Energy Charge	$0.0986/kW.h	98.60	98.60	98.60	98.60	98.60	98.60	98.60
YEC Proposed Energy Charge Decrease	**-$0.0136/kW.h**						**-13.60**	**-13.60**
2nd Block Energy Charge	$0.1045/kW.h	20.90	20.90	20.90	20.90	20.90	20.90	20.90
YEC Proposed 2nd Block Increase	**$0.0561/kW.h**						**11.22**	**11.22**
Customer Charge	$11.90/Cust.	11.90	11.90	11.90	11.90	11.90	11.90	11.90
Base Billing		131.40	131.40	131.40	131.40	131.40	129.02	129.02
YEC Rev Shortfall Rider J	14.93%	19.62	19.62	19.62	19.62	19.62	19.26	19.26
Fuel Adjustment Rider F	-see notes Table 1	9.49	11.57	11.57	22.32	22.32	0.00	0.00
YECL Interim Rider R	5.00%			-	6.57	6.57	6.45	
YECL Proposed Final Rider R	19.00%							24.51
YEC Interim Rider J	**-3.48%**					**-4.57**		
YEC Proposed Rider U	**$0.00496/kW.h**			**-**	**-**		**-4.96**	**-4.96**
Income Tax Rebate	-0.50%	-0.66	-0.66	-0.66	-0.66	-0.66	-0.65	-0.65
Rate Stabilization Fund	-$1.19 Cust. Chrg -$0.01738/kW.h	-18.57	-18.57	-18.57	-18.57	-18.57	0.00	0.00
Billing Before GST		141.28	143.36	143.36	160.68	156.11	149.13	167.19
GST	see note - Table 1	9.89	8.60	7.17	8.03	7.81	7.46	8.36
Total Billing		151.17	151.96	150.53	168.72	163.91	156.59	175.55

Table 3 -Bill Calculations for a Residential - Non Government Customer in Whitehorse (Hydro Zone)

Energy Consumption = 1,400 kW.h per mont

Items	Units	Jan-06	Jan-07	Jan-08	Aug 08 (After YECL Interim Increase)	Jan 09 (After YEC Interim Rate Decrease)	Aug 2009 (After Proposed YEC Rate Changes and RSF expires)	Aug 2009 (After Proposed YEC & YECL Rate Changes and RSF expires)
1st block Energy Charge	$0.0986/kW.h	98.60	98.60	98.60	98.60	98.60	98.60	98.60
YEC Proposed Energy Charge Decrease	**-$0.0136/kW.h**						**-13.60**	**-13.60**
2nd Block Energy Charge	$0.1045/kW.h	41.80	41.80	41.80	41.80	41.80	41.80	41.80
YEC Proposed 2nd Block Increase	**$0.0561/kW.h**						**22.44**	**22.44**
Customer Charge	$11.90/Cust.	11.90	11.90	11.90	11.90	11.90	11.90	11.90
Base Billing		152.30	152.30	152.30	152.30	152.30	161.14	161.14
YEC Rev Shortfall Rider J	14.93%	22.74	22.74	22.74	22.74	22.74	24.06	24.06
Fuel Adjustment Rider F	-see notes Table 1	11.07	13.49	13.49	26.04	26.04	0.00	0.00
YECL Interim Rider R	5.00%			-	7.62	7.62	8.06	
YECL Proposed Final Rider R	19.00%							30.62
YEC Interim Rider J	**-3.48%**					**-5.30**		
YEC Proposed Rider U	**$0.00496/kW.h**			**-**	**-**		**-4.96**	**-4.96**
Income Tax Rebate	-0.50%	-0.76	-0.76	-0.76	-0.76	-0.76	-0.81	-0.81
Rate Stabilization Fund	-$1.19 Cust. Chrg -$0.01738/kW.h	-18.57	-18.57	-18.57	-18.57	-18.57	0.00	0.00
Billing Before GST		166.78	169.20	169.20	189.36	184.06	187.49	210.05
GST	see note - Table 1	11.67	10.15	8.46	9.47	9.20	9.37	10.50
Total Billing		178.45	179.35	177.66	198.83	193.26	196.86	220.55

REFERENCE: October 6, 2008 Application, Page 3

YEC states "By reducing the surplus hydro generation, new industrial loads also advance the timing for potential renewed diesel generation in Yukon".

QUESTION:

a) Please explain what is meant by this statement.

b) Please explain what YEC is doing to reduce the need for diesel generation now and in the future.

c) Please provide details of diesel generation use in 2005, 2006, 2007 and 2008. This information should include, but not be limited to amount of diesel fuel used, cost of diesel-fired generation, kWh generated using diesel, and percentage of total generation provided by diesel.

ANSWER:

(a) and **(b)**

The above statement refers to the fact that continuing load increases being experienced in the test years (and anticipated to continue after the test years) will result in a material reduction in the surplus hydro-generated energy currently available on the system.

Page 10 of the Application notes as follows with regard to long term system bulk power supplies:

> With the completion of the CSTP Stage 1 and connection of the Minto mine, Yukon Energy's Whitehorse-Aishihik-Faro ("WAF") system is reaching a point where the material existing surplus hydro generation is becoming greatly diminished. Although sales of this surplus hydro at firm rates bring clear net benefits, evidenced by the rate reductions proposed in the Application, with ongoing load growth and expressed interest from other future industrial customers, the existing hydro generation is likely to be fully utilized within the next few years, necessitating new renewable supply sources in order to avoid reliance on high cost baseload diesel generation and the resulting GHG emissions issues.

Yukon Energy noted in both the current application as well as in the 2005 Required Revenues and Related Matters Application that the hydro surplus available in the past was finite and not expected to continue indefinitely as system loads increased over time. Thus, to address both near term and long term considerations related to bulk system planning and the need to continue to meet system requirements Yukon Energy in 2006 filed a 20-Year Resource Plan that at Chapter 4 addressed near term requirements and at Chapter 5 addressed longer term industrial developments.

Recent Yukon Energy activities have been focused on ensuring that near term capacity requirements are met and in this vein Yukon Energy has commenced, and in some cases completed, the major projects discussed in Tab 5 of the Application including completion of CSTP Stage 1, the purchase of the Minto diesels, the Whitehorse Mirrlees Rebuild, the Faro Mirrlees Rebuild and Aishihik 3rd Turbine.

Chapter 5 of the Yukon Energy 20-Year Resource Plan identified longer term bulk system planning requirements that Yukon Energy has started to address at this time to ensure that over the long term, and with diminishing available hydro electricity and increasing customer loads, Yukon Energy is able to continue to serve its customers in a cost effective and environmentally sound manner.

The Application (page 12) notes that to address the expected load increases, cost and environmental considerations provide strong incentives for Yukon Energy to expand the available complement of renewable generation, as well as transmission interconnections. Test year planning cost budgets accordingly include material expenditures for this next generation of power projects.

Specifically, Yukon Energy has embarked on a planning process to expand the available complement of renewable generation and transmission interconnections. Tab 5 (pages 5-19 to 5-21) describes the significant initiatives being undertaken in the test years related to planning and feasibility activities. These activities are directed at renewable resource development projects identified as potential opportunities (in combination) to displace 50 to 100 GWh of diesel generation in the 2010 to 2015 near term time period. Projects being investigated include Mayo B, CSTP Stage 2 Pre-feasibility, the Gladstone Diversion project, small scale Atlin winter storage, and Marsh Lake fall-winter storage. Feasibility studies are also being undertaken with regard to geothermal generation options and larger scale hydro generation.

For discussion of Supply Side Enhancement and DSM initiatives being investigated please see response to LE-YEC-1-61.

(c)

It is noted that the query did not specify whether details of diesel generation were to be provided for WAF only or for WAF and MD. The initial response provided only details on WAF diesel generation. This revised response provides additional details for 2008 and also provides similar information for the MD system.

YEC WAF diesel generation details for 2005 – 2008 are provided in the table below.

Annual Summary	Diesel Generation			Diesel - EFF		Diesel - Litres			Diesel - Price			Diesel - Cost		
	Whse KWh	Faro KWh	Total KWh	Whse KWh/L	Faro KWh/L	Whse	Faro	Total	Whse $/L	Faro $/L	Total $/L	Whse $	Faro $	Total $
2005	80,230	34,440	114,670	5.99	3.91	13,389	8,815	22,204	0.5012	0.5671	0.5274	6,710	4,999	11,710
2006	689,865	729,330	1,419,195	3.71	3.58	185,812	203,694	389,506	0.6419	0.7083	0.6766	119,280	144,268	263,548
2007	363,424	105,840	469,264	3.66	3.62	99,370	29,241	128,611	0.6895	0.7545	0.7043	68,517	22,061	90,578
2008	1,119,884	94,290	1,214,174	3.62	3.62	309,293	26,014	335,307	0.9342	0.8420	0.9270	288,942	21,904	310,846

Note that the above table incorporates a measurement mismatch with diesel generation and fuel consumption occurring in January 2005 (leading to fuel being recorded as being consumed in December 2004 that is related to generation occurring in January 2005, likely related to timing or accuracy of recording fuel measurements).

Percentage of YEC WAF generation provided by diesel is shown in the table below.

Year	Total KWh	Diesel KWh	% of Diesel Generation
2005	283,644,232	114,670	0.04%
2006	299,475,150	1,419,195	0.47%
2007	305,362,146	469,264	0.15%
2008	315,359,390	1,214,174	0.39%

YEC MD diesel generation details for 2005-2008 are provided in the table below:

Year	Diesel Generation			Diesel - EFF		Diesel - Litres			Diesel - Price			Diesel - Cost		
	Dawson KWh	Mayo KWh	Total KWh	Dawson KWh/L	Mayo KWh/L	Dawson	Mayo	Total	Dawson $/L	Mayo $/L	Total $/L	Dawson $	Mayo $	Total $
2005	461,350	3,780	465,130	3.51	0.64	131,519	5,901	137,420	0.7206	0.5117	0.7116	94,773	3,020	97,792
2006	271,466	3,560	275,026	4.03	2.28	67,306	1,561	68,867	0.7868	0.5671	0.7818	52,957	885	53,843
2007	756,845	21,000	777,845	3.83	3.25	197,725	6,457	204,182	0.8483	0.5986	0.8404	167,735	3,865	171,600
2008	447,435	840	448,275	3.74	(2.26)	119,703	(372)	119,331	0.9758	0.6257	0.9769	116,802	(233)	116,569

Percentage of MD generation provided by diesel is shown in the table below.

Year	Total KWh	Diesel KWh	% of Diesel Generation
2005	25,542,190	465,130	1.82%
2006	27,441,136	275,026	1.00%
2007	27,513,065	777,845	2.83%
2008	28,481,995	448,275	1.57%

REFERENCE: October 6, 2008 Application, Page 3

YEC states "To promote economy and efficiency as directed by OIC 1995/90, Rider U rate reductions are therefore proposed (where feasible) only for first block rates".

REFERENCE: October 22, 2008 Letter from YEC to YUB

YEC states "Yukon Energy's interim rate proposals are directed at rate stability objectives, i.e., the Application seeks to implement one set of YEC-related rate adjustments for both 2008 and 2009 (starting with the interim rates), and to avoid use of across-the-board rate riders that are clearly not appropriate and contrary to current rate design requirements reflective of the 1996/97 GRA rate design structure as well as OIC 1995/90 rate directives**."**

QUESTION:

a) Please provide YEC's understanding of what is meant by "promote economy and efficiency" per OIC 1995/90.

b) Please explain YEC's proposal to use an across-the-board rider instead of establishing cost-based, rider-free base rates.

c) Please explain and illustrate the impact on base rates of eliminating each rider currently in use.

ANSWER:

(a)

YEC's understanding of "promote economy and efficiency" per OIC 1995/90 is drawn from the YUB's 1992 Report to the Commissioner in Executive Council, "Review of Cost of Service and Rates Charged to Electricity Customers in Yukon", as well as previous Board Orders (1993-7 and 1993-8 and 1996-7).

The 1992 Report provides at page 37, that "the board considers the efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decisions regarding the future and current use of electricity." In the report, the

Board recommended at page 40 that "the runout rates for all zones should be adjusted to reflect short-run incremental costs." In GRA applications approved by the Board since this report was produced, runout rates have been set based on the incremental cost of diesel generation in the respective rate zones.

(b)

Yukon Energy is not proposing to use an across-the-board rider. The net rate reduction is proposed to be implemented by way of Rider U, which is specific to each class so as to target only the first block energy sales.

Order-in-Council 2008/149 requires the Board to ensure that rate adjustments for retail customer classes apply equally, when measured as percentages. Thus, the rate reduction to be applied to retail customer classes through Rider U is applied to each rate class as an equal percentage reduction overall to the class. The implementation of Rider U is focused solely on the first block of consumption for each rate class.

(c)

Were each rider currently in use to be eliminated, base rates would need to be adjusted as required to provide for this lost revenue.

For instance, Rider J was established to recover a 1997 cost of service shortfall arising due to the closure of Faro mine. Rider J was not intended to be time limited nor to recover only the specific shortfall amounts. Were Rider J to be eliminated corresponding amounts would need to be recovered from the customer classes to which Rider J is currently applied. The specific adjustments to do this might vary, depending on the rate component for each class:

- Dealing with second block runoff rates, these would normally be set (increased in today's situation) per OIC 1995/90 to reflect the "economy and efficiency" requirements discussed above. This would normally be a first step in such a rate change process; accordingly, second block rates would not tend to be affected by removal of Rider J (although its removal would be taken into consideration if second block rates were being set lower than full "economy and efficiency" would otherwise stipulate). Increased second block rates would yield added revenue which might offset in part removal of Rider J.

- The balance of the class revenue requirement would then need to be collected through first block energy rates and any fixed charges (customer charge for residential and demand charge for general service). These billing components are already being charged for Rider J, which charge would now come off. The net impact of the overall change required would depend upon the extent to which added second block rates more than offset the removal of Rider J charges to second block rates, i.e., if the second block rate increase for a retail class more than offset the removal of Rider J charges to second block rates to that class, there would be room for an overall reduction to first block rate and/or fixed charges to that retail class.

- In light of OIC 2008/149, it would be necessary to ensure at this time that no change was made to the overall revenue to be collected from each retail rate class.

- Rider J does not affect Rate Schedule 39.

Similar considerations and approach would apply for removal of any other across-the-board percentage rider applicable to all firm retail billing components.

In contrast, Rider F (which is a charge per kWh applied to all energy sales) was established at the outset as a Deferral Fuel Price Account to capture variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA-approved fuel price. This rider would be required to continue per OIC 1995/90. However, at each GRA it is expected that “base rates” (the rate components reviewed above) would be adjusted to reflect the fuel price forecast for the GRA, and Rider F determination would restart from this new reference point. The relevant considerations for making such adjustments would basically be as set out above for removal of Rider J.

REFERENCE: October 6, 2008 Application, Page 3

YEC states "After all current riders, rebates and subsidies, but prior to GST, the net effects are as follows for retail residential and general service customer classes…"

QUESTION:

a) Please confirm that the impacts referenced are to the rates of YEC's customers and not to the rates of customers of Yukon Electrical Company Limited.

ANSWER:

(a)

Not confirmed. Pursuant to OIC 1995/90 (section 4(1)(b)) rates for each class of non-governmental retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers. The impacts noted are for all YEC and YECL customers throughout Yukon.

REFERENCE: October 6, 2008 Application, Page 4

YEC states "…in 2007, 84% of non-government residential monthly bills used no more than 1,300 kW.h".

QUESTION:

a) Please provide billing data used to determine this conclusion.

b) Please provide similar billing data and analysis for 2005, 2006 and 2008.

ANSWER:

(a)

For billing data used to determine the above, please refer to Table 4.11 of Tab 4 of the Application.

(b)

The table provided below provides billing data and analysis for 2005, 2006 and 2007.

Residential Non-Government

	2005	2006	2007
Average # of Customer Consuming <1,300 kW.h	11,191	10,336	11,240
Total # of Customers	13,035	12,146	13,340
%	86%	85%	84%

Note 1: "Number of Customers" = Average number of bills per month.
Note 2: 2008 data are not available.

REFERENCE: October 6, 2008 Application, Page 4

YEC states "With completion of CSTP Stage I and connection of the Minto mine, Yukon Energy's Whitehorse-Aishihik-Faro ("WAF") system is reaching a point where the material existing surplus hydro generation is becoming greatly diminished. Although sales of this surplus hydro at firm rates bring clear net benefits, evidenced by the rate reductions proposed in the Application, with ongoing load growth and expressed interest from other future industrial customers, the existing hydro generation is likely to be fully utilized within the next few years, necessitating new renewable supply sources in order to avoid reliance on high cost baseload diesel generation and the resulting GHG emissions issues."

QUESTION:

a) Please provide details of the dates of completion of the CSTP Stage 1 project and the connection of the Minto (Capstone) mine.

b) Please provide details of Minto billing data to date.

c) Please provide details of the "expressed interest from other future industrial customers" including anticipated load, timing of connection and location on system.

d) Please provide data which illustrates that "existing hydro generation is likely to be fully utilized within the next few years".

ANSWER:

(a)

Please see response to YUB-YEC-1-5, Commencement of Delivery as defined in the PPA occurred on November 22, 2008.

(b)

Please see response to PWP/HML-YEC-1-16.

(c)

Please see response to CW-YEC-1-31(a).

(d)

Table 2.5 illustrates that hydro generation in 2009 is forecast at 340 GW.h, of which slightly less than 20 GW.h is serving secondary sales (including losses). Consequently, even with a total interruption of secondary sales, there is on the order of 320 GW.h of firm load in 2009.

Historic long term average hydro generation estimates of 351 GW.h, plus 5 GW.h for the Aishihik 3rd turbine, yield total long-term average hydro generation of 356 GW.h.

This surplus of approximately 36 GW.h at long-term average water flow levels is subject to reduction in the "next few years" by ongoing non-industrial load growth (on the order of 5 GW.h per year to as high as 10 GW.h per year), expected load increments at the Minto mine, the initiation of site reclamation activities at the Faro mine site, and potential new mining loads such as Carmacks Copper.

On the Mayo-Dawson system similar pressures indicate that, absent new renewable generation, a potential elimination of existing hydro surplus with the full resumption of commercial mining activities at Keno.

REFERENCE: October 6, 2008 Application, Page 5

YEC states "A total incurred cost of $0.643 million related to the regulatory review of Yukon Energy's 2006-2025 Resource Plan, as required by the Minister of Justice, to be amortized over 10 years consistent with the anticipated frequency of full Resource Plan updates."

QUESTION:

a) Please explain why this cost is not charged out to the capital projects reviewed as part of the Resource Plan.

ANSWER:

(a)

In accordance with past regulatory practice in the Yukon, major hearing related regulatory expenses are amortized over a given period associated with the hearing.

The Resource Plan hearing was not a hearing concerning the review of a particular project or projects per se, but a review of a comprehensive 20-Year Resource Plan for the Yukon. As such, and as discussed at page 3-17 and 3-18 of the Application, the costs of the Resource Plan proceeding are proposed to be amortized over 10 years (the anticipated period of time until another comprehensive Resource Plan will be prepared).

REFERENCE: October 6, 2008 Application, Page 5

YEC states "A total incurred cost of $0.243 million related to the regulatory review of the Minto Explorations Power Purchase Agreement, to be amortized over 12 years which is the currently anticipated economic life of the substantial terms of the PPA."

QUESTION:

a) Please explain why this cost is not charged directly to Minto (Capstone).

ANSWER:

(a)

The cost is not charged directly to Minto as there is no provision for such assignment of these costs in the YUB approved PPA. The costs also are not to be charged directly to Minto as part of their rate as the rate is fixed by OIC and not subject to revision to assign additional costs.

In each of orders 2007-7, 2007-8, 2007-9 and 2008-1, the Board directed Yukon Energy to record all hearing costs related to the PPA hearing, the Resource Plan hearing and the Part 3 hearing in a Hearing Reserve Account. As noted in Tab 6, page 6-7 of the Application, the noted hearing costs (including PPA hearing costs) were included in a Hearing Reserve Account and YEC is proposing to amortize PPA hearing costs over 12 years (the anticipated primary accounting life of the PPA).

REFERENCE: October 6, 2008 Application, Page 5

YEC states "A total incurred cost of $0.185 million related to the regulatory review of the Carmacks-Stewart Transmission Project ("CSTP") under Part 3 of the Public Utilities Act, as required by the Minister of Justice, to be amortized over 45 years consistent with the approximate average life for the project assets."

QUESTION:

a) Please explain why this cost is not charged to the CSTP.

ANSWER:

(a)

In each of orders 2007-7, 2007-8, 2007-9 and 2008-1, the Board directed Yukon Energy to record hearing costs related to the PPA hearing, the Resource Plan hearing and the Part 3 hearing in a Hearing Reserve Account.

As noted in Tab 6, page 6-7 of the Application, the noted hearing costs (including Part 3 hearing costs) were included in a Hearing Reserve Account and YEC is proposing to amortize Part 3 hearing costs over 45 years (the approximate life of the assets as per Yukon Energy's most recent depreciation study). The net effect of this treatment is equivalent to charging these amounts to the capital cost of the CSTP project.

REFERENCE: October 6, 2008 Application, Page 11

YEC states "Extension of efficient price signals to the General Service rate classes, however, will require future review as soon as feasible with YECL to assess rate redesign options that cannot be addressed in this Yukon Energy Application.

QUESTION:

a) Please provide details of planning and/or discussions held to date with YECL in this regard.

ANSWER:

(a)

Please see response to LE-YEC-1-4(a).

REFERENCE: October 6, 2008 Application, Pages 13 and 14

YEC states "Yukon Energy proposes that, as a first priority, future joint YEC/YECL attention be directed as soon as practicable at identifying and assessing rate design options for General Service rate classes as required to promote economy and efficiency in accordance with OIC 1995/90, taking into consideration current and near term forecast incremental system costs in Yukon in the same manner as such costs were considered by the Board and YEC/YECL in the 1996/97 General Rate Application. Yukon Energy further proposes that joint YEC/YECL action to prepare a Cost of Service Study be assigned a lower priority, with delayed timing as appropriate, to reflect the timely need to address the above near term rate design priorities that are not tied to Cost of Service Study assessments as well as the fact that OIC 2007/94 and the latest Rate Policy Directive in effect defer until after 2012 any cost-of-service based rate rebalancing adjustments or other rate shift programs affecting the percentage of overall rate revenues allocated to major industrial customers or to any retail customer class".

QUESTION:

a) Please explain how cost-based rates could be designed for review without going through a detailed cost of service study.

ANSWER:

(a)

In the quoted section of the Application, YEC provides proposals towards an orderly process for addressing relevant rate issues over the period leading to 2013, noting what rate changes can be addressed today (runoff rates) and what rate changes must be deferred now for implementation until after 2012 (namely rate changes, based on cost of service studies, that seek to change how much revenue is collected from each rate class).

Second block runout rates are not set based on the utility's revenue requirement or on an allocation of costs included in a cost of service study. Runout block rates are established based on the requirement provided in OIC 1995/90 (section 4(3)) and on rate design principles initially established by the Board subsequent to the 1992 Cost of Service and Rate Design proceeding, and approved in Orders 1993-8 and 1996-7.

These rate design principles provide that second block runout rates are to promote economy and efficiency through reflecting short-run incremental costs, which are not derived from a cost of service study. Pursuant to practice previously approved by the Board these incremental costs are based on the current cost of diesel in each of the rate zones.

Looking at what can be expected when a cost of service study is available, the following past experience is noted:

In past Yukon experience, “cost based rates” as tied to class revenue to cost ratios from a cost of service study, have been used to assess how much of the revenue requirement is to be recovered from certain rate classes. In this regard, cost-of-service studies had a material impact on overall industrial class rate levels after 1995, and provided guidance to reduce overall non-government General Service customer rates in the 1996/97 GRA. In contrast, as noted by the Board in the past, such cost-of-service studies to date have had limited impacts on overall rates for other major customer rate classes (e.g., non-government residential); similarly, cost of service information has had no material impact on setting fixed charges such as the residential monthly customer charge. To complete the picture, first block rates for retail classes in the past were set as the residual requirement to recover class revenue targets after deduction of forecast runoff rate block revenues and any fixed charge rate revenues.

REFERENCE: October 6, 2008 Application, Introduction, Page 1-2

When describing Rider J, YEC states "…that rider was set only to recover specific identifiable and major adverse impacts on Yukon Energy from the Faro mine closing".

QUESTION:

a) Please identify and quantify the specific adverse impacts that needed to be recovered / will need to be recovered through Rider J during 2005, 2006, 2007, 2008 and 2009.

b) Please provide the amount actually recovered through Rider J in 2005, 2006, 2007 and 2008.

c) Please identify rate classes that pay the Rider J. If there are classes that do not pay Rider J, please provide an explanation for their exclusion.

d) Please explain why YEC does not propose eliminating Rider J and simply recover cost of service through base rates.

ANSWER:

(a)

As noted in response to YUB-YEC-1-57 (provided during the 2005 Required Revenues and Related Matters hearing), Rider J was approved to cover both interim and permanent impacts on Yukon Energy due to the loss of the Faro mine in 1998. This is not a special purposes rider designed to yield targeted collections, but is a material part of Yukon Energy's general and normal revenues and rates.

As set out in detail in Order 2003-2, Rider J is not a mechanism to collect a given dollar value or shortfall, it is a means for Yukon Energy to collect revenues towards its general Revenue Requirement, exactly analogous to any other rate. Until such time as overall retail and wholesale rates in Yukon are redesigned to incorporate this approximately $6 million collection into base rates, Rider J is required to prevent Yukon Energy from experiencing shortfalls in excess of $6 million.

(b)

Schedule 11, at Tab 7 of the filing notes at line 46 actual amounts recovered through Rider J from 2005 through 2007. These amounts are as follows:

2005: $5.246 million
2006: $5.451 million
2007: $5.585 million

Actuals for 2008 are not currently available and will be supplied with the update filing.

(c)

Rider J is applicable to all electric service retail rates except for Rate Schedule 39 (Industrial Primary rate) and Rate Schedule 32 (Secondary Energy rate).

Rider J was implemented to deal with a net loss of recurring margin revenue that was used to cover both recurring and one-time system cost of service items after the Faro mine closed in 1997. The rate is not applicable to the Rate Schedule 32 customer as such sales are not firm sales and not linked to YEC's cost but rather to the customer's savings from reduced use of the alternative fuel (typically oil). The rider is not applicable to Rate Schedule 39 customers pursuant to OIC.

(d)

Yukon Energy is not undertaking a major re-design of rates at this time. Eliminating Rider J in order to recover amounts targeted by Rider J through base rates would require a re-design of rates.

REFERENCE: October 6, 2008 Application, Introduction, Page 1-3

YEC references the revenue to cost ratios report filed August 24, 2005 in response to a Board directive.

QUESTION:

a) Please identify any Board Orders or directions that resulted from this report.

b) Please provide an update to Table 1 of the August 2005 report which shows the actual revenue to cost ratios for 2005, 2006, 2007 and 2008.

c) Please explain YEC's position that a rate shift program could be properly designed without a current picture of how much of a shift is required by using the results of an updated cost allocation / rate design analysis.

d) Please explain YEC's position that potential rate impacts on customer classes could be determined without having the latest cost and revenue allocation data.

ANSWER:

(a)

No Board Orders or directions resulted from the report filed August 24, 2005.

(b)

Please see UCG-YEC-1-93.

(c) and **(d)**

Yukon Energy's position is that no rate shift program can be initiated prior to 2013.

In the event a rate shift program were possible, the joint report by YEC and YECL in 1995 (see attachment to YUB-YEC-1-23) indicated that the primary directionality for major adjustments required is quite clear. Based on that report, and the information therein, residential non-government rates would need to rise (likely to approximately the

level of residential government rates), and government General Service rates would need to be lowered (likely to the range of Non-government General Service). This is in part supported by the fact that the last full cost-of-service study (1997) indicated that the fully allocated costs of energy to each of these 4 classes (residential government, residential non-government, general service government, and general service non-government) are basically identical, the costs of demand-related costs are within 3% of each other, and the costs for customer related costs vary by less than $100/year among all four classes. Given this near identical cost profile, any change to costs resulting from developments since 1997 are likely to have applied almost equally to each class, resulting in likely very little relative change in revenue: cost coverage factors.

REFERENCE: October 6, 2008 Application, Introduction, Pages 1-2 and 1-3

YEC references the Board's January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025.

QUESTION:

a) Please provide an update on all 2008 and 2009 capital projects that are expected to exceed $1 million in cost and what steps YEC has taken / what processes have been implemented to adhere to the Board's recommendation that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please identify all capital projects initiated in 2007, 2008 and 2009 for which YEC has submitted an application to the Minister per Part 3 of the *Public Utilities Act*.

c) Please provide an update on the Marsh Lake Fall / Winter Storage Licence Revision project that the Board removed from near term projects.

d) Please provide an update to YEC's development of an independent power producer policy recommended by the Board.

e) Please provide an update on YEC's participation in the Board's recommended study of the potential for DSM initiatives in the Yukon.

f) Please explain why no evidence has been submitted regarding the Board's recommendation that evidence be provided as to what other utilities provide for Maximum Company Investment and that Yukon utilities model theirs accordingly.

ANSWER:

(a)

All 2008 and 2009 capital projects that exceed $1 million are set out in Table 5.2 as "Major Projects" and are subject to Board review at this proceeding. Each of the projects has also been the subject of review at previous hearings (Resource Plan, Minto PPA, CSTP Part 3).

(b)

Carmacks-Stewart Transmission Project.

(c)

Please see YUB-YEC-1-27(a).

(d)

Please see YUB-YEC-1-27(c).

(e)

The noted recommendation was for the Government of Yukon to undertake an independent study. YEC is not aware of any such independent study having been commissioned in response to the Board's recommendation.

(f)

Please see Tab 6, page 6-6.

REFERENCE: October 6, 2008 Application, Introduction, Page 1-7

YEC references the installation of the Aishihik Third Turbine in 2010.

REFERENCE: Yukon Utilities Board Report on Yukon Energy Corporation 20-Year Resource Plan, January 15, 2007, Page 30

"The Board's analysis in Sections 4 and 5 above, which was conducted assuming the base-case load forecast, has shown that YEC's proposed expansion plan would be more economic than the alternative plan provided that the Aishihik third turbine is installed in 2013. It should be noted, however, that the addition of the third turbine under YEC's plan is not a capacity requirement determined by the planning criteria, but rather a requirement driven strictly by economic reasons, namely to offset future diesel generation that is expected to increase under the base-case load forecast. However, should the actual loads turn out higher or lower that the loads under the base-case forecast, the optimal timing of the third turbine would move earlier or later than 2013. Therefore, to minimize the uncertainty around timing of the third turbine, the final decision to proceed with this project should be made closer to the date when economic reasons indicate that the turbine is needed. Therefore, the Board recommends that this project not proceed until that time unless YEC can justify an earlier in-service date."

QUESTION:

a) Please identify the economic reasons that justify moving forward with this project in 2010.

b) Please identify the regulatory approvals that YEC will be seeking for this project and the timing of related applications.

c) Please describe the process used to identify projects that were potentially eligible for the $5 million Eco-trust fund.

d) Please identify the projects other than the Aishihik Third Turbine that were considered for funding through the $5 million Eco-trust fund and explain why they were not recommended and/or accepted for funding.

ANSWER:

(a)

The original economic rationale for proceeding with this project is as described in Appendix C of Yukon Energy's 20-Year Resource Plan. The feasibility of the project was further described in the PPA Application and in Yukon Energy's 2007 Part 3 Application concerning the Carmacks Stewart Transmission Project. Footnote 23 at page 15 of Yukon Energy's Part 3 Application related to the Carmacks Stewart Transmission Project notes as follows regarding the economic and technical feasibility of proceeding with the Aishihik 3rd Turbine project based on the Resource Plan assessments:

> The available evidence confirms the economic and technical feasibility of the Aishihik 3rd Turbine, which is already fully licensed. As discussed in footnote 7 in Attachment B to the PPA Application, "the Resource Plan assumes Aishihik 3rd Turbine capital costs at about $7 million (2005$); Appendix C of the January 2006 Resource Plan, however, indicates PV (2005$) life cycle capital and operating costs for this project at about $6 million for in-service in 2011 (this number would be slightly higher for in-service in 2010, and slightly lower for in-service in 2013), which is slightly more than incremental savings to 2025 as noted in Table B-1. This analysis of incremental savings in Table B-1, however, ignores full life benefits for Aishihik 3rd Turbine due to ongoing diesel generation cost savings after 2025. As demonstrated in Appendix C of the January 2006 Resource Plan Report, PV savings after 2025 (in 2005$) due to diesel generation displacement have been estimated to exceed $4 million. Overall, based on life cycle costs, the Aishihik 3rd Turbine is an economically attractive project yielding NPV ratepayer savings with the Minto mine even over the period to 2025 (these NPV savings tend to be slightly higher with Aishihik 3rd Turbine in service in 2013 versus 2010)."

Exhibit B-9 (provided as Attachment 1 to this response) filed during the 2007 Part 3 hearing process also provides a summary of updated Aishihik 3rd Turbine Assessment cases after consideration of the $5 million government contribution as then announced. Specifically, Table 2 in Exhibit B-9 shows the costs and benefits of this project with in-service in 2010 at a gross cost of $7.7 million, the $5 million government contribution, no CSTP Stage 2 in place, and only the Minto mine as a major new industrial load. NPV

ratepayer savings from the project under these assumptions were estimated at approximately $8 million over the project lifetime.

Based on this information, the YUB report to the Minister regarding the Part 3 review of the CSTP recommended that, "if Stage One of the CSTP were to go forward, then by implication, there is an accelerated need for the third turbine at Aishihik. The Board accepts the submissions that on an opportunity basis for diesel displacement, with connection of new mine loads, there is economic justification to accelerate the construction of the Aishihik third turbine. This view and recommendation is consistent with the view expressed by the Board in its 20-Year Resource Plan Report" [as quoted in Application at page 5-12].

For further update on the effects of current project cost estimates and fuel prices, please see the response to YUB-YEC-1-36(h).

(b)

It is Yukon Energy's view that all regulatory approvals that are currently required to proceed with the project have been obtained. The response to UCG-YEC-1-90(b) provides as follows with regard to licences obtained to proceed with this project:

> The current Aishihik water license authorizes Yukon Energy to install a third turbine and associated appurtenances with a maximum generating capacity of 7 MW at the facility. No further licences are necessary.

UCG's March 24th letter suggests that YEC "should have indicated what approvals have been obtained so that an analysis could be conducted by YEC on what it believes is required for a project of this size. UCG is concerned that regulatory processes may have been circumvented by the government's participation in this project." UCG requests that, "YEC provide a more complete response by identifying all regulatory approvals obtained for the project."

Order 2009-4 noted that the information request had not been adequately responded to and directed YEC to respond accordingly.

In response it is reiterated that the only "regulatory approval" that Yukon Energy has understood to be required is with regard to the Water Licence for this plant. As part of

the extensive environmental assessment and licensing review that occurred to renew this plant's Water Licence, YEC's renewed Water Licence currently in effect for the Aishihik facility fully authorizes the construction of a third turbine up to 7 MW. As with any other such development project, various construction specific permits will likely also be required (e.g., for operating a construction camp), however, as with other such development projects, YEC expects that the constructor would obtain all such permits, not YEC, based on the prior environmental assessment reviews and the current Water Licence authorizations.

(c) and **(d)**

On March 30, 2007, Canada announced $5 million in funding for the Yukon as part of a trust fund set up to help reduce greenhouse gas emissions and air pollutants, and the Yukon Government announced that the funds will be used for the Aishihik 3rd Turbine project. Eligibility for this funding was determined by the Yukon Government and Yukon Energy has no additional insight into the process by which the government identified and assessed projects eligible for the Eco-trust fund, or other projects that were considered and why they ultimately were or were not provided funding.

Summary of Aishihik 3rd Turbine Assessment Cases: Updated Appendix C (YEC Resource Plan: 2006-2025, dated January 2006) (2005$, $000s)

	IRR lifetime (%)	Ratepayer Costs/(Savings) (NPV) lifetime	Ratepayer Costs/(Savings) (NPV) 20 years	Years until beneficial rate impact	Years mines Contribute
Table 1: Aishihik 3rd Turbine at 2010 under Base Case Loads	17.50%	(6,690)	(1,736)	6	0
Table 2: Aishihik 3rd Turbine at 2010 with Minto at 32.5 GWh	22.84%	(7,959)	(3,005)	2	7
Table 3: Aishihik 3rd Turbine at 2010 with Minto at 32.5 GWh and CC at 48.0 GWh	61.46%	(10,803)	(5,849)	0	8
Table 4: Aishihik 3rd Turbine 2010 and CS Interconnection 2010 with Minto at 32.5 GWh and CC at 48.0 GWh	62.55%	(12,093)	(7,139)	0	8

Key Update Assumptions:
- $5 Million Funding for Aishihik 3rd Turbine
- Minto and Pelly Crossing Loads per PPA Application, Table B-3
- Secondary Sales cap, peaking dispatch and economic assumptions per PPA Application, Table B-3
- Marsh Lake Fall/Winter storage not included

B-9

1A: Basecase: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales **Base Case load forecast**
•Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenue Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	-	-	-	3.48	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	3.9	-	22	22	-	3.48	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	3.9	-	91	91	-	3.48	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	3.9	-	183	183	-	3.48	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	3.9	-	289	-	(289)	3.48	83	83	60	5	not assessed	65	2,729	77	2,806	2,741
2011	-	-	-	3.9	-	413	-	(413)	3.48	119	119	87	7	not assessed	94	-	79	79	(15)
2012	-	-	-	3.9	-	566	-	(566)	3.48	163	163	122	10	not assessed	132	-	80	80	(52)
2013	-	-	-	3.9	-	767	4	(763)	3.48	219	219	167	14	not assessed	181	-	82	82	(99)
2014	-	-	-	3.9	-	1,035	60	(975)	3.48	280	280	218	19	not assessed	236	-	84	84	(153)
2015	-	-	-	3.9	-	1,389	153	(1,236)	3.48	355	355	282	24	not assessed	306	-	85	85	(220)
2016	-	-	-	3.9	-	1,850	264	(1,586)	3.48	456	456	368	32	not assessed	400	-	87	87	(313)
2017	-	-	-	3.9	-	2,437	392	(2,045)	3.48	588	588	484	41	not assessed	526	-	89	89	(437)
2018	-	-	-	3.9	-	3,166	547	(2,619)	3.48	752	752	633	54	not assessed	687	-	91	91	(596)
2019	-	-	-	3.9	-	4,051	745	(3,306)	3.48	950	950	815	70	not assessed	885	-	92	92	(792)
2020	-	-	-	3.9	-	5,106	1,006	(4,099)	3.48	1,178	1,178	1,031	88	not assessed	1,119	-	94	94	(1,025)
2021	722	-	(722)	3.9	185	5,618	1,355	(4,263)	3.48	1,225	1,410	1,258	109	not assessed	1,368	-	96	96	(1,272)
2022	7,299	1,899	(5,400)	3.9	1,385	464	-	(464)	3.48	133	1,518	1,381	131	not assessed	1,513	-	98	98	(1,415)
2023	13,997	8,597	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	not assessed	1,409	-	100	100	(1,309)
2024	20,819	15,419	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	not assessed	1,437	-	102	102	(1,335)
2025	27,768	22,368	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	not assessed	1,466	-	104	104	(1,362)
2026	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	not assessed	1,495	-	106	106	(1,389)
2027	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	not assessed	1,525	-	108	108	(1,417)
2028	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	not assessed	1,555	-	110	110	(1,445)
2029	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	not assessed	1,587	-	113	113	(1,474)
2030	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	not assessed	1,618	-	115	115	(1,503)
2031	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	not assessed	1,651	-	117	117	(1,534)
2032	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	not assessed	1,684	-	119	119	(1,564)
2033	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	not assessed	1,717	-	122	122	(1,595)
2034	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	not assessed	1,752	-	124	124	(1,627)
2035	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	not assessed	1,787	-	127	127	(1,660)
2036	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	not assessed	1,822	-	129	129	(1,693)
2037	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	not assessed	1,859	-	132	132	(1,727)
2038	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	not assessed	1,896	-	135	135	(1,762)
2039	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	not assessed	1,934	-	137	137	(1,797)
2040	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	not assessed	1,973	-	140	140	(1,833)
2041	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	not assessed	2,012	-	143	143	(1,869)
2042	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	not assessed	2,052	-	146	146	(1,907)
2043	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	not assessed	2,093	-	149	149	(1,945)
2044	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	not assessed	2,135	-	152	152	(1,984)
2045	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	not assessed	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	not assessed	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	not assessed	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	not assessed	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	not assessed	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	not assessed	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	not assessed	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	not assessed	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	not assessed	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	not assessed	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	not assessed	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	not assessed	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	not assessed	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	not assessed	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	not assessed	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	not assessed	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	not assessed	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	not assessed	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	not assessed	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	not assessed	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	not assessed	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	not assessed	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	not assessed	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	not assessed	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	not assessed	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	not assessed	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	not assessed	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	not assessed	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	not assessed	3,792	-	269	269	(3,523)
PV (2005)	7.52%											8,896	832		9,728	1,899	1,012	2,911	(6,817)
																Internal Rate of Return			17.50%

1B : Aishihik 3rd Turbine Economics (65 years) - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	83	60	5	not assessed	65	42	204	77	323	258
2011	119	87	7	not assessed	94	42	200	79	321	227
2012	163	122	10	not assessed	132	42	197	80	320	188
2013	219	167	14	not assessed	181	42	194	82	318	137
2014	280	218	19	not assessed	236	42	191	84	317	80
2015	355	282	24	not assessed	306	42	188	85	315	9
2016	456	368	32	not assessed	400	42	185	87	314	(86)
2017	588	484	41	not assessed	526	42	182	89	312	(214)
2018	752	633	54	not assessed	687	42	178	91	311	(376)
2019	950	815	70	not assessed	885	42	175	92	310	(575)
2020	1,178	1,031	88	not assessed	1,119	42	172	94	308	(811)
2021	1,410	1,258	109	not assessed	1,368	42	169	96	307	(1,061)
2022	1,518	1,381	131	not assessed	1,513	42	166	98	306	(1,207)
2023	1,385	1,285	123	not assessed	1,409	42	163	100	305	(1,104)
2024	1,385	1,311	126	not assessed	1,437	42	159	102	303	(1,134)
2025	1,385	1,337	128	not assessed	1,466	42	156	104	302	(1,163)
2026	1,385	1,364	131	not assessed	1,495	42	153	106	301	(1,194)
2027	1,385	1,391	134	not assessed	1,525	42	150	108	300	(1,225)
2028	1,385	1,419	136	not assessed	1,555	42	147	110	299	(1,256)
2029	1,385	1,448	139	not assessed	1,587	42	144	113	298	(1,288)
2030	1,385	1,477	142	not assessed	1,618	42	140	115	297	(1,321)
2031	1,385	1,506	145	not assessed	1,651	42	137	117	296	(1,354)
2032	1,385	1,536	147	not assessed	1,684	42	134	119	296	(1,388)
2033	1,385	1,567	150	not assessed	1,717	42	131	122	295	(1,422)
2034	1,385	1,598	153	not assessed	1,752	42	128	124	294	(1,458)
2035	1,385	1,630	157	not assessed	1,787	42	125	127	293	(1,493)
2036	1,385	1,663	160	not assessed	1,822	42	122	129	293	(1,530)
2037	1,385	1,696	163	not assessed	1,859	42	118	132	292	(1,567)
2038	1,385	1,730	166	not assessed	1,896	42	115	135	292	(1,604)
2039	1,385	1,765	169	not assessed	1,934	42	112	137	291	(1,643)
2040	1,385	1,800	173	not assessed	1,973	42	109	140	291	(1,682)
2041	1,385	1,836	176	not assessed	2,012	42	106	143	291	(1,722)
2042	1,385	1,873	180	not assessed	2,052	42	103	146	290	(1,762)
2043	1,385	1,910	183	not assessed	2,093	42	99	149	290	(1,803)
2044	1,385	1,948	187	not assessed	2,135	42	96	152	290	(1,846)
2045	1,385	1,987	191	not assessed	2,178	42	93	155	290	(1,888)
2046	1,385	2,027	195	not assessed	2,222	42	90	158	290	(1,932)
2047	1,385	2,068	198	not assessed	2,266	42	87	161	290	(1,976)
2048	1,385	2,109	202	not assessed	2,311	42	84	164	290	(2,022)
2049	1,385	2,151	207	not assessed	2,358	42	80	167	290	(2,068)
2050	1,385	2,194	211	not assessed	2,405	42	77	171	290	(2,115)
2051	1,385	2,238	215	not assessed	2,453	42	74	174	290	(2,163)
2052	1,385	2,283	219	not assessed	2,502	42	71	178	291	(2,211)
2053	1,385	2,328	224	not assessed	2,552	42	68	181	291	(2,261)
2054	1,385	2,375	228	not assessed	2,603	42	65	185	291	(2,312)
2055	1,385	2,422	233	not assessed	2,655	42	62	188	292	(2,363)
2056	1,385	2,471	237	not assessed	2,708	42	58	192	293	(2,416)
2057	1,385	2,520	242	not assessed	2,762	42	55	196	293	(2,469)
2058	1,385	2,571	247	not assessed	2,817	42	52	200	294	(2,523)
2059	1,385	2,622	252	not assessed	2,874	42	49	204	295	(2,579)
2060	1,385	2,675	257	not assessed	2,931	42	46	208	296	(2,636)
2061	1,385	2,728	262	not assessed	2,990	42	43	212	297	(2,693)
2062	1,385	2,783	267	not assessed	3,050	42	39	216	298	(2,752)
2063	1,385	2,838	272	not assessed	3,111	42	36	221	299	(2,812)
2064	1,385	2,895	278	not assessed	3,173	42	33	225	300	(2,873)
2065	1,385	2,953	283	not assessed	3,236	42	30	230	302	(2,935)
2066	1,385	3,012	289	not assessed	3,301	42	27	234	303	(2,998)
2067	1,385	3,072	295	not assessed	3,367	42	24	239	305	(3,063)
2068	1,385	3,134	301	not assessed	3,435	42	21	244	306	(3,128)
2069	1,385	3,196	307	not assessed	3,503	42	17	249	308	(3,195)
2070	1,385	3,260	313	not assessed	3,573	42	14	254	310	(3,263)
2071	1,385	3,325	319	not assessed	3,645	42	11	259	312	(3,333)
2072	1,385	3,392	326	not assessed	3,718	42	8	264	314	(3,404)
2073	1,385	3,460	332	not assessed	3,792	42	5	269	316	(3,476)
PV (2005)		8,896	832		9,728	414	1,612	1,012	3,037	(6,690)
7.52%								20 year NPV (2006-2025)		(1,736)

Table 2A: Basecase: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales **Base Case load forecast with Minto 32.5GWh from 2009 - 2016**
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenue Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	-	-	-	3.48	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	3.9	-	22	22	-	3.48	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	3.9	-	91	91	-	3.48	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	3.9	-	775	775	-	3.48	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	3.9	-	1,024	57	(967)	3.48	278	278	199	17	not assessed	216	2,729	77	2,806	2,589
2011	-	-	-	3.9	-	1,347	142	(1,205)	3.48	346	346	254	22	not assessed	275	-	79	79	(196)
2012	-	-	-	3.9	-	1,752	244	(1,518)	3.48	436	436	326	28	not assessed	354	-	80	80	(273)
2013	-	-	-	3.9	-	2,283	360	(1,924)	3.48	553	553	421	36	not assessed	457	-	82	82	(375)
2014	-	-	-	3.9	-	2,926	496	(2,430)	3.48	698	698	542	46	not assessed	589	-	84	84	(505)
2015	1,282	-	(1,282)	3.9	329	2,421	665	(1,756)	3.48	505	833	660	59	not assessed	720	-	85	85	(634)
2016	7,174	1,774	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	not assessed	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	2,543	415	(2,128)	3.48	612	612	504	43	not assessed	547	-	89	89	(458)
2018	-	-	-	3.9	-	3,293	575	(2,719)	3.48	781	781	657	56	not assessed	713	-	91	91	(623)
2019	-	-	-	3.9	-	4,202	780	(3,422)	3.48	983	983	843	72	not assessed	916	-	92	92	(823)
2020	-	-	-	3.9	-	5,280	1,053	(4,227)	3.48	1,215	1,215	1,063	91	not assessed	1,154	-	94	94	(1,060)
2021	2,413	-	(2,413)	3.9	619	4,126	1,415	(2,711)	3.48	779	1,398	1,247	113	not assessed	1,360	-	96	96	(1,264)
2022	8,990	3,590	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,260	121	not assessed	1,381	-	98	98	(1,283)
2023	15,688	10,288	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	not assessed	1,409	-	100	100	(1,309)
2024	22,510	17,110	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	not assessed	1,437	-	102	102	(1,335)
2025	29,458	24,058	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	not assessed	1,466	-	104	104	(1,362)
2026	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	not assessed	1,495	-	106	106	(1,389)
2027	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	not assessed	1,525	-	108	108	(1,417)
2028	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	not assessed	1,555	-	110	110	(1,445)
2029	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	not assessed	1,587	-	113	113	(1,474)
2030	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	not assessed	1,618	-	115	115	(1,503)
2031	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	not assessed	1,651	-	117	117	(1,534)
2032	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	not assessed	1,684	-	119	119	(1,564)
2033	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	not assessed	1,717	-	122	122	(1,595)
2034	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	not assessed	1,752	-	124	124	(1,627)
2035	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	not assessed	1,787	-	127	127	(1,660)
2036	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	not assessed	1,822	-	129	129	(1,693)
2037	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	not assessed	1,859	-	132	132	(1,727)
2038	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	not assessed	1,896	-	135	135	(1,762)
2039	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	not assessed	1,934	-	137	137	(1,797)
2040	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	not assessed	1,973	-	140	140	(1,833)
2041	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	not assessed	2,012	-	143	143	(1,869)
2042	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	not assessed	2,052	-	146	146	(1,907)
2043	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	not assessed	2,093	-	148	149	(1,945)
2044	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	not assessed	2,135	-	152	152	(1,984)
2045	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	not assessed	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	not assessed	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	not assessed	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	not assessed	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	not assessed	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	not assessed	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	not assessed	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	not assessed	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	not assessed	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	not assessed	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	not assessed	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	not assessed	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	not assessed	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	not assessed	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	not assessed	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	not assessed	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	not assessed	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	not assessed	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	not assessed	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	not assessed	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	not assessed	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	not assessed	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	not assessed	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	not assessed	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	not assessed	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	not assessed	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	not assessed	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	not assessed	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	not assessed	3,792	-	269	269	(3,523)
PV (2005)	7.52%											10,057	939		10,996	1,899	1,012	2,911	(8,085)
																Internal Rate of Return			22.84%

Table 2B: Aishihik 3rd Turbine Economics (65 years) - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast with Minto 32.5GWh from 2009 - 2016
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	278	199	17	not assessed	216	42	204	77	323	106
2011	346	254	22	not assessed	275	42	200	79	321	46
2012	436	326	28	not assessed	354	42	197	80	320	(34)
2013	553	421	36	not assessed	457	42	194	82	318	(139)
2014	698	542	46	not assessed	589	42	191	84	317	(272)
2015	833	660	59	not assessed	720	42	188	85	315	(404)
2016	1,385	1,119	107	not assessed	1,226	42	185	87	314	(913)
2017	612	504	43	not assessed	547	42	182	89	312	(235)
2018	781	657	56	not assessed	713	42	178	91	311	(402)
2019	983	843	72	not assessed	916	42	175	92	310	(606)
2020	1,215	1,063	91	not assessed	1,154	42	172	94	308	(846)
2021	1,398	1,247	113	not assessed	1,360	42	169	96	307	(1,053)
2022	1,385	1,260	121	not assessed	1,381	42	166	98	306	(1,075)
2023	1,385	1,285	123	not assessed	1,409	42	163	100	305	(1,104)
2024	1,385	1,311	126	not assessed	1,437	42	159	102	303	(1,134)
2025	1,385	1,337	128	not assessed	1,466	42	156	104	302	(1,163)
2026	1,385	1,364	131	not assessed	1,495	42	153	106	301	(1,194)
2027	1,385	1,391	134	not assessed	1,525	42	150	108	300	(1,225)
2028	1,385	1,419	136	not assessed	1,555	42	147	110	299	(1,256)
2029	1,385	1,448	139	not assessed	1,587	42	144	113	298	(1,288)
2030	1,385	1,477	142	not assessed	1,618	42	140	115	297	(1,321)
2031	1,385	1,506	145	not assessed	1,651	42	137	117	296	(1,354)
2032	1,385	1,536	147	not assessed	1,684	42	134	119	296	(1,388)
2033	1,385	1,567	150	not assessed	1,717	42	131	122	295	(1,422)
2034	1,385	1,598	153	not assessed	1,752	42	128	124	294	(1,458)
2035	1,385	1,630	157	not assessed	1,787	42	125	127	293	(1,493)
2036	1,385	1,663	160	not assessed	1,822	42	122	129	293	(1,530)
2037	1,385	1,696	163	not assessed	1,859	42	118	132	292	(1,567)
2038	1,385	1,730	166	not assessed	1,896	42	115	135	292	(1,604)
2039	1,385	1,765	169	not assessed	1,934	42	112	137	291	(1,643)
2040	1,385	1,800	173	not assessed	1,973	42	109	140	291	(1,682)
2041	1,385	1,836	176	not assessed	2,012	42	106	143	291	(1,722)
2042	1,385	1,873	180	not assessed	2,052	42	103	146	290	(1,762)
2043	1,385	1,910	183	not assessed	2,093	42	99	149	290	(1,803)
2044	1,385	1,948	187	not assessed	2,135	42	96	152	290	(1,846)
2045	1,385	1,987	191	not assessed	2,178	42	93	155	290	(1,888)
2046	1,385	2,027	195	not assessed	2,222	42	90	158	290	(1,932)
2047	1,385	2,068	198	not assessed	2,266	42	87	161	290	(1,976)
2048	1,385	2,109	202	not assessed	2,311	42	84	164	290	(2,022)
2049	1,385	2,151	207	not assessed	2,358	42	80	167	290	(2,068)
2050	1,385	2,194	211	not assessed	2,405	42	77	171	290	(2,115)
2051	1,385	2,238	215	not assessed	2,453	42	74	174	290	(2,163)
2052	1,385	2,283	219	not assessed	2,502	42	71	178	291	(2,211)
2053	1,385	2,328	224	not assessed	2,552	42	68	181	291	(2,261)
2054	1,385	2,375	228	not assessed	2,603	42	65	185	291	(2,312)
2055	1,385	2,422	233	not assessed	2,655	42	62	188	292	(2,363)
2056	1,385	2,471	237	not assessed	2,708	42	58	192	293	(2,416)
2057	1,385	2,520	242	not assessed	2,762	42	55	196	293	(2,469)
2058	1,385	2,571	247	not assessed	2,817	42	52	200	294	(2,523)
2059	1,385	2,622	252	not assessed	2,874	42	49	204	295	(2,579)
2060	1,385	2,675	257	not assessed	2,931	42	46	208	296	(2,636)
2061	1,385	2,728	262	not assessed	2,990	42	43	212	297	(2,693)
2062	1,385	2,783	267	not assessed	3,050	42	39	216	298	(2,752)
2063	1,385	2,838	272	not assessed	3,111	42	36	221	299	(2,812)
2064	1,385	2,895	278	not assessed	3,173	42	33	225	300	(2,873)
2065	1,385	2,953	283	not assessed	3,236	42	30	230	302	(2,935)
2066	1,385	3,012	289	not assessed	3,301	42	27	234	303	(2,998)
2067	1,385	3,072	295	not assessed	3,367	42	24	239	305	(3,063)
2068	1,385	3,134	301	not assessed	3,435	42	21	244	306	(3,128)
2069	1,385	3,196	307	not assessed	3,503	42	17	249	308	(3,195)
2070	1,385	3,260	313	not assessed	3,573	42	14	254	310	(3,263)
2071	1,385	3,325	319	not assessed	3,645	42	11	259	312	(3,333)
2072	1,385	3,392	326	not assessed	3,718	42	8	264	314	(3,404)
2073	1,385	3,460	332	not assessed	3,792	42	5	269	316	(3,476)
PV (2005)		10,057	939		10,996	414	1,612	1,012	3,037	(7,959)
7.52%								20 year NPV (2006-2025)		(3,005)

Table 3A: Basecase: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales **Base Case load forecast with Minto 32.5GWh from 2009 - 2016 & CC 48.0 from 2010 - 2017**
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h/litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h/litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenue Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	-	-	-	3.48	-	-	-	-	-	-	-	-	-
2007	-	-	-	3.9	-	22	22	-	3.48	-	-	-	-	-	-	-	-	-
2008	-	-	-	3.9	-	91	91	-	3.48	-	-	-	-	-	-	-	-	-
2009	-	-	-	3.9	-	775	775	-	3.48	-	-	-	-	-	-	-	-	-
2010	27,320	21,920	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	994	95	not assessed	1,089	2,729	77	2,806	1,717
2011	32,695	27,295	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,014	97	not assessed	1,111	-	79	79	(1,032)
2012	38,170	32,770	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	not assessed	1,133	-	80	80	(1,053)
2013	43,914	38,514	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	not assessed	1,156	-	82	82	(1,074)
2014	49,593	44,193	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	not assessed	1,179	-	84	84	(1,095)
2015	55,378	49,978	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	not assessed	1,202	-	85	85	(1,117)
2016	61,270	55,870	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	not assessed	1,226	-	87	87	(1,139)
2017	30,643	25,243	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,141	110	not assessed	1,251	-	89	89	(1,162)
2018	-	-	-	3.9	-	3,293	575	(2,719)	3.48	781	781	657	56	not assessed	713	-	91	91	(623)
2019	-	-	-	3.9	-	4,202	780	(3,422)	3.48	983	983	843	72	not assessed	916	-	92	92	(823)
2020	-	-	-	3.9	-	5,280	1,053	(4,227)	3.48	1,215	1,215	1,063	91	not assessed	1,154	-	94	94	(1,060)
2021	2,413	-	(2,413)	3.9	619	4,126	1,415	(2,711)	3.48	779	1,398	1,247	113	not assessed	1,360	-	96	96	(1,264)
2022	8,990	3,590	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,260	121	not assessed	1,381	-	98	98	(1,283)
2023	15,688	10,288	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	not assessed	1,409	-	100	100	(1,309)
2024	22,510	17,110	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	not assessed	1,437	-	102	102	(1,335)
2025	29,458	24,058	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	not assessed	1,466	-	104	104	(1,362)
2026	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	not assessed	1,495	-	106	106	(1,389)
2027	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	not assessed	1,525	-	108	108	(1,417)
2028	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	not assessed	1,555	-	110	110	(1,445)
2029	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	not assessed	1,587	-	113	113	(1,474)
2030	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	not assessed	1,618	-	115	115	(1,503)
2031	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	not assessed	1,651	-	117	117	(1,534)
2032	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	not assessed	1,684	-	119	119	(1,564)
2033	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	not assessed	1,717	-	122	122	(1,595)
2034	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	not assessed	1,752	-	124	124	(1,627)
2035	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	not assessed	1,787	-	127	127	(1,660)
2036	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	not assessed	1,822	-	129	129	(1,693)
2037	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	not assessed	1,859	-	132	132	(1,727)
2038	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	not assessed	1,896	-	135	135	(1,762)
2039	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	not assessed	1,934	-	137	137	(1,797)
2040	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	not assessed	1,973	-	140	140	(1,833)
2041	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	not assessed	2,012	-	143	143	(1,869)
2042	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	not assessed	2,052	-	146	146	(1,907)
2043	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	not assessed	2,093	-	149	149	(1,945)
2044	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	not assessed	2,135	-	152	152	(1,984)
2045	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	not assessed	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	not assessed	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	not assessed	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	not assessed	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	not assessed	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	not assessed	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	not assessed	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	not assessed	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	not assessed	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	not assessed	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	not assessed	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	not assessed	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	not assessed	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	not assessed	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	not assessed	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	not assessed	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	not assessed	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	not assessed	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	not assessed	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	not assessed	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	not assessed	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	not assessed	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	not assessed	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	not assessed	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	not assessed	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	not assessed	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	not assessed	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	not assessed	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	not assessed	3,792	-	269	269	(3,523)
PV (2005)	7.52%											12,639	1,202		13,840	1,899	1,012	2,911	(10,930)
																Internal Rate of Return			61.46%

Table 3B: Aishihik 3rd Turbine Economics (65 years) - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast with Minto 32.5GWh from 2009 - 2016 & CC 48.0 from 2010 - 2017
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	1,385	994	95	not assessed	1,089	42	204	77	323	(766)
2011	1,385	1,014	97	not assessed	1,111	42	200	79	321	(790)
2012	1,385	1,034	99	not assessed	1,133	42	197	80	320	(813)
2013	1,385	1,054	101	not assessed	1,156	42	194	82	318	(838)
2014	1,385	1,076	103	not assessed	1,179	42	191	84	317	(862)
2015	1,385	1,097	105	not assessed	1,202	42	188	85	315	(887)
2016	1,385	1,119	107	not assessed	1,226	42	185	87	314	(913)
2017	1,385	1,141	110	not assessed	1,251	42	182	89	312	(939)
2018	781	657	56	not assessed	713	42	178	91	311	(402)
2019	983	843	72	not assessed	916	42	175	92	310	(606)
2020	1,215	1,063	91	not assessed	1,154	42	172	94	308	(846)
2021	1,398	1,247	113	not assessed	1,360	42	169	96	307	(1,053)
2022	1,385	1,260	121	not assessed	1,381	42	166	98	306	(1,075)
2023	1,385	1,285	123	not assessed	1,409	42	163	100	305	(1,104)
2024	1,385	1,311	126	not assessed	1,437	42	159	102	303	(1,134)
2025	1,385	1,337	128	not assessed	1,466	42	156	104	302	(1,163)
2026	1,385	1,364	131	not assessed	1,495	42	153	106	301	(1,194)
2027	1,385	1,391	134	not assessed	1,525	42	150	108	300	(1,225)
2028	1,385	1,419	136	not assessed	1,555	42	147	110	299	(1,256)
2029	1,385	1,448	139	not assessed	1,587	42	144	113	298	(1,288)
2030	1,385	1,477	142	not assessed	1,618	42	140	115	297	(1,321)
2031	1,385	1,506	145	not assessed	1,651	42	137	117	296	(1,354)
2032	1,385	1,536	147	not assessed	1,684	42	134	119	296	(1,388)
2033	1,385	1,567	150	not assessed	1,717	42	131	122	295	(1,422)
2034	1,385	1,598	153	not assessed	1,752	42	128	124	294	(1,458)
2035	1,385	1,630	157	not assessed	1,787	42	125	127	293	(1,493)
2036	1,385	1,663	160	not assessed	1,822	42	122	129	293	(1,530)
2037	1,385	1,696	163	not assessed	1,859	42	118	132	292	(1,567)
2038	1,385	1,730	166	not assessed	1,896	42	115	135	292	(1,604)
2039	1,385	1,765	169	not assessed	1,934	42	112	137	291	(1,643)
2040	1,385	1,800	173	not assessed	1,973	42	109	140	291	(1,682)
2041	1,385	1,836	176	not assessed	2,012	42	106	143	291	(1,722)
2042	1,385	1,873	180	not assessed	2,052	42	103	146	290	(1,762)
2043	1,385	1,910	183	not assessed	2,093	42	99	149	290	(1,803)
2044	1,385	1,948	187	not assessed	2,135	42	96	152	290	(1,846)
2045	1,385	1,987	191	not assessed	2,178	42	93	155	290	(1,888)
2046	1,385	2,027	195	not assessed	2,222	42	90	158	290	(1,932)
2047	1,385	2,068	198	not assessed	2,266	42	87	161	290	(1,976)
2048	1,385	2,109	202	not assessed	2,311	42	84	164	290	(2,022)
2049	1,385	2,151	207	not assessed	2,358	42	80	167	290	(2,068)
2050	1,385	2,194	211	not assessed	2,405	42	77	171	290	(2,115)
2051	1,385	2,238	215	not assessed	2,453	42	74	174	290	(2,163)
2052	1,385	2,283	219	not assessed	2,502	42	71	178	291	(2,211)
2053	1,385	2,328	224	not assessed	2,552	42	68	181	291	(2,261)
2054	1,385	2,375	228	not assessed	2,603	42	65	185	291	(2,312)
2055	1,385	2,422	233	not assessed	2,655	42	62	188	292	(2,363)
2056	1,385	2,471	237	not assessed	2,708	42	58	192	293	(2,416)
2057	1,385	2,520	242	not assessed	2,762	42	55	196	293	(2,469)
2058	1,385	2,571	247	not assessed	2,817	42	52	200	294	(2,523)
2059	1,385	2,622	252	not assessed	2,874	42	49	204	295	(2,579)
2060	1,385	2,675	257	not assessed	2,931	42	46	208	296	(2,636)
2061	1,385	2,728	262	not assessed	2,990	42	43	212	297	(2,693)
2062	1,385	2,783	267	not assessed	3,050	42	39	216	298	(2,752)
2063	1,385	2,838	272	not assessed	3,111	42	36	221	299	(2,812)
2064	1,385	2,895	278	not assessed	3,173	42	33	225	300	(2,873)
2065	1,385	2,953	283	not assessed	3,236	42	30	230	302	(2,935)
2066	1,385	3,012	289	not assessed	3,301	42	27	234	303	(2,998)
2067	1,385	3,072	295	not assessed	3,367	42	24	239	305	(3,063)
2068	1,385	3,134	301	not assessed	3,435	42	21	244	306	(3,128)
2069	1,385	3,196	307	not assessed	3,503	42	17	249	308	(3,195)
2070	1,385	3,260	313	not assessed	3,573	42	14	254	310	(3,263)
2071	1,385	3,325	319	not assessed	3,645	42	11	259	312	(3,333)
2072	1,385	3,392	326	not assessed	3,718	42	8	264	314	(3,404)
2073	1,385	3,460	332	not assessed	3,792	42	5	269	316	(3,476)
PV (2005)		12,639	1,202		13,840	414	1,612	1,012	3,037	(10,803)
7.52%								20 year NPV (2006-2025)		(5,849)

Table 4A: Basecase: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales **Base Case load forecast with Minto 32.5GWh from 2009 - 2016 & CC 48.0 from 2010 - 2017**
-Assuming Aishihik Third Turbine in Service in 2010 and CS Interconnected in 2010

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h/litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h/litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenue Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	-	-	-	3.48	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	3.9	-	22	22	-	3.48	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	3.9	-	91	91	-	3.48	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	3.9	-	775	775	-	3.48	-	-	-	-	-	-	-	-	-	-
2010	14,237	8,837	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	994	95	not assessed	1,089	2,729	77	2,806	1,717
2011	20,187	14,787	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,014	97	not assessed	1,111	-	79	79	(1,032)
2012	26,248	20,848	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	not assessed	1,133	-	80	80	(1,053)
2013	32,587	27,187	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	not assessed	1,156	-	82	82	(1,074)
2014	38,874	33,474	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	not assessed	1,179	-	84	84	(1,095)
2015	45,277	39,877	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	not assessed	1,202	-	85	85	(1,117)
2016	51,798	46,398	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	not assessed	1,226	-	87	87	(1,139)
2017	22,690	17,290	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,141	110	not assessed	1,251	-	89	89	(1,162)
2018	-	-	-	3.9	-	5,977	1,334	(4,643)	3.48	1,334	1,334	1,122	96	not assessed	1,218	-	91	91	(1,127)
2019	-	-	-	3.9	-	7,368	1,787	(5,581)	3.48	1,604	1,604	1,376	118	not assessed	1,493	-	92	92	(1,401)
2020	-	-	-	3.9	-	8,960	2,372	(6,589)	3.48	1,893	1,893	1,656	142	not assessed	1,798	-	94	94	(1,704)
2021	-	-	-	3.9	-	10,762	3,111	(7,652)	3.48	2,199	2,199	1,962	168	not assessed	2,130	-	96	96	(2,034)
2022	5,723	323	(5,400)	3.9	1,385	7,057	3,699	(3,358)	3.48	965	2,350	2,139	198	not assessed	2,335	-	98	98	(2,237)
2023	13,137	7,737	(5,400)	3.9	1,385	1,884	-	(1,884)	3.48	541	1,926	1,788	165	not assessed	1,954	-	100	100	(1,855)
2024	20,689	15,289	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	not assessed	1,437	-	102	102	(1,335)
2025	28,380	22,980	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	not assessed	1,466	-	104	104	(1,362)
2026	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	not assessed	1,495	-	106	106	(1,389)
2027	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	not assessed	1,525	-	108	108	(1,417)
2028	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	not assessed	1,555	-	110	110	(1,445)
2029	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	not assessed	1,587	-	113	113	(1,474)
2030	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	not assessed	1,618	-	115	115	(1,503)
2031	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	not assessed	1,651	-	117	117	(1,534)
2032	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	not assessed	1,684	-	119	119	(1,564)
2033	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	not assessed	1,717	-	122	122	(1,595)
2034	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	not assessed	1,752	-	124	124	(1,627)
2035	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	not assessed	1,787	-	127	127	(1,660)
2036	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	not assessed	1,822	-	129	129	(1,693)
2037	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	not assessed	1,859	-	132	132	(1,727)
2038	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	not assessed	1,896	-	135	135	(1,762)
2039	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	not assessed	1,934	-	137	137	(1,797)
2040	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	not assessed	1,973	-	140	140	(1,833)
2041	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	not assessed	2,012	-	143	143	(1,869)
2042	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	not assessed	2,052	-	146	146	(1,907)
2043	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	not assessed	2,093	-	149	149	(1,945)
2044	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	not assessed	2,135	-	152	152	(1,984)
2045	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	not assessed	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	not assessed	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	not assessed	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	not assessed	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	not assessed	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	not assessed	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	not assessed	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	not assessed	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	not assessed	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	not assessed	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	not assessed	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	not assessed	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	not assessed	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	not assessed	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	not assessed	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	not assessed	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	not assessed	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	not assessed	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	not assessed	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	not assessed	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	not assessed	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	not assessed	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	not assessed	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	not assessed	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	not assessed	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	not assessed	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	not assessed	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	not assessed	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	not assessed	3,792	-	269	269	(3,523)
PV (2005)	7.52%											13,829	1,302		15,131	1,899	1,012	2,911	(12,220)
																Internal Rate of Return			62.55%

Table 4B: Aishihik 3rd Turbine Economics (65 years) - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast with Minto 32.5GWh from 2009 - 2016 & CC 48.0 from 2010 - 2017
-Assuming Aishihik Third Turbine in Service in 2010 and CS interconnected in 2010

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	1,385	994	95	not assessed	1,089	42	204	77	323	(766)
2011	1,385	1,014	97	not assessed	1,111	42	200	79	321	(790)
2012	1,385	1,034	99	not assessed	1,133	42	197	80	320	(813)
2013	1,385	1,054	101	not assessed	1,156	42	194	82	318	(838)
2014	1,385	1,076	103	not assessed	1,179	42	191	84	317	(862)
2015	1,385	1,097	105	not assessed	1,202	42	188	85	315	(887)
2016	1,385	1,119	107	not assessed	1,226	42	185	87	314	(913)
2017	1,385	1,141	110	not assessed	1,251	42	182	89	312	(939)
2018	1,334	1,122	96	not assessed	1,218	42	178	91	311	(907)
2019	1,604	1,376	118	not assessed	1,493	42	175	92	310	(1,184)
2020	1,893	1,656	142	not assessed	1,798	42	172	94	308	(1,490)
2021	2,199	1,962	168	not assessed	2,130	42	169	96	307	(1,823)
2022	2,350	2,139	196	not assessed	2,335	42	166	98	306	(2,029)
2023	1,926	1,788	166	not assessed	1,954	42	163	100	305	(1,650)
2024	1,385	1,311	126	not assessed	1,437	42	159	102	303	(1,134)
2025	1,385	1,337	128	not assessed	1,466	42	156	104	302	(1,163)
2026	1,385	1,364	131	not assessed	1,495	42	153	106	301	(1,194)
2027	1,385	1,391	134	not assessed	1,525	42	150	108	300	(1,225)
2028	1,385	1,419	136	not assessed	1,555	42	147	110	299	(1,256)
2029	1,385	1,448	139	not assessed	1,587	42	144	113	298	(1,288)
2030	1,385	1,477	142	not assessed	1,618	42	140	115	297	(1,321)
2031	1,385	1,506	145	not assessed	1,651	42	137	117	296	(1,354)
2032	1,385	1,536	147	not assessed	1,684	42	134	119	296	(1,388)
2033	1,385	1,567	150	not assessed	1,717	42	131	122	295	(1,422)
2034	1,385	1,598	153	not assessed	1,752	42	128	124	294	(1,458)
2035	1,385	1,630	157	not assessed	1,787	42	125	127	293	(1,493)
2036	1,385	1,663	160	not assessed	1,822	42	122	129	293	(1,530)
2037	1,385	1,696	163	not assessed	1,859	42	118	132	292	(1,567)
2038	1,385	1,730	166	not assessed	1,896	42	115	135	292	(1,604)
2039	1,385	1,765	169	not assessed	1,934	42	112	137	291	(1,643)
2040	1,385	1,800	173	not assessed	1,973	42	109	140	291	(1,682)
2041	1,385	1,836	176	not assessed	2,012	42	106	143	291	(1,722)
2042	1,385	1,873	180	not assessed	2,052	42	103	146	290	(1,762)
2043	1,385	1,910	183	not assessed	2,093	42	99	149	290	(1,803)
2044	1,385	1,948	187	not assessed	2,135	42	96	152	290	(1,846)
2045	1,385	1,987	191	not assessed	2,178	42	93	155	290	(1,888)
2046	1,385	2,027	195	not assessed	2,222	42	90	158	290	(1,932)
2047	1,385	2,068	198	not assessed	2,266	42	87	161	290	(1,976)
2048	1,385	2,109	202	not assessed	2,311	42	84	164	290	(2,022)
2049	1,385	2,151	207	not assessed	2,358	42	80	167	290	(2,068)
2050	1,385	2,194	211	not assessed	2,405	42	77	171	290	(2,115)
2051	1,385	2,238	215	not assessed	2,453	42	74	174	290	(2,163)
2052	1,385	2,283	219	not assessed	2,502	42	71	178	291	(2,211)
2053	1,385	2,328	224	not assessed	2,552	42	68	181	291	(2,261)
2054	1,385	2,375	228	not assessed	2,603	42	65	185	291	(2,312)
2055	1,385	2,422	233	not assessed	2,655	42	62	188	292	(2,363)
2056	1,385	2,471	237	not assessed	2,708	42	58	192	293	(2,416)
2057	1,385	2,520	242	not assessed	2,762	42	55	196	293	(2,469)
2058	1,385	2,571	247	not assessed	2,817	42	52	200	294	(2,523)
2059	1,385	2,622	252	not assessed	2,874	42	49	204	295	(2,579)
2060	1,385	2,675	257	not assessed	2,931	42	46	208	296	(2,636)
2061	1,385	2,728	262	not assessed	2,990	42	43	212	297	(2,693)
2062	1,385	2,783	267	not assessed	3,050	42	39	216	298	(2,752)
2063	1,385	2,838	272	not assessed	3,111	42	36	221	299	(2,812)
2064	1,385	2,895	278	not assessed	3,173	42	33	225	300	(2,873)
2065	1,385	2,953	283	not assessed	3,236	42	30	230	302	(2,935)
2066	1,385	3,012	289	not assessed	3,301	42	27	234	303	(2,998)
2067	1,385	3,072	295	not assessed	3,367	42	24	239	305	(3,063)
2068	1,385	3,134	301	not assessed	3,435	42	21	244	306	(3,128)
2069	1,385	3,196	307	not assessed	3,503	42	17	249	308	(3,195)
2070	1,385	3,260	313	not assessed	3,573	42	14	254	310	(3,263)
2071	1,385	3,325	319	not assessed	3,645	42	11	259	312	(3,333)
2072	1,385	3,392	326	not assessed	3,718	42	8	264	314	(3,404)
2073	1,385	3,460	332	not assessed	3,792	42	5	269	316	(3,476)
PV (2005)		13,829	1,302		15,131	414	1,612	1,012	3,037	(12,093)
7.52%								20 year NPV (2006-2025)		(7,139)

REFERENCE: October 6, 2008 Application, Introduction, Page 1-8

YEC states that "Forecast oil prices for 2009 are materially above levels approved for the 2005 Yukon Energy revenue requirement".

QUESTION:

a) Please provide details of the actual prices paid for diesel fuel in 2005, 2006, 2007 and 2008. Please include references to locations and amounts.

b) Please identify YEC's procurement practice and policy with respect to diesel fuel.

ANSWER:

(a)

The actual prices paid for diesel fuel in 2005, 2006, 2007 and 2008 are as follows:

	2005		
	Litres	Dollars ($)	Avg $/L
Faro	-	-	-
Dawson	151,934	122,256	0.8047
Mayo	10,000	7,160	0.7160
Whitehorse	40,910	25,708	0.6284
	202,844	155,124	0.7647

	2006		
	Litres	Dollars ($)	Avg $/L
Faro	214,880	166,283	0.7738
Dawson	105,913	83,864	0.7918
Mayo	-	-	-
Whitehorse	213,956	159,032	0.7433
	534,749	409,178	0.7652

	2007		
	Litres	Dollars ($)	Avg $/L
Faro	40,465	32,085	0.7929
Dawson	247,060	216,060	0.8745
Mayo	5,500	4,816	0.8757
Whitehorse	81,221	64,228	0.7908
	374,246	317,189	0.8475

	2008		
	Litres	Dollars $)	Avg $/L
Faro	40,005	42,979	1.0744
Dawson	139,289	154,356	1.1082
Mayo	-	-	-
Whitehorse	359,695	371,957	1.0341
	538,988	569,292	1.0562

(b)

Generally on an annual basis, Yukon Energy completes a public tender for the supply of generation fuel to its various plants. See PWP/HML-YEC-1-42 for copies of YEC's policies on competitive bidding.

REFERENCE: October 6, 2008 Application, Introduction, Page 1-9

YEC states that "Notwithstanding ongoing cost pressures, robust sales have allowed the Return on Equity ("ROE") earned in recent years by Yukon Energy to exceed the 9.05% level approved by the Board in 2005, permitting Yukon Energy to operate without any requirement for rate adjustments in the interim" and that actual ROE was 9.48% in 2005, 10.59% in 2006 and 9.45% in 2007.

REFERENCE: Yukon Utilities Board Report on Yukon Energy Corporation 20-Year Resource Plan, January 15, 2007, Page 50

"Now is an appropriate time for YEC and YECL to have a complete review of all GRA Phase I and Phase II matters. The Board recommends that YEC and YECL file a full GRA application before October 31, 2007. The application should include a full cost of service, rate design and an update of the Electric Service Regulations. The Board also suggests that YEC and YECL consider a performance-based regulation mechanism. As well, the Board recommends that evidence be provided as to what other utilities provide for Maximum Company Investment and model theirs accordingly."

REFERENCE: Hansard, Yukon Legislative Assembly, June 12, 2007
Archie Lang, Minister of Energy, Mines and Resources

"…and we're looking forward to a general rate application that will give money back to the consumers. At the end of the day, that will be a rate reduction for all ratepayers in the Yukon."

QUESTION:

a) Please provide the actual ROE for 2008.

b) Please provide a table that shows the allowed and actual ROE for 2005, 2006, 2007 and 2008 and the actual dollars associated with the under / over earnings. Please explain how these results have been weather normalized if applicable.

c) Please provide details of YEC's efforts to date to consider a performance-based regulation mechanism including earnings sharing.

d) Please describe mechanisms that would enable YEC to "give money back to the consumers" when earnings are higher than the levels determined as fair by the YUB.

ANSWER:

(a)

The 2008 financial statements are in the process of being finalized but are not yet complete and therefore the requested information based on final 2008 results is not available at this time. However, the Yukon Public Utilities Act sets out a requirement at section 25(1) for each utility to file a statement showing various financial information for the preceding year by March 31. Yukon Energy is currently preparing (unaudited) financial statements for this purpose and expects to meet the requirements of the Act. Once that material has been prepared, it will be possible to update and confirm the 2008 unaudited results in the form of Tab 7 to the Application. As was done in 2005, these schedules will be updated as soon thereafter as possible prior to the May hearing. It is presently expected that these updates will be filed in late March or early April.

(b)

The requested table is provided below.

	Last Approved	2005 Actual	2006 Actual	2007 Actual
ROE	9.05%	9.46%	10.59%	9.45%
Difference in Earnings Compared to Last Approved ROE ($000)		227	868	229

The results have not been weather normalized, as this is not applicable to actual ROE results.

(c)

As noted in response UCG-YEC-1-32 provided during the 2005 Required Revenues and Related Matters proceeding, a multi-year performance-based regulatory framework is not currently in place in Yukon. Implementing this form of regulation would likely require

significant changes to the regulatory framework in the Yukon that have not yet been assessed. Yukon Energy has not assessed measures that the Yukon Government might adopt to bring in legislation or policy related to performance-based regulation.

(d)

The regulatory framework in the Yukon does not currently provide mechanisms that would enable Yukon Energy or YECL either (i) to "give money back to the consumers" where earnings are higher than Board-determined ROE's, or (ii) to "get more money from the consumers" where earnings are lower than Board-determined ROE's. Such an approach would in effect result in a guaranteed ROE - which is not an approach that YEC has advocated.

The current Application provides an example where the utility set out to secure material net benefits and to propose rate reductions that reflect the outcome.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-2

YEC states that its "Total forecast sales are 316,031 MW.h for the 2008 test year and 343,581 MW.h for the 2009 test year. Total forecast sales for 2008 include 258,989 MW.h of primary (firm) wholesale sales, 6,845 MW.h of primary Major Industrial sales, 29,640 MW.h of firm Retail sales (i.e., all firm sales other than wholesale or Major Industrial), and 20,557 MW.h of secondary sales (most sold on a wholesale basis to YECL), while total forecast sales for 2009 include 266,926 MW.h primary wholesale sales, 29,023 MW.h Major Industrial sales, 31,019 MW.h firm Retail sales, and 16,613 MW.h of wholesale and retail secondary sales."

REFERENCE: Hansard, Yukon Legislative Assembly, December 10, 2008
Willard Phelps, Chair of Yukon Development Corporation and Yukon Energy Corporation

"We are dealing firstly with demand-side concerns. I certainly agree with the member that, as we get to a situation where our surplus is rapidly disappearing -- and it will be disappearing with more industry, more people and more mines -- the whole issue of demand-side management is increasingly important. Of course, one of the big arguments that many in the green movement in North America agree with is that it's a bad thing when rates are too low and don't reflect the real cost of the generation of electricity, which is certainly a strong argument in favour of not having subsidies. When people don't pay enough -- the real cost of their electricity -- they tend to waste it."

QUESTION:

a) Please provide details of demand-side management efforts that have been promoted to Yukon electricity ratepayers by YEC and others. In particular, please provide details of any DSM-related discussions / activities undertaken with the Yukon government regarding their own facilities.

b) Please provide details on the audit processes that have been completed on these DSM efforts.

c) Please provide details on how the impacts of DSM efforts are reflected in the load forecasts of YEC's customer classes including secondary sales customers.

d) Please provide details of YEC's DSM-related expenditures in 2005, 2006, 2007 and 2008 and their percentage of revenue requirement.

ANSWER:

(a), **(b)**, **(c)** and **(d)**

Yukon Energy has not carried out any material studies related to energy efficiency programs or DSM programs and consequently no audits have been undertaken of these activities. Energy efficiency issues typically need to be coordinated across fuels and across customers in Yukon. This coordination role is currently undertaken by ESC in conjunction with government. Yukon Energy continues to work cooperatively with ESC on energy efficiency and DSM issues.

1. Role of ESC in establishing energy efficiency and DSM programs

The 20-Year Resource Plan notes that "since 2000, management of DSM programs has been undertaken by the ESC. ESC is a service and program delivery agency for energy efficiency and green power programs for the Federal and Yukon governments. The programs run by ESC include electricity programs, and programs focused on improving the energy efficiency of other energy sources." (see page 2-12).

DSM activities historically undertaken by Yukon Energy and YECL were discussed in the 20-Year Resource Plan (see pages 2-17 to 2-22 of Chapter 2). Programs that have been developed and tested by Yukon Energy and ESC since 1992 are discussed in detail in Section 2.4: Bulk Power Planning Since 1992. It is also noted at page 2-10 that more recently DSM activities have been undertaken and coordinated by ESC.

2. Role of DSM in Yukon's 20-Year Resource Plan

The 20-Year Resource Plan notes that with regard to meeting capacity requirements "major new DSM initiatives or various other potential new generation technologies are not typically considered by utilities to provide reliable capacity towards meeting near term capacity shortfalls of the type forecast in Yukon" (see page 4-38).

However, with regard to longer term bulk planning issues the Resource Plan notes that Yukon Energy would possibly need to give greater consideration to DSM (in particular where industrial load scenarios provide for sustained 10 MW mine loads extending past 2016). At page 12 of the 20-Year Resource Plan it was noted in particular that, "If loads of this scale and duration develop, further consideration will be given to DSM programming focused primarily on reduction of system peak demand." (This is also discussed in chapter 5 pages 5-52 and 5-53).

3. Board Order 2009-2 and DSM

In respect of DSM, the Board has set out its expectations in Appendix A of Order 2009-2 which notes as follows at page 44:

> The Board views DSM as another critical issue for Yukon. The Board directs YECL in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to DSM initiatives and include this policy paper as part of YECL's and YEC's next GRA. To be clear, YEC and YECL are to jointly lead these processes and jointly submit the policy papers (IPP and DSM) in their next GRA. The DSM policy papers are to provide DSM initiatives developed through negotiations with Intervenors and communities in its service territory and YEC's service territory.

Yukon Energy has reviewed the Board's decision on this matter but has not yet had an opportunity to meet with YECL in this regard.

However, with regard to matters currently under review it is noted that Yukon Energy has not in its current GRA contemplated or budgeted for these activities. Further direction from the Board would be required related to the following:

(a) The scale of activities anticipated to be undertaken by the utilities.
(b) Confirmation that some form of deferral account for expenditures, presumably targeted for disposition at the next GRA.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-4

YEC states that its "2009 load forecasts are markedly higher than the YECL forecasts in their GRA reflecting Yukon Energy's analysis of wholesale load growth, including the WAF load growth analysis for the 2001-2004 period (averaging 2.2% per year), as reviewed in the Yukon Energy 20-Year Resource Plan 2006-2025 ("Resource Plan") and the more recent experienced growth rate in WAF wholesales from 2004 to 2007 actuals, at 2.5% per year. Yukon Energy has utilized a growth rate in this range (2.39%) as the basis for estimating load increases from 2008 to 2009 based on this evidence of the experienced longer-term load trends".

QUESTION:

a) Please provide a table showing load forecasts by customer class and by energy rate block for 2008 forecast, 2008 actual and 2009 forecast. Please explain how this data has been weather normalized if applicable.

b) Please provide a comparative table of the forecast and actual load forecast by customer class for 2005, 2006, 2007 and 2008. Please explain how this data has been weather normalized if applicable.

c) Please provide a comparative chart showing the differences between YEC's and YECL's load forecasts.

d) Please explain what discussions YEC has had with YECL to determine how best to forecast load in the Yukon.

ANSWER:

(a)

Yukon Energy does not forecast by energy rate block. Yukon Energy has relied upon YECL's forecast by rate block filed with their 2008/2009 General Rate Application.

For forecasts by customer class please see Schedule 11 in Tab 7 of the Application.

(b)

See table below.

Yukon Energy Corporation
Forecast and Actual Load by Customer Class - Company

Description	Forecast 2005	Actual 2005	Variance %	Forecast 2006	Actual 2006	Variance %	Forecast 2007	Actual 2007	Variance %	Forecast 2008	Actual 2008	Variance %
Residential												
Sales in MWh	10,201	10,169	*-0.32%*	10,271	10,665	*3.84%*	10,497	10,908	*3.91%*	11,155	11,359	*1.82%*
General Service												
Sales in MWh	16,808	18,438	*9.69%*	17,805	17,037	*-4.31%*	17,531	17,507	*-0.14%*	18,193	18,523	*1.81%*
Industrial												
Sales in MWh	0	0		0	0		0	0		6,845	3,200	*-53.24%*
Street lights												
Sales in MWh	252	257	*2.23%*	256	270	*5.47%*	270	275	*2.01%*	278	361	*29.79%*
Space lights												
Sales in MWh	13	14	*8.75%*	15	14	*-6.67%*	14	14	*3.03%*	14	17	*23.22%*
Total Company - Firm Retail & Ind.												
Sales in MWh	27,274	28,878	*5.88%*	28,346	27,987	*-1.27%*	28,313	28,705	*1.38%*	36,485	33,460	*-8.29%*
Wholesale sales												
Sales in MWh	234,542	237,419	*1.23%*	241,862	251,861	*4.13%*	253,227	254,914	*0.67%*	258,989	263,820	*1.87%*
Total Company - Firm												
Sales in MWh	261,816	266,296	*1.71%*	270,208	279,847	*3.57%*	281,541	283,619	*0.74%*	295,474	297,280	*0.61%*
Secondary												
Sales in MWh	20,613	18,933	*-8.15%*	20,550	22,185	*7.96%*	21,183	24,225	*14.36%*	20,557	18,753	*-8.78%*
Total Company												
Sales in KWh	282,428	285,229	*0.99%*	290,758	302,032	*3.88%*	302,722	307,844	*1.69%*	316,031	316,033	*0.00%*

Actual load data is from metered loads, and is not weather normalized.

(c)

The only rate class where YEC and YECL both prepare load forecasts is for wholesale purchases. Please see Table 2.1 at page 2-5.

(d)

Yukon Energy works with YECL annually to prepare business plan load forecasts for wholesale sales. Yukon Energy prepares its own load forecast for its customers without YECL input, as YECL has no knowledge of, or experience with, the loads in YEC served communities.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-5

YEC states that its "2009 load forecasts are markedly higher than the YECL forecasts in their GRA reflecting Yukon Energy's analysis of wholesale load growth, including the WAF load growth analysis for the 2001-2004 period (averaging 2.2% per year), as reviewed in the Yukon Energy 20-Year Resource Plan 2006-2025 ("Resource Plan") and the more recent experienced growth rate in WAF wholesales from 2004 to 2007 actuals, at 2.5% per year. Yukon Energy has utilized a growth rate in this range (2.39%) as the basis for estimating load increases from 2008 to 2009 based on this evidence of the experienced longer-term load trends".

QUESTION:

a) Please provide an update to Table 2-1 which includes actual 2008 sales for the full year.

b) Please provide a table showing the total actual monthly kWh usage in 2005, 2006, 2007 and 2008 of all residential customers in each Yukon community and the average Yukon residential monthly usage. Please identify the source of the information provided.

c) Please provide a table for 2005, 2006, 2007 and 2008 showing:
- the number of customers in each community at or below 1000 kWh usage for each month during the year;
- the number of customers in each community using between 1000 and 1300 kWh for each month during the year;
- the number of customers in each community using between 1300 and 1500 kWh for each month during the year; and
- the number of customers in each community using more than 1500 kWh for each month during the year.

d) Please identify the source of the information provided.

ANSWER:

(a)

Preliminary actuals for 2008 primary sales to YECL (in MW.h) are as follows:

	2008 prel. actual
Total	263,820
less: Pelly Crossing	(225)
Ongoing WAF and MD sales (excl Pelly)	263,595

(b), **(c)** and **(d)**

Yukon Energy does not have access to the necessary data by community required to complete the response. Most communities in Yukon are served at the retail level by YECL.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-5

YEC states that "Forecast industrial sales as provided in July 2008 by Minto Explorations Ltd. for the last three months of 2008 are 6,845 MW.h and forecast industrial sales for 2009 are 29,023 MW.h" and that "Based on Industrial Primary Rate Schedule 39 as provided for in OIC 2007/94, the forecast loads will pay an average of 10.36 cents per kWh in 2008 ($0.709 million) and 10.83 cents per kWh in 2009 ($3.142 million), excluding Rider F charges proposed to be set at 0.671 cents/kW.h in the August 25, 2008 Rate Schedule 39 filing with the Yukon Utilities Board".

QUESTION:

a) Please provide monthly details of Minto Exploration's (Capstone Mining's) electricity use, demand and bill component totals for 2008 (actual) and 2009 (forecast).

b) Please provide the calculations used to determine the average rates paid.

c) Please provide similar average rate calculations for the residential service classes for 2008 actual and 2009 forecast.

ANSWER:

(a)

Please see response provided to PWP-YEC-1-16(a).

(b) and **(c)**

See Table 2.1, and Excel spreadsheet for Tab 7 (Schedule 11) provided with response to CW-YEC-1-32. Actuals for 2008 will be provided with the anticipated update filing.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-7

YEC states that "On the MD grid, the Keno Hill property being developed by Alexco Resource Corp. ("Alexco") following its purchase of the UKHM assets in 2006, is not expected to be operational over the test years. Alexco has indicated plans to Yukon Energy that could potentially result in commencement of mining and milling operations at the Keno Hill property in early 2010, with a resultant electricity load in the 21-25 GW.h/yr range and a mine life of at least five years. Yukon Energy plans to discuss purchase power agreement arrangements with Alexco later this year".

QUESTION:

a) Please provide an update on discussions with Alexco and the forecast of electricity requirements.

ANSWER:

(a)

Please see response to LE-YEC-1-8; also see CW-YEC-1-31(a) with regard to information on forecast electricity requirement.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-8

YEC states that "Firm residential retail sales have grown from 10,169 MW.h in actual 2005 to 11,155 MW.h in forecast 2008 and 11,183 MW.h in forecast 2009. This reflects ongoing modest growth in the number of customers, and basically consistent use per customer over the period".

QUESTION:

a) Please provide monthly details of firm residential retail sales for 2005, 2006, 2007 and 2008.

b) Please provide monthly details of the number of firm residential customers for 2005, 2006, 2007 and 2008.

c) Please provide monthly details of the number of residential customers using electricity for space heating for 2005, 2006, 2007 and 2008.

d) Please provide a table showing revenue requirement per customer for 2005, 2006, 2007 and 2008. Please include details of the calculation of these averages.

ANSWER:

(a) and **(b)**

Firm Residential Customers and Retail Sales

	2005		2006		2007		2008*	
	Customers	Sales (MWh)	Customers	Sales (MWh)	Customers	Sales (MWh)	Customers	Sales (MWh)
January	1,305	1,154	1,322	1,108	1,363	1,246	1,388	1,273
February	1,304	1,046	1,323	972	1,361	1,070	1,392	1,226
March	1,309	882	1,334	938	1,355	1,080	1,393	1,062
April	1,319	839	1,352	859	1,372	960	1,414	959
May	1,332	702	1,372	809	1,391	740	1,438	803
June	1,338	729	1,375	753	1,401	777	1,451	747
July	1,354	712	1,383	758	1,411	718	1,447	740
August	1,372	711	1,391	703	1,410	672	1,449	732
September	1,366	788	1,403	771	1,426	743	1,467	778
October	1,361	769	1,385	849	1,409	851	1,443	801
November	1,340	894	1,371	930	1,394	934	1,417	979
December	1,334	933	1,365	1,177	1,389	1,038	1,416	1,048
Year-end Adjustment		9		38		79		210
Annual	1,336	10,169	1,365	10,665	1,390	10,908	1,426	11,359

*Preliminary actual

(c)

This information is not available to Yukon Energy and cannot be provided.

(d)

The requested table is provided below.

Revenue requirement per customer

	Actual 2005	Actual 2006	Actual 2007	Forecast 2008	Forecast 2009
Revenue requirement ($000) per Tab & Sch 5	26,124	27,398	27,899	29,217	31,599
Total firm customers (excluding secondary)	1,787	1,813	1,841	1,867	1,890
Average revenue requirement per customer ($000)	14.62	15.11	15.15	15.65	16.72

Average revenue requirements per customer are provided as requested. However, YEC has YECL as its major customer, which accounts for the largest share of its load and operational commitments. Therefore, the un-weighted average revenue requirements, provided as requested, are in YEC's view of limited value.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-8

YEC states that "Firm general service retail sales were 18,438 MW.h, in actual 2005, and are forecast at 18,193 MW.h in 2008 and 19,543 MW.h in 2009. Lower general service sales starting in 2006 and 2007 compared to 2005 can be attributed to a decline in total Faro load, related to the varying load for dewatering activities at the Faro mine site. Total Faro general service load dropped from 7,091 MW.h in 2005 to 5,488 MW.h in 2006 and 5,398 MW.h in 2007. This change in load is fundamentally due to changes at the Faro Mine site".

QUESTION:

a) Please provide monthly details of firm general service retail sales for 2005, 2006, 2007 and 2008.

b) Please provide monthly details of the number of firm general service customers for 2005, 2006, 2007 and 2008.

c) Please provide monthly details of the number of general service customers using electricity for space heating.

ANSWER:

(a) and **(b)**

Firm General Service Customers and Retail Sales

	2005		2006		2007		2008*	
	Customers	**Sales (MWh)**	**Customers**	**Sales (MWh)**	**Customers**	**Sales (MWh)**	**Customers**	**Sales (MWh)**
January	407	1,290	409	1,390	408	1,517	410	1,495
February	412	1,383	411	1,263	409	1,328	405	1,384
March	408	1,269	409	1,321	409	1,429	406	1,355
April	425	1,308	427	1,293	437	1,340	430	1,364
May	473	1,113	471	1,185	481	1,310	476	1,371
June	480	1,688	479	1,318	481	1,653	480	1,746
July	486	2,067	484	1,733	486	1,658	487	1,858
August	488	2,254	487	1,749	484	1,595	495	2,183
September	528	2,188	514	1,848	507	1,649	525	2,072
October	448	1,357	435	1,330	491	1,494	446	1,176
November	423	1,149	424	1,192	392	1,172	416	1,230
December	416	1,254	412	1,412	414	1,294	413	1,277
Year-end Adjustment		120		5		68		13
Annual	450	18,438	447	17,037	450	17,507	449	18,523

*Preliminary actual

(c)

This information is not available to Yukon Energy and cannot be provided.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-8

YEC states that "A portion of the increase in general service sales during the test years is due to forecast sales to Alexco for bulk sampling operations as a general service customer on the MD system. Over the 2009 period Alexco is expected to commence bulk sampling operations at Keno Hill. The GRA forecasts that such operations will occur over the period from January 2009 to December 2009. The customer is not expected to exceed a 1 MW peak demand, and as such is classed as a general service customer for the purposes of bulk sampling operations. Yukon Energy anticipates approximately 3 GW.h of sales to Alexco during 2009 (1 GW.h of base load plus 2 GW.h for bulk sampling)".

QUESTION:

a) Please provide details of the monthly demand and energy sales levels expected to the Keno Hill operations in 2008 and 2009.

b) Please provide all correspondence with Alexco as well as internally generated reports or documents prepared for or by YEC related to the expected demand and energy requirements of the Keno Hill operations.

c) Please provide a comparative analysis of the monthly bills to Alexco in 2008 and 2009 assuming they are billed: (1) as a general service customer; and (2) as an Industrial Primary Service customer. Please provide calculations of the total bill including all applicable riders and taxes.

ANSWER:

(a)

The information as provided in the Application remains current, and reflects the level of detail that YEC is able to provide. The application notes as follows regarding forecast General Service sales (at Tab 2 page 2-8):

> A portion of the increase in general service sales during the test years is due to forecast sales to Alexco for bulk sampling operations as a general service customer on the MD system. Over the 2009 period Alexco is

expected to commence bulk sampling operations at Keno Hill. The GRA forecasts that such operations will occur over the period from January 2009 to December 2009. The customer is not expected to exceed a 1 MW peak demand, and as such is classed as a general service customer for the purposes of bulk sampling operations. Yukon Energy anticipates approximately 3 GW.h of sales to Alexco during 2009 (1 GW.h of base load plus 2 GW.h for bulk sampling).

(b)

The information provided in the Application at Tab 2, page 2-8 remains current. Internal documents related to providing service to specific customers are considered confidential and cannot be provided.

(c)

Alexco does not currently qualify as an industrial customer due to the nature of the operations currently being undertaken at the Keno Hill site and due to the current load (i.e., it does not exceed 1 MW). Alexco mining operations are not expected to commence until after the test year, at which time its load will be supplied under Industrial Rate Schedule 39.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-9

With respect to secondary sales, YEC states that "For test year 2008, forecast sales decline to 20,557 MWh, primarily due to equipment outages at a small number of the largest secondary customers through the early part of the year. In test year 2009, the availability of surplus power is expected to decrease with increased firm loads (including grid service to Minto Mine)".

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-9

With respect to secondary sales, YEC states that it has "rules in place, as approved by the Board pursuant to Rate Schedule 32 that interrupt secondary sales as required to ensure these sales are not served by high-cost diesel generation but only by surplus hydro".

QUESTION:

a) Please provide details of the monthly secondary sales levels and number of customers for 2005, 2006, 2007 and 2008.

b) Please provide a listing of secondary sales customers and their individual sales levels in the Yukon. If privacy legislation prevents the identification of these customers, please list them generically.

c) Please provide details of the periods during 2007 and 2008 that electricity was not available for secondary sales.

d) Please provide an estimate of the additional costs incurred by secondary sales customers when the secondary energy has not been available.

ANSWER:

(a)

The requested information is provided in the table below.

WAF Grid Monthly Secondary Sales Levels and Number of Customers

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	Customers	19	20	21	21	21	19	17	17	19	19	21	22
Actual	Sales (MWh)	1,395	1,254	1,581	2,060	1,435	1,316	981	1,173	1,376	1,894	2,171	1,726
2006	Customers	22	22	20	18	18	20	19	18	18	19	20	20
Actual	Sales (MWh)	2,429	1,658	1,847	2,086	1,583	1,306	1,257	1,217	1,545	1,836	2,186	2,605
2007	Customers	21	20	20	20	20	20	18	17	19	20	20	20
Actual	Sales (MWh)	2,716	2,421	2,288	2,428	1,822	1,471	1,499	1,156	1,489	1,786	2,363	2,126
2008	Customers	20	20	21	21	20	20	17	17	21	21	21	21
Forecast	Sales (MWh)	2,339	1,770	1,742	1,893	1,194	1,069	962	1,079	1,428	1,783	2,236	2,412

Mayo-Dawson Grid Monthly Secondary Sales Levels and Number of Customers

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	Customers	1	1	1	1	1	1	1	1	1	1	1	1
Actual	Sales (MWh)	83	88	56	69	31	22	0	1	26	46	72	77
2006	Customers	1	1	1	1	1	1	1	1	1	1	1	1
Actual	Sales (MWh)	102	83	90	61	39	24	5	0	26	37	73	89
2007	Customers	1	1	1	1	1	1	1	1	1	1	1	1
Actual	Sales (MWh)	107	94	104	56	30	24	19	3	28	42	72	80
2008	Customers	1	1	1	1	1	1	1	1	1	1	1	1
Forecast	Sales (MWh)	114	71	79	65	49	24	5	0	30	50	80	85

(b)

The requested information is provided in the table below.

Yukon Secondary Sales Customers and Individual Sales Levels (MWh)

Customer	2005 Actual	2006 Actual	2007 Actual	2008 Forecast	2009 Forecast
WAF Grid					
G-1	3,343	3,649	4,449	3,782	2,652
G-2	181	115	63	184	127
G-3	4,878	7,644	8,277	6,399	5,086
G-4	2,156	2,431	3,871	2,344	2,180
G-5	3,859	3,581	3,059	2,928	2,543
G-6	792	628	506	578	414
G-7	-	-	-	333	550
G-8	67	78	67	91	51
G-9	28	28	25	28	20
G-10	217	231	281	285	203
C-1	16	17	12	8	8
C-2	146	169	199	190	131
C-3	55	68	54	55	44
C-4	82	77	140	108	84
C-5	23	24	14	14	10
C-6	2	3	3	2	1
C-7	9	(0)	0	0	-
C-8	576	664	548	414	410
C-9	397	399	336	391	283
C-10	1,515	1,706	1,615	1,732	1,162
C-11	2	17	17	19	11
C-12	18	28	31	20	13
C-13	2	0	-	0	-
MD Grid					
MD-1	570	630	659	652	630
Total Sales	18,933	22,185	24,225	20,557	16,613

Note: G - Government; C - Commercial.

(c)

The periods during 2007 and 2008 that electricity was not available for secondary sales are as follows in the table below:

Secondary Sales Curtailments				
Year	**Reason**	**Suspended**	**Reinstated**	**Days**
2007	N/A	None	None	0
2008	Loss of WH3	20-Oct-08	7-Nov-08	18
	Low Temperatures	15-Dec-08	12-Jan-09	28

(d)

Please see response provided to CW-YEC-1-8(d).

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-9

With respect to secondary sales, YEC states "While Yukon Energy has in the past pursued opportunities to increase the sale of surplus power to general service secondary customers, this marketing effort is no longer active as future opportunities for secondary sales on the WAF system have become severely limited as winter peak demands approach levels that would require some peaking diesel generation. Similarly, limits on Mayo generation in future are also anticipated to result in reduced availability of secondary sales on the Mayo-Dawson system, and as such this rate offering is also not being actively marketed on that system".

QUESTION:

a) Please confirm that surplus power is available throughout the year.

b) Please provide details of the amount of surplus power available per month in 2005, 2006, 2007, 2008 and 2009 (forecast).

c) Please provide details of the costs incurred to actively market surplus power.

ANSWER:

(a)

Not confirmed. Surplus power is not available during peak (winter) periods when diesel generation is required to supply loads.

As noted in Tab 2 at page 2-9 and 2-10, since 2005 further increases in secondary sales quantities have not been aggressively targeted as the remaining surplus available on the system was diminishing. At page 2-10 it is noted that "while Yukon Energy has in the past pursued opportunities to increase the sale of surplus power to general service secondary customers, this marketing effort is no longer active as future opportunities for secondary sales on the WAF system have become severely limited as winter peak demands approach levels that would require some peaking diesel generation. Similarly, limits on Mayo generation in further are also anticipated to result in reduced availability of secondary sales on the Mayo-Dawson system, and as such this rate offering is also not being actively marketed on that system.

(b)

The requested information is provided in the table below. This information reflects only that portion of "surplus" power relevant to secondary sales loads – as noted elsewhere, the overall total surplus in 2005 far exceed this number and continues to exceed it today.

Surplus power provided (made available) per month for the period of 2005-2009 (MW.h)

	Actual 2005	Actual 2006	Actual 2007	Forecast 2008	Forecast 2009
January	1,478	2,530	2,822	2,453	288
February	1,341	1,741	2,515	1,841	80
March	1,637	1,936	2,392	1,821	2,351
April	2,129	2,146	2,484	1,958	2,087
May	1,467	1,622	1,852	1,243	1,755
June	1,338	1,330	1,496	1,093	1,291
July	981	1,263	1,518	967	972
August	1,174	1,217	1,159	1,079	1,064
September	1,402	1,571	1,517	1,458	1,295
October	1,940	1,873	1,829	1,833	1,783
November	2,243	2,259	2,434	2,316	2,023
December	1,803	2,694	2,207	2,497	1,624
Total	**18,933**	**22,185**	**24,225**	**20,557**	**16,613**

(c)

Surplus power is not actively being marketed and no costs are being incurred.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-11

YEC states "Yukon Energy produces power on two independent systems – the Whitehorse – Aishihik – Faro ("WAF") system and the Mayo-Dawson ("MD") system. For both systems the predominant source of generation forecast for the test period is hydro, supplemented as necessary by a small amount of diesel for peaking or maintenance purposes. There is also a small amount of wind generation on the WAF system".

QUESTION:

a) Please provide monthly data for WAF diesel use and price per litre for 2005, 2006, 2007, 2008 and 2009 (forecast).

b) Please provide the average cost per kWh of generation on the WAF system for 2005, 2006, 2007, 2008 and 2009 (forecast). Please provide all relevant calculations.

c) Please provide the average cost per kWh of transmission on the WAF system for 2005, 2006, 2007, 2008 and 2009 (forecast). Please provide all relevant calculations.

d) Please provide the average cost per kWh of distribution on the WAF system for 2005, 2006, 2007, 2008 and 2009 (forecast). Please provide all relevant calculations.

e) Please provide monthly data for MD diesel use and price per litre for 2005, 2006, 2007, 2008 and 2009 (forecast).

f) Please provide the average cost per kWh of generation on the MD system for 2005, 2006, 2007, 2008 and 2009 (forecast). Please provide all relevant calculations.

g) Please provide the average cost per kWh of transmission on the MD system for 2005, 2006, 2007, 2008 and 2009 (forecast). Please provide all relevant calculations.

h) Please provide the average cost per kWh of distribution on the MD system for 2005, 2006, 2007, 2008 and 2009 (forecast). Please provide all relevant calculations.

i) Please provide monthly diesel use data for individual communities served by diesel-fuelled generation and price per litre for 2005, 2006, 2007, 2008 and 2009 (forecast).

j) Please provide the average cost per kWh of generation in the diesel communities for 2005, 2006, 2007, 2008 and 2009 (forecast). Please provide all relevant calculations.

k) Please provide the average cost per kWh of distribution in the diesel communities for 2005, 2006, 2007, 2008 and 2009 (forecast). Please provide all relevant calculations.

l) Please provide monthly data on generation from each of the two wind turbines for 2005, 2006, 2007, 2008 and 2009 (forecast).

m) Please provide annual revenue requirement (by component) for each of the two wind turbines for 2005, 2006, 2007, 2008 and 2009 (forecast).

n) Please provide the average cost per kWh of generation from each of the two wind turbines for 2005, 2006, 2007, 2008 and 2009 (forecast).

ANSWER:

(a)

WAF diesel use and price information for 2005 – 2008 actuals are provided in the table below. Note the monthly diesel volumes for YEC, where very little fuel is consumed in most months, can be an imprecise measurement. This is because tank level measurements (fuel dips) have a certain degree of imprecision, and further because there is a temperature volume adjustment calculation required that may not reflect temperatures in the tank at the time the measurement is taken. These variances resolve themselves over time, and solely relate to individual monthly measurements.

WAF Diesel Generation 2005-2008 Actuals

WAF Diesel Generation		Diesel - Litres			Diesel - Price		
		Whse L	Faro L	Total L	Whse $/L	Faro $/L	Total $/L
2005	JAN	3,375	1,127	4,502	0.4703	0.5671	0.4945
	FEB	4,382	1,108	5,490	0.5115	0.5672	0.5228
	MAR	2,975	325	3,300	0.5117	0.5671	0.5171
	APR	1,216	151	1,367	0.5114	0.5671	0.5176
	MAY	-2,179	145	-2,034	0.5116	0.5672	0.5076
	JUN	371	73	444	0.5116	0.5671	0.5207
	JUL	-3	-128	-131	0.4433	0.5671	0.5643
	AUG	47	3,598	3,645	0.5138	0.5671	0.5665
	SEP	1,329	172	1,501	0.5115	0.5672	0.5178
	OCT	1,456	381	1,837	0.5116	0.5671	0.5231
	NOV	-559	468	-91	0.5115	0.5671	0.2253
	DEC	979	1,395	2,374	0.5116	0.5671	0.5442
2006	JAN	88,574	113,889	202,463	0.6205	0.6701	0.6484
	FEB	15,156	-1,217	13,939	0.6332	0.7192	0.6257
	MAR	3,798	273	4,071	0.6332	0.7192	0.6390
	APR	17	1,971	1,988	0.6329	0.7192	0.7184
	MAY	26,978	37,727	64,705	0.6773	0.7599	0.7254
	JUN	1,251	4,075	5,326	0.6553	0.7599	0.7353
	JUL	614	257	871	0.6550	0.7585	0.6855
	AUG	1,732	561	2,293	0.6554	0.7599	0.6809
	SEP	12,906	-473	12,433	0.6553	0.7599	0.6513
	OCT	14,158	26,208	40,366	0.6675	0.7599	0.7275
	NOV	18,447	19,652	38,099	0.6675	0.7475	0.7087
	DEC	2,181	771	2,952	0.6688	0.7475	0.6894
2007	JAN	2,593	17,347	19,940	0.6688	0.7475	0.7373
	FEB	20,928	1,202	22,130	0.6688	0.7646	0.6740
	MAR	0	2,177	2,177	-	0.7646	-
	APR	4,221	-60	4,161	0.6689	0.7647	0.6675
	MAY	5,660	892	6,552	0.6688	0.7646	0.6819
	JUN	0	625	625	-	0.7645	-
	JUL	0	937	937	-	0.7646	-
	AUG	25,727	739	26,466	0.6927	0.7646	0.6947
	SEP	26,578	499	27,077	0.6927	0.7648	0.6941
	OCT	1,029	3,394	4,423	0.7278	0.7646	0.7561
	NOV	9,505	1,204	10,709	0.7278	0.7646	0.7320
	DEC	3,129	285	3,414	0.7279	0.7646	0.7310
2008	JAN	9,233	965	10,198	0.7278	0.7646	0.7313
	FEB	21,727	138	21,865	0.7668	0.7646	0.7668
	MAR	132	210	342	0.7668	0.7646	0.7655
	APR	2,046	0	2,046	0.7668	-	0.7668
	MAY	46,710	2,826	49,536	0.8458	0.8426	0.8456
	JUN	358	3	361	0.9477	0.8433	0.9469
	JUL	-349	0	-349	0.9477	-	0.9477
	AUG	67	1,127	1,194	0.9749	0.8426	0.8500
	SEP	677	0	677	0.9483	-	0.9483
	OCT	47,767	11,933	59,700	0.9971	0.8426	0.9662
	NOV	1,371	5,901	7,272	0.9974	0.8426	0.8718
	DEC	179,554	2,911	182,465	0.9728	0.8728	0.9712

Note that diesel fuel prices in the above table reflect inventory average blended values at time of use and not current costs to secure new fuel at such times.

(b), **(c)** and **(d)**

Yukon Energy cannot provide this information as a substantial component of YEC's costs are not functionalized and separated by system.

(e)

MD diesel use and price information for 2005 – 2008 actuals are provided in the table below.

Note that diesel fuel prices in the table reflect inventory average blended values at time of use and not current costs to secure new fuel at such times.

Mayo Dawson Diesel Generation 2005-2008 Actuals

Mayo Dawson Diesel Generation		Diesel - Litres			Diesel - Price		
		Dawson L	Mayo L	Total L	Dawson $/L	Mayo $/L	Total $/L
2005	JAN	0	-643	-643	-	0.4914	0.4914
	FEB	4,295	4,963	9,258	0.6221	0.4914	0.5521
	MAR	16,985	-3	16,982	0.6546	0.5667	0.6547
	APR	23,648	278	23,926	0.6615	0.5671	0.6604
	MAY	2,120	1	2,121	0.6615	0.5700	0.6614
	JUN	2,460	-51	2,409	0.6615	0.5671	0.6635
	JUL	8,720	40	8,760	0.6615	0.5673	0.6610
	AUG	2,200	117	2,317	0.6615	0.5671	0.6567
	SEP	753	125	878	0.6615	0.5671	0.6480
	OCT	58,380	980	59,360	0.7761	0.5671	0.7726
	NOV	11,361	8	11,369	0.7761	0.5675	0.7759
	DEC	597	86	683	0.7761	0.5671	0.7498
2006	JAN	230	161	391	0.7761	0.5671	0.6901
	FEB	2,400	-133	2,267	0.7691	0.5671	0.7810
	MAR	607	430	1,037	0.7691	0.5671	0.6854
	APR	1,762	-115	1,647	0.7691	0.5671	0.7832
	MAY	1,794	58	1,852	0.7691	0.5671	0.7628
	JUN	6,829	-75	6,754	0.7963	0.5672	0.7989
	JUL	0	0	0	-	-	-
	AUG	1,775	808	2,583	0.7963	0.5671	0.7246
	SEP	482	-17	465	0.7963	0.5671	0.8047
	OCT	46,500	125	46,625	0.7874	0.5671	0.7869
	NOV	539	249	788	0.7874	0.5671	0.7178
	DEC	4,388	70	4,458	0.7874	0.5671	0.7840
2007	JAN	37,021	322	37,343	0.8560	0.5671	0.8535
	FEB	975	264	1,239	0.8562	0.5671	0.7946
	MAR	1,673	77	1,750	0.8560	0.5671	0.8433
	APR	11,245	-1,283	9,962	0.8596	0.5671	0.8973
	MAY	0	1,336	1,336	-	0.5671	0.5671
	JUN	3,525	46	3,571	0.8596	0.5672	0.8558
	JUL	74,824	0	74,824	0.8537	-	0.8537
	AUG	14,360	40	14,400	0.8321	0.5673	0.8314
	SEP	13,502	2,178	15,680	0.8321	0.5671	0.7953
	OCT	33,190	0	33,190	0.8321	-	0.8321
	NOV	0	170	170	-	0.6256	0.6256
	DEC	7,410	3,307	10,717	0.8636	0.6256	0.7902
2008	JAN	2,219	-733	1,486	0.8636	0.6262	0.9808
	FEB	4,537	0	4,537	0.8866	-	0.8866
	MAR	65	70	135	0.8866	0.6256	0.7513
	APR	28,175	-312	27,863	0.9505	0.6250	0.9542
	MAY	1,614	0	1,614	0.9505	-	0.9505
	JUN	10,801	105	10,906	0.9505	0.6256	0.9474
	JUL	950	28	978	0.9505	0.6257	0.9412
	AUG	900	0	900	0.9505	-	0.9505
	SEP	6,450	246	6,696	0.9505	0.6256	0.9386
	OCT	28,450	548	28,998	0.9505	0.6259	0.9444
	NOV	6,002	-502	5,500	1.0493	0.6255	1.0879
	DEC	29,540	178	29,718	1.0493	0.6256	1.0467

(f), **(g)** and **(h)**

Yukon Energy cannot provide this information as a substantial component of YEC's costs are not functionalized and separated by system.

(i), **(j)** and **(k)**

Yukon Energy does not serve any primary power diesel-generation communities.

(l)

Monthly actual data on generation from each of the two wind turbines from 2005 to 2008 is provided in the table below.

Wind generation 2005 – 2008 Actuals

Wind Generation		150 kW KWh	Vesta 660 KWh	Combined KWh
2005	JAN	0	0	0
	FEB	39,750	98,611	138,361
	MAR	44,590	68,849	113,439
	APR	140	59,394	59,534
	MAY	0	74,087	74,087
	JUN	10,950	47,542	58,492
	JUL	10,360	35,013	45,373
	AUG	16,450	84,137	100,587
	SEP	20,680	100,833	121,513
	OCT	17,460	87,430	104,890
	NOV	0	0	0
	DEC	0	73,552	73,552
2006	JAN	0	0	0
	FEB	0	29,297	29,297
	MAR	0	0	0
	APR	0	70,919	70,919
	MAY	0	120,820	120,820
	JUN		26,405	26,405
	JUL	0	15,439	15,439
	AUG	22,260	69,430	91,690
	SEP	0	136,740	136,740
	OCT	53,870	32,330	86,200
	NOV	0	9,010	9,010
	DEC	0	18,260	18,260
2007	JAN	0	0	0
	FEB	0	0	0
	MAR	0	0	0
	APR	96,400	14,840	111,240
	MAY	23,360	63,070	86,430
	JUN	10,900	30,740	41,640
	JUL	12,600	29,680	42,280
	AUG	0	0	0
	SEP	26,930	36,040	62,970
	OCT	0	0	0
	NOV	0	0	0
	DEC	1,220	15,900	17,120
2008	JAN	0	0	0
	FEB	0	0	0
	MAR	44,710	-19,610	25,100
	APR	0	0	0
	MAY	51,300	123,490	174,790
	JUN	9,550	30,210	39,760
	JUL	29,070	41,430	70,500
	AUG	12,540	6,360	18,900
	SEP	0	0	0
	OCT	0	0	0
	NOV	60,050	41,340	101,390
	DEC	8,040	-1,590	6,450

(m) and **(n)**

Please see PWP/HML-YEC-1-18(a).

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-12

YEC states "Separately, as noted to the Board in Yukon Energy's application for approval of the Minto PPA, Yukon Energy has determined that 6.4 MW of diesel capacity can be added to the system in a flexible manner through purchase of the currently installed diesel units at the Minto mine-site. While this purchase was a term of the Minto PPA, it is also highly advisable for a number of reasons, as set out in Tab 5, including reducing line losses, reducing diesel generation near major population centers such as Whitehorse, as well as being the least cost source of new capacity available to Yukon Energy. This purchase will be completed in 2008".

QUESTION:

a) Please confirm that the Minto PPA requires Minto (Capstone) to pay for all costs associated with the referenced diesel units at the mine if these units are required to supply the Minto (Capstone) mine site.

b) Please confirm that Minto (Capstone) is not required to pay any costs associated with the referenced diesel units if they are used by YEC to supply the grid.

c) Please explain the process YEC uses to determine the costs associated with the Minto diesel generators.

d) Please provide details of the costs incurred to operate the referenced diesel units in 2008 and who was responsible for the costs and reasons why.

ANSWER:

(a) and **(b)**

As noted in response to UCG-YEC-1-25 and UCG-YEC-2-35 provided during the PPA hearing, YEC is generally responsible for all costs of operating and maintaining the Diesel Units, except under the special circumstances addressed in Sections 4.8 and 10.4(b) of the Power Purchase Agreement with Minto.

Section 10.4 of the PPA provides that subject to 10.4(b), YEC will be responsible for operation and maintenance costs for the Diesel Units for so long as the Diesel Units are leased by YEC from Caterpillar or owned by YEC and remain at the Mine Site. Minto is fully responsible under Section 10.3(b) for all payments to Caterpillar for these units.

Section 10.4(b) provides that during any period when YEC is unable to provide Grid Electricity to the Mine, and YEC is also otherwise unable to use the Diesel Units to supply Electricity to the WAF grid, Minto may by providing written notice to YEC require that the Diesel Units be used to supply the Mine with Electricity with the sole cost to Minto being costs for fuel and operator assistance.

Section 4.8 provides Minto with similar rights and cost obligations if it notifies YEC that it requires the Diesel Units be used to supply the Mine with Electricity under certain circumstances where Minto considers its equipment at the Mine to be at risk of damage from the supply of Grid Electricity and YEC is also unable to use the Diesel Units to supply Electricity to the WAF grid.

(c)

The PPA sets out that the sole cost to be charged to Minto for use of the diesels pursuant to section 10.4(b) is for fuel and operator assistance. The costs of fuel will be based on the metered or estimated quantity of fuel consumed during such operation. Time for Minto operator assistance is charged out at cost.

(d)

Grid service to the Minto Mine did not commence until November 22, 2008. The Minto diesels were not required to provide grid service for the remainder of that year.

REFERENCE: October 6, 2008 Application, Sales and Generation, page 2-15

YEC states "One capacity-related matter was noted in the Resource Plan in respect of the hydro systems. At that time, Yukon Energy established a reliable firm output for its Whitehorse Hydro plant at 24 MW in winter, but noted that investigations were required to determine if further revisions were needed, or possible, based on ice conditions on the Yukon River. Further investigation into Yukon River icing indicate that the 24 MW value remains valid for planning the system as a reliable winter peak output for this plant".

QUESTION:

a) Please provide all internally generated reports or documents prepared for or by senior management or otherwise related to the "further investigation" that concluded that 24 MW remains a valid winter peak output.

ANSWER:

(a)

Please see YUB-YEC-1-34(h).

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-2

YEC states "Completion of the Stage One CSTP, which contributes to these increased revenue requirements, is the key factor leading to an overall 2009 rate reduction (see Tab 4) due to additional revenues and cost savings derived from commencement of grid service to the Minto mine and Pelly Crossing."

QUESTION:

a) Please confirm that Yukon Electrical Company Limited is responsible for operating the diesel generators at Pelly Crossing and for distribution of power in the community.

b) Please provide details of the savings and costs to be realized at Pelly Crossing by YEC as well as by YECL as a result of the Stage One CSTP.

ANSWER:

(a)

Confirmed.

(b)

As noted in the YECL 2008/2009 GRA, completion of Yukon Energy's new transmission facilities to Pelly Crossing in 2008 enables YECL thereafter to secure approximately $600,000 ongoing fuel and other operating cost savings that are reflected in that Application's forecasts. This is based on actual 2007 fuel volumes (654,000 litres) and 2009 fuel price forecasts (89.33 cents per litre) in the YECL Application for Pelly Crossing (Exhibit B-4, Schedule 4.2 of that proceeding), YECL cost savings in 2009 after this community is connected to the grid would approximate $584,000 for fuel plus other savings for O&M costs (See also Grattan, YECL GRA Transcript page 281, lines 16-29).

As noted at page 2-3 of the Application Yukon Energy forecast an approximate 2,300 MW.h increase in annual wholesale sales to YECL due to the completion of the Stage 1 CSTP and the provision of grid service to Pelly Crossing.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-3

YEC states "The 2005 revenue requirement was based on fuel prices forecast in the 60 cent per litre range (the 2005 forecast prices) rather than the more recent forecast price of approximately $1.11 per litre in 2008 and $1.15 per litre in 2009".

QUESTION:

a) Please provide the actual cost of fuel in 2008 and a more current update of the price for 2009 for all Yukon locations. Please provide the source of data used to develop the forecast for 2009.

ANSWER:

(a)

Please see CW-YEC-1-16.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-3

YEC states "The forecast Non-Fuel Operating and Maintenance cost increase from 2005 to 2009 of $1.995 million (18% increase) accounts for the largest share (about 38%) of the overall revenue requirement change from 2005 to 2009. As noted in Table 3.3, over 60% of this Non-Fuel Operating and Maintenance cost increase is related to increased Labour costs and requirements for administration and other company operations, with 80% of this increase occurring by 2007".

QUESTION:

a) Please explain the increase in labour costs and the amount of labour costs that have been transferred to capital and deferred cost projects.

b) Please provide position titles and total compensation amounts for all positions that were compensated at more than $100,000 annually in 2005, 2006, 2007, 2008 and 2009 (forecast).

c) Please provide a table showing non-fuel operating and maintenance costs per customer for 2005, 2006, 2007 and 2008. Please include details of the calculation of these averages.

d) Please provide a comparison of YEC's forecast revenue requirement in 2008 and 2009 had the conditions and cost levels within the previous management services agreement with Yukon Electrical Company Limited / Canadian Utilities been maintained.

ANSWER:

(a)

Details with respect to the increase in labour costs and the amount of labour costs transferred to capital projects are provided in the table below.

Labour cost increases and labour charged capital and deferred projects

	2005	2006	2007	2008	2009
O&M labour	2,945	3,237	3,343	3,178	3,275
Admin labour	2,691	2,846	3,288	3,498	3,605
Labour expense	**5,636**	**6,083**	**6,631**	**6,676**	**6,880**
Labour charged to Capital/ Deffered Cost Projects	1,304	1,674	1,672	2,044	2,106
Labour charged to YDC/3rd Parties	186	91	92	113	116
Total Labour Charged to Other Areas:	**1,490**	**1,765**	**1,764**	**2,158**	**2,222**
Total	**7,126**	**7,848**	**8,395**	**8,834**	**9,102**
Yearly Increase as a %		10%	7%	5%	3%
Economic increase January 1st each year		3%	3%	3.75%	3.5%
Number of new positions added		4.0	3.0	3.2	0.0
Number of positions cancelled				(1.0)	
		4.0	3.0	2.2	0.0

Specific information on the new positions added is provided in LE-YEC-1-32.

(b)

Because it is not an agency of government YEC is not governed by ATIPP. It is governed by PIPEDA which prevents YEC from releasing personal information such as the information requested in this IR. However, s7(3)(c) states as follows

> 7(3) For the purpose of clause 4.3 of Schedule 1, and despite the note that accompanies that clause, an organization may disclose personal information without the knowledge or consent of the individual only if the disclosure is....
>
> (c) Required to comply with a subpoena or warrant issued or an order made by a court, person or body with jurisdiction to compel the production of information, or to comply with rules of court relating to the production of records.

Accordingly, given the Board's direction YEC is no longer prevented from releasing the information requested.

Provided as Attachment 1 to this response is a listing of position titles and total compensation amounts paid by YEC for the years requested.

The tables reflect actual compensation paid by Yukon Energy for 2005, 2006, 2007 and 2008 and forecast compensation for 2009. The amounts by position include all dollars, whether chargeable to operating or capital accounts. Total compensation includes base pay, overtime, standby, allowances and fringe benefits (see YECL-YEC-1-40 for detail description of components of pay); as well, forecast 2009 amounts include an economic increment of 3.5% as described in YECL-YEC-1-37.

(c)

The requested table is provided below.

Non-Fuel Operating, Maintenance and Administration Expenses per customer

	Actual 2005	Actual 2006	Actual 2007	Forecast 2008
Total OM&A ($000)	11,233	11,293	12,116	12,362
Total customers*	1,786	1,812	1,840	1,866
Average OM&A costs per customer ($000s)*	6.29	6.23	6.59	6.62

* Average OM&A costs per customer are provided as requested. However, YEC has YECL as its major customer, which accounts for the largest share of these costs. Therefore, the un-weighted average costs, provided as requested, are in YEC's view of limited value.

(d)

The response to McMahon-YEC-1-6(c) (provided during the 2005 Required Revenues and Related Matters hearing), in respect of revenue requirement impacts in 2005 related to Yukon Energy assuming direct management of its assets in 1998, noted that "Yukon Energy cannot hypothetically determine 'the conditions and cost levels' that would arise today based on a now expired management services agreement with Canadian Utilities." The same situation applies today.

UCG-YEC-1-35- Question b.)
Position Titles and Compensation Amounts Great Than $100K for 2005

	Title	Actual Compensation Paid by YEC
Union Contract	Maintenance Electrician	100,509.44
	Coordinator Mechanical Projects	100,917.16
	Sr. Powerline Technician- Faro	100,966.17
	Leadhand Mechanical Maintenance	101,554.87
	Powerline Technician-Dawson	101,729.34
	Powerline Technician-Dawson	102,347.27
	Systems Operator 2	104,577.88
	Sr. Powerline Technician- Mayo	111,195.40
	Leadhand Systems Control & Material Management	129,586.02
	Leadhand Transmission & Distribution	136,554.67
Out of Scope	Electrical Design Engineer	100,303.02
	Supervisor Mechanical Engineering	103,305.50
	Electrical Engineer	103,754.19
	Supervisor , Financial & Risk Management	112,550.55
	Resource Management Engineer	116,971.69
	Controller	117,139.15
	Chief Financial Officer	118,617.63
	Manager Oper. HS & Security	125,115.48
	Director Corp. Services	136,736.86
	Director of Technical Services	142,379.85
	Director Resource Planning & CIO	144,380.84
	Director of Operations	148,218.99
	President and CEO	186,847.25
	TOTAL	**2,746,259.22**

UCG-YEC-1-35- Question b.)
Position Titles and Compensation Amounts Great Than $100K for 2006

	Title	Actual Compensation Paid by YEC
Union Contract	Maintenance Mechanic	105,107.91
	Leadhand Mechanical Maintenace	106,232.55
	Powerline Technician- Mayo	107,803.14
	Powerline Technician- Dawson	108,616.91
	Maintenance Electrician	109,078.43
	Powerline Technician-Dawson	109,900.64
	Sr. Powerline Technician- Faro	110,396.64
	Coordinator Mechinical Projects	110,795.61
	Leadhand SCC & Material Management	116,998.97
	Sr. Powerline Technician- Mayo	119,809.70
	Leadhand Transmission & Distribution	134,105.03
Out of Scope	Supervisor of Communications	101,072.33
	Electrical Engineer	102,882.58
	Electrical Design Engineer	109,503.56
	Electrical Engineer	112,453.89
	Supervisor of Electrical Engineering	116,557.58
	Supervisor of Mechanical & Civil Eng.	116,608.99
	Civil & Hydrological Engineer	120,882.14
	Chief Financial Officer	124,861.26
	Controller	126,196.67
	Director of Health, Safety & Environment	128,375.26
	Director of Resource Planning & Regulatory Affairs	146,136.00
	Director of Human Resources & Information Management	147,456.68
	Director of Operations	152,424.99
	Director of Technical Services	152,644.87
	President and CEO	187,932.27
	TOTAL	**3,184,834.60**

UCG-YEC-1-35- Question b.)
Position Titles and Compensation Amounts Great Than $100K for 2007

	Title	Actual Compensation Paid by YEC
Union Contract	SCC Operator 2	101,282.10
	Coordinator Capital Projects	103,055.45
	Maintenance Electrician	103,923.69
	Leandhand Mechancial Maintenance	112,257.17
	Maintenace Mechanic	114,285.47
	Maintenance Mechanic	115,690.71
	Powerline Techincian- Mayo	116,842.51
	Sr. Powerline Techincian- Faro	121,924.30
	Leadhand SCC & Material Management	122,314.15
	Powerline Techincian- Dawson	129,983.81
	Sr. Powerline Techincian- Mayo	132,584.57
	Leadhand Transmission & Distribution	164,696.12
Out of Scope	Supervisor Communications	106,654.55
	Electrical Engineer	109,233.04
	Supervisor Financial & Risk Mgt.	109,573.75
	Electrical Engineer	110,873.03
	Electrical Engineer	118,739.70
	Civil Engineer	121,889.47
	Supervisor Mechancial & Civil Eng.	123,883.70
	Controller	130,386.67
	Chief Finance Officer	142,899.60
	Director of Resource Planning & Reg. Affairs	150,620.40
	Director of Human Resources & Information Management	160,230.35
	Director of Techincal Services	163,725.23
	Director of Operations	166,048.75
	President & CEO	235,556.53
	Total	**3,389,154.82**

UCG-YEC-1-35- Question b.)
Position Titles and Compensation Amounts Great Than $100K for 2008

	Title	Actual Compensation Paid by YEC
Union Contract	SCC Operator 2	101,400.97
	Network/System Administrator	102,303.80
	Coordinator Property & Security	102,439.01
	SCC Operator 1	102,907.75
	Coordinator Capital Projects	103,963.35
	Maintenance Electrician	104,486.36
	Plant Operator 2- Whitehorse	104,990.99
	Leadhand Mechanical Maintenance	106,769.97
	Maintenance Electrician	107,879.89
	Maintenance Electrician	112,111.73
	Powerline Technician- Whitehorse	112,225.27
	Maintenance Mechanic	112,387.14
	Maintenance Electrician	114,732.95
	Supervisor Communications	115,322.14
	Maintenance Mechanic	115,968.79
	Leadhand SCC & Material Management	124,545.53
	Sr. Powerline Technician- Faro	131,695.38
	Plant Operator 2- Mayo	132,593.59
	Powerline Technician- Mayo	134,932.40
	Powerline Technician- Dawson	155,129.00
	Leadhand Distribution and Transmission	169,566.65
Out of Scope	Revenue & Financial Analyst	100,695.81
	Manager of Health, Safety & Environment	101,189.32
	Manager of Environmental Assessment & Licensing	106,210.65
	Electrical Engineer	112,676.68
	Electrical Engineer	114,157.01
	Supervisor Electrical Engineering	114,670.17
	Supervisor Mechancial & Civil Engineering	119,265.84
	Electrical Engineer	119,840.29
	Supervisor Financial & Risk Management	125,823.56
	Civil Engineer	127,817.02
	Controller	136,760.49
	Vice President Operations & Engineering	137,489.63
	Director of Operations	140,602.93
	Director of Resource Planning & Reg. Affairs	148,557.34
	Chief Financial Officier	153,683.08
	Director of Human Resources & Information Management	175,527.31
	President and CEO	204,521.30
	Total	**4,707,841.09**

UCG-YEC-1-35- Question b.)
Position Titles and Compensation Amounts Great Than $100K for 2009

	Title	Forecast Compensation To be paid by YEC
Union Contract	Plant Operator II- Whitehorse	100,505.52
	Leadhand, Electrical Maintenance	100,648.10
	Powerline Technician- Whitehorse	101,164.72
	Corporate Secretary	101,171.31
	Revenue & Financial Analyst	101,245.23
	Powerline Technician- Whitehorse	102,864.44
	SCC Operator II	103,173.70
	Maintenance Electrician	103,324.83
	Network Administrator	104,342.95
	Maintenance Electrician	105,557.55
	Maintenance Mechanic	106,194.21
	Coordinator, Property & Security	106,315.65
	Maintenance Electrician	106,663.17
	Maintenance Mechanic	106,911.59
	Plant Operator II- Mayo	107,663.76
	Network Administrator	110,014.98
	Maintenance Mechanic	110,330.99
	Senior Powerline Technician- Dawson	111,408.51
	Maintenance Mechanic	111,501.47
	Coordinator, Mechanical Projects	111,584.01
	Powerline Technician- Dawson	112,627.58
	Coordinator, Projects & Planning	113,036.99
	Maintenance Electrician	114,563.36
	Electrical Engineer	120,630.02
	Electrical Engineer	120,773.86
	Senior Powerline Technician- Faro	126,656.83
	Electrical Engineer	127,315.49
	Leadhand, Mechanical Maintenance	131,130.72
	Powerline Technician-Mayo	131,508.76
	Leadhand, SCC & Materials Management	138,369.39
	Powerline Technician- Mayo	144,562.57
	Leadhand, Transmission & Distribution	174,082.41
Out of Scope	Manager, Environmental Assessment & Licensing	116,004.70
	Supervisor, Communications	116,619.65
	Supervisor, Financial & Risk Management	129,450.24
	Supervisor, Electrical Engineering	131,451.97
	Civil Engineer	138,165.27
	Supervisor, Mechanical & Civil Engineering	141,552.33
	Controller	142,434.66
	Manager, Health & Safety	151,603.30
	Manager, Operations	153,167.41
	Chief Financial Officer	169,930.30
	Director, Resource Planning & Regulatory Affairs	177,176.89
	Director, Operations	183,244.46
	Director, Engineering Services	186,071.05
	Director, Human Resources & Information Management	186,582.94
	Vice-President, Operations & Engineering	188,578.82
	President & CEO	223,542.55
		6,203,421.21

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-3

YEC states "The forecast Return on Rate Base cost increase from 2005 to 2009 of $1.241 million (13% increase) accounts for about 24% of the overall revenue requirement change from 2005 to 2009. Mid-year rate base increases by 8.5% from 2005 to 2009. Debt costs, as part of Return on Rate Base, increase by $1.287 million (about 30%); in contrast, equity return decreases by $0.046 million, due to the reduced return on equity forecast for 2009 (8.64%) compared to the equity return allowed in 2005 (9.05%) and actually earned in 2005 (9.46%)".

QUESTION:

a) Other than the Auditor General's review of the Mayo-Dawson transmission line project and regular internal audits, have there been any independent audits completed on YEC's operating and capital expenses or YEC's debt management program?

b) Please provide a copy of any independent audits conducted in 2005, 2006, 2007 and 2008.

ANSWER:

(a) and **(b)**

There have been no independent financial audits completed outside of normal year-end processes.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-6; Table 3-3 – Non-Fuel Operating, Maintenance and Administration Expenses**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the revenue requirement approved for 2005 remained the approved amount for 2006 and 2007.

c) Please provide an explanation for any variances between the 2008 actual and 2009 forecast and the Non-Fuel Operating, Maintenance and Administration cost level last approved by the YUB for 2005.

d) Please explain what is meant by using columns labeled “existing” and “proposed” for 2008; in particular, explain the significance the reader is supposed to draw when the existing and proposed values in the same year are identical.

ANSWER:

(a)

Updated Table 3.3 from the 2008/2009 General Rate Application is provided below.

Table 3.3
Non-Fuel Operating and Maintenance Expenses
($000)

					Forecast		Forecast	
	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	$ 5,371	$ 5,636	$ 6,084	$ 6,632	$ 6,676	$ 6,676	$ 6,880	$ 6,880
Production	906	797	761	793	657	657	798	798
Transmission	333	340	354	470	507	507	612	612
Distribution	171	163	310	97	148	148	178	178
General O&M	526	592	644	732	807	807	858	858
Administration	2,167	2,450	1,978	2,223	2,347	2,347	2,544	2,544
Insurance and Reserve for Injuries/Damages	100	1,009	913	914	964	964	1,002	1,102
Property Taxes	250	246	249	256	256	256	256	256
Total OM&A	$ 9,824	$ 11,233	$ 11,293	$ 12,116	$ 12,362	$ 12,362	$ 13,128	$ 13,228

Data for 2008 Actuals will be provided as part of the update process.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there were “Board approvals” in respect of each year.

(c)

Please see responses to UCG-YEC-1-40(c), UCG-YEC-1-41(c), UCG-YEC-1-42(c), UCG-YEC-1-43(c), UCG-YEC-1-44(c), UCG-YEC-1-45(c), and UCG-YEC-1-46(c) which detail the underlying factors driving variances between 2005 GRA and 2009 forecast costs in relation to employee complement history, Transmission costs, Distribution Costs, General Operating and Maintenance Costs, Administration Costs, RFID Costs and Property Tax Costs.

(d)

As in past GRA filings provided by Yukon Energy, columns labeled “existing” refer to revenue requirement costs that would exist absent a General Rate Application, while columns labeled “proposed” refer to revenue requirement costs with a General Rate Application.

Where values between “existing” and “proposed” columns are identical in the same year it means that the General Rate Application has no impact on these particular cost items.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-6

YEC states "Increases in labour expense make up the remainder of the increase totaling $1.244 million, or 62%. Most of this increase occurred between 2005 and 2007 ($0.996 million). This reflects additional positions, as well as negotiated and step increases. A further $0.248 million is the forecast increase in labour expenses over 2007-2009 (about 1.9% per year)".

QUESTION:

a) Please provide details of total remuneration by component (i.e., base salary, overtime, profit sharing or incentive payments, etc.) for each of the YEC employee groupings for 2005 (allowed), 2005 (actual), 2006 (actual), 2007 (actual), 2008 (actual) and 2009 (forecast).

b) Please provide individual amounts paid by YEC to each member of the Board of Directors for 2005 (allowed), 2005 (actual), 2006 (actual), 2007 (actual), 2008 (actual) and 2009 (forecast).

c) Please explain how YEC and YDC-related costs are tracked and allocated within YEC's revenue requirement.

ANSWER:

(a)

See below.

Labour Expenses by component

$000s	2005 Actuals	2006 Actuals	2007 Actuals	2008 Forecasts	2009 Forecasts
Production					
Overtime	216	140	153	125	129
Standby	80	72	63	74	76
Labour	1,230	1,428	1,441	1,245	1,282
Fringe	634	778	830	671	692
Total	2,161	2,418	2,488	2,114	2,179
Transmission					
Overtime	25	42	53	34	35
Standby	21	16	2	5	5
Labour	164	161	151	278	286
Fringe	85	88	87	150	156
Total	295	307	293	466	482
Distribution					
Overtime	17	20	31	27	28
Standby	89	89	81	91	93
Labour	164	170	212	252	260
Fringe	84	93	122	136	141
Total	354	372	446	505	522
General					
Overtime	4	7	4	3	3
Standby	-	-	-	-	-
Labour	87	86	71	58	60
Fringe	45	47	41	31	31
Total	135	139	116	92	94
Administation					
Overtime	48	49	40	41	42
Standby	-		2	0	0
Labour	1,744	1,811	2,060	2,247	2,314
Fringe	899	987	1,187	1,210	1,247
Total	2,691	2,846	3,288	3,498	3,604

There are no profit sharing or incentive plans in the GRA revenue requirement.

(b)

Because it is not an agency of government YEC is not governed by ATIPP. It is governed by PIPEDA which prevents YEC from releasing personal information such as the information requested in this IR. However, s7(3)(c) states as follows;

> 7(3) For the purpose of clause 4.3 of Schedule 1, and despite the note that accompanies that clause, an organization may disclose personal information without the knowledge or consent of the individual only if the disclosure is....
>
> (c) Required to comply with a subpoena or warrant issued or an order made by a court, person or body with jurisdiction to compel the production of information, or to comply with rules of court relating to the production of records.

Accordingly, given the Board's direction YEC is no longer prevented from releasing the information requested.

A listing of the directors (without the specific names of the directors mentioned) with the information requested for 2005, 2006, 2007 and 2008 is provided as Attachment 1 to this response. The budget for Board member honoraria for 2009 is $94,800. This budget is not prepared at the Board member level; accordingly, no table is provided for this year.

(c)

YEC costs are budgeted by position based on function. There are no YDC-related costs in YEC’s revenue requirement.

TOTAL HONORARIA PAID TO YEC BOARD MEMBERS FOR 2005-2008

2005		2006		2007		2008	
Director 1	$50.00						
Director 2	$5,100.01	Director 2	$4,200.00	Director 2	$5,800.00	Director 2	$4,985.94
Director 3	$5,550.00	Director 3	$300.00				
Director 4	$4,873.01						
Director 5	$2,100.00	Director 5	$5,050.00	Director 5	$7,350.00	Director 5	$6,099.28
Director 6	$4,833.34	Director 6	$4,200.00	Director 6	$5,200.00	Director 6	$5,763.80
Director 7	$4,100.01	Director 7	$4,683.33	Director 7	$6,000.00	Director 7	$6,272.42
		Director 8	$2,800.00	Director 8	$5,700.00	Director 8	$4,254.95
		Director 9	$2,800.00	Director 9	$5,600.00	Director 9	$3,800.00
Vice Chair	$8,950.00	Vice Chair	$10,950.00	Vice Chair	$9,800.00	Vice Chair	$12,454.13
Chairman	$35,733.34	Chairman	$30,433.33	Chairman	$38,200.00	Chairman	$57,197.86
Total	**$71,289.71**	**Total**	**$65,416.66**	**Total**	**$83,650.00**	**Total**	**$100,828.38**

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-7; Table 3-4 – Employee Complement History**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the employee complement included in the revenue requirement approved for 2005 remained the approved complement for 2006 and 2007.

c) Please provide an explanation for any variances between the 2008 actual and 2009 forecast and the Employee Complement level last approved by the YUB for 2005.

ANSWER:

(a)

Updated Table 3.4 from the 2008/2009 General Rate Application is provided below.

Table 3.4
Employee Complement History

	Actual 2004	GRA 2005	Actual 2005	Actual 2006	Actual 2007	Preliminary Actual 2008	GRA 2008	GRA 2009
President	1.44	1.60	1.60	1.50	2.50	2.50	2.50	2.50
Communications	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Human Resources & Info. Mgmt.	5.01	6.00	6.06	6.01	6.00	7.00	7.00	7.00
Business Development	0.87	1.00	1.08	1.00	1.00	1.00	1.00	1.00
Finance, Cust. Acctg. & Purchasing	9.83	9.96	11.05	11.49	11.63	12.94	12.81	12.81
Operations	33.19	33.28	34.82	39.43	38.60	40.25	40.20	40.10
Engineering Services	13.27	13.23	13.21	13.58	14.00	12.67	12.67	12.00
Health, Safety & Environment	1.00	1.00	1.00	1.00	3.00	3.36	3.33	3.33
Total	65.61	67.07	69.82	75.01	77.73	80.72	80.51	79.74

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was “Board approvals” in respect of each year.

(c)

Please see LE-YEC-1-32.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-7; Table 3-5 – Production Costs**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the production costs included in the revenue requirement approved for 2005 remained the approved amounts for 2006 and 2007.

c) Please provide an explanation for any variances between the 2008 actual and 2009 forecast and the Production cost level last approved by the YUB for 2005.

d) Please explain what is meant by using columns labelled "existing" and "proposed" for 2008 and 2009; in particular, explain the significance the reader is supposed to draw when the existing and proposed values in the same year are identical.

ANSWER:

(a)

Updated Table 3.5 from the 2008/2009 General Rate Application is provided below.

Table 3.5
Production Costs
($000)

					Forecast		Forecast	
	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	$ 2,039	$ 2,161	$ 2,418	$ 2,488	$ 2,114	$ 2,114	$ 2,179	$ 2,179
Diesel	293	173	189	147	191	191	194	194
Hydro	555	602	551	602	423	423	560	560
Wind	58	22	5	21	8	8	8	8
Operation Supervision	0	0	16	23	35	35	36	36
Total Production	$ 2,945	$ 2,958	$ 3,179	$ 3,281	$ 2,771	$ 2,771	$ 2,977	$ 2,977

Data for 2008 Actuals will be provided as part of the update process.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was "Board approvals" in respect of each year.

(c)

Material variances in Production Costs are as follows:

	2005 Approved	2009 Forecast	Variance
Labour	$ 2,039	$ 2,179	$ 139
Diesel	293	194	$ (99)
Hydro	555	560	$ 5
Wind	58	8	$ (50)
Operation Supervision		36	$ 36
Total Production	$ 2,945	$ 2,977	$ 31

- **Increase in Labour Costs:** The 2005 Application included Operations Supervisors costs in other functions. This change in allocation accounts for $84,000 of the labour cost change from 2005 approved levels to 2009 forecast. Other than this change, the increase in labour costs is only $54,000, or less than 3% over the period.

- **Decrease in Diesel Costs:** The diesel component of Production Cost from 2005 actuals to 2009 forecasts is stable. The 2005 forecast levels, however, included budgets for materials and small tools that were not sustained into the actual values for the intervening years.

- **Hydro:** The costs forecast for hydro in 2005 are approximately equal to the costs forecast for 2009.

- **Wind Cost Decrease:** Wind costs are down from 2005 forecast levels due primarily to no new wind monitoring being budgeted in O&M expense for 2009.

- **Operations Supervision:** These costs were not included in Production costs in the 2005 Application and were instead included in other operations and maintenance functions.

(d)

As in past GRA filings provided by Yukon Energy, columns labeled “existing” refer to revenue requirement costs that would exist absent a General Rate Application, while columns labeled “proposed” refer to revenue requirement costs with a General Rate Application.

Where values between “existing” and “proposed” columns are identical in the same year it means that the General Rate Application has no impact on these particular cost items.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-8; Table 3-6 – Transmission Costs**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the transmission costs included in the revenue requirement approved for 2005 remained the approved amounts for 2006 and 2007.

c) Please provide an explanation for any variances between the 2008 actual and 2009 forecast and the Transmission cost level last approved by the YUB for 2005.

d) Please explain what is meant by using columns labeled "existing" and "proposed" for 2008 and 2009; in particular, explain the significance the reader is supposed to draw when the existing and proposed values in the same year are identical.

ANSWER:

(a)

Updated Table 3.6 from the 2008/2009 General Rate Application is provided below.

Table 3.6
Transmission Costs
($000)

					Forecast		Forecast	
	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	$ 430	$ 295	$ 307	$ 293	$ 466	$ 466	$ 482	$ 482
Brushing	100	158	117	239	257	257	377	377
Other Non-Labour	233	182	237	231	250	250	235	235
Total Transmission	$ 763	$ 635	$ 661	$ 763	$ 973	$ 973	$ 1,094	$ 1,094

Data for 2008 actuals will be provided as part of the update process.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was "Board approvals" in respect of each year.

(c)

Material variances in Transmission Costs are as follows:

	2005 Approved	2009 Forecast	Variance
Labour	$ 430	$ 482	$ 51
Brushing	$ 100	377	$ 277
Other Non-Labour	$ 233	235	$ 2
Total Transmission	$ 763	$ 1,094	$ 330

The variance of $277,000 is due to brushing costs for L169 and L170. The brushing program requirements and costs to be incurred in the test years are discussed in responses to YUB-YEC-1-37(d) and (e), and LE-YEC-1-33.

(d)

As in past GRA filings provided by Yukon Energy, columns labeled "existing" refer to revenue requirement costs that would exist absent a General Rate Application, while columns labeled "proposed" refer to revenue requirement costs with a General Rate Application.

Where values between "existing" and "proposed" columns are identical in the same year it means that the General Rate Application has no impact on these particular cost items.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-8; Table 3-7 – Distribution Costs**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the distribution costs included in the revenue requirement approved for 2005 remained the approved amounts for 2006 and 2007.

c) Please provide an explanation for any variances between the 2008 actual and 2009 forecast and the Distribution cost level last approved by the YUB for 2005.

d) Please explain what is meant by using columns labeled "existing" and "proposed" for 2008 and 2009; in particular, explain the significance the reader is supposed to draw when the existing and proposed values in the same year are identical.

ANSWER:

(a)

Updated Table 3.7 from the 2008/2009 General Rate Application is provided below.

Table 3.7
Distribution Costs
($000)

					Forecast		Forecast	
	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	$ 395	$ 354	$ 372	$ 446	$ 505	$ 505	$ 521	$ 521
Brushing	31	14	72	1	40	40	46	46
Other Non-Labour	140	149	238	96	108	108	132	132
Total Distribution	$ 566	$ 517	$ 682	$ 543	$ 653	$ 653	$ 699	$ 699

Data for 2008 actuals will be provided as part of the update process.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was "Board approvals" in respect of each year.

(c)

Material variances in Distribution Costs are as follows:

	2005 Approved	2009 Forecast	Variance
Labour	$ 395	$ 521	$ 126
Brushing	$ 31	46	$ 15
Other Non-Labour	$ 140	132	$ (8)
Total Distribution	$ 566	$ 699	$ 133

The material variance in 2009 forecast compared to 2005 approved related to labour is explained in LE-YEC-1-32, and relates primarily to the addition of apprentices.

(d)

As in past GRA filings provided by Yukon Energy, columns labeled "existing" refer to revenue requirement costs that would exist absent a General Rate Application, while columns labeled "proposed" refer to revenue requirement costs with a General Rate Application.

Where values between "existing" and "proposed" columns are identical in the same year it means that the General Rate Application has no impact on these particular cost items.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-8; Table 3-8 – General Operating and Maintenance Costs**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the General Operating and Maintenance costs included in the revenue requirement approved for 2005 remained the approved amounts for 2006 and 2007.

c) Please provide an explanation for any variances between the 2008 actual and 2009 forecast and the General Operating and Maintenance cost level last approved by the YUB for 2005.

d) Please explain what is meant by using columns labeled "existing" and "proposed" for 2008 and 2009; in particular, explain the significance the reader is supposed to draw when the existing and proposed values in the same year are identical.

ANSWER:

(a)

Updated Table 3.8 from the 2008/2009 General Rate Application is provided below.

Table 3.8
General Operating and Maintenance
($000)

					Forecast		Forecast	
	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	$ 92	$ 135	$ 139	$ 116	$ 92	$ 92	$ 94	$ 94
Transportation	274	291	321	370	386	386	394	394
Maintenance of Company Owned Properties	177	230	242	290	342	342	384	384
SCADA Communication and Special Projects	75	71	81	72	79	79	80	80
Total General O&M	$ 618	$ 727	$ 783	$ 848	$ 899	$ 899	$ 952	$ 952

Data for 2008 actuals will be provided as part of the update process.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was "Board approvals" in respect of each year.

(c)

Material variances in General Operating and Maintenance Costs are as follows:

	2005 Approved	2009 Forecast	Variance
Labour	$ 92	$ 94	$ 1
Transportation	$ 274	394	$ 120
Maintenance of Company Owned Properties	$ 176	384	$ 208
SCADA Communication and Special Projects	$ 76	80	$ 4
Total General O&M	$ 618	$ 952	$ 333

Variances in General Operating and Maintenance Costs are due to the following factors:

- **Transportation:** key factors underlying the variance from 2005 GRA include:
    1. **Gasoline/Heating Fuel:** $131,000 Increase (from $140,000 to $271,000) due to increase in the cost of fuel and number of vehicles in the fleet.
    2. **Vehicle O&M Capital Credits:** $34,000 decrease (from $-64,000 to $-98,000) due to higher vehicle costs resulting in a larger transfer to capital.

- **Maintenance of Company Owned Properties:** Main drivers underlying the variance from 2005 GRA include:
    1. **Gasoline/Heating Fuel: $**0 forecast in 2005 and $56,000 have been allocated in 2009 GRA, fuel for company owned or arranged houses in the communities.
    2. **Materials:** $0 forecast in 2005 and $31,000 in 2009 GRA due to required maintenance on the house at Aishihik.
    3. **Office Rent / Yard Rent:** $0 forecast in 2005 and $29,000 forecast in 2009 GRA due to requirement for rental of office space for file storage.
    4. **Snow Removal:** Increase costs from $13,000 in 2005 to $57,000 in 2009.

(d)

As in past GRA filings provided by Yukon Energy, columns labeled “existing” refer to revenue requirement costs that would exist absent a General Rate Application, while columns labeled “proposed” refer to revenue requirement costs with a General Rate Application.

Where values between “existing” and “proposed” columns are identical in the same year it means that the General Rate Application has no impact on these particular cost items.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-10; Table 3-9 – Administration**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the administration costs included in the revenue requirement approved for 2005 remained the approved amounts for 2006 and 2007.

c) Please provide an explanation for any variances between the 2008 actual and 2009 forecast and the Administration cost level last approved by the YUB for 2005.

d) Please provide details and explanations of the cost incurred to operate the fish hatchery that were included in the approved 2005 revenue forecast, 2008 actual and 2009 forecast.

e) Please provide an explanation and details of the spending on training in 2005, 2006, 2007 and 2008. Was any of this training available and / or taken within the Yukon? Why or why not?

f) Please provide details of the training forecast for 2009.

g) For what positions were staff recruited in 2005, 2006, 2007 and 2008? What were the compensation levels for these positions?

h) For what positions are staff anticipated to be recruited in 2009? What are the anticipated compensation levels for these positions?

i) Please provide the amount of cost for the Board of Directors included in the YUB-approved revenue requirement for 2005.

j) Please provide details of costs identified under regulatory affairs for 2005, 2006, 2007, 2008 and 2009 (forecast).

k) Please explain what is meant by using columns labeled “existing” and “proposed” for 2008 and 2009; in particular, explain the significance the reader is supposed to draw when the existing and proposed values in the same year are identical.

ANSWER:

(a)

Updated Table 3.9 from the 2008/2009 General Rate Application is provided below.

Table 3.9
Administration
($000)

					Forecast		Forecast	
	Approved 2005	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Existing 2008**	**Proposed 2008**	**Existing 2009**	**Proposed 2009**
Labour	$ 2,414	$ 2,691	$ 2,846	$ 3,288	$ 3,498	$ 3,498	$ 3,605	$ 3,605
Resource Planning	17	1	6	21	17	17	17	17
Communications	0	72	87	118	87	87	105	105
Customer Accounting	168	164	170	189	201	201	206	206
Environmental Mgmt	47	46	7	30	35	35	52	52
General	899	873	805	597	745	745	734	734
Information Systems	189	213	265	341	351	351	425	425
Fish Hatchery	143	126	106	132	130	130	136	136
Fish Ladder	17	18	33	11	25	25	26	26
Safety	39	38	54	133	59	59	162	162
Training	174	177	139	142	201	201	211	211
Recruitment	165	170	19	181	165	165	169	169
Board of Directors	156	156	91	166	145	145	148	148
Union	26	54	27	32	25	25	26	26
Regulatory Affairs	0	0	6	106	93	93	57	57
Material Management	87	300	155	14	42	42	43	43
Contracting	25	26	8	6	11	11	11	11
Professional Development	15	16	0	4	15	15	15	15
Total Administration	$ 4,581	$ 5,141	$ 4,824	$ 5,511	$ 5,845	$ 5,845	$ 6,148	$ 6,148

Data for 2008 Actuals will be provided as part of the update process.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was “Board approvals” in respect of each year.

(c)

Material variances in Administration Costs from 2005 actuals to 2009 GRA forecasts are provided in CW-YEC-1-23(a). The only notable differences between the 2005 approved levels and the 2005 actuals is related to 3 categories:

- Labour: 2005 actual labour was above 2005 approved levels by $0.275 million due primarily to the addition of FTEs compared to the 2005 forecast levels, one procurement and contract administrator, one network administrator and one powerline technician, as well as somewhat higher level of casuals used in operations.

- Materials management: 2005 actual materials management included substantial one-time write downs above the levels forecast for 2005 at the time of the YUB hearing.

- Communications: The 2005 forecasts did not separately track communications, as these amounts were previously included in Administration-General.

(d)

Please see table provided below.

$000s	2005 Approved	2009 Forecast
Consultants	32	5
Contractors	180	263
Materials(Small Tools)	1	
Outside Service	10	
Total Cost	223	268
less: Grant / Funding	-80	-133
Net Cost	143	136

The main difference in the 2005 and 2009 GRA forecasts for hatchery operations is that the hatchery management contract was renewed in 2008. A value driven open tender process was carried out in order to hire a new hatchery management company. The new management contract that came into effect on July 1, 2008 resulted in a significant increase in contractor costs due mostly to higher salary costs.

A funding agreement with Government of Yukon Department of Environment is still currently in place and runs until 2010. This funding agreement stipulates the amount and composition of the grant/funding.

(e) and **(f)**

Please see response to YECL-YEC-1-43(a).

(g)

Employees were recruited for the following positions in the following compensation ranges between 2005 and 2008:

January 1, 2005 to December 31, 2005

Position	**Salary Range**	
	Minimum	**Maximum**
CFO	108,622	124,915
Powerline Technician Mayo	54,279	61,176
Sr. Powerline Technician Mayo	65,590	72,488
Supervisor, Electrical Engineer	83,066	95,527
Assistant Buyer	48,210	55,107
IT Technical Suppport	49,726	56,624
Land Technician	55,382	62,280
SCC Operator - 3 yr term	56,899	63,798

January 1, 2006 to December 31, 2006

Maintenance Electrician	60,386	71,042
Buyer	55,482	62,586
Coordinator, Captial Projects	66,325	78,030
Financial Administrator	51,985	61,159
Plant Operator	53,208	60,311
Procurement & Contract Administrator	51,985	61,159
Supervisor, Financial & Risk Management	70,000	105,000
CFO	95,520	143,280
Admin Assistant/Receptionist - Term	38,785	45,629
Floater PLT	60,386	71,042
Floater PLT/SCC Operator	60,386	71,042
Engineer-in-Training	53,680	80,520
Apprentice PLT Whs	Apprentices are paid a % of the base salary of a journey position based on the training term the apprentice is in.	
Apprentice PLT Mayo	Apprentices are paid a % of the base salary of a journey position based on the training term the apprentice is in.	

January 1, 2007 to December 31, 2007

Position		
Admin Assistance/Receptionist	39,949	46,998
Draftsperson	53,545	62,994
Financial Administrator	53,545	62,994
Maintenance Elctrician	62,198	73,173
PLT Whs - was Floater	62,198	73,173
PLT Dawson	62,198	73,173
Supervisor, Electrical Engineering	72,100	108,150
Finance Administrator Term	53,545	62,994
VP Operations & Engineering	107,038	160,556
Manager, Operations	72,100	108,150
Manager, Health & Safety	63,920	95,880
Manager, Environment	63,920	95,880
Documentation Specialist	53,545	62,994

January 1, 2008 to December 31, 2008

Position		
Financial Administrator	55,553	65,356
Finance Administrator Term	55,553	65,356
PLT Mayo	64,530	75,917
Director, Engineering Services	84,162	126,243
Supervisor, Electrical Engineering	74,804	112,206
Director, Operations	84,162	126,243
Manager, Operations	74,804	112,206
Electrical Engineer	62,408	93,612
Leadhand, Mechanical Maintenance	78,776	92,678
PLT Dawson	64,530	75,917
Maintenance Mechanic	64,530	75,917
Buyer	64,530	75,917
PLT Whitehorse	65,530	75,917

(h)

YEC will run recruitments for all vacant positions. As of the date of this response, the Corporation is actively running competitions for a Supervisor, Electrical Engineering position and two Power Line Technician positions. For the remainder of the year, management cannot predict which positions will become vacant.

(i)

See **(c)** above which notes $156,000 approved in the 2005 YUB hearing.

(j)

Please see table provided below.

$000s	2005 Actuals	2006 Actuals	2007 Actuals	2008 Forecasts	2009 Forecasts
Consultants		4	35	60	26
Legal		1	63	27	26
Small items routinely under $5k		1	8	6	6
Total		6	106	93	57

The reduction in 2009 regulatory affairs compared to 2008 reflects the completion of the YECL GRA process, which was budgeted in 2008.

(k)

As in past GRA filings provided by Yukon Energy, columns labeled “existing” refer to revenue requirement costs that would exist absent a General Rate Application, while columns labeled “proposed” refer to revenue requirement costs with a General Rate Application.

Where values between “existing” and “proposed” columns are identical in the same year it means that the General Rate Application has no impact on these particular cost items.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-13; Table 3-10 – Insurance and Reserve for Injuries & Damages**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the insurance and reserve for injuries & damages costs included in the revenue requirement approved for 2005 remained the approved amounts for 2006 and 2007.

c) Please provide an explanation for any variances between the 2008 actual and 2009 forecast and the Insurance and Reserve for Injuries & Damages cost level last approved by the YUB for 2005.

d) Please provide all internally generated reports or documents prepared for or by senior management or otherwise related to the determination of the two-part "solution to the Reserve account".

ANSWER:

(a)

Updated Table 3.10 from the General Rate Application is provided below.

Table 3.10
Insurance and Reserve for Injuries & Damages
($000)

					Forecast		Forecast	
	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Insurance	$ -	$ 909	$ 813	$ 814	$ 914	$ 914	$ 952	$ 952
Reserve Appropriation	100	100	100	100	50	50	50	150
One-time Transfer	744	744				463		
Less: Application of fire gain funds	(744)	(744)				(463)		
Total RFID	$ 100	$ 1,009	$ 913	$ 914	$ 964	$ 964	$ 1,002	$ 1,102

Data for 2008 actuals will be provided as part of the update process.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was “Board approvals” in respect of each year.

(c)

Please see response to YECL-YEC-1-29.

(d)

Please see Tab 3, pages 3-12 to 3-15.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-15; Table 3-12 – Property Taxes**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the property tax provision included in the revenue requirement approved for 2005 remained the approved amounts for 2006 and 2007.

c) Please provide details of the property tax paid by community for 2005 (allowed), 2005 (actual), 2006 (actual), 2007 (actual), 2008 (actual) and 2009 (forecast).

d) Please provide an explanation for any variances between the 2008 actual and 2009 forecast and the Property Tax cost level last approved by the YUB for 2005.

e) Please provide documentation outlining YEC's requirement to make payments in lieu of property taxes to municipalities.

ANSWER:

(a)

Updated Table 3.12 from the 2008/2009 General Rate Application is provided below.

Table 3.12
Property Taxes
($000)

					Forecast		Forecast	
	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Property Taxes	$ 250	$ 246	$ 249	$ 256	$ 256	$ 256	$ 256	$ 256

Data for 2008 actuals will be provided as part of the update process.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was "Board approvals" in respect of each year.

(c)

For 2005 through 2007 actuals please refer to the table below. 2005 approved values are not available by community. YEC forecasts for 2008 and 2009 were based on 2007 historical cost.

Property Taxes by Community ($000)

	2005 Actual	2006 Actual	2007 Actual
Dawson City	82	80	80
Faro	35	36	37
Mayo	3	3	3
Whitehorse	126	130	136
Total	**245**	**249**	**256**

(d)

There has been basically no variance in property tax costs.

(e)

Yukon Energy is owned by the YTG and therefore it makes payment in lieu of property taxes to municipalities instead of actually paying property taxes.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-16

YEC states "Yukon Energy's depreciation costs continue to be based on depreciation rates approved by the YUB in Order 2005-12".

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-3

YEC states "The forecast Depreciation and Amortization cost increase from 2005 to 2009 of $1.551 million (29% increase) accounts for about 30% of the overall revenue requirement change from 2005 to 2009. Over 50% of the Depreciation and Amortization cost increase is due to amortization cost increases, including costs for planning studies, regulatory activities and licensing costs related to Yukon Energy's ongoing generation and transmission requirements. Although fixed asset depreciation increases by $1.504 million (30%) from 2005 to 2009, net depreciation costs after customer contributions only increase by $0.733 million (about 16%), reflecting in part contributions to the CSTP costs from Minto Explorations, the Yukon Government and Yukon Development Corporation".

QUESTION:

a) Please confirm that the depreciation rates approved in Order 2005-12 were based on a study conducted by Gannett Fleming related to YEC's plant as of December 31, 2003.

b) Given Gannett Fleming's suggestion that the completion of full depreciation reviews should be undertaken every 3 to 5 years (per YEC's response to MCMAHON-YEC-1-16 in the 2005 Required Revenues and Related Matters proceeding), please explain why YEC did not undertake a depreciation study for this current application.

c) Please indicate when YEC intends to undertake its next full depreciation study.

ANSWER:

(a)

Confirmed. As noted in the depreciation study included at Tab 11 in the 2005 Required Revenues and Related Matters Application the calculated annual depreciation accrual rates presented in the report are related to the utility plant in service as of December 31, 2003.

(b)

Yukon Energy sought to manage the extent of studies and costs for regulatory filings. There are not expected material issues with the currently approved depreciation rates as established by the 2003 Gannett-Fleming Study, and as such there is no justification for incurring the expense of a further study at this time.

(c)

Yukon Energy currently has no plans to undertake a further depreciation study at this time.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-17**

YEC states "The largest component of deferred charges relates to planning and study costs, regulatory hearing costs and licencing costs related to maintaining licences of YEC's hydro facilities and air emission permits. The cost for amortization of deferred charges has increased $0.818 million, from $0.889 million in actual 2005 to $1.707 million forecast in 2009 as set out in Tab 5. The largest component of this increase since 2005 ($0.547 million) relates to planning and study costs, which is primarily studies of the existing system and options for expanding the quantity of renewable generation, as well as studies related to the safety and reliability of the system, the Minto Mine PPA negotiations, and other small projects, offset by the termination of amortization since 2005 on old study amounts as they become fully amortized".

QUESTION:

a) Please provide a detailed listing of all deferred charges, descriptions of the charges incurred and a description of the reason for incurring the costs for 2005 (allowed), 2005 (actual), 2006 (actual), 2007 (actual), 2008 (actual) and 2009 (forecast).

b) Please explain why "Minto Mine PPA negotiations" and the "PPA proceeding" would be a cost to be paid by ratepayers versus the Minto (Capstone) mine.

ANSWER:

(a)

For descriptions of all actual deferred charges incurred from 2005 through 2007 please see Tables 5.3 through 5.7 in Tab 5 of the Application. For 2005 Allowed charges please see Table 5.3 in Tab 5 of the 2005 Required Revenues and Related Matters Application.

Actuals for 2008 are currently not available.

(b)

Ratepayers secured significant benefits through the negotiation of the Power Purchase Agreement with Minto mine, through increased revenues from grid service to Minto mine and Pelly Crossing as well as long term infrastructure benefits through contributions to the CSTP.

Please see response to UCG-YEC-1-10. The PPA proceeding costs are not charged directly to Minto as there is no provision for such assignment of these costs in the YUB approved PPA. The costs also are not to be charged directly to Minto as part of their rate as the rate is fixed by OIC and not subject to revision to assign additional costs.

Also, YUB-YEC-1-10(b) notes that, “the Minto PPA negotiations are accounted for in this manner because it is considered to be a regulatory cost”.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-19; Table 3-14 – Cost of Capital**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the capital structure, cost of debt and return on equity provisions included in the revenue requirement approved for 2005 remained the approved amounts for 2006 and 2007.

c) Please provide YEC's understanding of the YUB's role in determining and approving the deemed capital structure of YEC for rate-setting purposes.

ANSWER:

(a)

Table 3.14 from the 2008/2009 General Rate Application is revised below to include the "Approved 2005" information.

Table 3.14
Cost of Capital

					Forecast		Forecast	
	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Average Cost of Debt	5.12%	5.18%	5.47%	5.49%	5.67%	5.68%	6.16%	6.19%
Return on Equity	9.05%	9.46%	10.59%	9.45%	9.55%	8.64%	11.03%	8.64%
Average Cost of Capital	6.69%	6.89%	7.52%	7.07%	7.22%	6.86%	8.11%	7.17%

For 2008 Actuals please see Attachment B1 of Appendix B of the April 24, 2009 update filing.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was “Board approvals” in respect of each year.

(c)

The Board has jurisdiction to determine a fair rate of return of Yukon utilities, and in this regard may (and does) assess the reasonableness of a utility’s capital structure.

Regulation of Yukon Energy to date has been based on the actual capital structure for the utility and as such there has been no “deemed capital structure”.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-19

YEC states "Yukon Development has provided long-term advances totaling $40.032 million as at December 31, 2007, with interest rates ranging from 5.28% to 6.03%. Additional advances of $3.515 million from Yukon Development are forecast at December 31, 2008 and a further $5.043 million at December 31, 2009, with forecast interest rates of 5.28% to maintain the 60% debt and 40% equity balance" and that "Debt issued between Yukon Development and Yukon Energy is priced based on a "spread" over long Canada bonds of 120 basis points. The long Canada bond yield during the preparation of this filing was 4.08%, supporting a rate for new long term debt of 5.28%".

REFERENCE: Schedule 13 of Tab 7

QUESTION:

a) Please provide a detailed description of the purpose for each of the unsecured advances from YDC.

b) Please describe in detail the calculations of the interest rates attached to each of the unsecured advances from YDC. Please include references to all source documents.

c) Please explain how this method of interest calculation was determined.

d) Please provide all internally generated reports or documents prepared for or by senior management or otherwise related to the determination of method of interest calculation for the unsecured advances from YDC.

ANSWER:

(a)

The unsecured advances from YDC are to maintain an appropriate capitalization of Yukon Energy.

Yukon Energy's practice with respect to dividends and issuances of long-term debt is to declare dividends out of equity and issue long-term debt annually, as required in order to maintain a 60% debt: 40% equity capital structure at year end, while retaining a minimum of cash in the utility outside of amounts required to finance the ongoing capital program. These unsecured advances are required to maintain a 60:40 debt equity ratio and to address repayment of other debt during the course of each year.

(b)

The interest rates attached to the YDC advances are the Long-Term Benchmark Canada Bond Yields for December 31 of the respective year plus 120 basis points.

	2005[1]	2006	2007	2008[2]
Long Term Bond Rate	4.22	4.14	4.08	3.45
Premium	1.2	1.2	1.2	1.2
Interest Rate	5.4	5.34	5.28	4.65

This method of interest rate determination is in accordance with corporate policy, and is based on market analysis prepared by RBC Dominion Securities in 1990 and previously reviewed by the Board.[3]

(c) and **(d)**

Please see CW-YEC-1-26(a).

[1] For 2005, 2006 and 2007, Long Term Government of Canada Bond rates were extracted from published public information (i.e. newspaper) on or near the effective date of the instrument.
[2] Long Term Government of Canada Bond Rates extracted from the Bank of Canada website.
[3] See Order 1993-8. The YUB has since approved revenue requirements in Order 2006-7 and 2005-12 where this policy has been applied.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-19

YEC states "Yukon Energy has agreed to purchase the diesel units currently installed at the Minto mine (the "Minto Diesels") and finance the $2.24 million purchase price of these units with Minto over 7 years. The rate on this financing is 7.5%, equal to all interest rates on advances contained in the Minto Power Purchase Agreement ("PPA") as reviewed by the YUB in early 2007, and payments are equal blended principal and interest monthly. The outstanding balances on this advance total $2.179 million at year-end 2008 and $1.921 million in 2009, with interest costs of $0.042 million (partial year 2008) and $0.155 million (full year 2009) respectively".

QUESTION:

a) Please confirm that the 7.5% cost of capital rate incorporated into the Minto Power Purchase Agreement was deemed to be YEC's average weighted cost of debt and equity for new capital projects.

b) Please provide a calculation of YEC's actual average weighted cost of debt and equity for new capital projects in 2008.

ANSWER:

(a)

Confirmed.

(b)

YEC does not plan to borrow specific debt for individual capital projects. New capital secured for YEC in 2009 is forecast to cost 8.49% for equity, and 5.28% for debt, or an average of 6.56% at a 60:40 ratio.

As to actual 2008, Yukon Energy's proposed fair return on equity is 8.64% and 4.65% was the cost of new long-term debt declared at year-end 2008, which yields an average of 6.25% (at 60:40 debt:equity).

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-20

YEC states: "In order to provide the 60% long-term debt component of the Mayo-Dawson project capital costs, and to ensure ratepayers would not be worse off in any year as a result of the Mayo-Dawson project than they would have been had Dawson remained on diesel fuel generation, Yukon Development provided an $18 million advance with flexible terms with respect to interest payable ("Mayo Dawson Note"). The forecast balance on the Mayo-Dawson Note is $15.607 million as at year-end 2008 and $15.157 million at year-end 2009. The face interest rate on the note is 6.55% and, due to the present substantial benefits to ratepayers arising from the Mayo-Dawson line given current and forecast diesel fuel prices, the full 6.55% face interest rate is forecast to be paid in 2008 and 2009".

QUESTION:

a) Please explain how the interest rate on the reference note was determined.

b) Given the ongoing reductions in interest rates, has YEC considered refinancing this debt at a more favourable interest rate?

ANSWER:

(a)

Please see response to LE-YEC-1-37.

(b)

No.

The Mayo-Dawson Note is long term debt incurred as a component of financing the Mayo Dawson Project. Consistent with its structure as long-term debt, the face interest rate on the note is fixed for the duration of the note.

Further, the provisions of the Mayo Dawson Note are designed to protect ratepayers in the event of underperformance of the line, ensuring ratepayers will not pay more in any year than they would have had Dawson remained on diesel generation. The 6.55% face interest on the promissory note is the Maximum Interest Payable, and actual interest in any given year can be adjusted downwards to ensure that ratepayers are not paying any more in any year of the Project than the costs that would have been payable had Dawson remained on diesel generation. Consequently, the lender (YDC) bears risks with respect to the performance of the line and its role in YEC's system. It is not expected that any outside lender would accept such terms in any refinancing.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-20**

YEC states: "The outstanding balance on the TD Canada Trust term note at year-end 2008 is $7.163 million and $6.471 million at year-end 2009. This note has an effective interest rate of 7.81% with equal blended monthly principal and interest payments, and is due in 2011".

QUESTION:

a) Given the ongoing reductions in interest rates, has YEC considered refinancing this debt at a more favourable interest rate?

ANSWER:

(a)

Please see response to LE-YEC-1-38.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-20**

YEC states: "Yukon Energy's cost of equity in 2009 is a function of the risks inherent in Yukon Energy's business, the returns that could be earned elsewhere with equity investments of equivalent risk, and the requirement in OIC 1998/32 that Yukon Energy receive a fair return on equity less 0.5%."

QUESTION:

a) To YEC's knowledge, have there ever been any discussions related to increasing the 0.5% adjustment to YEC's rate of return on equity as a means for reducing overall costs to be recovered from ratepayers? If yes, please provide details.

ANSWER:

(a)

To YEC's knowledge there have been no discussions related to changing the 0.5% overall adjustment to YEC's rate of return on equity.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-21

YEC states: "In particular, in the 2005 proceeding, the fair ROE for test year 2005 was proposed by Yukon Energy to be set by reference to the British Columbia Utilities Commission ("BCUC") formulaic ROE approach, based on Yukon Energy receiving a 52 basis points premium due to its risk compared to low risk utility. This was accepted by the Board in Order 2005-12. As set out in Tab 8, Yukon Energy has maintained this same approach to set the proposed ROE for 2008, at 8.64%. For 2009, Yukon Energy proposes that the ROE be set using the same approach, based on the BCUC calculations to be completed approximately at the end of November, 2008, and that this ROE be incorporated in the requested approvals for 2009 at that time. For the purposes of this filing document, a 2009 "placeholder" ROE of 8.64% has been utilized, to be consistent with 2008".

QUESTION:

a) Please confirm that the BCUC has determined that the allowed return on common equity for a low-risk benchmark utility in 2009 is 8.47% which results in a proposed 8.49% ROE for YEC in 2009.

b) Please provide a calculation of YEC's average weighted cost of capital for 2009 assuming a proposed 8.49% ROE.

c) Please provide a calculation of YEC's return on rate base using an 8.49% ROE for 2009.

d) Please provide justification for YEC's proposed 52 basis points premium related to risk in 2008 and 2009. Please provide the qualifications of the person providing this justification.

e) In what way was YEC or data specific to YEC included in the statistical analysis or deliberations conducted by the BCUC when developing and then enhancing its formulaic approach? If YEC-related data used in BCUC deliberations, please provide details of utilities comparable to YEC that have been included in the BCUC's analysis.

ANSWER:

(a)

Please see response to LE-YEC-1-39(a) and YUB-YEC-1-15(d).

(b) and **(c)**

All other assumptions unchanged, using 8.49% for the test years would change the weighted average cost of capital in Schedule 4.C of Tab 7 of the Application from 7.17% to 7.11%. Similarly, with all other assumptions unchanged, the total return on rate base for the test years would change from $10.859 million to $10.768 million.

(d)

Please see discussion in 2005 Required Revenues and Related Matters Application related to the justification of the 52 basis point risk premium for Yukon Energy (at pages 8-4 to 8-6). This Application was reviewed by the Yukon Utilities Board in 2005 where the Board determined that the 52 basis point risk premium was appropriate.

Also see YUB-YEC-1-15(c).

(e)

Yukon Energy has previously noted in response to information request MCMAHON-YEC-1-32(c) (during the 2005 Required Revenues and Related Matters hearing) that, “YEC is not aware that the BCUC considered YEC or any YEC specific data in developing its approach to setting the return on equity for a benchmark utility”.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-21

YEC states that the Deferred Fuel Price Account (Rider F) was "established pursuant to Order in Council 1995/90 section 8. This account captures all variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA-approved fuel prices. Pursuant to Board Order 2005-12, Yukon Energy also credits this account with all variations (positive or negative) in the ongoing quarterly adjustment to the prices of secondary sales, compared to the most recent GRA-approved price. As with the typical situation where final rates are put in place following the start of the test year, once final approvals are received for new test year fuel prices, Yukon Energy recalculates the balances in these accounts to ensure that all charges to the accounts are precisely equal to what would have occurred had the ultimate YUB approvals been known at the start of the first test year".

QUESTION:

a) Please confirm that Rate Schedule 39 for industrial customers includes a provision that Rider F is set to $0.00 for this class of customer.

b) Please provide a calculation of what the Rider F charge would be in 2007, 2008 and 2009 for industrial customers under Rate Schedule 39 if it was not eliminated by Order-in-Council.

c) Please calculate the total amount of Rider F revenue that would have been collected from the industrial class in 2007, 2008 and 2009 under Rate Schedule 39 if the rates calculated in (b) had been charged.

d) Please provide a calculation of Rider F for the residential and commercial classes for 2007, 2008 and 2009. Please fully explain any differences in the calculations for the different customer classes.

e) Please provide YEC's rationale for keeping secondary sales customers immune from Rider F.

f) Please identify when the referenced "most recent GRA-approved price" was set.

g) Please confirm that the benchmark upon which Rider F is determined would be adjusted to match fuel costs approved for 2008 and 2009 in this proceeding.

ANSWER:

(a)

Not confirmed. The Rider F for Rate Schedule 39 is set to $0.00 only for the "fuel price forecast filed November 20, 2006".

(b) and **(c)**

Yukon Energy did not serve any industrial customer under Rate Schedule 39 for 2007 and most of 2008. Service to Minto only commenced in late November, 2008. Since that time Minto has been paying a Rider F of 0.671 cents/kW.h, as set out in Yukon Energy's August 25, 2008 filing with the Board.

(d)

There is no difference in Rider F for individual firm retail customer classes. Rider F calculations reflect joint YEC/YECL forecasts of the overall Rider F account balances, as set out in filings made with the YUB when each change is made to Rider F. These assessments address fuel price variance impacts from the last GRA approved fuel price for each utility, and also YEC's secondary energy sale price variance impact from the last GRA approved energy sale price.

Rider F filings since February 2006 are included in Attachment 1 to this response, setting out the process for deriving the Rider F changes in each instance. The latest Rider F change will occur March 1, 2009 (when Rider F will be set to zero).

(e)

Secondary sales provided under Rate Schedule 32 are interruptible sales (not firm). Rates for this service are set to reflect the customer's alternative cost of heating (i.e., oil). There is no basis in this type of rate to include an additional Rider F charge.

(f)

The "most recent GRA-approved price" for YEC was set for 2005 by Order 2005-12 subsequent to the 2005 Required Revenues and Related Matters proceeding. Rider F is a consolidated rider with YECL; in the case of YECL the "most recent GRA-approved price" is presently the 1997 fuel price approved in the 1996/97 GRA.

(g)

Confirmed. It is anticipated that all charges and credits by YEC to the Deferred Fuel Price Account (the Rider F account) will be re-stated back to January 1, 2008 after a final Board order is received approving a 2008/2009 Revenue Requirement for Yukon Energy.

The Yukon Electrical Company Limited
An ***ATCO*** Company

February 7, 2006

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Acting Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90 and due to the increases in diesel fuel prices, The Yukon Electrical Company Limited and Yukon Energy Corporation are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from 0.7909 cents per kW.h to 1.2799 cents per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after March 1, 2006.

As of January 31, 2006, the Companies are owed approximately $635,000 in cumulative fuel price variance shortfalls. We also expect to incur, on average, approximately $240,000 per month in charges in excess of the forecast fuel prices currently included in rates.

As described in Yukon Energy's 2005 Revenue Requirements Application, this is the first Rider F calculation that includes a component for the variance between the forecast and actual secondary sales rates. As the actual 2005 rate was higher than the forecast rate, a favourable variance of $18,761 was created to offset the cumulative negative fuel variance. Between February 2006 and February 2007, a favourable secondary sales variance of approximately $211,000 has been forecast.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to February 28, 2007. As in the past, the Companies commit to review the situation on an ongoing basis to ensure the balance in the account and the collections from ratepayers is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Doug Tenney
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

The Yukon Electrical Company Limited
Yukon Energy Corporation
Rider F Calculation
As At January 31, 2006
(Forecast Implementation Date in CIS = March 1, 2006)

The Yukon Electrical Company Limited

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	
Due From (To) Customers - as at January 31, 2006					675,363
Feb-06	Estimated Net			50,000	
Mar-06	33.48	85.92	479,987	251,695	
Apr-06	33.84	83.75	454,098	226,627	
May-06	34.18	83.84	428,642	212,877	
Jun-06	33.58	83.03	442,714	218,936	
Jul-06	33.32	84.12	411,906	209,241	
Aug-06	32.79	83.20	458,014	230,874	
Sep-06	32.90	82.87	453,359	226,529	
Oct-06	33.97	82.36	447,008	216,329	
Nov-06	33.50	85.08	519,092	267,759	
Dec-06	33.26	84.94	568,107	293,624	
Jan-07	33.00	83.18	612,509	307,372	
Feb-07	34.00	83.35	561,654	277,151	
Sub total				2,989,012	2,989,012
YECL Shortfall					**3,664,375**

Yukon Energy Corporation

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	Secondary Sales Adjmt	
Due From (To) Customers - as at January 31, 2006						(39,554)
Feb-06	Estimated Net			(10,000)	(33,620)	
Mar-06	0.5995	80.00	21,231	16,858	(29,913)	
Apr-06	0.5995	72.06	20,409	14,584	(13,821)	
May-06	0.5995	72.06	19,520	13,949	(10,914)	
Jun-06	0.5995	72.06	21,602	15,437	(8,921)	
Jul-06	0.5995	72.06	24,449	17,471	(7,134)	
Aug-06	0.5995	72.06	22,837	16,319	(7,227)	
Sep-06	0.5995	72.06	24,852	17,759	(10,856)	
Oct-06	0.5995	72.06	19,473	13,916	(13,050)	
Nov-06	0.5995	72.06	20,682	14,779	(17,004)	
Dec-06	0.5995	72.06	22,730	16,243	(19,363)	
Jan-07	0.5995	72.06	24,383	17,424	(20,241)	
Feb-07	0.5995	72.06	22,773	16,274	(19,211)	
Sub total				181,014	(211,274)	(30,260)
YEC Shortfall						**(69,815)**

Combined YEC/YECL shortfall **3,594,561**

2006 - 2007 Forecast Retail Sales (kwh's) - March 1, 2006 - February 28, 2007

YECL	252,400,000	
YEC	28,453,016	
Total		280,853,016

Rider F rate - price per kwh (cents) to recover 100% of shortfall to February 28, 2007 **1.279872601**

The Yukon Electrical Company Limited
An ATCO Company

November 10, 2006

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Acting Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of a decrease in the automatic fuel price adjustment rider (Rider F) from 1.2799 cents per kW.h to .9638 cents per kW.h based on the attached forecast. The decrease will be effective for bills rendered on or after December 1, 2006.

Rider F collections since March 1, 2006 have reduced the accumulated deficit for fuel price variance down from $657,000 so that as of October 31, 2006, the Companies are owed approximately $35,000 in cumulative fuel price variance shortfalls. We expect to incur, on average, charges of approximately $245,000 per month in excess of the forecast fuel prices currently included in rates. This monthly fuel variance is forecast to be offset by a favorable Secondary Sales rate variance averaging $19,000 per month for a combined variance of $226,000 per month.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to November 2007. As in the past, the Companies commit to review the situation on an ongoing basis to ensure the balance in the account and the collections from ratepayers is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Doug Tenney
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

100 – 1100 First Avenue, Whitehorse, YT Y1A 3T4 tel: 867-633-7000 or 1-800-661-0513 fax: 867-668-3965

WHITEHORSE 2007 JEUX DU CANADA GAMES
OFFICIAL SUPPLIER - FOURNISSEUR OFFICIEL
WHITEHORSE 2007 JEUX DU CANADA GAMES

The Yukon Electrical Company Limited
Yukon Energy Corporation
Rider F Calculation
As At October 31, 2006
(Forecast Implementation Date in CIS = December 1, 2006)

The Yukon Electrical Company Limited

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	
Due From (To) Customers - as at October 31, 2006					34,538
Nov-06	Estimated Net			74,500	
Dec-06	33.26	83.56	568,107	285,767	
Jan-07	33.00	83.56	607,281	307,041	
Feb-07	34.00	83.56	561,654	278,356	
Mar-07	33.48	83.56	479,987	240,377	
Apr-07	33.84	83.56	454,098	225,778	
May-07	34.18	83.56	428,642	211,663	
Jun-07	33.58	83.56	442,714	221,268	
Jul-07	33.32	83.56	411,906	206,942	
Aug-07	32.79	83.56	458,014	232,534	
Sep-07	32.90	83.56	453,359	229,672	
Oct-07	33.97	83.56	447,008	221,671	
Nov-07	33.50	83.56	519,092	259,857	
Sub total				2,995,427	2,995,427
YECL Shortfall					**3,029,965**

Yukon Energy Corporation

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	Secondary Sales Adjmt	
Due From (To) Customers - as at October 31, 2006						-
Nov-06	Estimated Net			(50,000)	-	
Dec-06	59.95	78.68	11,374	2,130	(25,766)	
Jan-07	59.95	78.68	12,083	2,263	(27,665)	
Feb-07	59.95	78.68	11,114	2,082	(25,518)	
Mar-07	59.95	78.68	10,802	2,023	(23,373)	
Apr-07	59.95	78.68	10,167	1,904	(19,081)	
May-07	59.95	78.68	9,765	1,829	(15,380)	
Jun-07	59.95	78.68	10,793	2,021	(11,997)	
Jul-07	59.95	78.68	12,559	2,352	(9,232)	
Aug-07	59.95	78.68	11,657	2,183	(10,977)	
Sep-07	59.95	78.68	12,861	2,409	(15,320)	
Oct-07	59.95	78.68	9,557	1,790	(18,669)	
Nov-07	59.95	78.68	10,763	2,016	(23,430)	
Sub total				(24,997)	(226,408)	(251,404)
YEC Shortfall						**(251,404)**
Combined YEC/YECL shortfall						**2,778,560**

2006 - 2007 Forecast Retail Sales (kwh's) - December 1, 2006 - November 30, 2007

	YECL	260,000,000	
	YEC	28,301,881	
	Total		288,301,881
Rider F rate	- price per kwh (cents) to recover 100% of shortfall to November 30, 2007		**0.963767648**

The Yukon Electrical Company Limited
An ATCO Company

April 16, 2008

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from .9638 cents per kW.h to 1.233 cents per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after May 1, 2008.

Due to actual fuel prices being significantly higher than fuel prices provided for in rates, the diesel fuel price variance has increased over the past 4 months driving the deficit owing from ratepayers to the companies up to $224,616 at the end of March 2008. This variance will continue to grow with current and rising fuel prices at the existing Rider F rate of .9638 cents per kWh.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to April 2009. As in the past, the Companies commit to review the variables impacting Rider F on an ongoing basis to ensure the balance in the account and the collections from ratepayers is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Jerome Babyn
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

The Yukon Electrical Company Limited
Yukon Energy Corporation
Rider F Calculation
As At March 31, 2008
(Forecast Implementation Date in CIS = May 1, 2008)

The Yukon Electrical Company Limited

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	
Due From (To) Customers - as at March 31, 2008					224,616
Apr-08	Estimated Net			250,000	
May-08	33.73	96.56	446,685	280,651	
Jun-08	33.40	96.56	417,188	263,478	
Jul-08	34.92	96.56	420,249	259,050	
Aug-08	32.88	96.56	414,012	263,633	
Sep-08	33.94	96.56	433,963	271,764	
Oct-08	33.98	96.56	470,103	294,197	
Nov-08	34.16	96.56	547,955	341,932	
Dec-08	35.00	96.56	618,229	380,612	
Jan-09	33.43	96.56	576,926	364,217	
Feb-09	34.28	96.56	514,615	320,494	
Mar-09	35.38	96.56	522,506	319,693	
Apr-09	32.88	96.56	451,015	287,227	
Sub total				3,896,946	3,896,946
YECL Shortfall					**4,121,562**

Yukon Energy Corporation

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	Secondary Sales Adjmt	
Due From (To) Customers - as at March 31, 2008						-
Apr-08	Estimated Net			(45,000)	-	
May-08	59.95	88.66	17,992	5,166	(37,201)	
Jun-08	59.95	88.66	21,219	6,092	(30,665)	
Jul-08	59.95	88.66	23,017	6,608	(19,236)	
Aug-08	59.95	88.66	21,644	6,214	(21,576)	
Sep-08	59.95	88.66	23,794	6,831	(28,553)	
Oct-08	59.95	88.66	18,087	5,193	(35,660)	
Nov-08	59.38	81.70	46,124	10,295	(44,710)	
Dec-08	59.40	82.00	48,198	10,890	(48,235)	
Jan-09	59.42	82.21	49,749	11,336	(54,111)	
Feb-09	59.34	81.23	53,996	11,818	(51,142)	
Mar-09	59.34	81.26	54,246	11,890	(47,667)	
Apr-09	59.95	88.66	20,189	5,796	(48,644)	
Sub total				53,128	(467,400)	(414,272)
YEC Shortfall						**(414,272)**

Combined YEC/YECL shortfall **3,707,290**

2008-2009 Forecast Retail Sales (kwh's) - May 1, 2008 - April 30, 2009

YECL	271,266,000	
YEC	29,304,299	
Total		300,570,299

Rider F rate - price per kwh (cents) to recover 100% of shortfall to April 30, 2009 **1.233418745**

The Yukon Electrical Company Limited
An ATCO Company

July 10, 2008

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from 1.233 cents per kW.h to 1.860 cents per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after August 1, 2008.

Due to actual fuel prices being significantly higher than fuel prices provided for in rates, the diesel fuel price variance has continued to increase over the past 3 months driving the deficit owing from ratepayers to the companies up to $505,000 at the end of June 2008. This variance will continue to grow with current and rising fuel prices at the existing Rider F rate of 1.233 cents per kWh.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level until the completion of the General Rate Applications. At this point the Rider will be adjusted accordingly.

Yours sincerely,

The Yukon Electrical Company Limited

Jerome Babyn
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

The Yukon Electrical Company Limited
Yukon Energy Corporation
Rider F Calculation
As At June 30, 2008
(Forecast Implementation Date in CIS = August 1, 2008)

The Yukon Electrical Company Limited

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall		
Due From (To) Customers - as at June 30, 2008						504,626
Jul-08	Estimated Net			150,000		
Aug-08	32.88	125.00	446,954	411,723		
Sep-08	33.94	125.00	438,421	399,243		
Oct-08	33.98	125.00	473,011	430,541		
Nov-08	34.16	125.00	502,146	456,157		
Dec-08	35.00	125.00	607,319	546,617		
Jan-09	33.43	125.00	504,558	462,026		
Feb-09	34.28	125.00	508,574	461,370		
Mar-09	35.38	125.00	490,743	439,826		
Apr-09	32.88	125.00	427,616	393,940		
May-09	33.73	125.00	400,548	365,579		
Jun-09	33.40	125.00	406,044	371,918		
Jul-09	34.92	125.00	400,198	360,507		
Sub total				5,249,447		5,249,447
YECL Shortfall						**5,754,073**

Yukon Energy Corporation

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	Secondary Sales Adjmt	
Due From (To) Customers - as at June 30, 2008						-
Jul-08	Estimated Net				(45,000)	
Aug-08	59.95	95.05	22,630	7,943	(33,443)	
Sep-08	59.95	95.05	24,800	8,705	(44,257)	
Oct-08	59.95	95.05	19,207	6,742	(55,273)	
Nov-08	59.38	88.95	49,497	14,635	-	
Dec-08	59.40	89.18	51,456	15,323	-	
Jan-09	59.42	89.34	52,850	15,812	-	
Feb-09	59.34	88.52	57,831	16,876	-	
Mar-09	59.34	88.52	57,829	16,876	-	
Apr-09	59.95	95.05	21,195	7,439	-	
May-09	59.95	95.05	19,332	6,786	(58,592)	
Jun-09	59.95	95.05	22,321	7,835	(47,841)	
Jul-09	59.95	95.05	24,026	8,433	(30,126)	
Sub total				133,405	(314,531)	(181,126)
YEC Shortfall						**(181,126)**

Combined YEC/YECL shortfall **5,572,947**

2008 - 2009 Forecast Retail Sales (KwH's) August 1, 2008 - July 31, 2009

YECL	271,179,000	
YEC	28,466,374	
Total		299,645,374

Rider F rate Price per KWH (cents) to recover 100% of shortfall to July 31, 2009 **1.860**

The Yukon Electrical Company Limited
An ATCO Company

February 9, 2009

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of a decrease in the automatic fuel price adjustment rider (Rider F) from 1.860 cents per kW.h to zero (0.0) cents per kW.h. The decrease will be effective for bills rendered on or after March 1, 2009.

Due to fuel price decreases since the last adjustment in August 2008, the diesel fuel price variance shortfall accumulated during 2008 has been recovered. There will be an estimated surplus in the Rider F account of $600,000 by the end of February 2009 (based on use of the last GRA fuel price of 1997 for YECL and 2005 for YEC). This surplus is forecast to be eliminated by the end of May with the revised lower Rider F rate.

The Rider will be materially impacted by the Board's imminent ruling on YECL's General Rate Application ("GRA"). Accordingly, Rider F will remain at the new adjusted level of zero at least until the Board's decision on that GRA is implemented. We expect this will not be until June 1st, given the timelines faced for the Compliance filing and lead time for rate changes in the billing system.

In the meantime, the Companies believe it is important to lower Rider F which will benefit ratepayers immediately.

Yours sincerely,

The Yukon Electrical Company Limited

Jerome Babyn
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

REFERENCE: **October 6, 2008 Application, Revenue Requirement, page 3-21**

YEC states: "For the test years, no use of the DCF is forecast. The DCF has a balance of $0.856 million as at December 31, 2007 (including interest earned monthly); this balance is proposed to be retained in the fund as it is intended to be available in the event of a drought. The DCF will not be advanced in the "diesel on the margin" mode until such time as the system has firm loads that exceed the long-term average capability of the system over the course of a long period (many months to years). This will not occur until after secondary sales have been basically fully interrupted over the long-term on the WAF system. The DCF could be required in the event of a drought within the test years."

QUESTION:

a) Please confirm that secondary and industrial sales customers will not receive any benefits from the Diesel Contingency Fund.

b) Please describe how the DCF will be allocated if triggered.

ANSWER:

(a)

Confirmed for the test years as regards firm load customers.

The Diesel Contingency Fund is designed to stabilize the utility's costs of diesel that arise from fluctuations in generation related to higher or lower than average long-term hydro generation due to water availability. Under present firm load conditions, were a severe drought to arise giving rise to the requirement for diesel generation for baseload supply, the DCF would pay the utility for this quantity of diesel fuel (at GRA fuel prices). There would be no direct impact to firm retail or industrial customer rates. The GRA is intended to avoid the need for rates to fluctuate depending on test year water flow conditions.

Given that secondary sales would be interrupted prior to diesel generation being required for baseload purposes, the secondary sales customers would not benefit from

any DCF use. Further, as noted in the Application, the DCF does not protect the utility from loss of forecast secondary sales revenues due to drought conditions.

With respect to industrial customers, rates in the test years are fixed at the levels set out in OIC 2007/94 and consequently industrial rates would not in any event presently be subject to variation due to drought or flood conditions. The DCF protects the utility, however, from such changes in water flow conditions

(b)

Pursuant to the approved rules for the DCF, any withdrawals will be allocated to the cost of diesel fuel related to low water conditions.

REFERENCE: October 6, 2008 Application, Rates, Page 4-11

Table 4.4 – Equivalent Price of Electricity for Heating - August 13, 2008 Oil Prices

QUESTION:

a) Please update this table with current oil prices.

b) Please provide the referenced Yukon Housing Corporation data used to create Table 4.4.

ANSWER:

(a)

Below is the update to Table 4.4 with rates as at December 31, 2008.

Table 4.4 -Updated
Equivalent Price of Electricity for Heating – December 31, 2008 Oil Prices

	Whitehorse	Faro	Mayo	Dawson
Price of Furnace Oil December 31, 2008 ($/litre)	0.95	1.00	1.10	1.06
Oil price excluding GST	0.90	0.95	1.05	1.01
Equivalent Price of Electricity (cents/kW.h) at 80% efficiency furnace (excl GST)	0.1054	0.1113	0.1225	0.1174

(b)

Attachment 1 to this response provides the Yukon Bureau of Statistics document referenced to create Table 4.4. The relevant pages are pages 14, 16, 17, and 19.

Fuel Survey: December 2008

1 Retail Motor Fuel Prices in the Yukon

Average prices as of December 31st, 2008

	Self-serve		
	regular	premium	diesel
Whitehorse	86.8	93.9	109.1
Beaver Creek	99.9	104.9	121.9
Carcross	109.9	129.9	129.9
Carmacks	92.9	108.9	115.9
Dawson City	125.0	152.7	147.0
Destruction Bay	92.9	97.9	113.9
Haines Junction	90.9	95.9	111.9
Mayo	115.0	N/A	138.0
Pelly Crossing	102.9	-	119.9
Ross River	121.9	-	169.9
Tagish	89.9	99.8	107.8
Teslin	86.9	89.9	110.4
Watson Lake	104.9	114.9	118.9

	Full-serve			
	regular	premium	diesel	propane
Whitehorse	88.8	98.9	112.4	88.1
Dawson City	-	-	-	118.0
Destruction Bay	-	-	-	155.9
Haines Junction	94.9	-	116.9	108.9
Mayo	112.9	-	135.9	129.0
Tagish	-	-	-	98.0
Teslin	-	-	-	115.9
Watson Lake	-	-	159.9	126.4

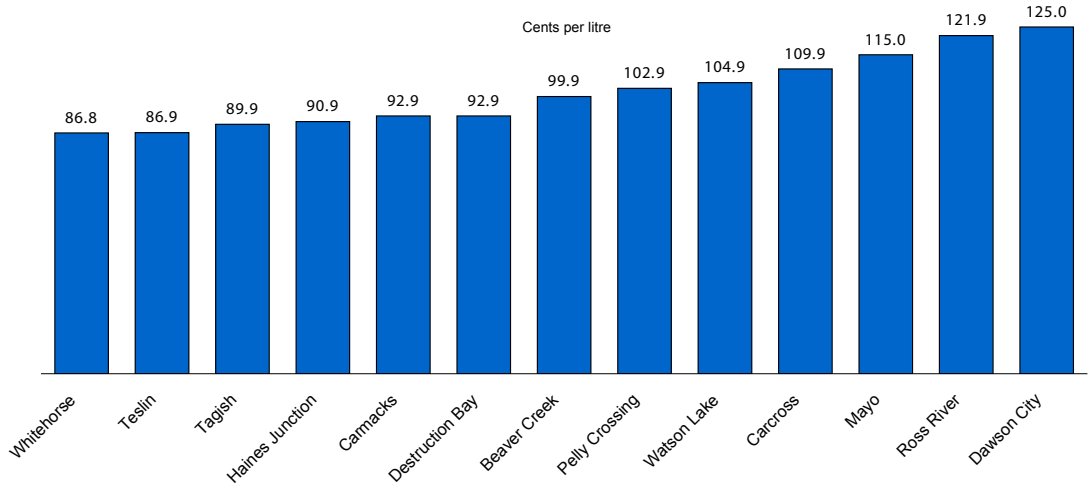
Note: All prices are Canadian cents per litre, including all applicable taxes.
"-" Indicates this service is not available in this community at this time.
"N/A" indicates this information is not available for the reporting period.

Current average gasoline prices for regular self-serve in the Yukon range from 86.8¢ per litre in Whitehorse to 125.0¢ per litre in Dawson City. The price for premium self-serve ranges from 89.9¢ per litre in Teslin to 152.7¢ per litre in Dawson City. The lowest price for self-serve diesel is in Tagish—107.8¢ per litre.

For full-serve regular gasoline, the average price ranges from 88.8¢ per litre in Whitehorse to 112.9¢ per litre in Mayo. The price for full-serve diesel ranges from 112.4¢ per litre in Whitehorse to 159.9¢ per litre in Watson Lake.

Whitehorse has the lowest price for propane, at 88.1¢ per litre, while Destruction Bay has the highest, at 155.9¢ per litre.

Average Retail Gasoline Prices
Regular Self-serve — December 31st, 2008

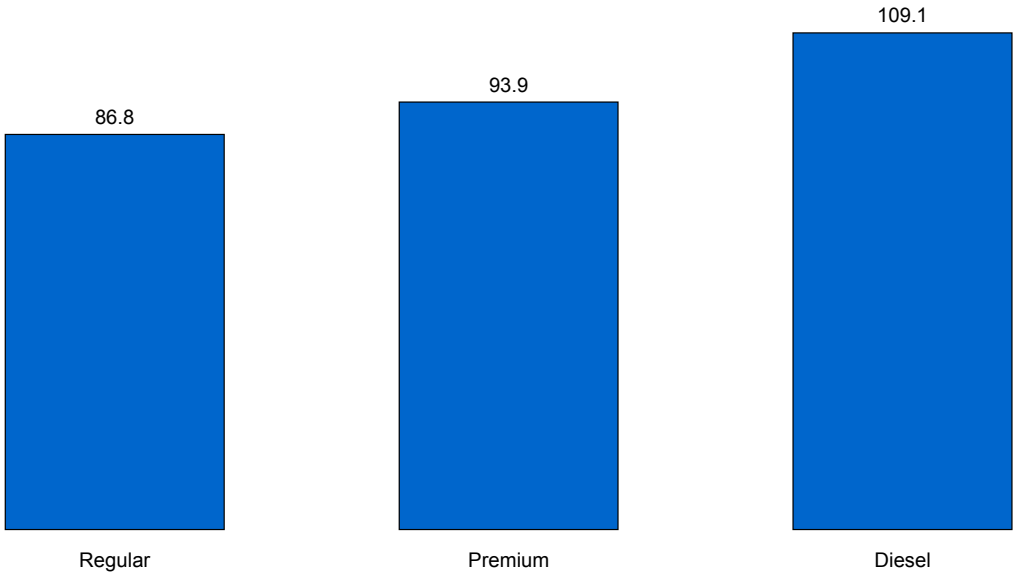


2 Retail Motor Fuel Prices — Whitehorse

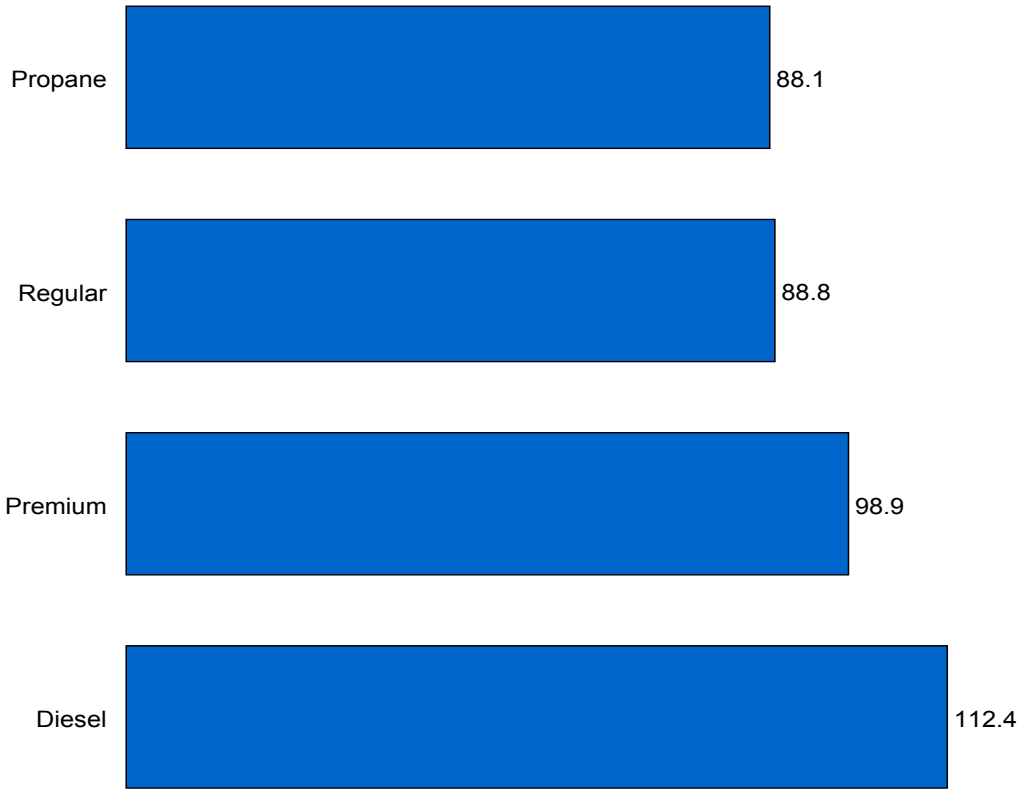
	Self-serve				Full-serve				
	regular	mid-grade	premium	diesel	regular	mid-grade	premium	diesel	propane
31-Dec-08	86.8	-	93.9	109.1	88.8	-	98.9	112.4	88.1
17-Dec-08	89.1	-	96.1	110.0	89.8	-	106.4	117.4	88.1
3-Dec-08	93.6	-	100.8	117.8	97.1	-	112.2	128.7	89.3
19-Nov-08	103.7	-	110.3	126.7	108.3	-	126.9	135.7	93.9
5-Nov-08	110.6	-	116.8	132.0	112.0	-	129.4	141.9	96.4
22-Oct-08	121.5	-	130.0	137.5	127.1	-	137.9	140.2	94.9
8-Oct-08	130.8	-	137.2	140.8	136.3	-	142.7	146.2	100.9
24-Sep-08	139.7	-	145.3	142.1	142.8	-	147.6	148.3	102.4
10-Sep-08	139.4	-	145.5	143.5	141.5	-	146.9	147.6	102.4
27-Aug-08	140.0	-	146.4	145.8	141.4	-	146.6	148.3	102.6
13-Aug-08	141.0	-	146.8	148.3	144.8	-	150.6	155.2	106.2
30-Jul-08	144.4	-	150.2	152.6	144.8	-	150.6	155.2	107.3
16-Jul-08	146.1	-	151.4	154.7	146.4	-	152.6	157.6	106.3
2-Jul-08	144.9	-	151.0	150.6	145.8	-	151.9	151.2	104.9
18-Jun-08	144.3	-	150.3	148.7	145.1	-	151.2	150.6	105.2
4-Jun-08	141.0	-	146.3	146.8	140.8	-	146.9	146.9	100.9
21-May-08	137.2	-	142.8	141.9	137.8	-	144.9	142.2	101.9
7-May-08	136.3	-	142.1	140.8	137.8	-	144.9	142.2	101.6
22-Apr-08	126.6	-	132.8	135.4	126.4	-	132.6	137.6	94.9
9-Apr-08	120.6	-	126.9	132.0	120.8	-	128.9	136.6	92.6
26-Mar-08	120.2	-	126.2	129.5	120.8	-	128.9	130.6	92.6
12-Mar-08	120.2	-	125.8	123.6	120.1	-	128.2	125.2	92.6
27-Feb-08	115.6	-	121.7	120.0	117.1	-	124.9	122.6	92.6
13-Feb-08	115.6	-	121.6	119.1	117.8	-	125.6	121.9	92.6
30-Jan-08	115.6	-	121.6	119.1	117.8	-	125.6	121.9	92.6
16-Jan-08	115.8	-	121.4	119.4	117.4	-	125.6	118.6	92.6
2-Jan-08	115.8	-	121.2	120.3	117.4	-	125.6	121.9	90.2
19-Dec-07	115.8	-	121.9	120.1	117.8	-	128.9	123.2	90.2
5-Dec-07	116.5	-	122.2	119.6	117.8	-	128.9	123.2	90.2
November '07	115.6	-	122.2	113.0	117.1	-	127.9	115.1	85.3
October '07	116.4	-	122.5	109.1	119.1	-	128.9	113.3	86.3
September '07	119.9	-	124.0	109.1	122.4	-	127.9	111.9	82.3
August '07	119.8	-	124.9	108.9	121.8	-	127.7	111.9	80.9
July '07	119.8	-	124.9	108.5	121.8	-	125.9	111.9	80.9
June '07	120.1	-	124.9	107.7	121.8	-	128.6	111.9	80.9
May '07	115.3	-	120.2	108.2	116.5	-	124.1	112.8	80.9
April '07	104.6	-	109.9	104.5	105.5	-	116.1	109.2	80.0
March '07	104.7	-	110.6	106.3	104.8	-	114.7	108.8	79.9
February '07	97.4	-	102.8	103.1	97.8	-	110.1	102.9	79.2
January '07	99.1	-	105.1	106.3	98.9	-	108.6	102.9	78.9
December '06	97.8	-	104.5	101.0	97.7	-	109.8	103.6	71.9
November '06	96.2	-	103.0	98.6	96.4	-	108.1	102.2	64.7
October '06	99.1	-	105.9	99.9	100.1	-	114.0	104.3	76.5
September '06	110.5	117.2	116.7	110.4	111.6	118.9	124.2	117.6	83.2
August '06	119.7	124.1	125.7	114.0	121.8	124.4	130.1	117.2	84.6
July '06	116.0	120.8	122.8	110.7	119.4	122.9	127.5	112.6	83.4
June '06	113.6	119.9	121.8	109.7	118.2	122.9	127.5	110.3	82.9
May '06	114.4	118.6	122.1	108.7	118.2	122.9	127.5	110.6	82.9
April '06	117.1	123.2	123.0	108.5	119.8	123.2	127.5	114.2	81.2
March '06	101.6	106.3	109.2	101.8	102.6	107.2	111.9	102.3	80.2
February '06	105.6	109.9	111.9	105.1	105.8	109.4	114.1	112.1	82.1
January '06	105.7	110.0	112.0	108.1	105.8	109.4	114.1	113.9	83.2

2 Retail Motor Fuel Prices — Whitehorse

Average Self-serve, as of December 31st, 2008 (cents per litre)



Average Full-serve, as of December 31st, 2008 (cents per litre)



3 Retail Motor Fuel Prices — Carmacks

	Self-serve			Full-serve
	regular	premium	diesel	propane
31-Dec-08	92.9	108.9	115.9	-
17-Dec-08	92.9	117.9	126.9	-
3-Dec-08	102.9	112.9	128.9	-
19-Nov-08	115.9	124.4	144.9	-
5-Nov-08	129.9	138.4	147.4	-
22-Oct-08	144.9	156.4	156.9	-
8-Oct-08	149.9	159.4	159.9	-
24-Sep-08	153.9	160.9	162.4	-
10-Sep-08	153.9	160.9	162.4	-
27-Aug-08	153.9	160.9	162.4	-
13-Aug-08	153.9	160.9	162.4	-
30-Jul-08	159.4	168.4	169.9	-
16-Jul-08	158.9	168.9	169.9	-
2-Jul-08	153.9	161.4	158.9	-
18-Jun-08	153.9	160.4	161.9	-
4-Jun-08	149.9	156.9	159.9	-
21-May-08	145.9	153.5	149.9	-
7-May-08	139.9	146.9	147.9	-
22-Apr-08	129.9	137.4	142.4	-
9-Apr-08	129.9	137.4	142.4	-
26-Mar-08	129.9	139.4	142.4	115.0
12-Mar-08	129.9	139.4	142.4	115.0
27-Feb-08	125.9	134.9	137.9	102.0
13-Feb-08	125.9	134.9	137.9	102.0
30-Jan-08	125.9	134.9	137.9	97.0
16-Jan-08	125.9	134.9	137.9	97.0
2-Jan-08	125.9	134.9	137.9	97.0
19-Dec-07	125.9	134.9	137.9	98.0
5-Dec-07	125.9	134.9	133.9	98.0
November '07	122.9	131.7	128.7	93.5
October '07	125.9	135.4	122.9	97.0
September '07	125.9	135.4	121.4	97.0
August '07	125.6	135.4	121.4	97.0
July '07	125.4	135.4	120.7	96.5
June '07	129.9	138.9	121.4	96.0
May '07	129.9	137.2	121.4	92.0
April '07	119.9	126.4	119.9	91.5
March '07	115.4	122.7	112.7	93.5
February '07	106.9	116.4	111.9	94.0
January '07	115.9	132.4	111.4	94.0
December '06	109.9	128.9	111.4	94.0
November '06	109.9	119.9	110.2	94.0
October '06	109.9	119.9	107.7	94.0
September '06	115.9	124.7	118.9	93.5
August '06	127.6	136.4	126.4	93.0
July '06	127.9	135.9	121.2	93.0
June '06	129.9	138.9	123.9	94.0
May '06	129.9	138.2	123.9	93.5
April '06	122.4	132.2	115.9	93.0
March '06	107.1	115.2	111.4	93.0
February '06	108.9	117.9	114.7	93.0
January '06	108.9	117.9	115.9	93.0

4 Retail Motor Fuel Prices — Dawson City

	Self-serve			Full-serve		
	regular	premium	diesel	regular	diesel	propane
31-Dec-08	125.0	152.7	147.0	-	-	118.0
17-Dec-08	127.0	159.5	149.7	-	-	N/A
3-Dec-08	141.3	155.0	154.3	-	-	120.0
19-Nov-08	147.6	158.3	160.0	-	-	120.0
5-Nov-08	151.3	161.9	160.2	-	-	120.0
22-Oct-08	155.0	161.9	165.4	-	-	120.0
8-Oct-08	164.6	174.1	169.4	-	-	120.0
24-Sep-08	168.6	173.6	169.5	-	-	120.0
10-Sep-08	168.6	173.7	171.2	-	-	120.0
27-Aug-08	168.4	173.4	171.5	-	-	126.0
13-Aug-08	171.7	176.9	176.0	-	-	126.0
30-Jul-08	170.9	177.2	177.0	-	-	126.9
16-Jul-08	170.9	174.5	177.0	-	-	126.0
2-Jul-08	167.7	174.2	173.0	-	-	126.0
18-Jun-08	165.9	172.5	172.0	-	-	121.0
4-Jun-08	163.1	168.7	170.7	-	-	121.0
21-May-08	161.3	165.7	166.2	-	-	121.0
7-May-08	159.7	163.6	161.2	-	-	121.0
22-Apr-08	152.2	155.8	158.6	-	-	121.0
9-Apr-08	145.2	149.0	151.0	-	-	113.0
26-Mar-08	145.7	148.0	147.0	-	-	99.9
12-Mar-08	140.8	148.1	139.2	-	-	99.9
27-Feb-08	140.1	146.7	138.2	-	-	99.9
13-Feb-08	140.1	146.7	138.2	-	-	99.9
30-Jan-08	139.7	146.7	138.3	-	-	99.9
16-Jan-08	139.7	146.7	138.3	-	-	99.9
2-Jan-08	139.4	147.2	139.0	-	-	99.9
19-Dec-07	138.4	147.2	139.0	-	-	99.9
5-Dec-07	138.2	146.0	136.3	-	-	99.9
November '07	139.7	147.3	136.1	-	-	99.9
October '07	139.7	147.3	135.0	-	-	99.9
September '07	140.4	147.5	134.1	-	-	99.9
August '07	140.8	147.5	134.5	-	-	99.9
July '07	141.1	147.5	134.6	-	-	97.9
June '07	142.1	147.2	133.9	-	-	97.9
May '07	140.1	146.9	134.2	-	-	97.9
April '07	132.6	140.1	131.1	-	-	97.9
March '07	125.1	132.8	130.5	-	-	97.9
February '07	121.9	129.1	129.1	-	-	97.9
January '07	122.0	127.9	126.8	-	-	97.9
December '06	119.3	123.6	120.1	-	-	97.9
November '06	119.8	124.3	120.8	-	-	98.2
October '06	122.5	127.3	122.8	-	-	98.5
September '06	130.3	135.1	129.1	-	-	98.5
August '06	136.5	142.2	130.8	-	-	98.5
July '06	134.4	139.8	129.2	-	-	98.2
June '06	133.7	139.1	129.0	131.5	130.0	96.8
May '06	133.5	139.2	130.3	129.0	126.0	95.0
April '06	133.6	139.6	128.8	125.0	123.0	94.0
March '06	121.9	128.4	125.6	119.0	120.0	86.5
February '06	123.2	129.2	126.2	117.0	126.5	86.5
January '06	123.2	129.1	126.0	110.0	125.0	86.5

5 Retail Motor Fuel Prices — Haines Junction

	Self-serve			Full-serve		
	regular	premium	diesel	regular	diesel	propane
31-Dec-08	90.9	95.9	111.9	94.9	116.9	108.9
17-Dec-08	94.9	99.9	116.9	94.9	116.9	108.9
3-Dec-08	99.9	104.9	121.9	99.9	131.9	108.9
19-Nov-08	107.9	112.9	127.9	117.9	134.9	108.9
5-Nov-08	115.9	129.0	131.9	126.9	139.9	108.9
22-Oct-08	124.0	128.9	141.5	135.9	142.9	108.9
8-Oct-08	145.7	152.6	147.3	135.9	142.9	108.9
24-Sep-08	146.0	153.5	147.3	142.9	147.9	108.9
10-Sep-08	147.3	155.9	150.9	142.9	147.9	108.9
27-Aug-08	151.5	160.9	155.0	142.9	149.9	108.9
13-Aug-08	151.7	161.2	155.9	142.9	149.9	108.9
30-Jul-08	153.9	162.2	160.2	149.9	158.9	108.9
16-Jul-08	155.2	163.9	160.7	149.9	158.9	108.9
2-Jul-08	153.2	162.9	159.0	146.9	156.9	108.9
18-Jun-08	153.0	162.6	158.0	146.9	154.9	108.9
4-Jun-08	145.9	155.2	153.9	140.9	151.9	105.9
21-May-08	145.9	155.2	149.4	140.9	151.9	105.9
7-May-08	145.7	154.9	149.2	140.9	151.9	105.9
22-Apr-08	133.7	143.2	143.2	130.9	135.9	105.9
9-Apr-08	125.3	133.7	137.6	122.9	131.9	105.9
26-Mar-08	124.0	132.5	127.3	117.9	120.9	92.9
12-Mar-08	124.0	132.5	123.6	117.9	120.9	92.9
27-Feb-08	117.5	122.9	121.5	117.9	120.9	92.9
13-Feb-08	117.9	122.9	120.9	117.9	120.9	92.9
30-Jan-08	117.5	122.9	121.5	117.9	120.9	92.9
16-Jan-08	117.5	122.9	121.5	117.9	120.9	92.9
2-Jan-08	117.5	122.9	121.5	117.9	120.9	92.9
19-Dec-07	121.3	130.4	122.9	117.9	116.9	92.9
5-Dec-07	121.3	130.4	122.9	117.9	116.9	92.9
November '07	122.4	130.4	119.4	117.9	116.9	83.9
October '07	122.6	131.6	119.3	120.4	116.9	83.9
September '07	125.0	133.8	119.4	122.9	116.9	83.9
August '07	125.7	134.6	119.4	122.9	116.9	83.9
July '07	125.7	134.6	119.4	122.9	116.9	83.9
June '07	125.7	134.6	119.4	122.9	116.9	79.5
May '07	124.2	133.6	118.8	119.9	116.9	79.5
April '07	119.3	128.8	117.9	114.4	115.4	79.5
March '07	108.2	115.9	109.3	108.9	110.4	79.5
February '07	106.7	114.4	108.6	105.9	115.9	79.5
January '07	106.4	114.2	111.3	105.9	115.9	79.5
December '06	106.0	113.9	107.0	105.9	105.9	79.5
November '06	106.0	113.9	106.0	105.9	105.9	79.5
October '06	106.9	114.9	107.9	105.9	105.9	79.5
September '06	116.9	124.1	117.9	114.9	114.9	79.5
August '06	125.5	133.2	118.2	125.2	116.6	79.5
July '06	121.2	128.3	115.0	119.9	114.4	79.5
June '06	120.4	127.4	114.3	117.9	112.9	79.5
May '06	118.7	128.9	115.4	118.9	112.9	79.5
April '06	120.7	127.7	115.7	116.9	111.4	79.5
March '06	107.9	115.4	111.9	105.9	105.9	79.5
February '06	110.4	116.9	110.4	110.9	109.4	79.5
January '06	110.9	116.9	110.9	110.9	107.9	79.5

6 Retail Motor Fuel Prices — Mayo

	Self-serve			Full-serve			
	regular	premium	diesel	regular	premium	diesel	propane
31-Dec-08	115.0	N/A	138.0	112.9	-	135.9	129.0
17-Dec-08	123.5	123.0	147.5	112.9	-	135.9	129.0
3-Dec-08	132.5	141.0	147.5	138.9	-	160.9	129.0
19-Nov-08	137.0	141.0	151.5	138.9	-	160.9	129.0
5-Nov-08	151.5	157.0	156.5	138.9	-	160.9	129.0
22-Oct-08	155.5	157.0	158.0	153.9	-	166.9	129.0
8-Oct-08	161.0	167.0	158.0	166.9	-	166.9	129.0
24-Sep-08	162.5	167.0	159.5	169.9	-	169.9	129.0
10-Sep-08	162.5	167.0	159.5	166.9	-	166.9	129.0
27-Aug-08	164.5	167.0	161.5	169.9	-	188.3	129.0
13-Aug-08	166.5	172.0	164.5	169.9	-	169.9	129.0
30-Jul-08	166.5	172.0	164.5	169.9	-	183.3	129.3
16-Jul-08	166.5	172.0	164.5	169.9	-	169.9	129.9
2-Jul-08	162.5	172.0	160.5	167.9	-	157.9	102.9
18-Jun-08	162.5	172.0	160.5	163.9	-	159.9	99.2
4-Jun-08	153.5	165.0	155.0	159.9	-	159.9	129.1
21-May-08	153.5	165.0	155.0	159.9	-	159.9	99.2
7-May-08	153.5	165.0	146.0	149.9	-	159.9	99.2
22-Apr-08	147.5	153.0	143.5	149.9	-	159.9	99.2
9-Apr-08	139.5	147.0	136.5	149.9	-	159.9	99.2
26-Mar-08	139.5	147.0	136.5	139.9	-	138.5	99.2
12-Mar-08	137.5	140.9	129.0	139.9	-	138.5	99.2
27-Feb-08	136.9	140.9	128.9	139.9	-	138.5	99.2
13-Feb-08	136.9	140.9	128.9	139.9	-	138.5	99.2
30-Jan-08	136.9	140.9	128.9	139.9	-	138.5	99.2
16-Jan-08	136.9	140.9	128.9	139.9	-	138.5	99.2
2-Jan-08	136.9	140.9	128.9	139.9	-	138.5	99.2
19-Dec-07	136.9	140.9	128.9	139.9	-	138.5	92.9
5-Dec-07	136.9	140.9	128.9	139.9	-	122.9	99.2
November '07	136.9	140.9	128.9	139.9	-	126.0	99.2
October '07	136.9	140.9	128.9	139.9	-	122.9	99.2
September '07	136.9	140.9	128.9	138.0	-	125.5	99.2
August '07	136.9	140.9	128.9	138.0	-	125.5	99.2
July '07	136.9	140.9	128.9	134.9	-	123.4	99.2
June '07	136.9	140.9	128.9	137.4	-	123.2	99.2
May '07	132.9	132.9	124.9	128.2	-	125.2	92.3
April '07	128.9	132.9	120.9	118.8	-	122.9	92.3
March '07	120.9	132.9	120.9	117.4	-	122.9	92.3
February '07	120.9	132.9	120.9	113.9	-	122.9	92.3
January '07	120.9	132.9	127.9	115.1	-	121.2	92.3
December '06	112.9	132.9	115.9	114.9	-	120.4	92.3
November '06	112.9	132.9	115.9	115.9	-	120.4	92.3
October '06	117.9	132.9	121.9	117.9	-	122.9	92.3
September '06	125.9	132.9	127.9	134.9	-	128.9	92.3
August '06	128.2	132.9	128.2	134.1	-	128.6	92.8
July '06	124.9	132.9	124.9	128.4	-	127.4	93.2
June '06	124.9	132.9	124.9	124.4	-	127.4	93.2
May '06	124.9	132.9	124.9	124.4	-	127.4	92.3
April '06	119.9	132.9	123.4	119.9	-	127.4	92.3
March '06	112.2	132.9	121.9	115.4	-	127.4	92.3
February '06	110.9	132.9	121.9	115.4	-	127.4	92.3
January '06	116.9	132.9	125.9	115.4	-	127.4	92.3

7 Retail Motor Fuel Prices — Teslin

	Self-serve				Full-serve
	regular	mid-grade	premium	diesel	propane
31-Dec-08	86.9	-	89.9	110.4	115.9
17-Dec-08	89.9	-	93.9	115.4	115.9
3-Dec-08	98.4	-	101.9	122.4	115.9
19-Nov-08	107.4	-	110.9	128.9	115.0
5-Nov-08	120.4	-	118.9	133.9	115.0
22-Oct-08	129.9	-	133.9	144.4	115.9
8-Oct-08	137.4	-	138.9	144.4	115.9
24-Sep-08	141.4	-	143.0	146.9	115.0
10-Sep-08	141.4	-	143.9	147.4	115.9
27-Aug-08	142.4	-	147.9	149.4	115.9
13-Aug-08	144.4	-	145.9	152.4	115.9
30-Jul-08	146.9	-	150.9	155.4	110.0
16-Jul-08	147.9	-	150.9	155.9	115.0
2-Jul-08	145.9	-	148.9	152.4	115.0
18-Jun-08	145.9	-	149.9	152.4	115.0
4-Jun-08	139.4	-	142.9	148.9	110.0
21-May-08	138.9	-	142.9	144.4	110.0
7-May-08	137.4	-	139.9	142.4	100.0
22-Apr-08	127.9	-	130.9	137.4	100.0
9-Apr-08	122.9	-	124.9	134.4	100.0
26-Mar-08	120.9	-	126.9	129.4	90.0
12-Mar-08	118.9	-	122.9	124.9	90.0
27-Feb-08	115.9	-	121.9	120.9	90.0
13-Feb-08	115.9	-	121.9	120.9	90.0
30-Jan-08	115.9	-	121.9	120.9	90.0
16-Jan-08	115.9	-	121.9	120.9	90.0
2-Jan-08	115.9	-	121.9	120.9	90.0
19-Dec-07	115.9	-	121.9	120.9	90.0
5-Dec-07	115.9	-	121.9	120.9	90.0
November '07	116.7	-	121.9	114.2	90.0
October '07	118.8	-	123.9	108.3	90.0
September '07	121.9	-	126.9	112.4	90.0
August '07	121.9	-	126.9	111.4	90.0
July '07	121.9	-	126.9	111.4	90.0
June '07	121.4	-	125.9	111.4	90.0
May '07	116.7	-	119.9	109.9	90.0
April '07	109.4	-	113.9	107.9	90.0
March '07	100.9	-	103.9	104.8	90.0
February '07	98.9	-	103.9	106.4	90.0
January '07	101.1	-	105.9	109.6	90.0
December '06	97.7	-	102.9	101.4	90.0
November '06	96.9	-	102.9	101.4	90.0
October '06	103.2	-	107.4	104.2	90.5
September '06	113.3	117.0	117.5	114.5	90.0
August '06	120.8	123.6	126.6	115.4	90.0
July '06	116.7	118.4	121.4	109.4	90.0
June '06	112.9	115.9	118.9	108.7	90.0
May '06	112.9	115.9	118.9	106.4	89.0
April '06	119.0	121.5	123.5	104.2	84.9
March '06	101.9	104.9	106.9	106.4	95.9
February '06	105.9	107.9	109.9	111.7	95.4
January '06	105.9	107.9	109.9	112.9	91.4

8 Retail Motor Fuel Prices — Watson Lake

	Self-serve			Full-serve		
	regular	premium	diesel	regular	diesel	propane
31-Dec-08	104.9	114.9	118.9	-	159.9	126.4
17-Dec-08	109.9	119.9	129.9	-	159.9	126.4
3-Dec-08	109.9	119.9	129.9	-	159.9	126.4
19-Nov-08	116.9	126.9	136.9	-	159.9	126.4
5-Nov-08	123.9	133.9	140.9	-	159.9	126.4
22-Oct-08	133.9	143.9	140.9	-	159.9	126.4
8-Oct-08	138.9	153.9	142.9	-	159.9	126.4
24-Sep-08	146.4	155.9	146.9	-	159.9	122.2
10-Sep-08	147.9	157.9	147.9	-	159.9	118.9
27-Aug-08	147.9	157.9	147.9	-	159.9	118.9
13-Aug-08	152.4	159.4	153.9	-	159.9	118.9
30-Jul-08	152.4	157.9	153.9	-	159.9	118.9
16-Jul-08	152.9	163.5	159.4	-	159.9	118.6
2-Jul-08	151.4	157.9	156.4	-	159.9	118.9
18-Jun-08	151.4	157.9	158.4	-	159.9	118.6
4-Jun-08	143.4	150.9	151.9	-	149.9	118.0
21-May-08	142.4	149.9	150.9	-	143.9	118.0
7-May-08	142.9	149.9	147.9	-	143.9	107.9
22-Apr-08	138.9	146.9	145.9	-	139.9	110.0
9-Apr-08	135.9	143.9	140.9	-	139.9	105.5
26-Mar-08	130.9	138.9	140.9	-	133.9	99.5
12-Mar-08	129.9	138.9	134.9	-	120.9	89.9
27-Feb-08	128.9	137.9	131.9	-	120.9	89.9
13-Feb-08	126.9	133.9	129.9	-	120.9	89.9
30-Jan-08	126.9	139.9	129.9	-	120.9	89.9
16-Jan-08	126.9	137.9	129.9	-	120.9	89.9
2-Jan-08	126.9	137.9	135.9	-	120.9	89.9
19-Dec-07	125.9	134.4	131.9	-	120.9	89.9
5-Dec-07	124.9	135.9	133.9	-	120.9	89.9
November '07	121.2	132.4	119.7	-	120.9	89.9
October '07	121.4	133.4	115.9	-	120.9	89.9
September '07	120.9	133.2	116.9	-	120.9	89.9
August '07	124.1	132.7	115.8	-	120.9	89.9
July '07	123.7	132.1	115.2	-	120.9	89.9
June '07	125.7	133.4	115.7	-	120.9	89.9
May '07	123.3	129.3	115.6	-	120.9	89.9
April '07	114.6	121.3	114.9	119.9	120.9	89.9
March '07	109.9	117.2	110.6	116.9	113.9	89.9
February '07	109.9	117.6	111.5	116.9	113.9	89.9
January '07	109.9	118.6	113.1	116.9	117.9	89.9
December '06	109.9	118.4	106.6	116.9	117.9	89.9
November '06	109.9	118.7	106.9	116.9	117.9	89.9
October '06	113.4	121.9	110.4	116.9	117.9	89.9
September '06	123.4	129.2	118.4	128.9	121.9	89.9
August '06	125.7	131.8	119.4	128.9	121.9	89.9
July '06	123.5	128.8	117.4	128.9	119.9	89.9
June '06	119.9	125.7	114.3	120.9	117.9	89.9
May '06	119.9	125.7	113.9	120.9	117.9	89.9
April '06	117.3	124.1	115.3	118.9	117.9	89.9
March '06	109.6	118.2	113.2	112.9	117.9	89.9
February '06	109.6	118.2	115.6	112.9	117.9	89.9
January '06	109.6	118.2	115.6	112.9	117.9	89.9

9 Retail Motor Fuel Prices — Other Yukon Communities

	Beaver Creek Self-serve		
	regular	premium	diesel
31-Dec-08	99.9	104.9	121.9
17-Dec-08	99.9	104.9	121.9
3-Dec-08	104.9	109.9	127.9
19-Nov-08	118.9	123.9	140.9
5-Nov-08	129.9	134.9	145.9
22-Oct-08	137.9	142.9	151.9
8-Oct-08	148.9	153.9	152.9
24-Sep-08	152.9	157.9	152.9
10-Sep-08	152.9	157.9	158.9
27-Aug-08	152.9	157.9	158.9
13-Aug-08	152.9	157.9	158.9
30-Jul-08	155.9	169.0	166.9
16-Jul-08	160.9	165.9	168.9
2-Jul-08	157.9	162.9	166.9
18-Jun-08	155.9	161.9	162.9
4-Jun-08	150.9	155.9	162.9
21-May-08	150.9	155.9	156.9
7-May-08	150.9	155.9	156.9
22-Apr-08	138.9	143.9	146.9
9-Apr-08	132.9	137.9	140.9
26-Mar-08	133.9	138.9	142.9
12-Mar-08	133.9	138.9	126.9
27-Feb-08	128.9	133.9	126.9
13-Feb-08	128.9	133.9	126.9
30-Jan-08	128.9	133.9	126.9
16-Jan-08	128.9	133.9	126.9
2-Jan-08	N/A	N/A	N/A
19-Dec-07	128.9	133.9	126.9
5-Dec-07	128.9	133.9	126.9
Nov '07	128.9	133.9	122.9
Oct '07	128.9	133.9	122.9
Sep '07	130.1	133.9	123.7
Aug '07	131.3	133.9	124.4
Jul '07	131.3	133.9	122.9
Jun '07	130.8	133.9	124.0
May '07	129.5	132.4	124.0
Apr '07	126.9	128.4	124.4
Mar '07	124.6	120.9	121.2
Feb '07	123.3	120.9	120.4
Jan '07	123.3	120.9	123.9
Dec '06	120.3	120.9	121.1
Nov '06	120.3	120.9	120.3
Oct '06	122.3	120.9	120.4
Sep '06	127.3	126.9	123.4
Aug '06	130.4	137.6	123.8
Jul '06	126.7	133.4	122.9
Jun '06	125.9	131.9	122.4
May '06	124.2	126.0	121.7
Apr '06	124.4	131.0	119.9
Mar '06	118.0	119.2	118.0
Feb '06	124.5	120.9	125.0
Jan '06	124.8	120.9	123.5

	Burwash Landing Full-serve	
	regular	diesel
31-Dec-08	-	-
17-Dec-08	-	-
3-Dec-08	-	-
19-Nov-08	-	-
5-Nov-08	-	-
22-Oct-08	-	-
8-Oct-08	-	-
24-Sep-08	149.9	148.9
10-Sep-08	149.9	148.9
27-Aug-08	155.9	165.9
13-Aug-08	155.9	165.9
30-Jul-08	158.9	165.9
16-Jul-08	158.9	165.9
2-Jul-08	158.9	165.9
18-Jun-08	153.9	165.9
4-Jun-08	153.9	165.9
21-May-08	143.9	150.9
7-May-08	143.9	150.9
22-Apr-08	N/A	N/A
9-Apr-08	N/A	N/A
26-Mar-08	N/A	N/A
12-Mar-08	N/A	N/A
27-Feb-08	N/A	N/A
13-Feb-08	N/A	N/A
30-Jan-08	N/A	N/A
16-Jan-08	N/A	N/A
2-Jan-08	129.9	129.9
19-Dec-07	N/A	N/A
5-Dec-07	129.0	127.0
Nov '07	N/A	N/A
Oct '07	N/A	N/A
Sep '07	129.9	127.4
Aug '07	129.9	126.9
Jul '07	127.9	126.9
Jun '07	126.9	126.9
May '07	121.9	121.9
Apr '07	N/A	N/A
Mar '07	N/A	N/A
Feb '07	106.9	109.9
Jan '07	106.9	109.9
Dec '06	106.9	109.9
Nov '06	106.9	109.9
Oct '06	109.5	111.9
Sep '06	120.5	117.5
Aug '06	129.9	119.9
Jul '06	N/A	N/A
Jun '06	122.5	N/A
May '06	N/A	N/A
Apr '06	N/A	N/A
Mar '06	N/A	N/A
Feb '06	N/A	N/A
Jan '06	N/A	N/A

9 Retail Motor Fuel Prices — Other Yukon Communities

	Carcross Self-serve		
	regular	premium	diesel
31-Dec-08	109.9	129.9	129.9
17-Dec-08	109.9	129.9	129.9
3-Dec-08	109.9	129.9	129.9
19-Nov-08	109.9	129.9	129.9
5-Nov-08	129.9	139.9	135.9
22-Oct-08	129.9	133.9	135.9
8-Oct-08	136.9	149.9	147.9
24-Sep-08	136.9	149.9	147.9
10-Sep-08	145.9	149.9	149.9
27-Aug-08	145.9	149.9	149.9
13-Aug-08	145.9	149.9	157.0
30-Jul-08	N/A	N/A	N/A
16-Jul-08	149.9	154.9	159.9
2-Jul-08	149.9	154.9	159.9
18-Jun-08	149.9	154.9	159.9
4-Jun-08	149.9	159.9	159.9
21-May-08	149.9	157.9	157.9
7-May-08	144.9	149.9	149.9
22-Apr-08	134.9	139.9	144.9
9-Apr-08	129.9	138.9	142.9
26-Mar-08	125.9	132.9	141.9
12-Mar-08	123.0	129.9	126.0
27-Feb-08	119.9	129.9	121.9
13-Feb-08	119.9	129.9	121.9
30-Jan-08	119.9	124.9	121.9
16-Jan-08	119.9	124.9	121.9
2-Jan-08	119.9	124.9	121.9
19-Dec-07	119.9	129.9	121.9
5-Dec-07	119.9	124.9	119.9
Nov '07	115.0	124.9	117.9
Oct '07	121.3	127.4	116.4
Sep '07	124.2	129.9	114.9
Aug '07	124.9	129.9	114.9
Jul '07	129.9	136.9	121.9
Jun '07	129.9	136.9	121.9
May '07	124.9	134.9	121.9
Apr '07	115.9	125.9	121.9
Mar '07	110.9	120.9	118.4
Feb '07	105.9	115.9	114.9
Jan '07	105.6	125.2	114.9
Dec '06	99.7	129.9	110.9
Nov '06	99.5	129.9	110.9
Oct '06	113.9	129.9	121.9
Sep '06	119.9	129.9	124.9
Aug '06	123.2	133.6	123.2
Jul '06	121.9	129.9	119.9
Jun '06	120.9	129.9	119.9
May '06	120.9	129.9	119.9
Apr '06	119.9	127.9	116.4
Mar '06	104.9	114.6	114.4
Feb '06	106.9	117.9	117.9
Jan '06	108.9	119.9	121.9

	Destruction Bay Self-serve			Full-serve
	regular	premium	diesel	propane
31-Dec-08	92.9	97.9	113.9	155.9
17-Dec-08	96.9	101.9	118.9	155.9
3-Dec-08	101.9	106.9	123.9	155.9
19-Nov-08	112.9	117.9	132.9	155.9
5-Nov-08	120.9	125.9	136.9	155.9
22-Oct-08	128.9	133.9	142.9	160.0
8-Oct-08	136.9	141.9	146.9	160.0
24-Sep-08	146.9	151.9	146.9	155.9
10-Sep-08	146.9	151.9	152.9	106.9
27-Aug-08	146.9	151.9	152.9	106.9
13-Aug-08	146.9	151.9	152.9	106.9
30-Jul-08	149.9	154.9	160.9	110.0
16-Jul-08	141.9	156.9	162.9	110.0
2-Jul-08	151.9	156.9	160.9	106.9
18-Jun-08	151.9	156.9	156.9	106.9
4-Jun-08	144.9	149.9	156.9	106.9
21-May-08	144.9	149.0	150.9	106.9
7-May-08	149.0	149.0	150.0	106.9
22-Apr-08	132.9	141.9	140.9	106.9
9-Apr-08	129.9	135.9	138.9	106.9
26-Mar-08	130.9	135.9	139.9	106.9
12-Mar-08	130.9	135.9	123.9	106.9
27-Feb-08	125.9	130.9	123.9	106.9
13-Feb-08	125.9	130.9	123.9	106.9
30-Jan-08	125.9	130.9	123.9	106.9
16-Jan-08	125.9	130.9	123.9	106.9
2-Jan-08	125.9	130.9	123.9	106.9
19-Dec-07	125.9	130.9	123.9	106.9
5-Dec-07	125.9	130.9	123.9	106.9
Nov '07	125.9	130.9	119.9	106.9
Oct '07	125.9	130.9	119.9	106.9
Sep '07	125.9	130.9	119.9	106.9
Aug '07	125.9	130.9	119.9	106.9
Jul '07	125.9	130.9	119.9	106.9
Jun '07	125.9	130.9	119.9	106.9
May '07	122.9	130.4	119.9	108.4
Apr '07	117.4	126.4	119.9	109.9
Mar '07	112.4	121.4	113.4	108.4
Feb '07	109.9	119.9	111.9	106.9
Jan '07	109.9	117.9	118.9	106.9
Dec '06	109.9	117.9	111.4	106.9
Nov '06	109.9	117.9	109.9	101.0
Oct '06	110.9	117.9	110.8	98.9
Sep '06	117.9	123.9	117.9	98.9
Aug '06	127.6	133.9	118.9	98.9
Jul '06	122.9	128.9	116.9	98.9
Jun '06	122.9	128.9	112.9	94.4
May '06	122.9	128.9	112.9	94.4
Apr '06	122.9	128.9	112.9	89.9
Mar '06	108.9	119.9	108.9	89.9
Feb '06	112.9	118.9	113.9	89.9
Jan '06	112.9	118.9	113.9	89.9

9 Retail Motor Fuel Prices — Other Yukon Communities

	Pelly Crossing	
	regular	diesel
31-Dec-08	102.9	119.9
17-Dec-08	115.9	137.9
3-Dec-08	115.9	137.9
19-Nov-08	126.9	149.0
5-Nov-08	139.0	149.0
22-Oct-08	147.9	159.9
8-Oct-08	153.9	164.9
24-Sep-08	159.9	164.9
10-Sep-08	159.9	164.9
27-Aug-08	159.9	174.9
13-Aug-08	159.9	174.9
30-Jul-08	159.9	174.9
16-Jul-08	159.9	169.9
2-Jul-08	159.9	169.9
18-Jun-08	154.9	169.9
4-Jun-08	149.9	159.9
21-May-08	149.9	159.9
7-May-08	139.9	149.9
22-Apr-08	139.9	149.9
9-Apr-08	139.9	149.9
26-Mar-08	129.9	139.9
12-Mar-08	129.9	139.9
27-Feb-08	129.9	139.9
13-Feb-08	129.9	139.9
30-Jan-08	129.9	139.9
16-Jan-08	129.9	149.9
2-Jan-08	129.9	139.9
19-Dec-07	129.9	132.9
5-Dec-07	N/A	N/A
Nov '07	129.9	124.9
Oct '07	129.9	124.9
Sep '07	129.9	124.9
Aug '07	129.9	125.6
Jul '07	129.9	124.9
Jun '07	129.9	124.9
May '07	129.9	124.9
Apr '07	119.9	124.9
Mar '07	111.4	124.9
Feb '07	108.9	124.9
Jan '07	116.9	129.9
Dec '06	111.9	113.9
Nov '06	111.9	113.9
Oct '06	111.9	113.9
Sep '06	117.9	120.4
Aug '06	128.2	126.6
Jul '06	129.9	124.9
Jun '06	124.9	119.9
May '06	118.9	119.9
Apr '06	124.9	119.9
Mar '06	109.6	117.2
Feb '06	112.9	119.9
Jan '06	112.9	119.9

	Ross River	
	regular	diesel
31-Dec-08	121.9	169.9
17-Dec-08	121.9	169.9
3-Dec-08	121.9	169.9
19-Nov-08	145.9	169.9
5-Nov-08	145.9	169.9
22-Oct-08	161.9	169.9
8-Oct-08	161.9	169.9
24-Sep-08	161.9	169.9
10-Sep-08	161.9	169.9
27-Aug-08	161.9	169.9
13-Aug-08	161.9	169.9
30-Jul-08	161.9	169.9
16-Jul-08	161.9	169.9
2-Jul-08	161.9	169.9
18-Jun-08	N/A	N/A
4-Jun-08	147.9	156.9
21-May-08	147.9	156.9
7-May-08	147.9	156.9
22-Apr-08	142.9	151.9
9-Apr-08	135.9	151.9
26-Mar-08	135.9	151.9
12-Mar-08	135.9	151.9
27-Feb-08	128.9	132.9
13-Feb-08	128.9	132.9
30-Jan-08	128.9	132.9
16-Jan-08	128.9	132.9
2-Jan-08	128.9	132.9
19-Dec-07	129.9	132.9
5-Dec-07	N/A	N/A
Nov '07	128.9	132.9
Oct '07	128.9	132.9
Sep '07	128.9	127.9
Aug '07	128.9	121.9
Jul '07	128.9	121.9
Jun '07	123.9	113.9
May '07	123.9	113.9
Apr '07	119.9	124.9
Mar '07	119.9	124.9
Feb '07	119.9	124.9
Jan '07	119.9	124.9
Dec '06	119.9	124.9
Nov '06	119.9	124.9
Oct '06	119.9	124.9
Sep '06	129.9	129.9
Aug '06	132.2	127.2
Jul '06	132.4	121.9
Jun '06	127.9	121.9
May '06	121.9	123.9
Apr '06	115.9	119.9
Mar '06	115.9	119.9
Feb '06	115.9	119.9
Jan '06	115.9	122.9

	Tagish Self-serve			Full-serve
	regular	premium	diesel	propane
31-Dec-08	89.9	99.8	107.8	98.0
17-Dec-08	97.9	99.8	118.4	106.0
3-Dec-08	106.9	114.8	122.9	106.0
19-Nov-08	117.2	136.8	132.4	106.0
5-Nov-08	122.4	136.8	139.4	106.0
22-Oct-08	130.9	136.8	146.4	106.0
8-Oct-08	136.9	146.8	144.9	106.0
24-Sep-08	141.4	146.8	149.9	106.0
10-Sep-08	140.9	149.8	146.4	106.0
27-Aug-08	142.9	149.8	149.4	106.0
13-Aug-08	145.9	149.8	153.4	106.0
30-Jul-08	147.4	154.8	155.9	106.0
16-Jul-08	148.4	154.8	155.9	106.0
2-Jul-08	148.4	154.8	155.9	106.0
18-Jun-08	148.4	154.8	155.9	106.0
4-Jun-08	142.9	146.8	148.9	106.0
21-May-08	140.9	142.8	145.9	106.0
7-May-08	139.9	139.8	145.9	106.0
22-Apr-08	129.8	133.8	139.8	106.0
9-Apr-08	122.9	130.8	132.9	96.0
26-Mar-08	122.9	127.8	127.4	96.0
12-Mar-08	122.9	127.8	127.4	96.0
27-Feb-08	120.4	127.8	122.4	96.0
13-Feb-08	120.4	127.8	122.4	96.0
30-Jan-08	120.4	127.8	125.9	95.0
16-Jan-08	122.4	127.8	123.9	85.0
2-Jan-08	122.4	127.8	122.9	85.0
19-Dec-07	122.4	127.8	125.9	85.0
5-Dec-07	122.4	127.8	125.9	85.0
Nov '07	124.9	N/A	118.9	89.0
Oct '07	121.4	127.8	115.9	85.0
Sep '07	122.4	127.8	115.9	85.0
Aug '07	121.7	127.8	115.4	85.0
Jul '07	121.4	127.8	114.4	85.0
Jun '07	120.7	127.8	113.9	85.0
May '07	115.4	122.3	114.4	85.0
Apr '07	111.4	116.8	112.9	85.0
Mar '07	107.4	108.8	110.9	85.0
Feb '07	104.4	104.8	110.2	85.0
Jan '07	105.2	104.8	113.7	85.0
Dec '06	107.4	104.8	111.2	85.0
Nov '06	104.9	105.8	108.4	85.0
Oct '06	105.2	108.3	109.4	85.0
Sep '06	114.2	121.8	113.7	85.0
Aug '06	122.4	116.7	-	-
Jul '06	120.9	113.2	-	-
Jun '06	118.4	111.4	-	-
May '06	117.4	113.0	-	-
Apr '06	108.9	110.5	-	-
Mar '06	102.6	109.3	-	-
Feb '06	107.9	113.0	-	-
Jan '06	108.4	114.9	-	-

10 Residential Fuel Prices in the Yukon

Average prices as of December 31st, 2008

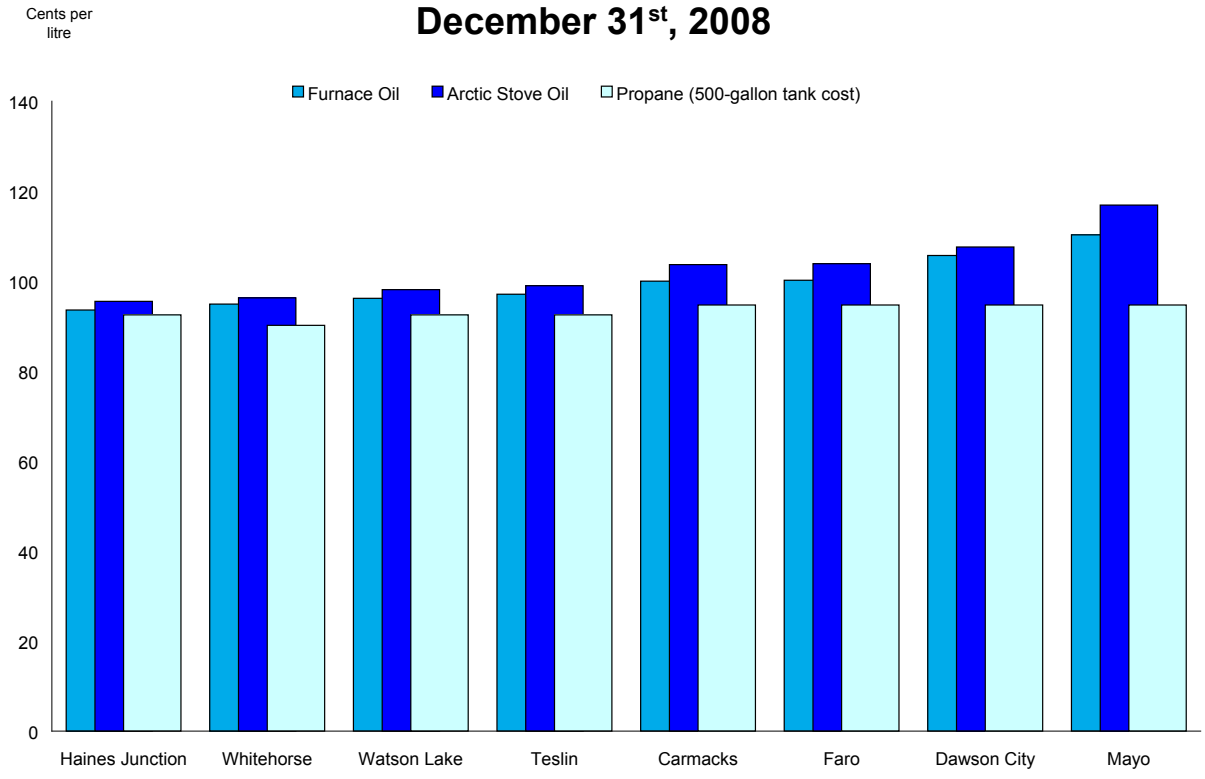
	Residential Heating Fuels		
	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
Whitehorse	94.9	96.3	90.2
Carmacks	100.0	103.7	94.7
Dawson City	105.7	107.6	94.7
Faro	100.2	103.9	94.7
Haines Junction	93.6	95.5	92.5
Mayo	110.3	116.9	94.7
Teslin	97.1	99.0	92.5
Watson Lake	96.2	98.1	92.5

Notes: All prices are Canadian cents per litre, including all applicable taxes.
"N/A" indicates this information is not available for the reporting period.

Average prices for residential furnace oil in the Yukon range from 93.6¢ per litre in Haines Junction to 110.3¢ per litre in Mayo. The price of arctic stove oil varies from 95.5¢ per litre in Haines Junction to 116.9¢ per litre in Mayo. Whitehorse had the lowest propane price at 90.2¢ per litre, while Carmacks, Dawson City, Faro and Mayo had the highest at 94.7¢ per litre.

Price discounts may apply to seniors, members of unions or service groups, or for quick payment. Ask your fuel supplier for details.

Average Residential Heating Fuel Prices December 31st, 2008



11 Residential Heating Fuel Prices — Whitehorse

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	94.9	96.3	90.2
17-Dec-08	97.9	101.2	90.2
3-Dec-08	108.0	111.6	88.6
19-Nov-08	117.0	120.7	92.1
5-Nov-08	125.9	129.2	94.1
22-Oct-08	131.0	134.4	95.8
8-Oct-08	135.0	138.3	95.8
24-Sep-08	132.4	135.9	98.5
10-Sep-08	135.7	139.3	97.4
27-Aug-08	134.9	138.3	97.9
13-Aug-08	139.1	142.3	97.9
30-Jul-08	140.0	143.5	97.9
16-Jul-08	146.9	150.4	99.0
2-Jul-08	144.0	147.2	99.9
18-Jun-08	142.4	145.6	99.9
4-Jun-08	139.0	141.9	97.3
21-May-08	137.9	141.7	107.1
7-May-08	130.1	133.5	93.5
22-Apr-08	127.7	131.1	93.5
9-Apr-08	125.1	128.5	93.5
26-Mar-08	122.7	125.8	93.5
12-Mar-08	116.8	120.0	88.2
27-Feb-08	112.5	115.7	88.2
13-Feb-08	109.3	112.4	88.2
30-Jan-08	109.6	112.4	88.2
16-Jan-08	112.9	116.3	86.1
2-Jan-08	112.6	115.8	83.5
19-Dec-07	113.4	116.6	82.0
5-Dec-07	112.6	115.8	78.9
November '07	106.5	109.6	77.3
October '07	99.8	103.2	73.8
September '07	99.0	102.3	73.0
August '07	97.9	101.6	72.1
July '07	95.5	99.2	70.7
June '07	95.8	99.2	70.4
May '07	97.3	100.4	70.4
April '07	99.8	103.0	69.6
March '07	98.0	101.1	68.8
February '07	96.4	99.4	68.8
January '07	98.0	101.1	67.0
December '06	92.6	95.9	65.4
November '06	87.6	91.0	65.4
October '06	87.0	90.4	66.3
September '06	92.5	95.9	66.3
August '06	105.4	108.7	68.4
July '06	99.7	103.1	70.0
June '06	97.8	101.2	67.7
May '06	95.5	98.9	67.7
April '06	95.6	99.5	73.2
March '06	88.2	92.0	65.2
February '06	91.0	95.1	65.2
January '06	94.3	98.4	63.1

12 Residential Heating Fuel Prices — Carmacks

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	100.0	103.7	94.7
17-Dec-08	104.2	107.9	94.7
3-Dec-08	111.6	115.3	94.7
19-Nov-08	124.3	128.0	98.9
5-Nov-08	131.2	134.9	102.1
22-Oct-08	137.1	140.2	106.3
8-Oct-08	137.1	140.2	106.3
24-Sep-08	137.1	140.2	111.6
10-Sep-08	138.6	142.0	112.7
27-Aug-08	138.6	142.0	113.7
13-Aug-08	150.3	153.5	113.7
30-Jul-08	150.3	153.5	113.7
16-Jul-08	146.1	156.9	113.7
2-Jul-08	146.1	156.9	109.2
18-Jun-08	143.9	147.1	109.2
4-Jun-08	143.9	147.1	109.2
21-May-08	132.3	135.5	109.2
7-May-08	132.3	135.5	109.2
22-Apr-08	129.1	132.3	109.2
9-Apr-08	129.1	132.3	109.2
26-Mar-08	124.9	128.0	109.2
12-Mar-08	118.5	121.7	98.6
27-Feb-08	114.3	117.4	98.6
13-Feb-08	114.3	117.4	98.6
30-Jan-08	117.4	120.6	98.6
16-Jan-08	117.4	120.6	94.3
2-Jan-08	117.4	120.6	94.3
19-Dec-07	117.4	120.6	94.3
5-Dec-07	117.4	120.6	92.2
November '07	106.9	110.1	89.0
October '07	102.6	105.8	89.0
September '07	102.6	105.8	87.4
August '07	102.6	105.8	85.4
July '07	102.6	105.8	84.4
June '07	102.6	105.8	83.8
May '07	101.5	104.7	83.8
April '07	101.5	104.7	82.7
March '07	101.5	104.7	81.5
February '07	101.5	104.7	81.5
January '07	102.6	110.4	78.1
December '06	96.2	100.5	76.8
November '06	90.9	95.2	76.8
October '06	91.7	96.0	76.6
September '06	96.9	101.2	76.6
August '06	108.4	112.7	77.3
July '06	101.3	105.6	77.3
June '06	100.3	104.6	78.9
May '06	101.3	105.6	75.1
April '06	99.7	104.0	73.2
March '06	95.2	99.5	73.2
February '06	96.0	100.3	73.2
January '06	98.8	104.5	73.2

13 Residential Heating Fuel Prices — Dawson City

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	105.7	107.6	94.7
17-Dec-08	110.5	112.4	94.7
3-Dec-08	122.2	124.0	94.7
19-Nov-08	132.8	134.6	98.9
5-Nov-08	138.9	140.7	102.1
22-Oct-08	141.8	143.4	106.3
8-Oct-08	142.3	146.0	106.3
24-Sep-08	142.3	146.0	111.6
10-Sep-08	143.6	147.3	112.7
27-Aug-08	143.6	147.3	113.7
13-Aug-08	148.9	152.6	113.7
30-Jul-08	154.8	158.5	113.7
16-Jul-08	152.6	156.4	113.7
2-Jul-08	150.5	153.7	109.2
18-Jun-08	151.6	152.6	109.2
4-Jun-08	151.6	152.6	109.2
21-May-08	139.9	146.8	109.2
7-May-08	139.9	143.1	109.2
22-Apr-08	132.9	137.0	109.2
9-Apr-08	132.9	132.7	109.2
26-Mar-08	128.7	126.9	109.2
12-Mar-08	120.5	123.7	98.6
27-Feb-08	118.1	120.5	98.6
13-Feb-08	116.8	120.5	98.6
30-Jan-08	121.3	122.1	98.6
16-Jan-08	116.3	120.0	94.3
2-Jan-08	116.3	120.0	94.3
19-Dec-07	116.3	120.0	94.3
5-Dec-07	116.3	120.0	92.2
November '07	115.1	118.8	91.2
October '07	114.0	117.7	91.2
September '07	114.0	117.7	89.6
August '07	114.0	117.7	87.9
July '07	114.6	117.7	87.4
June '07	114.0	117.7	86.8
May '07	113.5	117.2	86.8
April '07	113.5	117.2	85.2
March '07	112.4	116.1	83.6
February '07	111.4	115.1	83.6
January '07	110.6	113.8	80.3
December '06	105.5	109.3	79.0
November '06	102.3	106.6	79.0
October '06	103.5	107.8	78.7
September '06	112.5	116.8	78.7
August '06	119.0	122.7	79.5
July '06	111.3	115.6	79.5
June '06	111.3	115.6	77.4
May '06	108.1	112.4	76.3
April '06	110.4	114.8	75.3
March '06	106.3	110.6	75.3
February '06	109.2	113.5	75.3
January '06	111.3	115.6	75.3

14 Residential Heating Fuel Prices — Faro

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	100.2	103.9	94.7
17-Dec-08	104.4	108.1	94.7
3-Dec-08	111.8	115.5	94.7
19-Nov-08	124.6	128.3	98.9
5-Nov-08	131.4	135.2	102.1
22-Oct-08	137.3	140.5	106.3
8-Oct-08	137.3	140.5	106.3
24-Sep-08	137.3	140.5	111.6
10-Sep-08	139.9	143.1	112.7
27-Aug-08	139.9	143.1	113.7
13-Aug-08	150.5	153.7	113.7
30-Jul-08	150.5	153.7	113.7
16-Jul-08	146.3	149.5	113.7
2-Jul-08	146.3	149.5	109.2
18-Jun-08	144.2	147.3	109.2
4-Jun-08	144.2	147.3	109.2
21-May-08	132.5	135.7	109.2
7-May-08	132.5	135.7	109.2
22-Apr-08	129.3	132.5	109.2
9-Apr-08	129.3	132.5	109.2
26-Mar-08	125.1	128.3	109.2
12-Mar-08	118.7	121.9	98.6
27-Feb-08	114.6	117.8	98.6
13-Feb-08	114.6	116.7	98.6
30-Jan-08	117.7	120.8	98.6
16-Jan-08	117.7	120.8	94.3
2-Jan-08	117.7	120.8	94.3
19-Dec-07	117.7	120.8	94.3
5-Dec-07	117.7	120.8	92.2
November '07	107.5	110.3	91.2
October '07	102.8	106.0	91.2
September '07	102.8	106.0	89.6
August '07	102.8	106.0	87.9
July '07	102.8	106.0	87.4
June '07	102.8	106.0	86.8
May '07	101.8	104.9	86.8
April '07	101.8	104.9	85.2
March '07	101.8	104.9	83.6
February '07	101.8	104.9	83.6
January '07	103.2	107.1	80.3
December '06	101.8	100.7	79.0
November '06	101.8	95.4	79.0
October '06	97.2	96.2	78.7
September '06	97.2	101.4	78.7
August '06	108.6	112.9	79.5
July '06	101.5	105.8	79.5
June '06	101.5	105.8	77.4
May '06	101.5	105.8	75.3
April '06	99.9	104.2	73.2
March '06	95.5	99.7	73.2
February '06	96.2	100.5	73.2
January '06	100.5	104.8	73.2

15 Residential Heating Fuel Prices — Haines Junction

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	93.6	95.5	92.5
17-Dec-08	97.8	99.7	92.5
3-Dec-08	107.1	109.0	92.5
19-Nov-08	119.0	120.9	96.8
5-Nov-08	122.5	124.3	102.1
22-Oct-08	127.0	128.6	104.2
8-Oct-08	131.0	136.1	104.2
24-Sep-08	130.2	134.5	109.5
10-Sep-08	132.3	137.0	110.6
27-Aug-08	131.8	135.5	111.6
13-Aug-08	140.5	142.8	111.6
30-Jul-08	147.7	146.5	111.6
16-Jul-08	145.5	150.8	111.6
2-Jul-08	141.3	145.8	107.1
18-Jun-08	140.2	144.7	107.1
4-Jun-08	139.2	141.5	107.1
21-May-08	131.5	136.1	107.1
7-May-08	130.7	133.1	107.1
22-Apr-08	128.3	132.9	107.1
9-Apr-08	125.9	130.2	107.1
26-Mar-08	119.0	124.2	107.1
12-Mar-08	115.9	121.8	96.5
27-Feb-08	109.8	115.2	96.5
13-Feb-08	108.2	111.3	96.5
30-Jan-08	112.7	112.6	96.5
16-Jan-08	113.7	115.4	92.2
2-Jan-08	113.7	116.5	92.2
19-Dec-07	114.6	119.3	92.2
5-Dec-07	113.7	116.8	90.1
November '07	106.4	111.2	89.0
October '07	100.1	99.6	86.5
September '07	98.9	101.6	87.4
August '07	97.7	100.7	85.8
July '07	96.9	99.8	85.3
June '07	96.5	98.4	84.7
May '07	96.8	99.5	84.7
April '07	98.5	101.4	83.1
March '07	97.6	101.4	81.5
February '07	96.0	98.5	81.5
January '07	98.7	102.2	78.1
December '06	90.3	94.0	76.8
November '06	87.1	89.7	76.8
October '06	89.1	91.9	76.6
September '06	97.9	98.6	76.6
August '06	105.6	109.4	77.3
July '06	99.9	104.2	77.3
Jun '06	98.7	102.5	75.3
May '06	97.6	100.1	74.2
April '06	95.7	99.7	73.2
March '06	93.0	96.1	73.2
February '06	92.3	94.9	73.2
January '06	95.7	98.2	73.2

16 Residential Heating Fuel Prices — Mayo

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	110.3	116.9	94.7
17-Dec-08	114.6	128.0	94.7
3-Dec-08	122.0	131.8	94.7
19-Nov-08	137.7	140.8	98.9
5-Nov-08	141.6	144.2	102.1
22-Oct-08	147.4	149.5	106.3
8-Oct-08	147.4	154.8	106.3
24-Sep-08	147.4	154.8	111.6
10-Sep-08	150.1	153.3	112.7
27-Aug-08	150.1	153.3	113.7
13-Aug-08	160.7	163.9	113.7
30-Jul-08	160.7	163.9	113.7
16-Jul-08	156.5	159.6	113.7
2-Jul-08	156.5	159.6	109.2
18-Jun-08	154.3	152.0	109.2
4-Jun-08	154.3	146.5	109.2
21-May-08	142.7	142.6	109.2
7-May-08	133.9	139.8	109.2
22-Apr-08	132.3	138.2	109.2
9-Apr-08	130.2	136.8	109.2
26-Mar-08	128.0	128.8	109.2
12-Mar-08	125.0	126.1	98.6
27-Feb-08	125.0	126.6	98.6
13-Feb-08	123.8	125.4	98.6
30-Jan-08	127.8	128.2	98.6
16-Jan-08	127.8	128.2	94.3
2-Jan-08	127.8	128.2	94.3
19-Dec-07	127.8	128.2	94.3
5-Dec-07	127.8	123.8	92.2
November '07	117.3	118.5	91.2
October '07	113.0	115.1	91.2
September '07	114.5	114.5	89.6
August '07	113.7	115.0	87.9
July '07	114.3	115.0	87.4
June '07	113.0	113.9	86.8
May '07	111.5	112.6	86.8
April '07	111.5	112.8	85.2
March '07	111.3	112.3	83.6
February '07	111.5	112.6	83.6
January '07	110.8	112.1	80.3
December '06	105.4	106.9	79.0
November '06	103.6	105.0	79.0
October '06	106.5	107.9	78.7
September '06	112.1	113.5	78.7
August '06	118.7	120.4	79.5
July '06	112.8	114.2	79.5
June '06	110.9	112.3	77.4
May '06	110.9	112.3	76.3
April '06	109.2	110.9	75.3
March '06	109.5	110.9	75.3
February '06	110.1	111.5	75.3
January '06	112.5	113.9	75.3

17 Residential Heating Fuel Prices — Teslin

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	97.1	99.0	92.5
17-Dec-08	105.1	107.0	92.5
3-Dec-08	111.6	119.1	92.5
19-Nov-08	124.3	125.5	96.8
5-Nov-08	131.2	130.5	102.1
22-Oct-08	137.1	140.2	104.2
8-Oct-08	137.1	137.4	104.2
24-Sep-08	137.1	140.2	109.5
10-Sep-08	138.6	142.9	110.6
27-Aug-08	138.6	142.9	111.6
13-Aug-08	150.3	153.5	111.6
30-Jul-08	150.3	153.5	111.6
16-Jul-08	146.1	149.2	111.6
2-Jul-08	146.1	149.2	107.1
18-Jun-08	143.9	147.1	107.1
4-Jun-08	143.9	147.1	107.1
21-May-08	132.3	135.5	107.1
7-May-08	132.3	131.8	107.1
22-Apr-08	129.1	129.2	107.1
9-Apr-08	129.1	129.2	107.1
26-Mar-08	124.9	122.3	107.1
12-Mar-08	118.5	116.5	96.5
27-Feb-08	114.3	114.4	96.5
13-Feb-08	114.3	114.4	96.5
30-Jan-08	117.4	116.0	96.5
16-Jan-08	117.4	120.6	92.2
2-Jan-08	116.5	118.1	92.2
19-Dec-07	117.4	120.6	92.2
5-Dec-07	117.4	115.4	90.1
November '07	106.9	108.5	89.0
October '07	102.6	105.8	89.0
September '07	102.6	104.8	87.4
August '07	102.6	105.1	85.8
July '07	102.6	105.8	85.3
June '07	102.6	105.8	84.7
May '07	101.5	104.7	84.7
April '07	101.5	103.5	83.1
March '07	101.5	102.7	81.5
February '07	101.5	102.2	81.5
January '07	103.3	101.8	78.1
December '06	96.2	96.4	76.8
November '06	90.9	93.2	76.8
October '06	91.7	94.7	76.6
September '06	96.9	101.2	76.6
August '06	108.4	110.8	77.3
July '06	101.3	105.6	77.3
June '06	101.3	105.6	75.3
May '06	101.3	105.6	74.2
April '06	99.7	104.0	73.2
March '06	95.2	99.5	73.2
February '06	96.0	100.3	73.2
January '06	100.3	104.5	73.2

18 Residential Heating Fuel Prices — Watson Lake

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	96.2	98.1	92.5
17-Dec-08	98.3	101.2	92.5
3-Dec-08	104.7	108.7	92.5
19-Nov-08	114.7	118.7	96.8
5-Nov-08	121.4	125.9	102.1
22-Oct-08	131.4	135.1	104.2
8-Oct-08	134.0	137.7	104.2
24-Sep-08	131.8	135.6	109.5
10-Sep-08	134.5	138.3	110.6
27-Aug-08	134.8	139.1	111.6
13-Aug-08	142.8	146.5	111.6
30-Jul-08	146.4	150.2	111.6
16-Jul-08	149.4	153.2	111.6
2-Jul-08	146.6	150.5	107.1
18-Jun-08	145.1	148.9	107.1
4-Jun-08	143.7	147.5	107.1
21-May-08	137.9	141.7	107.1
7-May-08	134.4	138.2	107.1
22-Apr-08	131.7	134.8	107.1
9-Apr-08	131.0	134.8	107.1
26-Mar-08	128.2	131.9	107.1
12-Mar-08	123.7	127.6	96.5
27-Feb-08	118.2	122.0	96.5
13-Feb-08	112.8	116.6	96.5
30-Jan-08	113.9	117.7	96.5
16-Jan-08	115.2	119.4	92.2
2-Jan-08	116.2	120.0	92.2
19-Dec-07	118.7	122.5	92.2
5-Dec-07	117.1	120.9	90.1

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
November '07	107.3	111.1	89.0
October '07	101.4	105.5	89.0
September '07	100.9	104.7	87.4
August '07	99.9	103.0	85.8
July '07	98.5	102.2	85.3
June '07	98.6	101.9	84.7
May '07	98.5	101.8	84.7
April '07	99.7	103.0	83.1
March '07	100.8	104.1	81.5
February '07	98.5	101.4	81.5
January '07	100.4	103.6	78.1
December '06	91.4	95.3	76.8
November '06	87.5	91.3	76.8
October '06	88.4	92.2	76.6
September '06	92.6	96.3	76.6
August '06	105.4	109.4	77.3
July '06	100.5	104.9	77.3
June '06	98.3	102.7	75.3
May '06	98.9	103.4	74.2
April '06	96.8	101.2	73.2
March '06	91.0	95.4	73.2
February '06	92.1	96.5	73.2
January '06	97.4	102.3	73.2

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REFERENCE: October 6, 2008 Application, Rates, Page 4-12

YEC states "In summary, runoff rates no longer conform with the 1996/97 GRA principles and OIC 1995/90, and as a result it is now actually cheaper to heat with electricity at current runoff rates (even including all riders) than it is with oil, which has the effect of encouraging inefficient and inappropriate use of electric heating in Yukon homes".

QUESTION:

a) Please provide YEC's understanding of the reasons why Yukon homeowners have installed electricity over the years as a source for space heating including any incentives that have been made available over the years.

b) Please describe what efforts YEC has taken to encourage Yukoners, construction companies and land developers to move away from electric heating systems as a primary source of space heating since the Yukon government's Cabinet Commission on Energy identified this issue as part of its recommendations in 1998 and the Yukon government accepted all of the Commission's recommendations in November 1998 with its *Implementation Plan for the Final Report on the Cabinet Commission on Energy*.

c) Please describe efforts being undertaken by other Yukon government departments and agencies to either lessen the burden on ratepayers using electricity for space heating or to assist these ratepayers to shift to another fuel source.

d) Please explain why YEC has not proposed / considered other pricing structures to discourage consumption overall, or to shift demand to less costly periods. In particular, please describe YEC's evaluation of alternatives such as stepped rates for rate classes, critical period rates, tariffs focused on promoting energy efficient new construction, and the consideration of the benefits of 'smart' or advanced metering technology which offer potential for greater consumption information and control being available to the consumer.

ANSWER:

(a)

Yukon Energy is not aware of the reasons why customers made those choices and Yukon Energy is not aware of any incentives being made available to homeowners to encourage the installation of electric space heating.

(b)

Yukon Energy has no direct contact with construction companies in the Whitehorse area as Yukon Energy is not the retail power supplier in this area.

Yukon Energy notes that the closer second block electricity rates are set to conform with the "economy and efficiency" direction of OIC 1995/90, the more efficient the market price signal is to existing and potential customers to conserve their energy usage. YEC's proposal to increase the second block rate for residential customers is a step to send the right price signal to customers so they are making informed decisions on their use and choice of heating systems

(c)

Yukon Energy cannot answer for Yukon government departments and agencies.

Yukon Energy is aware that the Energy Solution Center (ESC) and Yukon Housing deliver a number programs aimed at improving energy efficiency in your home or business. Information and details on the programs that they provide is available on the ESC and Yukon Housing websites at the following address:

http://www.emr.gov.yk.ca/energy/aboutesc.html

http://www.housing.yk.ca/index.html

(d)

On ***stepped rates***, this rate structure which is now being pursued in other jurisdictions such as BC and Manitoba, has been in place in Yukon since at least the early 1990s. Yukon Energy is proposing in this application to enhance the stepped rate price signal.

On ***critical period rates***, Yukon Energy manages the secondary sales rate program to interrupt loads in "critical" periods, defined by the need for diesel generation. There is no practical application of a similar rate structure to firm rates.

On ***tariffs focused on promoting energy efficient new construction***, see part (a) above. This matter is not presently under consideration by Yukon Energy.

On ***consideration of the benefits of 'smart' or advanced metering technology which offer potential for greater consumption information and control being available to the consumer***, Yukon Energy notes that it is not the retailer of power for most Yukoners, and as such is not in control of the metering technologies being put into service in Yukon.

REFERENCE: October 6, 2008 Application, Rates, Page 4-12

YEC states "…current run out rates in all rate zones simply are not in keeping with the conservation principles of OIC 1995/90 nor are such rates consistent with the overriding principles outlined in the YTG's climate change policy".

QUESTION:

a) Please confirm that by "overriding principles", YEC is referring to the Guiding Principles referenced on page 5 of the referenced Climate Change Strategy document.

b) Please explain how current run out rates are not consistent with these Guiding Principles.

c) Please provide YEC's rationale for keeping 1000 kWh as the year-round size of the first energy block.

ANSWER:

(a)

The comment is in general relation to the overarching principles of Yukon's climate change policies.

(b)

Current run-out rates do not encourage efficient use of energy to the same degree as was achieved during 1997 when the current run out rates were set.

(c)

Yukon Energy is not proposing general rate redesign at this time. The 1000 kW.h per month cutoff is a component of the existing rates, and is consistent with OIC 1995/90.

REFERENCE: October 6, 2008 Application, Rates, Page 4-12

YEC states "It is also important to note that without proper economic signals there may be a tendency in new construction for electric heating to be preferable to customers due to the lower capital cost of electric heating (baseboards) compared to oil (furnaces)".

QUESTION:

a) Please describe the discussions that YEC has had with builders and land developers concerning the "proper economic signals" they feel are required.

b) Please provide YEC's cost analysis for the installation of electric heating versus oil-fired heating. Please provide the source of any referenced data.

ANSWER:

(a)

To be clear, the "proper economic signals" noted are required by the current Rate Policy Directive in place in the Yukon (OIC 1995/90) and not just by Yukon Energy. Yukon Energy is bringing forward a GRA Application that respects the direction provided by OIC 1995/90.

OIC 1995/90 requires that the Board fix runoff rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency. As noted at page 4-12 of the Application, current runoff rates for residential customers in the Hydro and Large Diesel rate zone communities (including all riders) are only 14.39 cents/kWh. Were the rate design approaches for runoff rates approved by the Board during 1996/97 GRA to be strictly applied the target runoff rates would be closer to 37.37 cents/kWh. The Application provides a modest increase to ensure runoff rates better reflect the OIC and past Board direction related to runoff rates.

Please see the response to UCG-YEC-1-59(b) in respect of discussions with builders and land developers.

(b)

Installing baseboard heating is less costly than installing oil heating, but no specific capital cost estimates are available to YEC. The Board Report to the Commission in Executive Counsel provided after the 1992 Resource Plan hearing provides that, “it was clearly demonstrated during the course of the proceeding that electric heating uses more resources than direct combustion of fuels. Although the capital cost of installing electric heating is less than for direct combustion fuels, in the long run electric heating is more expensive.”

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "…electricity prices today should at least be in the 20-22 cents/kW.h range (i.e., at least 25 to 40% higher than oil heating costs) to promote in the short term "economy and efficiency" by once again starting to discourage electric heating. Further, given the system realities these rates should be planned now to be set in the near term at even higher levels (e.g., in excess of 30 to 35 cents per kW.h based on the current GRA diesel fuel price forecasts), if the rate design principles adopted by the Board in the 1996/97 GRA are to be followed in the future".

QUESTION:

a) Please update YEC's 20-22 cents per kWh price range based on current heating oil costs. Please provide details of source data used for calculations.

b) Please identify bill impacts if YEC's estimate of where rates should be (i.e., 30-35 cents per kWh) is realized.

c) Please provide the calculations and sources of data for YEC's conclusions.

d) Please provide details of the rate rebalancing efforts by BC Hydro that were initiated in 2007 by the BC Utilities Commission.

ANSWER:

(a)

The target range has not changed.

In the GRA, Yukon Energy only sought to move second block rates a modest amount towards the full efficient level of 37.37 cents/kW.h At today's diesel prices of approximately 76 cents/litre at Whitehorse (per CW-YEC-1-16), the full required level is approximately 24.8 cents/kW.h,[1] still above the 20-22 cents/kW.h targeted by Yukon Energy.

[1] 76 cents/litre divided by 3.6 kW.h/litre plus 10% for system losses plus 1.6 cents/kW.h for non-fuel variable O&M expense.

(b)

Bill impacts by class will be $0, as any increases in the second block rate will be offset by decreases in the first block rate.

(c)

Please see **(a)** above.

(d)

Yukon Energy does not have specific knowledge of the process or efforts expended in BC, but notes the following information collected from the BCUC and BC Hydro website:

BC Hydro filed its Rate Design Application (its first since 1991) with the BC Utilities Commission (BCUC) on March 15, 2007.

Filing of the Application was followed by a three-and-a-half month regulatory review process directed by the BCUC.

On October 26, 2007, the BCUC issued its decision on BC Hydro's 2007 Rate Design Application. On February 20, 2008, BC Hydro filed an application for reconsideration on the rebalancing component of the RDA. BC Hydro sought to suspend the rate rebalancing orders due to pending provincial legislation to set aside the Order. Components of the RDA not relating to the rate rebalancing were approved by the BCUC and came into effect on April 1, 2008.

On March 7, 2008, the BCUC approved BC Hydro's request to suspend the implementation of the rate rebalancing portion of the RDA decision.

For more information on process and outcomes please see link to BC Hydro's website provided below:

http://www.bchydro.com/planning_regulatory/regulatory/rate_design_application.html?WT.mc_id=rd_ratedesign

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "In the residential class, by far the minority of sales are made at the second block rates. As shown in Table 4.9, less than 20% of the residential energy sold in Yukon at second block rates for the non-government class, and only slightly higher (approximately 23%) for the government class"

QUESTION:

a) Please provide the billing data upon which YEC has determined the distribution of residential energy sales by rate block.

ANSWER:

(a)

Please see Table 4.9 which notes forecast 2009 Second Block energy sales for Residential Non-Government customers at 19.53% of total sales for the class. This is based on:

- YEC sales per its GRA forecast; and

- YECL sales per YEC's wholesale forecast included in the Application (which includes a 1.2% escalation in Hydro Zones compared to YECL's 2009 GRA forecasts, and YECL forecast values in all non-hydro communities).

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "This can be done by establishing an offsetting decrease to first block rates so as to ensure the residential share of overall electricity charges remain the same".

QUESTION:

a) Please confirm that YEC is not suggesting that the residential class' share of YEC's actual cost of service nor residential bills will remain the same.

b) Please explain why YEC is maintaining the current rate block structure given the variation in seasonal use and the adverse impacts identified for users of more electricity.

ANSWER:

(a)

As noted previously in responses UCG-YEC-1-13, and UCG-YEC-1-15, the Residential Class' share of the actual cost of service that would otherwise exist will remain the same. Pursuant to the direction provided by OIC 2008/149, the rate decrease will be applied in equal percentages across each class.

Individual residential bills will vary, depending on the energy use profile of the customer.

(b)

Yukon Energy is not proposing any such rate redesign in this Application regarding seasonal use, as any such proposals would go far beyond what YEC sees as feasible to address as a near term priority.

Aspects of the current block structure are imposed by government OIC (1995/90). Section 4(2) of that OIC notes as follows:

> 4(2) the Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and

such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.

While the OIC would provide for some upward adjustment to the rate block structure, i.e., the runoff block may be set higher than 1,000 kWh, such a change to the currently approved rate design would need to be undertaken jointly by YEC and YECL.

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "…the General Service class is dominated by sales at second block rates (approximately 71% of sales in the non-government class, and 87% of sales in the government class)".

QUESTION:

a) Please provide the billing data upon which YEC has determined the distribution of general service energy sales by rate block.

ANSWER:

(a)

Please see Table 4.9 which shows the forecast 2009 Second Block energy sales for General Service Non-Government customers. This is based on:

- YEC sales per its GRA forecast; and

- YECL sales per YEC's wholesale forecast included in the Application (which includes a 1.2% escalation in Hydro Zones compared to YECL's 2009 GRA forecasts, and YECL forecast values in all non-hydro communities).

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "…when dealing with a large and relatively non-homogenous group, rate structures that impose a notable inverted structure require careful attention given the range of impacts on the different profiles of customers in the class. For example, in order to provide fair price signals it may require establishing multiple general service rate subclasses, or further rate blocks. Yukon Energy does not believe that it is practical to properly analyze and implement an appropriate rate design package in a Yukon Energy Revenue Requirement proceeding".

QUESTION:

a) Please explain whether this current proceeding is to address a general rate application or a revenue requirement application.

b) Please explain how the YUB can ignore the issue of the non-homogenous ratepayer groups identified by YEC in this application when making decisions on the rate issues proposed by YEC.

ANSWER:

(a)

The requested approvals are as set out at pages 3 to 5 of Yukon Energy's 2008/2009 General Rate Application.

(b)

Yukon Energy is not suggesting the Board ignore any issues. Yukon Energy is only noting that the required information to undertake General Service rate redesign is not available to it or the Board in this proceeding, and that the matter of redesigning general service rates requires extensive data only available to YECL. Consequently, as noted at Tab 6 of the Application (page 6-4 to 6-5) Yukon Energy proposes "as a first priority" that future joint attention by YEC and YECL be directed towards identifying and assessing rate design options for the General Service rate classes to promote economy and efficiency in accordance with OIC 1995/90.

Yukon Energy is seeking approval of only the first steps in addressing necessary runoff rate adjustment issues that are ultimately required for all customer classes. The current proposal is limited to a partial adjustment to the Residential Class runoff rate, such that it better accords with the direction provided by OIC 1995/90 and the rate design approach established by the Board subsequent to the 1992 Cost of Service and Rate Design proceeding and affirmed in the 1996/97 General Rate Application.

As noted in the Application (at page 4-13), it is practical at this time to address this concern as it related to Residential customer classes since the minority of residential sales (less than 20%) are in the second block. Material rate design issues would need to be addressed prior to implementing any runout rate adjustments to general service class rates since sales for this group of customers are predominantly in the second block.

REFERENCE: October 6, 2008 Application, Rates, Page 4-14

YEC states "In conclusion, although it is patently clear that run out rates must be changed, a second block level today for residential customers based on 2009 diesel price forecasts and full implementation of 1996/97 GRA principles is not reasonably achievable in one rate change, given obvious potential rate impacts to individual customers of a required 160% increase in the Hydro/Large Diesel zone runoff rate. However, a more gradual transition to higher runoff rates based on the cost of diesel generation is both necessary and feasible today for the residential classes, with a first step designed to increase Hydro zone residential runoff rates by 40 to 50%, i.e., to the 20 to 22 cents/kW/h range net of GST".

QUESTION:

a) Please explain how a gradual and stable transition to cost-based rates can be realistically and fairly designed without first establishing the actual level of cost based rates.

b) Please provide an analysis of how the proposed runoff rates compare to the actual marginal cost of providing electricity.

ANSWER:

(a)

The above referenced quote from the Yukon Energy Application does not reference a transition towards any form of embedded cost-based rates, but a transition towards more efficient price signals that meet the requirements of OIC 1995/90. This transition is not linked to establishing cost of service for each rate class.

As discussed in responses to UCG-YEC-1-13, and UCG-YEC-1-15, an embedded cost of service is not relevant or appropriate to any necessary adjustments to runout rates to ensure that such rates better reflect rate design principles approved by the Board (most recently in Order 1996-7). Based on their relevant considerations reviewed, runout rates must be set to ensure economy and efficiency by reflecting short term incremental energy costs for each rate zone.

(b)

As noted at pages 4-11 and 4-12 of the Application, applying the same rate design approach for 2009 as approved in the 1996/97 GRA would yield target runoff rates for hydro zone communities of approximately 37.37 cents/kW.h. The current effective runout rate for the Hydro zone is only 14.39 cents/kWh and as such does not meet the requirements of OIC 1995/90 or the rate design principles previously established by the YUB. The applied for increase in the runout rate provides for a gradual transition to higher runoff rates based on the cost of diesel generation by modestly adjusting hydro zone residential runout rates upwards to the 21 cents/kWh range (net of GST) as shown in Table 4.7.

REFERENCE: October 6, 2008 Application, Rates, Page 4-14

YEC states "With the completion of the Carmacks-Stewart Transmission Project and the connection of the Minto mine, Yukon Energy is able to implement substantial rate reductions for all retail customer classes throughout Yukon. For 2009, this reduction totals $1.334 million, or 3.48% of total Yukon-wide base rate revenues as forecast by Yukon Energy".

QUESTION:

a) Please provide the cost and revenue data used to determine the $1.334 million benefit to non-industrial customers.

b) Please provide a breakdown of the data contain in Table 4.6 between YEC and YECL.

c) Please provide a table similar to the table provided in response to part (b) for 2008 benefits.

ANSWER:

(a)

Please see Table 4.1 provided at page 4-3 of Tab 4 of the Application which sets out Yukon Energy's revenue required from Rates for 2008 and 2009.

(b)

Please see Table 4.9 provided in Tab 4 of the Application.

(c)

Please see response to (a) above. Table 4.1 provides Yukon Energy Revenue Requirement from Rates for both 2008 and 2009.

REFERENCE: October 6, 2008 Application, Rates, Page 4-17

YEC states "Yukon Energy proposes to implement a system-wide revenue-neutral adjustment to firm residential non-government and residential government rates for both Yukon and YECL retail customers".

QUESTION:

a) Please confirm that the application should read "…rates for both YEC and YECL retail customers".

b) Please provide an explanation for YEC's interpretation of OIC 2008/149 that rate adjustments designed and proposed only by YEC are supposed to be (i) revenue neutral and (ii) applicable to customers of both YEC and YECL.

c) Please provide details of discussions and correspondence between YEC and YECL on YEC's rate design proposals.

ANSWER:

(a)

Confirmed.

(b)

Yukon utilities can address rate changes only if they are applicable to customers of both utilities, i.e., YEC's rate reduction benefits all Yukon retail customers. The test of revenue neutrality relates to an added requirements when changing retail rates prior to 2013.

Order-in-Council 1995/90 at section 4(1)(b) provides that "rates for each class of non-government retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited Customers." The recent OIC (2008/149) amends OIC 1995/90 to add section 2.1(1) which set out that "The Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers."

(c)

Please see LE-YEC-1-4 and YUB-YEC-1-20.

REFERENCE: October 6, 2008 Application, Rates, Page 4-21 and 4-22

Table 4.9 – Primary Sales by YEC/YECL Rate Class & Billing Determinants - 2009 Existing Rates.

Table 4.10 – Primary Sales by YEC/YECL Rate Class & Billing Determinants - 2009 with Proposed Rate Rebalancing.

QUESTION:

a) Please explain why YEC accepted YECL's sales forecast except within the hydro zones (to which YEC added a 1.2% escalation factor).

ANSWER:

(a)

Yukon Energy has no experience with, nor reason to dispute, YECL's forecasts for isolated diesel-served communities.

REFERENCE: **October 6, 2008 Application, Rates, Pages 4-23, 4-24, 4-26, 4-27**

Table 4.11 – Bill Comparisons: 2009 Proposed Rates vs. Existing – Residential Non-Government

Table 4.12 – Bill Comparisons: 2009 Proposed Rates vs. Existing – Residential Non-Government (Absent RSF)

Table 4.14 – Bill Comparisons: 2009 Proposed Rates vs. Existing – General Service Non-Government

Table 4.15 – Bill Comparisons: 2009 Proposed Rates vs. Existing – General Service Non-Government (Absent RSF)

QUESTION:

a) Please update the referenced tables assuming that the first energy block for residential customers is 1100, 1200 and 1300 kWh and the first block for general service customers is 2200, 2400 and 2600 kWh.

ANSWER:

(a)

While YEC has general information on the consumption of the various rate classes throughout Yukon, the precise information about bill determinants as required to answer the above question can only be derived from YECL data that is not available to YEC.

The implementation of such a change would require material rate redesign of YEC and YECL rates to ensure the full revenue requirement of both utilities was collected. For example, as second block energy is presently sold at a higher price than first block energy, increasing the size of the first block (and reducing the number of units sold at second block prices) would lead to a requirement to raise the rate for the first block to collect the same revenues from the class. The same situation arises for Rider U calculations (in that increasing first block sales will decrease Rider U).

REFERENCE: **October 6, 2008 Application, Rates, Appendix 4.1 – Rate Schedules**

YEC's rate schedules state that "The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours".

QUESTION:

a) Please provide a copy of YEC's current Electric Service Regulations as approved by the YUB.

b) Please provide any analysis that YEC has made to verify that the miscellaneous charges (e.g., connection fees, reconnection charge, meter test fee, late payment charge, dishonoured cheque charge, maximum company investments) within the Electric Service Regulations are still appropriate given associated costs.

c) Please explain how customers resolve billing or service disputes with provider (i.e., does the service provider make final decision or is there an independent arbitrator available besides the Yukon Utilities Board?).

d) Please explain how a dispute is to be brought to the YUB and if there are informal processes available.

e) Has YEC ever been involved in a dispute with a residential customer that has been taken to the YUB? If yes, please describe the circumstances and process.

f) Please provide YEC's rationale for not having a Customer Bill of Rights as is the case in many other jurisdictions.

ANSWER:

(a)

Please see Attachment 1 to this response.

(b)

This type of analysis is not available and cannot be provided.

(c)

Yukon Energy works with customers to resolve all issues raised by customers to the extent possible. Customers who are dissatisfied with a decision or treatment by Yukon Energy relative to a regulated activity are directed to contact the YUB.

(d)

Part 4, Sections 44-49 of the Public Utilities Act describes the process for complaint notification and settlement.

(e)

YEC is not aware of any dispute with a residential customer that has been taken to the YUB.

(f)

Yukon Energy (and YECL) provide regulated service under an approved set of Electrical Service Regulations. The ESRs set out the rights and obligations of customers and the utility.

YUKON ENERGY CORPORATION

AND

THE YUKON ELECTRICAL COMPANY LIMITED

ELECTRIC SERVICE REGULATIONS

INDEX

HEADING		PAGE
1.	INTERPRETATION	
1.1	Definitions	4
2.	INTRODUCTION	
2.1	Board Approval	6
2.2	Electric Service Tariff	6
2.3	Effective Date	6
3.	GENERAL PROVISIONS	
3.1	Regulations Prevail	7
3.2	Ownership of Facilities	7
3.3	Use of Energy	7
3.4	Customer Extensions	7
3.5	Customer Generation	7
3.6	Frequency and Voltage Levels	7
4.	APPLICATION FOR AND CONDITIONS OF SERVICE	
4.1	General Requirements	9
4.2	Conditions of Service	9
4.3	Connection Fee	9
4.4	Application of Rate Schedules	9
4.5	Extensions to Electric Heat Customers	9
4.6	Multiple Dwellings	10
4.7	Totalized Metering	10
4.8	Consolidated Billing	10
4.9	Security Deposit	10
4.10	Use of Security Deposit	11
4.11	Delay in Taking Service - Other	11
4.12	Extension of Service	11
4.13	Underground Subdivision Extensions	11
4.14	Conversion from Overhead to Underground Service	11
4.15	Temporary Service	12
4.16	Mobile Homes	12
4.17	Relocation of Company Facilities	12
4.18	Reconnection/Restoration of Service	12
4.19	Construction Contribution Cost Sharing	13

5. RIGHTS-OF-WAY AND ACCESS TO FACILITIES

5.1	Easements	14
5.2	Right of Entry	14
5.3	Vegetation Management	14
5.4	Interference with Company's Facilities	14
5.5	Customer Brushing	14

6. METERS

6.1	Installation	15
6.2	Location	15
6.3	Meter Tests and Adjustments	15
6.4	Energy or Demand Diversion	15

7. METER READING AND BILLING

7.1	Reading and Estimates	17
7.2	Proration of Initial and Final Billings	17
7.3	Payment of Accounts	17
7.4	Late Payment Charge	17
7.5	Dishonored Cheques	17
7.6	Outstanding Charges	18

8. SERVICE CHANGES

8.1	Notice by Customer	19
8.2	Responsibility for Damage	19
8.3	Changes to Company Facilities	19

9. COMPANY RESPONSIBILITY AND LIABILITY

9.1	Continuous Supply	20
9.2	Planned Outages	20
9.3	Company Liability	20
9.4	Extraordinary Circumstances	20

10. CUSTOMER RESPONSIBILITY AND LIABILITY

10.1	Provide Permit	21
10.2	Customer Responsibility	21
10.3	Protective Devices	21
10.4	Service Calls	21

11. TERMINATION OF SERVICE

11.1 Customer-requested Termination 22
11.2 Company Termination for Safety or Technical Reasons 22
11.3 Company Termination - Other Than Safety 22
11.4 Removal of Facilities 23

SCHEDULE A - Standard Supply Specifications 24

SCHEDULE B - Maximum Company Investment 25

SCHEDULE C - Conditions for Underground Subdivisions 26

YUKON ENERGY CORPORATION

AND

THE YUKON ELECTRICAL COMPANY LIMITED

ELECTRIC SERVICE REGULATIONS

1. INTERPRETATION

1.1 Definitions

Unless the context requires otherwise, the following words and phrases, whenever used in these Regulations, the Electric Service Tariff or an application, contract or agreement for service, shall have the meanings set out below.

"billing demand" - the demand upon which billing to a customer is based.

"Board" - the Yukon Utilities Board.

"Company" - The Yukon Electrical Company Limited or Yukon Energy Corporation.

"connected load" - the sum of the capacities or ratings of the electric energy consuming apparatus connected to a supplying system.

"construction contribution" - the difference between the cost of extending the Company's facilities to serve a customer and the maximum Company investment specified in Schedule B.

"customer" - means a person, firm, corporation, association or organization which has applied for or is receiving the provision of service by the utility. This would include joint tenants whether or not their name appears on the application.

"demand" - the rate at which electric energy is delivered by the Company (expressed in kilowatts, kilovoltamperes or other suitable unit) at a given instant or averaged over any designated period of time.

"energy" - electric energy (expressed in kilowatt hours).

"extraordinary circumstances" - circumstances not reasonably within the control of the Company, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, and any other cause, whether of the kind herein enumerated or otherwise.

"facilities" - a physical plant (including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery).

"family dwelling" - a residential dwelling unit which is not a multiple dwelling, consists of single family living quarters having in one self-contained unit at least sleeping quarters, a kitchen and bathroom (see definition of "multiple dwelling").

"in-service date" - the date on which the customer specifies service is to be available or the date the service is actually available, whichever is later.

"interconnected system" - those portions of the Company's facilities which are connected to the Whitehorse/Aishihik/Faro (WAF) power grid or to the Mayo-Dawson grid.

"isolated system" - those portions of the Company's facilities which do not form part of the interconnected system.

"load" - the demand and energy delivered to or required at any point of delivery.

"load factor" - the ratio of the average demand (in kilowatts) supplied during a designated period to the peak or maximum load (in kilowatts) occurring in the period. To express load factor as a percentage:

(a) multiply the energy used in the period by 100;
(b) multiply the maximum demand by the number of hours in the period; and
(c) divide (a) by (b).

"multiple dwelling" - a residential building containing more than one residential dwelling unit.

"point of delivery" - the point at which the Company's service conductors are connected to the wires or apparatus of a customer.

"power factor" - the ratio of the highest metered kilowatt demand in a billing period to the highest metered kilovoltampere demand in that same billing period.

"service" - the delivery of energy by the Company at the demand required by a customer.

2. INTRODUCTION

2.1 Board Approval

These regulations have been approved by the Board.

The Company may amend these regulations by filing a notice of amendment with the Board. Included in the notice to the Board shall be notification of which customer groups are affected by the amendment and an explanation of how affected customers will be notified of the amendments. The amendment will take effect 120 days after such notice is filed unless the Board orders otherwise.

2.2 Electric Service Tariff

These regulations are the Electric Service Regulations referred to in the Company's Electric Service Tariff and form part of the Electric Service Tariff.

2.3 Effective Date

These regulations come into force on October 18, 2005, and replace the Company's previous Electric Service Regulations. Whenever the Board approves an amendment to these Regulations, revisions will be issued, with the effective date of the amendments indicated on the top of each affected page.

3. GENERAL PROVISIONS

3.1 Regulations Prevail

These regulations apply to the Company and to every customer.

No agreement can provide for the waiver or alteration of any part of these regulations unless such agreement is first filed with and approved by the Board.

3.2 Ownership of Facilities

The Company remains the owner of all facilities it provides to serve the customer, unless a contract between the Company and customer specifically provides otherwise.

Payment made by customers for costs incurred by the Company in installing facilities does not entitle customers to ownership of any such facilities, unless a contract between the Company and the customer specifically provides otherwise.

3.3 Use of Energy

Unless otherwise provided in a contract with the Company, a customer shall not sell energy provided by the Company unless the Company has first given written consent.

3.4 Customer Extensions

A customer shall not extend service facilities beyond property owned or occupied by the customer.

3.5 Customer Generation

A customer must sign an agreement with the Company if he/she wishes to use service.

a) in parallel operation with; or
b) as supplementary, auxiliary or stand-by service to any other source of electric energy.

3.6 Frequency and Voltage Levels

The Company will make every reasonable effort to supply energy at 60-Hertz alternating current. The voltage levels and variations will comply with the Canadian Standards Association standards and as specified in Schedule A.

Some voltage levels set out in Schedule A may not be available at all locations served by the Company.

4. APPLICATION FOR AND CONDITIONS OF SERVICE

4.1 General Requirements

To enable the Company to provide the requested service, applicants for service shall supply information regarding their load and preferred supply conditions.

An applicant shall be required to sign an application or a contract for service and may be required to provide credit information or references.

4.2 Conditions of Service

Before connecting any service, the Company will inform the customer if there are any special conditions that must be satisfied.

4.3 Connection Fee

Whenever a connection is made, the customer will pay a non-refundable connection fee of either:

(a) $15 if the connection is made during the Company's regular business hours; or

(b) an amount not to exceed the Company's actual costs if the connection is made at any other time, which shall be included in the customer's first billing (save and except that, where the customer has paid a construction contribution for the service, the connection fee shall be deemed to be included in the construction contribution).

4.4 Application of Rate Schedules

Whether or not a Customer has signed an application or contract for service, the Regulations and the rate schedule applicable to the service supplied by the Company shall apply. In addition to payments for electric service, the customer is required to pay the Company the amount of any tax or assessment levied by any tax authority on electric service delivered to the customers.

4.5 Extensions to Electric Heat Customers

On isolated systems, service for electric space heating purposes may be supplied to customers only with the prior written permission of the Company.

4.6 Multiple Dwellings

Each individual unit within a multiple dwelling will be served as a separate point of delivery unless the Company agrees otherwise. The Company and the customer may agree that one bill will be issued covering all individual units in a multiple dwelling. Where the Company and a customer have agreed that service to a multiple dwelling shall be delivered through a single point of delivery, the applicable general service (non-residential) rate will apply to the service.

4.7 Totalized Metering

Normally, the Company will issue a separate bill for each point of delivery.

When service is provided through multiple points of delivery to a customer's plant site consisting of centralized processing facilities or product transportation facilities located on lands leased or owned by the customer, where such multiple points of delivery are located within a radius of half a mile of each other, the customer and Company may agree that the demand and energy at each point of delivery be totalized and only one bill issued for each billing period.

The customer shall pay the incremental metering cost associated with totalized metering.

4.8 Consolidated Billing

The Company will issue a separate bill for each point of delivery. However, the customer and Company may agree that the Company will issue one bill totaling charges for service delivered at more than one point of delivery.

4.9 Security Deposit

The Company may require any customer who has not established a satisfactory credit rating with the utility and cannot provide evidence of employment or who has been disconnected or where a current-limiting device has been installed, to provide a security deposit which shall not exceed the Company's estimate of the customer's total bills for any three-month period.

The Company will pay simple interest on the security deposit from the date the deposit is paid, at a rate of interest equal to the rate fixed for the most recent rate of the Yukon Landlord and Tenant Act and such interest will be credited to the customer's account on the first billing following December 31 of each year.

The Company may refund a security deposit when the customer has established a satisfactory payment history over a 12-month period or when the customer's service is terminated. Any interest owing at the time a security deposit is refunded will be included in the refund or credited to the customer's account.

4.10 Use of Security Deposit

If a customer fails to pay any amount billed, the Company may apply all or any portion of that customer's security deposit to the unpaid amount.

When the Company has to take this step, the customer may be required to pay a security deposit up to the maximum amount allowed in regulation 4.9.

4.11 Delay in Taking Service - Other than Subdivision

Except in the case of a customer who requests service to a subdivision if service is not taken within 30 days of the in service date, the Company may begin billing the customer for the minimum amount specified in the appropriate rate schedule or as specified in the contract between the Companyand the customer, whichever is greater.

4.12 Extension of Service

If the Company's estimated costs of extending facilities at the request of a customer are less than the maximum Company investment specified in Schedule B for the type of service provided, the customer will not be required to make any contribution.

In all other cases, an agreement for payment of the construction contribution must be made between the customer and the Company before any work on the extension is commenced.

4.13 Underground Subdivision Extensions

Underground subdivision extensions shall be undertaken subject to the conditions set out in Schedule C.

4.14 Conversion from Overhead to Underground Service

When a customer requests that existing Company facilities be converted from overhead to underground, the customer will be charged for all costs incurred by the Company in connection with the conversion, including the following:

(a) the estimated cost of removing the existing facilities, less the estimated salvage value, plus

(b) the estimated cost for the installation of the new underground facilities, less any applicable increase in Company investment as specified in Schedule B.

4.15 Temporary Service

Where the Company reasonably believes that a requested service will be temporary, it may require the customer requesting the service to pay the Company's total estimated cost of installation and removal of the service, plus the cost of unsalvageable material.

The Company may require that such payment be made before the temporary service is installed.

4.16 Mobile Homes

Service shall normally be provided to mobile homes through separate points of delivery, based on the applicable residential rate schedule.

Service provided to common use areas (e.g., laundry facilities) in a mobile home park shall be separately metered and billed at the applicable general service rate.

In mobile home parks or trailer courts where the Company reasonably believes homes are temporary, the Company may elect to provide service only through the point of delivery billed to the mobile home park or trailer court.

4.17 Relocation of Company Facilities

The Company may require a customer to pay all reasonable costs incurred by the Company in relocating any Company facility at the customer's request.

If requested by the Company, the customer shall pay the estimated cost of the relocation in advance.

4.18 Reconnection or Restoration of Service

This section applies when the Company is asked to reconnect or restore service to a customer whose service was previously restricted by a current-limiting device or discontinued (whether at the request of the customer or not).

This section does not apply when a customer's service was disconnected for safety reasons. (See regulation 11.2)

Before reconnecting or restoring service, the customer shall pay:

(a) any amount owing to the Company;

(b) a collection charge of $45 if the reconnection is made during the Company's normal business hours, or, in any other case, an amount not exceeding the Company's actual cost of reconnection;

(c) the security deposit, if any, required under regulation 4.9;

(d) the minimum monthly bill for each month of disconnection, if service is reconnected within 12 months of disconnection for all rate schedules and service except seasonal service.

4.19 Construction Contribution Cost Sharing

Existing electrical customers may be entitled to cost sharing of the construction contribution for their extension, in accordance with the following terms. "Cost Sharing" refers to the procedure of having new customers who connect to an existing facility for which someone else has paid a contribution, assessed their share of that cost, which is then refunded to the existing customer.

Construction contributions share costing will be administered for a five year term commencing December 31 of the year of construction of the original extension. The utility will not administer refunds of less than $50.00.

5. RIGHTS OF WAY AND ACCESS TO FACILITIES

5.1 Easements

The customer shall grant, or cause to be granted, to the Company, without cost to the Company, such easements or rights-of-way over, upon or under the property owned or controlled by the customer as the Company reasonably requires to provide service to such customer, including extensions thereof.

5.2 Right of Entry

The Company's employees or agents shall have the right to enter a customer's property at all reasonable times for the purpose of installing, maintaining, monitoring and removing the Company's facilities and for any other purpose incidental to the provision of service.

The customer shall provide the Company with reasonable access to Company facilities located on the customer's property.

5.3 Vegetation Management

The customer shall permit the Company to manage vegetation on the property owned or controlled by the customer to maintain proper clearances and reduce the risk of contact with the Company's facilities.

The Company shall endeavor to notify a customer before such work is performed.

5.4 Interference with Company's Facilities

Customers shall not place any structures that would interfere with the proper and safe operation of the Company's facilities or which would adversely affect compliance with any applicable legislation.

5.5 Customer Brushing

Customers requesting service that requires new electrical facilities/powerlines, shall be responsible for brushing to Company specification along with providing an unobstructed access to each structure.

6. METERS

6.1 Installation

The Company shall provide, install and seal all meters necessary for measuring the energy supplied to a customer, unless otherwise specifically provided in a contract with the customer.

Each customer shall provide and install a CSA-approved meter receptacle or other CSA-approved facilities suitable to the Company for the installation of the Company's meter or metering equipment.

6.2 Location

Meter locations shall be approved by the Company based on type of service and convenience of access to the meter. Where a meter is installed on a customer-owned pole, the pole shall be provided and maintained by the customer as required by the Canadian Electric Code and any other applicable legislation.

6.3 Meter Tests and Adjustments

The Company may inspect and test a meter at any reasonable time.

At the request of a customer, and upon payment of a $25 fee, the Company shall arrange for a meter to be tested by an official designated for that purpose by Industry Canada or such other federal government agency as may, from time to time, be designated for the purpose.

If a test determines that the meter is not accurate within the limits set by government standards, the customer's bill will be adjusted accordingly. Where it is impossible to determine when the error commenced, it shall be deemed to have commenced three months before the test or on the date of the meter installation, whichever occurred later.

In the event that an adjustment is required, the $25 shall be refunded.

6.4 Energy or Demand Diversion

If under any circumstances, a person prevents a meter from accurately recording the total demand or energy supplied, the Company may disconnect the service, or take other appropriate actions.

The Company may then estimate the demand and amount of energy supplied but not registered at the point of delivery. The customer shall pay the cost of the estimated demand and energy consumption plus all costs related to the investigation and resolution of the diversion.

7. METER READING AND BILLING

7.1 Reading and Estimates

Customers' bills will be based on meter readings made by the Company from time to time or on estimates for those billing periods when the meter is not read.

Whenever a bill is based on an estimate, an adjustment to reflect actual usage will be made after the meter is next read.

7.2 Proration of Initial and Final Billings

The amount of any initial and final charges, other than energy, may be prorated, based upon the ratio of the number of days that service was provided to a customer in the billing period to the total number of days in the billing period.

The Company may elect not to charge a customer for the billing period if, during that period, demand was five kilowatts or less, service was provided for five days or less and energy consumption was five kilowatt hours or less.

For all new accounts, the Company may add the charges for service provided during the initial period to the bill for the following billing period.

7.3 Payment of Accounts

Payment of a bill for service is due when rendered and payable by the date indicated on the bill.

Failure to receive a bill does not release a customer from the obligation to pay the amount owing for any service provided by the Company.

7.4 Late Payment Charge

The Company may add a service charge equal to 1.0% per month (effectively 12.68% per annum) on any overdue amount.

7.5 Dishonored Cheques

The Company may add a service charge of $20 to a customer's bill in respect of any cheque returned by the customer's bank for any reason.

7.6 Outstanding Charges

The Company may add to the customer's bill any outstanding charges owing to the Company (e.g. construction contribution, account receivable charges, former overdue accounts etc.).

8. SERVICE CHANGES

8.1 Notice by Customer

A customer shall give to the Company reasonable prior written notice of any change in service requirements, including any change in load to enable the Company to determine whether or not it can supply such revised service without changes to its facilities.

When a residential customer operates a business or commercial undertaking (collectively, a "business") in the customer's residence and when that business consumes electric energy, the customer shall notify the company of that fact. When the company is notified of business energy consumption, or has reasonable grounds to suspect business energy consumption, the company may request the customer to provide full particulars of all business energy consumption at the residence. The customer shall promptly provide the requested particulars. When the provided particulars confirm business energy consumption at the residence or when the customer provides inadequate or no particulars, the company may commence charging a general service rate for all energy provided. The general service rate shall apply until the customer has, to the company's reasonable satisfaction, caused separate metering systems to be installed for accurate and segregated recording of residential and business energy consumption at the residence (and, if such metering is installed, then the general service rate would apply only to the metered business energy consumption).

8.2 Responsibility for Damage

The customer shall be responsible for all damage caused to the Company's facilities as the result of the customer changing service requirements without the Company's permission.

8.3 Changes to Company facilities

If the Company must modify its facilities to accommodate a customer load or service change, the customer shall pay for all costs in connection with such modification including the following costs:

(a) the estimated cost of removing the existing facilities, less the estimated salvage value, less

(b) any applicable increased Company investment.

9. COMPANY RESPONSIBILITY AND LIABILITY

9.1 Continuous Supply

The Company shall make all reasonable efforts to maintain a continuous supply of energy to its customers, but the Company cannot guarantee an uninterrupted supply of energy.

9.2 Planned Outages

The Company reserves the right to interrupt, discontinue or reduce the supply of energy to any customer to allow for repairs and improvements to its facilities.

The Company shall endeavor to give prior notice to customers who will have service interrupted and will endeavor to ensure that such interruptions are as short and infrequent as circumstances permit.

9.3 Company Liability

The Company shall not be liable for any loss, damage, expense, charge, cost or liability of any kind (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising out of or in any way connected with any failure, defect, fluctuation, reduction or interruption in the provision of service by the Company to its customers. For the purpose of the foregoing and without otherwise restricting the generality thereof, "direct physical loss, injury or damage" shall not include loss of profits, loss of earnings, or any other similar damage or loss whatsoever, arising out of or in any way connected with the failure, defect, fluctuation, reduction or interruption in the provision of service to a customer.

9.4 Extraordinary Circumstances

Should the Company be unable, because of extraordinary circumstances, to provide a continuous supply of energy to a customer, the Company's responsibilities, so far as they are affected by the extraordinary circumstances, shall be suspended during the duration of such circumstances. Where practical, the Company shall give notice to the affected customers of such extraordinary circumstances.

10. CUSTOMER RESPONSIBILITY AND LIABILITY

10.1 Provide Permit

The customer shall provide permits, licences and authorizations prior to commencement of service or any change of service requirements at any point of delivery.

10.2 Customer Responsibility

The customer shall be responsible for the installation and condition of all facilities on the customer's side of the point of delivery.

The customer shall indemnify and save harmless the Company from and against any claim or demand for injury to persons or damage to property arising out of or in any way connected with the use of the service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the Company, its employees and agents.

The customer shall be responsible for any damage to Company facilities located on the customer's premises where the damage is caused by the negligent acts or omissions or willful misconduct of the customer or anyone permitted by the customer to be on the premises.

10.3 Protective Devices

The customer shall be responsible for determining whether the customer needs any devices to protect his equipment from damage that may result from the provision of service by the Company. The customer shall provide and install any such devices.

10.4 Service Calls

The Company may require a customer to pay the actual costs of a customer-requested service call if the source of the problem is the customer's own facilities.

11. TERMINATION OF SERVICE

11.1 Customer-requested Termination

Except where otherwise provided in a written agreement between the Company and a customer, a customer may, at any time, give the Company reasonable notice (in writing) that he wishes to terminate his service. Upon receipt of such notice, the Company shall read the customer's meter within a reasonable time, and, shall use its best efforts to read the customer's meter at the time requested by the customer. A customer shall pay for all service provided to the time of such reading.

A customer is responsible for all service provided until notice of termination is given and the meter is read.

11.2 Company Termination for Safety or Technical Reasons

The Company may, without notice, terminate a customer's service where, in the Company's opinion:

(a) the customer has permitted the wiring of his/her facilities to become hazardous; or
(b) the wiring of the customer's facilities fails to comply with applicable law; or
(c) the use of the service may cause damage to the Company's facilities or interfere with or disturb service to any other customer.

The Company will reconnect the service when the safety problem is resolved and when the customer has provided, or paid the Company's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance.

11.3 Company Termination Other Than For Safety

The Company, or anyone acting under its authority, may, upon giving at least 48 hours' notice to the customer, terminate the customer's service or install a current-limiting device to restrict the service to such customer if the customer:

(a) violates any provision of these regulations or of the Company's tariff;
(b) tampers with any service conductors, meters, seals or any other facilities of the Company;
(c) neglects or refuses to pay the charges for service due to the Company within 30 days of the date the bill for such service was rendered;
(d) violates the provision of any contract or rate schedule applicable to the service;
(e) changes service requirements without the permission of the Company; or
(f) makes fraudulent use of the service being provided.

11.4 Removal of Facilities

Upon termination of service, the Company shall be entitled to remove any of its facilities located upon the property of the customer and to enter upon the customer's property for that purpose.

SCHEDULE A
STANDARD SUPPLY SPECIFICATIONS

The Company's standard supply specifications, which are in accordance with Canadian Standards Association standard CAN-C235-83, are as follows:

(a) Residential:

240/120 V	- single phase, three wire - secondary conductors are supplied by the Company - overhead or, in designated areas, underground conductors

(b) General Service:

240/120 V	- single phase, three wire - overhead secondary conductors are supplied by the Company - underground secondary conductors are supplied by the customer
208 Y/120 V	- three phase, four wire - overhead secondary conductors are supplied by the Company - underground secondary conductors are supplied by the customer
480 Y/277 V	- three phase, four wire - overhead secondary conductors are supplied by the Company for loads 15 KVA to 300 KVA - overhead secondary conductors are supplied by the customer for loads 300 KVA to 1,500 KVA
600 Y/347 V	- three phase, four wire - underground secondary conductors are supplied by the customer for loads 150 KVA to 2,500 KVA; and
4160 Y/2400 Y	- three phase, four wire, 2,000 KVA to 10,000 KVA - overhead secondary conductors are supplied by the customer

SCHEDULE B
MAXIMUM COMPANY INVESTMENT

1. (a) **"Cost"** means the estimated cost of materials, labour, equipment, expenses, and any other direct costs incurred by the Company in extending Service to a Point of Delivery.

   (b) **"Annual Cost"** means the estimated cost of generating and transmitting electric energy to the Customer, operating and maintaining the facilities constructed to serve the Customer and the fixed charges, including return, income tax and depreciation, on the cost of facilities constructed to serve the Customers.

2. Subject to the provisions of paragraph 3 of this Schedule B, the maximum **cost** which the Company will incur to extend service to a point of delivery (herein referred to as the "Maximum Company Investment") shall be determined as follows:

   (a) **Residential Service:**
   $900 per single family dwelling; and
   $450 per Multiple Dwelling Unit

   (b) **General Service:**
   $400 per kilowatt of estimated billing demand, which shall not be less than five kilowatts, provided that if the estimated life is less than 25 years or seasonal the Company investment will be reduced proportionally, then the Maximum Company Investment shall be determined in the manner described in paragraph 3;

   c) **Municipal Street Lighting:**
   $700 per light

   d) **General Service – Secondary:**
   One half of one year of forecast retail sales revenues.

   At the end of one year of service the Company will re-assess whether the customer's estimates of their consumption were accurate, and will collect from the customer (or refund) any contributions, based on the Maximum Company Investment rules then in place in paragraph 2 or paragraph 3, that are required if the loads are significantly different than originally estimated.

3. The Maximum Company Investment for an extension of service not specified in paragraph 2, and the Maximum Company Investment in any extension of service, whether or not specified in paragraph 2, the Load characteristics of which are expected to vary materially from the average for that type of service, shall be determined on the basis of a detailed analysis of the **Annual Cost** of such extension and the revenue expected to be derived therefrom. If the **Annual Cost** of serving a customer is higher than the revenue expected to be received from such service, then the Maximum Company Investment shall be the **Cost** of the extension less the present value of the annual amounts over the expected life of the service by which the **Annual Cost** is expected to exceed the revenue.

SCHEDULE C
CONDITIONS FOR UNDERGROUND SUBDIVISIONS

The Company shall extend service by underground conductor lines upon and subject to the following terms and conditions (**"developer"** means the person or party who has requested the underground service):

(a) No service is then available in the area to be served by such extension, and not less than 25 single family dwellings (or such lesser number as may be agreed to by the Company) will be connected to such extension (the "underground service area"), each of which is situated upon said subdivision;

(b) All permanent service in the underground service area shall be provided exclusively through underground conductor lines;

(c) The developer shall provide, without cost to the Company, such rights-of-way, easements, utility corridors and transformer locations as the Company may require for the installation, operation and maintenance of such extension, which the developer shall keep free and clear of any buildings, structures, fences, pavement, trees or any other obstructions which may hinder the Company in installing, maintaining or removing its facilities;

(d) The Company shall not be obligated to install such extension until it is reasonably satisfied that the extension will not thereafter be damaged or interfered with, and, in any event, any costs incurred by the Company in relation to the relocation, reinstallation or as a result of damage to such extension shall be paid by the developer;

(e) Service, for purposes other than residential use and street lighting, may be provided from such extension only with the consent of the Company;

(f) In relation to the standard underground service, the developer shall cause to be provided a meter socket and service conductor protection from sixty centimeters below grade level to the line side of the meter socket and will ensure the installation of a service having a 200 ampere capacity. Non-standard services will be subject to prior written approval by the utility;

(g) The developer shall provide to the Company a certified copy of the registered plan of subdivision and final construction plans showing the location and elevation of sidewalks, curbs and gutters, and underground utilities together with such evidence as the Company may reasonably require to the effect that all rules and regulations applicable to the development have been or will be compiled with by the developer;

(h) Survey stakes indicating grades and property lines shall be installed and maintained by the developer;

(i) The surface of the ground for a distance of not less than one point five (1.5) meters on each side of the alignments for the underground conductor lines shall be graded by the developer to within eight (8) centimeters of a final grade;

(j) Unless otherwise agreed to by the Company, the developer shall provide a survey for the location of transformers, street light bases and cable routing, as required;

(k) Sidewalks, curbs and gutters may be constructed by the developer but no other permanent improvements shall be made until approved by the Company.

(l) Costs related to the installation of distribution system infrastructure shall be the responsibility of the developer; and

(m) The Company investment will be applied toward the individual customer service connection in accordance with "Schedule B".

In addition, the service shall be subject to such other conditions as may be specified by the Company from time to time.

data\95gra\esrscorr

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-3

YEC states "The Stage One CSTP involves a new 138 kV transmission line of approximately 98 km between the WAF grid at Carmacks and Pelly Crossing, and a new switching station at Carmacks. It has been developed in conjunction with the 25 kV transmission line and related YEC substations (the "Minto Spur") required to connect Stage One of the CSTP in the Minto Landing area to the copper-gold project operated by Minto Explorations Ltd. ("Minto Explorations"). This stage is scheduled for completion by October, 2008".

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-7

YEC states "Currently, the net capital cost to Yukon Energy of the Stage One CS/MS development being brought into service in fall 2008, after all customer and other capital contributions, is forecast at $3.744 million (as compared to zero net cost as forecast in the Part 3 hearing). Since the Part 3 hearing, forecast Stage One CSTP costs have increased by approximately $5.8 million (from $22.60 million (2007$) to approximately $28.394 million)…"

REFERENCE: April 30, 2007 Reasons for Decision on the Power Purchase Agreement between YEC and Minto exploration (Board Order 2007-5)

The Board states on page 5 that it "agrees with Intervenor concerns regarding the lack of a complete COS study. The Board is of the view that due to the articulating nature of a COS study, rates cannot be developed in isolation. Therefore, the Board reiterates its earlier direction that YEC and YECL must provide a complete COS study and rate design with their next GRA. The COS is to include updated studies on allocators, and will look at the feasibility of direct assigning assets, where applicable to certain rate classes. Further, the Board expects to see justification on the allocation of transmission assets. In addition, the Board questions the rationale of defining the CSTP project as one of diesel displacement in light of YEC's comments that the project is to serve system requirements. The Board would like to explore the COS evidence in this regard when it is filed in YEC's next GRA".

QUESTION:

a) Please confirm that your references to "Stage One CS/MS" and "Stage One CSTP" refer to the same project.

b) Please provide an update on the in-service dates of Stage One CSTP and the Minto (Capstone) spur.

c) Please provide a breakdown of all budgeted and actual costs (i.e., project development, preliminary engineering, surveying, regulatory costs, clearing right-of-way, construction, etc.) associated with the Stage One CSTP and the Minto (Capstone) spur. Please provide an explanation of variances from budget and clearly identify the specific costs that will be paid by Minto Explorations.

d) Please describe what YEC has done in response to the Board's recommendation (on page 13 of its Report on the CSTP Part 3 review) that YEC was to consult with the Minister before making any decision to proceed if the tendering process results in a capital cost that is materially above the high end of the estimate of $25.9 million.

e) Please provide a schedule showing the timing of rate base additions for Stage One CSTP and the Minto (Capstone) spur and the associated calculations of how these rate base addition amounts have been determined.

f) Please provide a calculation of any revenue requirement impact of this project in 2008 and 2009.

g) Please comment on how the response to part (f) compares to YEC's testimony at the Part 3 review hearing that at a simple level, the project will bring $3-to $4 million in additional revenues with absolutely no capital costs and insignificant operating costs (Transcript, page 219).

h) Please explain why YEC ignored the Board's specific direction in Board Order 2007-5 that "YEC and YECL must provide a complete COS study and rate design with their next GRA. The COS is to include updated studies on allocators, and will look at the feasibility of direct assigning assets, where applicable to certain rate classes".

ANSWER:

(a)

Stage One CSTP is the H-frame transmission line running from the existing WAF grid at Carmacks to the community of Pelly Crossing. Stage One CS/MS includes the above line, plus the 25kV spur line to the Minto Mine (connects to CSTP Stage One at Minto Landing).

(b)

The project was deemed to be in service November 22, 2008.

(c)

Please see response to LE-YEC-1-46 & 47. In accordance with the terms and conditions of the Power Purchase Agreement, Minto Explorations Ltd. is responsible for paying the cost of the Spur, as well as a $7.2 million contribution to the Main Line.

(d)

Please see YUB-YEC-1-39(b).

(e)

The GRA reflects a CSTP capital cost of $38.383 million, as shown in Table 5.2. Offsetting this amount is $34.639 million in contributions, made up of $10.450 million from the Yukon Government, $7.000 million from YDC, $7.200 million from Minto for the main line, and $9.989 million from Minto for the spur. Consequently the net addition is $3.744 million.

The date of in-service in the GRA is October 1, 2008, or 91 days in 2008. Over this 91 days, the calculated net depreciation is $0.030 million, for a net book value at year-end of $3.714 million.

The typical approach to capital additions is to include them in ratebase at a "mid-year" value, which based on the above number, would have included CSTP in ratebase at $1.857 million (half of $3.714 million closing balance). However, given the specific in-service date in question, the more appropriate carrying amount in 2008 ratebase is $0.929 million ($3.729 average balance over 3/12 of the year). In order to reflect this adjustment, Yukon Energy adjusted rate base down in 2008 by the difference ($0.928 million) as shown in Tab 7, Schedule 1 row 20.

(f)

Please see YUB-YEC-1-36(a) and UCG-YEC-1-3(b).

(g)

As noted in the Application, S5.2.1.1 page 5-7, costs are higher than previously expected. See LE-YEC-1-46 and LE-YEC-1-47 for details of cost changes since original budgets. Please see YUB-YEC-1-36 (a) for benefits of CSTP at the current cost levels.

(h)

Please see response to YUB-YEC-1-20.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-4

YEC states "Stage Two of the CSTP entails construction of a new 138 kV transmission line of approximately 74 km from Pelly Crossing to Stewart Crossing, including new substations at Pelly Crossing and Stewart Crossing. Stage Two of the project is anticipated to occur concurrent with the development of a second industrial customer, either Carmacks Copper mine owned by Western Copper Corporation, or the reopening of the Elsa/Keno mine now owned by Alexco Resource Corp."

REFERENCE: December 8, 2008 Hansard, Yukon Legislative Assembly

Mr. Morrison: The Carmacks-Stewart line — when we went to the Yukon Utilities Board two and a half years ago with the project as a whole, we anticipated that the costs for the second phase would be about $30 million. My guess is, at the moment — because I don't know much more than that; we haven't had engineers look at tendering equipment or anything — because costs over this period have gone up, it's probably closer to $40 million.

QUESTION:

a) Please identify any costs that have been incurred to date with respect to Stage Two of the CSTP.

b) Please provide an update on the expected total cost for this project.

ANSWER:

(a)

The Corporation has incurred approximately $0.850 million with respect to Stage 2 of CSTP. These costs generally relate to allocation of overall CSTP/MS costs related to pre-2008 YESAB screening, preliminary engineering, permitting, consultation and related owner's costs.

(b)

No further update is available since the reference noted in the question.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-7

YEC states "Since the PPA and Part 3 hearings, forecast Minto Spur capital costs have increased by $6.159 million (from the PPA estimated in-service costs of $3.83 million to current forecast costs of $9.989 million). This increase reflects higher substation costs as well as higher line costs. Minto Explorations is responsible for the entire cost increase for the Minto Spur capital costs pursuant to the PPA. Section 5.4 of the PPA provides for an adjustment to the time period within which Mine Spur capital cost financing must be paid by Minto Explorations if the Mine Spur Capital Costs exceed $4.8 million" and "Under Section 5.4, a two year extension will be provided for payments under Section 5.2(b)(i) where (a) Minto has provided confirmation by December 31, 2008 under section 5.2(d) regarding its ability and commitment to process Additional Reserves at the Mine prior to December 31, 2017, sufficient to sustain an additional three years of processing at the Mine at the Daily Processing Level, and (b) the extension of the payments will not go beyond the date which Minto confirms in writing to the satisfaction of YEC that ore reserves at the Mine are planned to be processed at the Mine, provided the processing level planned is not less than the Daily Processing Level. Any extension of such payment period is now also limited under the provisions of the May 25, 2007 PPA amendment".

QUESTION:

a) Please provide a copy of any correspondence received from Minto (Capstone) regarding a commitment to process additional reserves at the mine.

b) Please provide a calculation of the carrying costs associated with the higher cost of the Minto (Capstone) spur project. Please confirm that all carrying and administrative costs of financing will be recovered from Minto (Capstone) and explain how YEC will be tracking these costs.

ANSWER:

(a)

Please see response provided to PWP/HML-YEC-1-24(a) which notes that YEC is currently in discussions with Minto regarding this issue. Minto is currently in the process

of firming up its estimate of reserves and filing required documentation with the regulator.

(b)

Under the current PPA, Minto is required to pay the capital cost of the Mine Spur Capital Costs plus interest at 7.5% per annum (i.e., the “carrying cost” for Minto). The risks for this loan are now borne by YDC, not YEC. By arrangement with YDC, the carrying costs for YEC’s corresponding debt obligation mirror the carrying costs borne by Minto.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-10

YEC states "In short, the costs per MW for the Minto diesels ($0.498 million/MW) remain fully competitive with the Mirrlees refurbishment costs ($0.482 million / MW), and well below costs for 6.4 MW of new diesel generation at the mine site (estimated at $6.6 million, or $1.035 million per MW). Purchase of the Minto diesels adds additional low cost options for YEC to augment its winter peaking diesel capacity to meet growing WAF loads".

QUESTION:

a) Please provide detailed calculations of the $6.6 million cost for new diesel generation.

b) Please identify the advantages / disadvantages from an operational and cost perspective between the Minto (Capstone) diesels and new diesels.

c) Please provide details of all other options considered in YEC's efforts to justify the purchase of the Minto (Capstone) units as the least cost option.

d) Please provide a schedule showing the timing of rate base additions for the acquisition of the Minto (Capstone) diesels and the Mirrlees refurbishment projects and the associated calculations of how these rate base addition amounts have been determined.

e) Please provide a calculation of any revenue requirement impact of these projects in 2008 and 2009.

ANSWER:

(a)

Yukon Energy received proposed pricing in 2008 for a 6.4 MW plant comprised of 4 new 3516 engines, with generator enclosures and switchgear for $6.627 million ($1.04 million/MW) in a format that could be deployed at a greenfield location (but without costs yet included for new common infrastructure, such as transmission or fuel tanks). This is generally consistent, if not lower than, the estimate prepared as part of the Resource

Plan that new diesel units at a developed (non-greenfield) site would cost in the $0.8 million/MW to $0.9 million/MW range in 2005$, plus additional costs for buildings and common systems in the event the units were to be developed at a greenfield site.

(b)

First and foremost, the acquisition of the Minto diesels is a term of the PPA Yukon Energy signed with the Minto Mine, which was necessary to secure the material benefits for ratepayers shown in YUB-YEC-1-36(a).

The Minto diesels entail a resource that is already developed and as such can be secured at a very low risk to YEC and ratepayers. The units are installed and operable at the present time, and provide significant other benefits as noted at section 5.2.1.2 of the Application. Operationally, some investment is required by Yukon Energy to ensure that the units are capable of operating appropriately in a standby format, to utility standards, but even with this cost included the units are considerably lower cost (less than half) the cost of new diesel capacity.

There are very limited if any benefits to new units compared to the Minto units, with the exception of condition.

(c)

Yukon Energy's least cost options for new capacity were the subject of major review at the 20 Year Resource Plan hearing in 2006. In particular, this topic formed the entire basis for Chapter 4 of the Resource Plan, and review of various options to address capacity issues from Mirrlees refurbishments to new transmission, to new diesels, to other new resources (such as Marsh Lake Fall/Winter Storage) and including CSTP. That review confirmed that the lowest cost source of capacity (as required to meet system winter peak load reliability requirements) to Yukon Energy was the Whitehorse Mirrlees refurbishment, now estimated at $0.482 million/MW, as well as the Faro Mirrlees (which was already the subject of immediate commitment prior to the Minto diesels being acquired). In this regard, no further review of "least cost options" was required in respect of the Minto diesels, as no other options have been identified since the Resource Plan, and there are no expected material changes to the relative costs or feasibility of the options reviewed in 2006.

Given this, the Minto diesels were compared to the Whitehorse Mirrlees life extension project, to which the Minto diesels were determined to be favourable (including in light of the matters noted in part (b) above).

(d)

The GRA includes the Minto diesels and related costs added to ratebase as follows:

- 2008: $2.440 million
- 2009: $0.750 million

For the Whitehorse Mirrlees Life Extension Project additions to ratebase, please see page 5-9 of the Application.

(e)

Each of the Whitehorse Mirrlees capital additions and the Minto diesels are forecast to occur at a depreciation rate of 2.182% (the normal composite generation depreciation rate for YEC). Assuming all additions occur at mid-year, for simplicity, the revenue requirement impact is shown in the following table. The table does not address the alternative higher costs that would have to be incurred to secure the same amount of capacity from other sources were the Minto diesels not acquired and WD3 retired instead of refurbished.

Whitehorse Mirrless and Minto Diesels – Additions to Ratebase and Revenue Requirement Impact 2007, 2008 and 2009

$000s	2007	2008	2009
Minto diesels			
opening		0	2413
addition		2440	750
depreciation		27	61
closing		2413	3103
mid-year		1207	2758
return		83	189
per Tab 7 Sch 5		*at 6.86%*	*at 7.17%*
total cost		109	250
Whitehorse Mirrlees (common systems plus WD3)			
opening	0	463	1986
addition	468	1550	0
depreciation	5	27	43
closing	463	1986	1943
mid-year	231	1224	1964
return	16	84	135
per Tab 7 Sch 5	*at 7.07%*	*at 6.86%*	*at 7.17%*
total cost	21	111	178

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-11

YEC states "The diesel units are located near key major loads at the end of long transmission line. At times when WAF diesel generation is required, having these units at this location reduces line losses in addition to providing greater grid support".

QUESTION:

a) Please provide YEC's calculations related to the reduction in line losses.

b) Please provide more explanation of what is meant by grid support provided by the Minto (Capstone) diesels and under what circumstances this support would be provided.

c) Please describe the support provided by the Minto (Capstone) diesels during outages on the YEC system during 2007 and 2008.

ANSWER:

(a)

No detailed calculation of line losses has been performed. In general terms, Yukon Energy's transmission level losses on WAF approximate 7%-8%, which would be largely avoided in the event Minto load was supplied by diesels located at the mine site rather than from Whitehorse generation.

(b)

Grid support refers to the use of distributed diesel units to help supply loads during supply constraints, in a manner that lessens the load to be served from centralized generation such as in Whitehorse.

(c)

The Minto Diesels were not connected to the grid system until November 22, 2008. They were not used for grid support or YEC peaking requirements during 2008.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-11

YEC states "These units can be run without any emissions impact in Whitehorse".

QUESTION:

a) Please provide the data that supports this statement concerning the Minto (Capstone) diesels.

ANSWER:

(a)

The Minto mine is located 240 km north of Whitehorse. Given the distance, running the diesel units in Minto is not expected to have any emissions impact on Whitehorse.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-12

YEC states that work on the Faro Mirrlees Diesel (FD1) Recommissioning began in 2007 and will be completed in 2008, with $0.407 million in costs in 2007 and $1.158 million budgeted for 2008. The project is expected to be complete in 2008.

QUESTION:

a) Please provide a breakdown of all budgeted and actual costs (i.e., project development, preliminary engineering, regulatory costs, etc.) associated with the Faro Mirrlees Diesel Recommissioning. Please provide an explanation of variances from budget and the timing of when the expenditures occurred.

b) Please confirm whether an application for an energy project certificate or energy operation certificate associated with this project was ever forwarded to the Minister per Part 3 of the *Public Utilities Act*. If not, then please elaborate on why this application was not made.

c) Please identify any regulatory reviews of this project other than the cursory review as part of YEC's 20-Year Resource Plan.

d) Please provide details on efforts made by YEC to sell the Faro diesel generator to another party and the reasoning behind these efforts.

ANSWER:

(a)

Please see response to YUB-YEC-1-36(d).

(b)

No.

The Public Utilities Act provides that energy project certificates (required pursuant to section 37 of the Act) and energy operation certificates (required pursuant to Section 38 of the Act) are only required for a "regulated project" as defined under Section 36 of the

Act. A "regulated project" as defined "means any energy project that the Commissioner in Executive Council considers to be significant in the matter of any form of energy and, by order, designates as a regulated project." The Commissioner in Executive Council did not designate the Faro Mirrlees project as a regulated project.

(c)

No other regulatory reviews were required or undertaken with regard to this project.

The technical feasibility of rehabilitating the retired Faro Mirrlees was discussed in the 20-Year Resource Plan (filed as Exhibit B-16 in that proceeding). The Board reviewed the project as part of the Resource Plan and recommended that the rehabilitation of the Mirrlees proceed in its report to the Commissioner in Executive Council filed January 15, 2007.

The Board noted as follows at page 34 of its Report to the Minister:

> …new capacity should be added to the WAF system as soon as possible.
>
> The Board is of the view that, of all the projects that have been discussed in this proceeding, refurbishments of existing diesel units are the only options that could be implemented in a relatively short period of time to alleviate the current shortfall situation in the WAF system. Furthermore, the Board concurs with YEC that the previously retired Mirrlees unit, currently situated at the Faro plant, should be the one to proceed first, as it would contribute 5 MW of capacity and could be started at any time without impacting the rest of the existing capacity. Therefore, the Board recommends that YEC proceed with refurbishing the Faro unit as expeditiously as possible.

(d)

In the time period for planning the Faro Mirrlees project, YEC did not actively market the unit to any other party.

REFERENCE: October 6, 2008 Application, Capital Projects, Pages 5-12 and 5-13

YEC states "This near term project was identified in Yukon Energy's 20-Year Resource Plan. During the Part 3 hearing process for CSTP, the implications of the relationship between Stage One of the CSTP and the need for and timing of the Aishihik 3rd Turbine was reviewed. In the YUB report to the Minister regarding the Part 3 Review of the CSTP, the YUB recommended that, "if Stage One of the CSTP were to go forward, then by implication, there is an accelerated need for the third turbine at Aishihik. The Board accepts the submissions that on an opportunity basis for diesel displacement, with connection of new mine loads, there is economic justification to accelerate the construction of the Aishihik third turbine. This view and recommendation is consistent with the view expressed by the Board in its 20-Year Resource Plan Report. The addition of a seven megawatt turbine installed at the existing Aishihik generation station at a cost of approximately $8.5 million will help to reduce future diesel generation through both more efficient use of water at Aishihik, as well as better ability to use the plant to meet short-term peak loads (as an alternative to diesel generation)".

REFERENCE: Yukon Utilities Board Report on Yukon Energy Corporation 20-Year Resource Plan, January 15, 2007, Page 30

"It should be noted, however, that the addition of the third turbine under YEC's plan is not a capacity requirement determined by the planning criteria, but rather a requirement driven strictly by economic reasons, namely to offset future diesel generation that is expected to increase under the base-case load forecast. However, should the actual loads turn out higher or lower that the loads under the base-case forecast, the optimal timing of the third turbine would move earlier or later than 2013. Therefore, to minimize the uncertainty around timing of the third turbine, the final decision to proceed with this project should be made closer to the date when economic reasons indicate that the turbine is needed. Therefore, the Board recommends that this project not proceed until that time unless YEC can justify an earlier in-service date."

QUESTION:

a) Please provide a comparative chart of the Aishihik 3rd turbine project's $8.5 million budget (7 MW) in the current application against the $3.5 million budget (5 MW) in the 1992 Resource Plan and the $7 million budget (7 MW) in YEC's 20-

year Resource Plan 2006-2026. Please provide descriptions of the variances in project scope and budget as well as the drivers of these variances.

b) Please provide a schedule showing the timing of rate base additions for the Aishihik 3rd turbine project and the associated calculations of how these rate base addition amounts have been determined.

c) Please provide a calculation of any revenue requirement impact of this project in 2008 and 2009.

ANSWER:

(a)

Yukon Energy does not have the data from the 1992 Resource Plan readily available. It is noted that at that time the project was expected to be a 5 MW turbine, while the present project is for 7 MW (pursuant in part to a YUB recommendation).

The 20 Year Resource Plan May Update noted that the cost at that time was estimated at $7.155 million in 2005$ (approximately $7.9 million in 2010$). The current project was forecast in the GRA at $8.5 million for a 2010 in-service; however, note that this estimate remains a projection without the benefit of tendered prices.

The main reason for the cost updates are better definition of what is required to complete the project.

(b) and **(c)**

Aishihik 3rd Turbine will not be complete and in service until 2010 therefore any spending will remain in Work in Progress until that time and will not affect the revenue requirement in 2008 or 2009.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-14

YEC states that customer extensions are budgeted to cost $475,000 in each of 2008 and 2009 (offset by customer contributions of $400,000 in each year). YEC states that it "is required to provide service to new customers coming onto the system, and consequently, customer extensions are forecast and budgeted as a capital items without identifying specific projects. Most costs of customer extensions are covered by customer contributions pursuant to the Electrical Service Regulations".

QUESTION:

a) Please provide details of the budgeted and actual costs of customer extensions in 2005, 2006, 2007 and 2008 as well as the number of customers connected.

b) Please confirm that the budgets for customer extensions would be less of a contributor to YEC's revenue requirement if this budgeted amount was removed and a deferral account was established to collect actual customer extension costs as they are incurred for disposition in a subsequent year.

ANSWER:

(a)

Page 5-25 in the application, which shows customer extension spending for 2005 to 2007, contains an error in the categorization of certain elements of distribution spending. A corrected version is provided as an attachment to the April 24, 2009 Update Filing.

The total spending on customer extensions, from 2005 to 2008 actuals, is set out in the following table:

Yukon Energy Actual Spending on Customer Extensions 2005-2008

	2005	2006	2007	2008
Budget	400,000	400,000	400,000	400,000
Actual Spending	476,043	422,200	290,089	184,100

Total customers added in each year are as follows:

2005 – 56 new customers
2006 – 52 new customers
2007 – 40 new customers
2008 – 42 new customers

(b)

Not confirmed. The amounts are already capital and consequently depreciated over time.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-14

YEC states that the Land Management and Easement Project ($100,000 in each of 2008 and 2009) will "secure easements for Yukon Energy's distribution lines over 2008 and 2009".

QUESTION:

a) Please provide details of the specific easements being secured.

b) Please provide details of budget actually spent in 2008.

c) Please confirm that the budget for securing easements would be less of a contributor to YEC's revenue requirement if this budgeted amount was removed and a deferral account was established to collect actual easement costs as they are incurred for disposition in a subsequent year.

ANSWER:

(a)

The purpose of this project is as follows: to obtain the agreement of property owners, and to register the resulting easements with the Land Titles Office, in locations where a YEC-owned line or piece(s) of equipment are located on, or pass over, property owned by others. This includes residential, commercial and industrial properties

Easements have been sought for both primary and secondary distribution lines and equipment. The main areas of focus have been the YEC distribution systems in Faro, Mayo and Dawson. Of the estimated 3600 easements required about 750 have been completed and registered.

(b)

Spending on this project in 2008 was $97,675.

(c)

Not confirmed. The amounts are already capital in nature and consequently depreciated over time.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-15

YEC states that budgets for Vehicle Purchases ($209,000 in 2008 and $288,000 in 2009) are based on three service bodies "expected to need replacing" in 2008 and two service bodies "expected to need replacing" in 2009.

QUESTION:

a) Please provide details of budget actually spent in 2008.

b) Please confirm that the budget for vehicle purchases would be less of a contributor to YEC's revenue requirement if this budgeted amount was removed and a deferral account was established to collect actual vehicle purchase costs as they are incurred for disposition in a subsequent year.

ANSWER:

(a)

Please see the table provided below which provides actual 2008 spending.

2008 Vehicle Purchases

Description	Total
Truck - Ford F-150 XL White	34,391
Truck - Dodge 2500 Ram Pickup	43,239
Truck - Chevrolet Silverado Lt	33,077
Total	110,707

(b)

Not confirmed. The amounts are already capital and consequently depreciated over time.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-16

YEC states that the budget for an Off-Road Maintenance Vehicle Purchase ($150,000 in 2008 plus $300,000 in 2009) is to replace a leased 1979 Nodwell from Arctic Power that is at end of life.

QUESTION:

a) Please provide details of budget actually spent in 2008.

b) Please provide details of the analysis performed that concludes that it is more economical for YEC to purchase a new unit and boom than to lease it.

c) Please confirm that the budget for this vehicle purchase would be less of a contributor to YEC's revenue requirement if this budgeted amount was removed and a deferral account was established to collect actual vehicle purchase costs as they are incurred for disposition in a subsequent year.

ANSWER:

(a)

The actual budget expenditures for 2008 are $0.099 million.

(b)

Please see payback table provided as Attachment 1 to this response. The purchase produces positive value after 5 years under simple payback analysis and positive after 7 years under discounted payback versus lease.

(c)

Not confirmed. The amounts are already capital and consequently depreciated over time.

YUKON ENERGY Simple Payback Analysis

Project ***Date*** 26-Nov-07

Capital Cost	$485,000	***Simple Payback***	***5***	years
Discount Rate	7.00%	***Discounted Payback***	***7***	years
Base Year	2009			
In-service Year	2009			

Year	***Capital Expense***	***Project Savings***	***Simple Cash Flow***	***Cumulative Cash flow***	***Year from In-service***	***Discounted Cash Flow***	***Cumulative DCF***	***Year from In-service***
2009	-$485,000	$96,000	-$389,000	-$389,000	0	-$485,000	-$485,000	0
2010		$96,000	$96,000	-$293,000	1	$89,720	-$395,280	1
2011		$96,000	$96,000	-$197,000	2	$83,850	-$311,430	2
2012		$96,000	$96,000	-$101,000	3	$78,365	-$233,066	3
2013		$96,000	$96,000	-$5,000	4	$73,238	-$159,828	4
2014		$96,000	$96,000	$91,000	5	$68,447	-$91,381	5
2015		$96,000	$96,000	$187,000	6	$63,969	-$27,412	6
2016		$96,000	$96,000	$283,000	7	$59,784	$32,372	7
2017		$96,000	$96,000	$379,000	8	$55,873	$88,245	8
2018		$96,000	$96,000	$475,000	9	$52,218	$140,462	9
2019		$96,000	$96,000	$571,000	10	$48,802	$189,264	10
2020		$96,000	$96,000	$667,000	11	$45,609	$234,873	11
2021		$96,000	$96,000	$763,000	12	$42,625	$277,498	12
2022		$96,000	$96,000	$859,000	13	$39,837	$317,334	13
2023		$96,000	$96,000	$955,000	14	$37,230	$354,565	14
2024		$96,000	$96,000	$1,051,000	15	$34,795	$389,360	15
2025		$96,000	$96,000	$1,147,000	16	$32,519	$421,878	16
2026		$96,000	$96,000	$1,243,000	17	$30,391	$452,269	17
2027		$96,000	$96,000	$1,339,000	18	$28,403	$480,672	18
2028		$96,000	$96,000	$1,435,000	19	$26,545	$507,217	19
2029		$96,000	$96,000	$1,531,000	20	$24,808	$532,025	20

Notes: 1/Discount Rate to be used is the Blended Cost of Capital Rate for Yukon Energy
2/ The simple payback period in years is the first year the the cumulative cash flow is positive in column E
3/ The discounted cash flow payback period is the first year that the Cumulative discounted cash flow (DCF) is positive in column H
4/ As the capital cost is a negative cash flow it should entered as a negative number
5/ For paybacks exceeding 5 years the discounted payback should be used as the time value of money becomes more significant

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-16

YEC states that the budget for SCADA Replacement ($150,000 in 2008 and $118,000 in 2009) is to replace the existing VMS-based SCADA system that has been in service since 1997.

QUESTION:

a) Please provide details of budget actually spent in 2008.

b) Please provide details of the analysis performed to establish the budget for this system.

c) Please identify if any of the referenced lower annual maintenance costs are included in the proposed revenue requirements for 2008 and 2009.

ANSWER:

(a)

Details on amounts spent in 2008 are provided in the table below.

Cost Type	Total ($000)
Computer Hardware & Software	144
Contractors	9
Labour	6
Materials	93
Travel	4
AFUDC	1
ES&G	13
Grand Total	270

The project was completed in 2008.

(b)

The budget was established based on quotations from the vendor of the existing system for the upgrade to the SQL platform. Additional furniture and operator controls were also purchased to handle the upgraded system.

(c)

No reduction in maintenance cost for the SCADA system was included in the 2008 or 2009 budgets.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-16

YEC states that the budget for the development of a Disaster Recovery Plan / Business Continuity Plan ($150,000 in 2008 and $75,000 in 2009) is an important part of an overall framework for identifying and managing risk.

QUESTION:

a) Please confirm whether YEC has an existing disaster recovery plan and/or business continuity plan. If yes, please identify when it was developed, the costs incurred and how thee costs were treated from a recovery perspective.

b) Please provide details of budget actually spent in 2008.

ANSWER:

(a)

Yukon Energy does not currently have a Disaster Recovery Plan, and expenditures are being incurred during the test years to develop a plan.

(b)

Details on the amounts spent in 2008 related to the Disaster Recovery Plan/ Business Continuity Plan are provided below.

Cost Type	Total 2008 ($000)
Consultants	60
Travel	9
AFUDC	1
ES&G	3
Grand Total	**73**

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-17

YEC states that the budget for the replacement of its Financial Systems Software ($125,000 in 2008, $450,000 in 2009 and $425,000 in 2010) will involve the completion of replacement system needs assessment, a product review and the presentation of recommendations to the Board of Directors in 2008 and implementation beginning in 2009.

QUESTION:

a) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

b) Please provide details of budget actually spent in 2008.

ANSWER:

(a)

For the purposes of this application this project will be in WIP at the end of 2009.

(b)

Details on amounts spent in 2008 related to the replacement of the Financial Systems Software are provided below.

Cost Type	2008 ($000)
Consultants	64
Labour	3
ES&G	2
AFUDC	2
Grand Total	**71**

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-17

YEC states that the budget for an Electronic Document Management ($125,000 in 2008, $100,000 in 2009 and $100,000 in 2010) will be spent on a records management consultant in 2008 to assess records management issues and propose solutions with implementation starting in 2009.

QUESTION:

a) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

b) Please provide details of budget actually spent in 2008.

c) Please provide a copy of the assessment of the records management consultant and describe any research they conducted into the electronic document repositories now in use by various energy regulators throughout Canada.

ANSWER:

(a)

For the purposes of this application this project is excluded from the calculation for the determination of ratebase as the project remains in WIP at the end of 2009.

(b)

Details on the amounts spent related to the Electronic Document Management in 2008 are provided below.

Cost Type	2008 ($000)
Consultants	16
Materials	30
AFUDC	1
ES&G	2
Grand Total	50

(c)

No report has been prepared.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-20;

YEC states that the Mayo B hydro generation enhancement project ($1.7 million in 2008 and $6.5 Million in 2009 has been identified as a potential priority near term hydro generation expansion opportunity.

REFERENCE: **December 8, 2008, Hansard, Yukon Legislative Assembly**

Mr. McRobb: Still with capital plans, the officials mentioned **Mayo B**, which of course is an enhancement of the existing facility to provide a greater amount of generation. Can the officials indicate what the anticipated cost, timelines and process are for that facility?

Mr. Morrison: Well, timelines are difficult because it depends on where loads are and, with this mining environment, things are shifting a little bit. But the costs that we have seen so far, which are very expensive, are **$100 million**.

Mr. McRobb: And does that cover basically all of the expenses to upgrade the facility itself, including any shoreline mitigation or improvements to the transmission line or anything? Can the officials comment on that?

Mr. Morrison: To be clear, it **doesn't include the cost of a transmission line**. That's something separate. Secondly, it does cover all of the costs, as we know it, for the purposes of upgrading the capacity of the Mayo plant. I want to be clear, though, that from our perspective — we haven't looked at shoreline mitigation. We haven't made any decision that would, at least in the current plan, even include the possibility of shoreline mitigation.

QUESTION:

a) Please provide cost details and descriptions of components of the proposed Mayo B hydro generation enhancement project.

b) Please provide details on costs incurred to date, during the 2008 and 2009 test years, and estimated for subsequent years.

c) Please explain how this project fits in with YEC's 20-Year Resource Plan.

d) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

e) Please explain why Mayo B is now on the potential priority near term expansion opportunities when it was not even on the radar during the review of the 20-Year Resource Plan process.

ANSWER:

(a)

The components of the Mayo B Hydro Generation Enhancement Project are set out in the attached newsletter (provided as Attachment 1 to this response). Cost estimates provided in the 20 year Resource Plan were $101 million (2005$) (approximately $116 million in 2012$). These estimates are presently being updated.

(b)

The Application at page 5-20 notes forecast costs for 2008 and 2009 as $1.7 million and $6.5 million respectively. Budgets are subject to ongoing review. The total project cost, if developed, has been estimated at approximately $120 million; the net cost to Yukon Energy will depend on contributions from government, which are yet to be determined.

(c)

Mayo B was included in the 2006 Yukon Energy 20-Year Resource Plan filing (at Appendix B) as part of an inventory of hydro project options. As noted at page B-1 of the Resource Plan, the projects included in Appendix B represented "the primary alternatives identified to date based on review of the numerous studies conducted in Yukon." Mayo B was specifically discussed as one of a group of small projects being considered (within the 5 to 10 MW range) at page B-10 where the following was noted regarding the project:

> The existing hydro site at Mayo has the potential to be enhanced by various changes in configuration, either to develop further head below the existing reservoir or an expansion of capacity utilizing the same head. This leads to multiple potential alternatives. However, as a supply option

> to WAF, these various projects are only of relevance if the Carmacks-Stewart transmission line is previously in service. The full capability of various potential Mayo enhancements to supply an interconnected WAF and MD system (as opposed to MD on its own) has not been fully studied, and should be re-examined in the event that the interconnection proceeds.
>
> One configuration alternative considered is a 10 MW, 48 GW.h, $101 million (2005$) variation based on a separate conveyance route from the existing reservoir to a new plant lower in elevation than the existing plant, which would be able to operate in parallel with the existing plant. This concept has an initial LCOE of 11.2 cents/kW.h. Various other concepts require further study. However, although work is still in preliminary stages, it must be recognized that it is possible no credible facility enhancements of this type exist at Mayo.

The Resource Plan noted that small hydro projects in the range of 5-10 MW were potential candidates for development under Chapter 5 forecasts under the 25 MW industrial scenario or larger. These projects could also potentially be part of a development plan under the larger 40 MW scenario.

(d)

This project will be in Work-in-Progress until it is complete (the earliest possible in-service date is 2011 or 2012), at which time the net cost to YEC for the project will be included in rate base.

(e)

As noted in **(c)** above, Mayo B was included in the 20-Year Resource plan as potential small hydro project to address industrial development scenarios described in Chapter 5 of the Resource Plan. Reviews carried out in 2007-2008 to identify priority projects to provide 50 to 100 GWH/yr of new renewable energy within the 2010 to 2015 period identified Mayo B as the largest single source of such new energy, with good prospects to be in-service between late 2011 and 2012.

Yukon Energy Corporation
2008-2009 General Rate Application
UCG-YEC-1-89(a) Attachment 1

YUKON ENERGY

PROPOSED MAYO HYDRO ENHANCEMENT PROJECT (MAYO B)

What is involved?

Electrical loads in Yukon are increasing. By 2011, Yukon Energy expects to need additional renewable power to help minimize the use of diesel to generate electricity. As outlined in Yukon Energy's 20-Year Resource Plan (found at www.yukonenergy.ca), the first priority for increasing renewable energy is through enhancements to existing hydro facilities. As such, Yukon Energy is looking at enhancing the existing Mayo hydro plant, a potential project referred to as Mayo B.



Mayo control structure

What are the benefits?

Yukon Energy is the primary generator of power in Yukon. As electrical load grows in Yukon, the opportunity exists to develop additional renewable energy rather than serve those loads with diesel. The Mayo B project, if developed, will help reduce the future need for running diesel, and enable Yukoners to offset greenhouse gas emissions of up to 28,000 tonnes a year.

Regulatory Approvals/Reviews

No decisions have been made at this time to proceed with this proposed project. Yukon Energy first plans to consult with local governments, stakeholders and the public. Before any project regarding Mayo B moves ahead, government permits and approvals would be required for land use, activities affecting water bodies, and other activities.

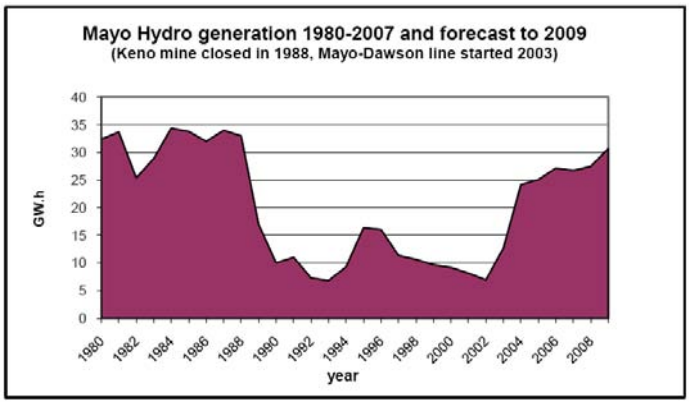
Environmental and socio-economic assessment would be needed under the *Yukon Environmental and Socio-Economic Assessment Act (YESAA*). An Executive Committee Screening of the project would be done by the Yukon Environmental and Socio-Economic Assessment Board (YESAB). In addition, the project would need a new or revised water licence from the Yukon Water Board.

Table of Contents

The existing Mayo facility—page 2
Proposed Mayo B project—page 3
Detailed map—page 4
Project components/options—page 5
Have your say—page 6

The Existing Facility

Operation of the Mayo facility



The Mayo hydro facility supplied the loads of both the Keno mine and the community of Mayo from 1951 until the mine closed in 1988/89. During this period, the plant typically operated at full capacity, and the storage range at Mayo Lake was largely used each year. After the closure of the mine and up until the Mayo-Dawson line was energized in 2003, the plant generated power only for local loads in Mayo and Keno. Since the Mayo-Dawson line went into service, the plant has also provided power to Dawson and Stewart Crossing. The Mayo hydro facility continues to operate below its full capability. The existing plant has an annual generation capability of just over 40 gigawatt hours (GWh) each year. Regardless of whether the Mayo B project is developed, the Mayo facility will return to operating at its full potential as loads grow and new mines go into production, including using the full range of Mayo Lake storage.

.

Components of the existing Mayo hydro facility

Wareham Lake: the original project involved construction of a 32 metre high earthen dam that created Wareham Lake. The dam controls the lake levels within a licensed range. From the lake, water passes through an intake structure and a tunnel (approximately half a kilometre) to the generating station.



Wareham Lake spillway



Existing Mayo plant

Generating Station: located on the Mayo River, the plant has two generating units of approximately 2.7 megawatts each, which operate with 36 metres of 'head' or vertical drop between Wareham Lake and the existing generating station.

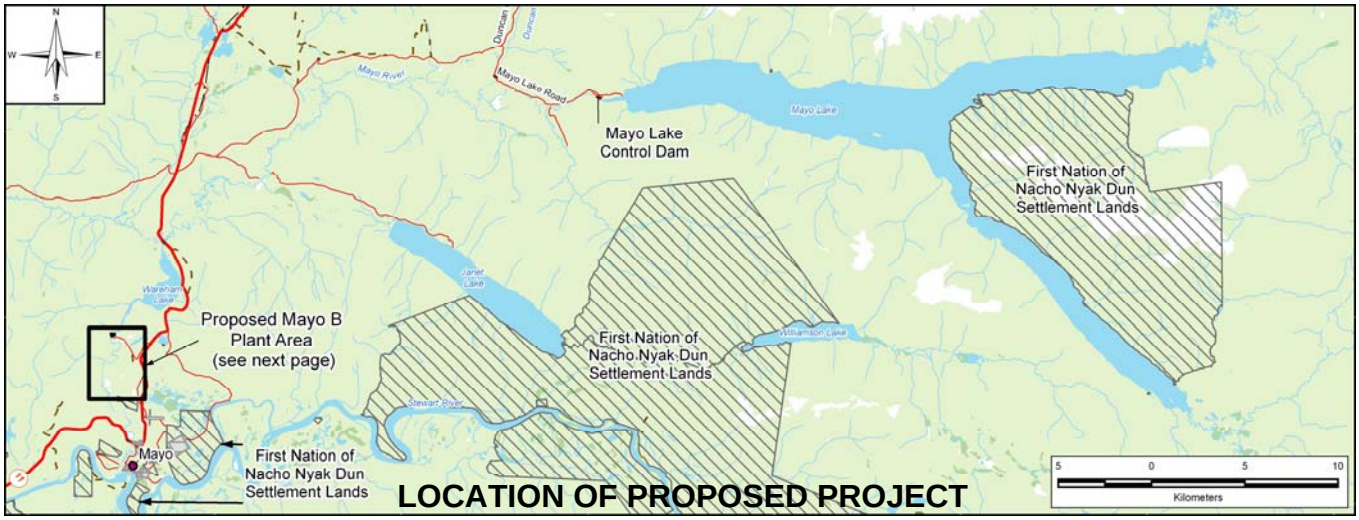


Mayo Lake

Mayo Lake Water Storage: approximately 40 to 50 kilometres upstream of Wareham Lake, the Mayo Lake dam provides the ability to control the level of Mayo Lake. Yukon Energy's water license sets a fixed maximum controlled lake level. Yukon Energy is permitted to release water to lower the lake from this level (draw it down) by 2.5 metres, which it typically does in the winter. The released water flows to Wareham Lake where it is used to generate power. The Mayo Lake dam is a six metre high rock-filled wood structure that was rebuilt in 1988/89.

The Proposed Mayo B Project

No decisions have been made at this time to proceed with the project. Any decision to proceed will only occur after meaningful consultation with all stakeholders in the Yukon and all permits and approvals are obtained.



LOCATION OF PROPOSED PROJECT

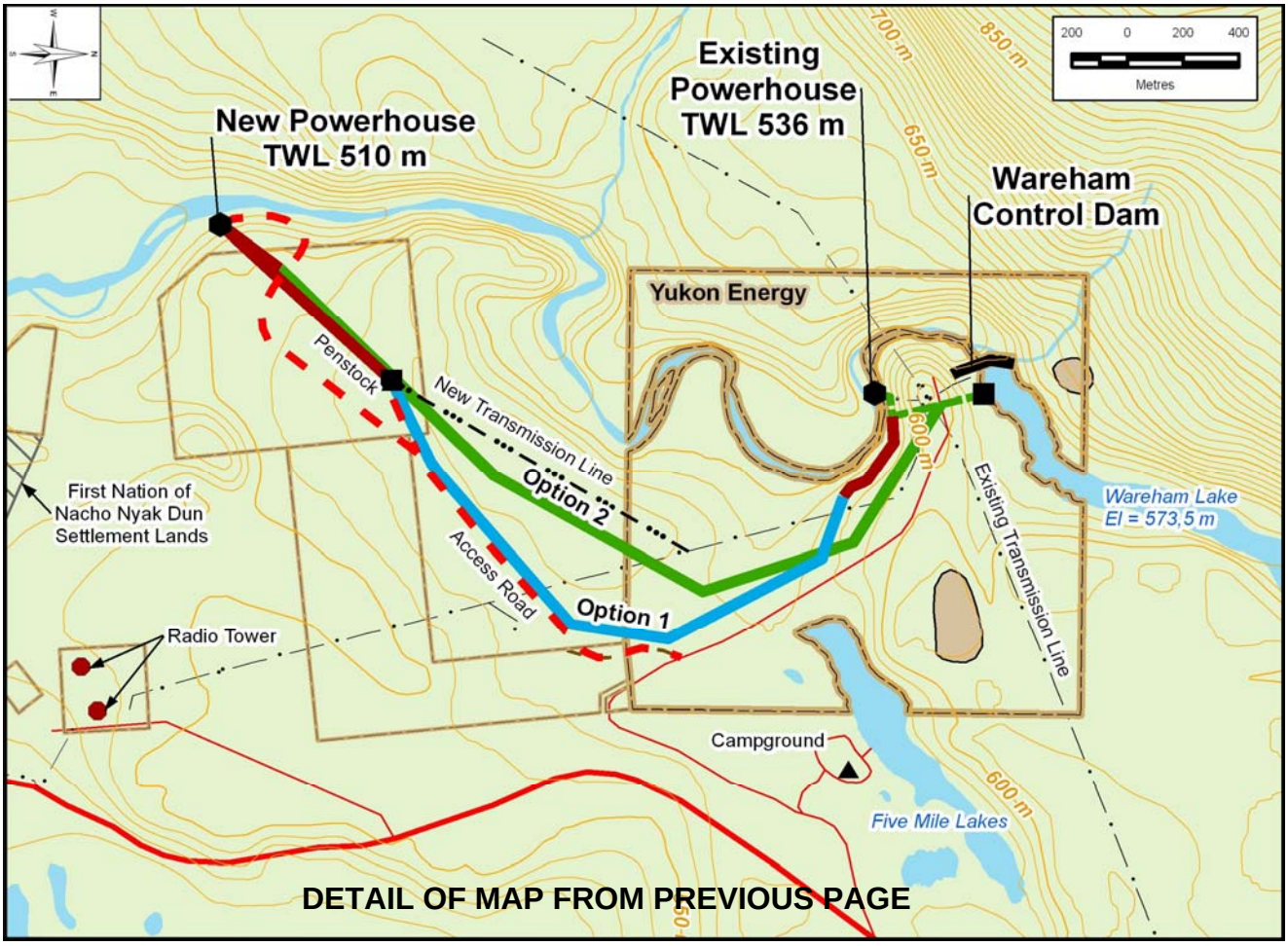
The proposed Mayo B project involves construction of a new powerhouse about three kilometres downstream from the existing powerhouse. The project will approximately double the amount of energy that can be generated from the Mayo River. No changes would be required at Wareham Lake or to the Wareham dam. The current plan is to maintain the existing power house for use as required in the future.

Yukon Energy is proposing to enhance the storage at the Mayo dam by lowering the current licensed minimum level for Mayo Lake. This would allow up to one metre of additional winter drawdown range, leading to a lower spring level than is currently permitted in the water licence. With the large natural spring inflows to the lake, this lower lake level would be temporary each spring.

Mayo B would be developed to help supply Yukon-wide power loads, which is conditional upon the completion of Stage 2 of the Carmacks-Stewart Transmission Project to interconnect the Mayo-Dawson and WAF (Whitehorse-Aishihik-Faro) systems.

Dam safety

The existing Mayo hydroelectric facilities are inspected to ensure the safety of the operation. This includes routine inspections (day to day observations, monthly checklist-driven inspections, and 24 hour equipment monitoring), annual formal inspections by Yukon Energy engineering staff, and an independent dam safety review every five years as per Canadian Dam Association guidelines and current licence requirements. The most recent five-year review was completed in November 2005.



Studies to date

Field studies on the local environment (water, land, wildlife, heritage resources) have been done and preliminary information collected on how people use the area or may be affected by the project.

The following studies have been completed:
-Geotechnical studies (test holes) to assist in determining which project options are feasible;
-Specific aquatic information on the use of the Mayo River by Chinook salmon and the use of Mayo Lake by lake trout, to enable Yukon Energy to address potential effects on the aquatic environment; and
-A heritage resources assessment has been completed.

The collection and analysis of data is on-going and will be used to help predict the potential effects of Mayo B on the existing environment and assist in shaping the project details.

The project concept is still being developed. Results of the public consultation process will help shape the project.

Project Components and Options

There are four parts to the Mayo B proposed project:

New Powerhouse

The new powerhouse will result in a total head or drop in elevation (between Wareham Lake and the new powerhouse) of 65 metres. By developing more head, the same water can be used to generate more power. It would include two to three turbines with a plant capacity of approximately 13 mega-watts. The plant would be large enough to allow most of the river flow to be used to generate power, compared to the existing plant that results in some of the water being spilled or wasted.

The powerhouse would be set back from the river and would be built on a bedrock foundation. Its tail-race (a component of the powerhouse that directs the flow of water once it has passed through the turbines) would extend to the Mayo River.

Water Diversion Options

A major part of the Mayo B project would be the construction of a mechanism to divert water from the existing intake to a new powerhouse.

Option 1 *- canal and/or penstock (see map page 4)*
Moving water at or near the land surface using a canal and/or a penstock (a pipe likely buried about one to two metres beneath the surface). This conveyance would begin at the existing intake tunnel and be approximately three kilometres long. It would follow the land contours before heading off the ridge into the new powerhouse.

Option 2 *- tunnel (see map page 4)*
Moving water using an underground tunnel approximately 3.5 metres in diameter and 3,200 metres long. It would be buried 65 to 100 metres below the ground surface tapping into the existing tunnel near the intake at Wareham Lake. Located near the new powerhouse, the tunnel would convert to a penstock that would run about 200 metres into the powerhouse.

Water Storage Improvements

Revising the licensed drawdown range at Mayo Lake (from 2.5 metres today to 3.5 metres) requires very little change to the Mayo Lake dam. Some of the pipes that release water would need to be re-placed with larger pipe, to allow the lower storage range to be used.

Additional Infrastructure

-New all-weather access road along the Option 1 alignment to the new powerhouse.
-Possible changes to the sub-station at the existing Mayo generating station
-Distribution line to new plant
-Pits for sand and gravel if Option 1 is chosen
-Site for stockpiling tunnel rock if Option 2 is chosen
-Temporary work camp for 50-75 people for up to two years

Construction activities would include clearing, tunnelling and/or penstock excavation, and heavy equipment operations associated with building an access road and power house.

Opportunities for Public Engagement

Public involvement is important to help Yukon Energy plan and shape the Mayo B Project, and to help YESAB carry out its environmental and socio-economic assessment of potential project effects. Yukon Energy's consultations to date with key stakeholders in the vicinity of Mayo (First Nation of Nacho Nyak Dun, Village of Mayo and the Mayo Renewable Resources Council) focused on summer and fall field study issues. More consultation opportunities are now planned with the First Nation of Nacho Nyak Dun, key stakeholders in the Mayo and Whitehorse areas, and the broader Yukon public. Future consultation will occur in the New Year after Yukon Energy's filing with YESAB.

Public Involvement Opportunities Before a Filing with YESAB

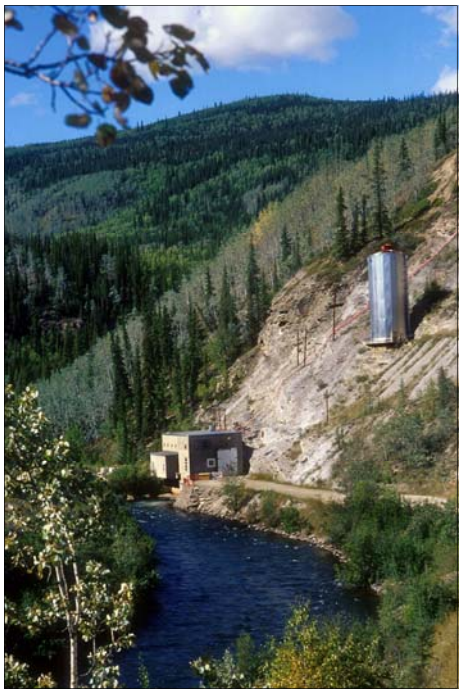
Project Introduction and Issues Identification

Potential Project Effects and Mitigation

Public Communication After a Filing with YESAB

Fall 2008
Yukon Energy is currently introducing the project and seeking feedback on issues of concern, planning options, potential project effects and mitigations.

First Quarter 2009



Existing Mayo generating plant



Mayo control structure

Comments? Questions?

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www.yukonenergy.ca

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-22

YEC states that the Aishihik Water License Renewal project ($167,000 in 2008 and $130,000 in 2009) includes monitoring the fish populations in Aishihik Lake and undertaking a subsistence fishery monitoring program.

QUESTION:

a) Please provide details of budget actually spent in 2008.

b) Please explain how the Aishihik 3rd Turbine project can be initiated prior to completion of this water license renewal.

ANSWER:

(a)

Amounts spent in 2008 on Aishihik Water License Renewal project are as noted in the table below:

Actual Spending for Aishihik Water Licence Renewal Project

Cost Type	2008 Spending
AFUDC	$ 1,781
Consultants	$ 55,659
Courier/Freight	$ 361
ES&G Build-up	$ 6,367
Legal	$ 1,050
Materials	$ 12,230
Regular Time	$ 3,246
Outside Services	$ 37,631
Grand Total	**$ 118,325**

The costs are associated with the following 3 projects:
Aishihik License Annual Payment
Aishihik Heritage Mitigation
Aishihik Fish Monitoring

(b)

The current Aishihik water license authorizes Yukon Energy to install a third turbine and associated appurtenances with a maximum generating capacity of 7 MW at the facility. No further licences are necessary.

REFERENCE: **October 6, 2008 Application, Capital Projects, Page 5-25 to 5-32**

QUESTION:

a) Please provide details of YEC's project management policy.

b) Has YEC had its contracting and purchasing practices reviewed by a consultant? If yes, please provide the results of that review and the actions taken by YEC as a result.

c) Please confirm that YEC uses an internal Project Review Committee to review and assess capital projects.

d) Please confirm that $100,000 has been established as a limit whereby projects forecast above this limit require more detailed scope and costing within YEC.

e) Please provide the project identification / cost-benefit worksheets used by the Project Review Committee for all projects with costs greater than $300,000 proposed to have expenditures in 2008 and 2009 and / or are being added to rate base in 2008 and 2009.

ANSWER:

(a)

YEC does not currently maintain a policy called "project management". For description of the Corporate capital project approval process, see YECL-YEC-1-11(a).

(b)

YEC contracting and purchasing practices were prepared with the assistance of a consultant – no report separate from the actual policies was produced.

(c)

Confirmed.

(d) and **(e)**

Not confirmed. Yukon Energy does not use dollar limits in determining the process for review of projects. Projects are reviewed under various approaches depending on their nature, such as the following:

- Strategic projects: Projects that tend to be (but not necessarily) of a larger dollar value that are dealt with by senior management. These projects tend to have less flexibility in terms of scheduling within the overall capital program, as schedules are often driving by other external factors (such as CSTP to capture the benefits of serving Minto load at the earliest opportunity).

- Core capital: This is made up of projects that comprise the overall capital plan, and must be managed in light of overall capital spending targets, available staff and contractor resources, and system operating constraints (such as ensuring an overhauls of one unit is coordinated with other required work to the same unit, and at the same time does not coincide with other planned work that, in combination, may excessively reduce the capacity resources available to operate the system). Within this core capital, there are also certain categories of review:
  - Required or blanket projects: This comprises spending that is effectively non-discretionary or standardized, such as work to meet the terms of a Water Licence, or standard annual budgets for purchasing computers. There is typically very little room to move or re-schedule these type of requirements, but they do comprise one component of capital spending that must be accommodated within overall spending targets
  - Other projects: The remainder of the capital plan typically has room to adapt, either in terms of timing, or scale, or in determinations as to the ultimate need for the project.

The particular $100,000 threshold value cited is used in the GRA to determine which projects receive detailed write-up in the Application document. Projects over $50,000 are specifically noted on the tables in Tab 5, and the numerous smaller projects are noted as

a line item “other projects under $50k”. This is the same approach that was used by YEC in its 2005 filing.

The only projects over $300,000 in the test years are either (a) major strategic projects as noted in Table 5.2, page 5-25 (which are projects over $1 million) or (b) the JDE software replacement.

For the JDE software replacement, please see YUB-YEC-1-37(c) and LE-YEC-1-57.

As noted in part (d), the projects that meet the definition of strategic project do not go through the Project Review Committee. Only limited information on these projects provided to the Project Review Committee, solely related to coordination or budgets and resources. Detailed project justification and cost/benefit related reviews has been completed for all of these projects, involving key senior managers, the Board of Directors and the regulator, as appropriate. The table below provides cross references to detailed needs analysis in other responses.

Project	**Project identification/Cost-benefit**
CSTP I/Minto Spur	See CW-YEC-1-29; YUB-YEC-1-36(a) and (b)
Minto Diesels	See CW-YEC-1-29; YUB-YEC-1-36 (c)
FD-1 rebuild	See CW-YEC-1-29; YUB-YEC-1-36(d)
WD3 rebuild	See CW-YEC-1-29
AH3 Construction	See CW-YEC-1-29; YUB-YEC-1-36(h)
Financial Information System	See YUB-YEC-1-37(c)
P126 Mirrlees Cooling System Upgrade	See CW-YEC-1-29; YUB-YEC-1-37(b)

REFERENCE: **October 6, 2008 Application, Capital Projects, Page 5-28 to 5-32; Tables 5.3 through 5.7 - Continuity Schedule of Planning and Study Costs**

QUESTION:

a) Please identify any current or planned capital projects to which these planning and study costs are associated.

ANSWER:

(a)

These costs are not associated with any committed current or planned project.

The cost of planning activities or studies that do not result in any specific project being undertaken are amortized as planning and study costs.

Planning and study costs incurred that lead to commitments to a specific capital project being implemented are included in the costs of the specified project.

REFERENCE: October 6, 2008 Application, Board Directives, Page 6-1

YEC states that "YEC/YECL jointly filed a required report with the Board in August 2005 that provided information on the revenue to cost ratios by customer class for both companies using the most recent cost of service allocation study, including comments on the implementation of a rate shift program over 10 years".

QUESTION:

a) Please update the August 2005 revenue to cost ratios report using proposed revenue requirement data available for 2008 and 2009. Revenues should be based on existing rates and utility proposed rates.

b) Please update the August 2005 revenue to cost ratios report using proposed revenue requirement data available for 2008 and 2009. Revenues should be based on existing rates and rates assuming that residential rates use a first energy block of 1300 kWh.

ANSWER:

(a) and **(b)**

The requested information cannot be provided. The 2005 cost-of-service report did not, at that time, update revenue to cost ratios as to complete such an update for all classes requires a full cost of service study to be performed.

REFERENCE: October 6, 2008 Application, Board Directives, Page 6-2;

YEC states that "Yukon Energy has recorded all further project-related costs, including all costs associated with the claims process, outside of rate base and revenue requirement. The claims process with Chant Construction is now complete, and there were no recoveries to Yukon Energy. Accordingly, no interest bearing account has been established".

QUESTION:

a) Please confirm that the out of court settlement related to the Mayo-Dawson transmission line resulted in YEC paying Chant Construction $3 million.

b) Please provide details of the total cost associated with this claim process. Please identify how much in costs internal to YEC (e.g., labour, overhead, general plant, etc.) have been incurred for this process and the amount allocated to this process.

c) Please identify where these capitalization transfers are reflected in the Application.

d) Please confirm that YEC's parent, Yukon Development Corporation is paying the full cost of this dispute.

e) Please provide details of the payments / transfers made by YEC to YDC (dividends and other) for 2005, 2006, 2007 and 2008.

ANSWER:

(a)

The net amount paid by YEC, and funded by YDC, to settle the litigation arising from the construction of the Mayo Dawson Transmission Line was $3 million.

(b)

Please see the table provided below:

Costs Associated with Claims Process	
Internal Labour	17,758
Travel	12,689
Office Exepenses	15,614
Legal	1,545,374
Other Consultant	295,703
Total	**$ 1,887,137**

(c)

As directed by the YUB, these costs are not allowed in regulated operations and so are excluded from this application.

(d)

All costs of this dispute are to the Shareholder's account.

(e)

Please see response provided to YECL-YEC-1-30.

REFERENCE: October 6, 2008 Application, Board Directives, Page 6-4

YEC states that "OIC 2007/94 in effect defers, until after December 31, 2012, any cost of service based rate rebalancing adjustments or rate shifts affecting major industrial customers".

QUESTION:

a) Please confirm that while the YUB's hands have been tied with respect to rates it can approve for the industrial customers, nothing in OIC 2007/94 prevents the Board from investigating cost of service issues or determining the parameters for a rate rebalancing program.

ANSWER:

(a)

The Board was provided with specific direction via the OIC. The OIC is clear that Cost of Service cannot be useful for rate design purposes at this time and will not become useful until rates are set for the period after 2012. The OIC does not have to specify what logically follows from its directions, i.e., that there is no practical reason to investigate cost of service issues or determining the parameters for a rate rebalancing program at this time given the direction provided by OIC 2008/149.

Yukon Energy proposes that such a review would occur towards 2012, as noted in the January 6, 2009 Workshop Presentation.

Please see also YUB-YEC-1-20.

REFERENCE: October 6, 2008 Application, Board Directives, Page 6-6

With respect to Maximum Utility Investment, YEC states that "Yukon Energy is continuing to examine options, based on the current PPA experience with Minto, where joint partnership of industry, Yukon Energy and the Yukon Government can best enable development of critical new bulk power supply infrastructure in a cost effective manner as regards all Yukon ratepayers".

QUESTION:

a) Please describe the efforts that YEC have made to address Maximum Utility Investment since Board Order 2007-5 was issued on April 30, 2007.

b) Please provide an estimate on the amount of time that YEC staff and consultants have spent on this issue.

ANSWER:

(a)

The matter was addressed in part during the Part 3 review process concerning the CSTP. To date this issue has not received further material attention.

(b)

No estimate of time is available.

REFERENCE: **October 6, 2008 Application, Board Directives, Page 6-8; Table 6.1 - Cost Awards 2007-7, 2007-8, 2007-9 and 2008-1**

QUESTION:

a) Please confirm that the cost award amount for UCG's lawyer should be $19,517.52 for the Resource Plan and $7,189.98 for the PPA proceeding.

ANSWER:

(a)

Confirmed. Table 6.1 provided in Tab 6 incorrectly added the total of all GST costs awarded in Order 2007-9 to Resource Plan Costs ($1506.46). This total amount should be divided between the Resource Plan and the PPA hearing with $406.98 of GST added to PPA hearing costs and $1099.48 added to Resource Plan costs. The sum of the two proceedings is correct.

REFERENCE: **October 6, 2008 Application, Board Directives, Tab 7; Schedule 2 – Computation of Allowance for Working Capital**

QUESTION:

a) Please confirm that the calculation on line 5 is based on a net revenue lag calculated for 2005.

b) Please provide the actual net revenue lag for 2005, 2006, 2007 and 2008. Please provide the detailed calculations used to determine these revenue lags and the sources of data used in these calculations.

ANSWER:

(a) and **(b)**

Please see YECL-YEC-1-10.

YUKON ELECTRICAL COMPANY LIMITED
(YECL)

REFERENCE: **Overall**

TOPIC: **Generation Outages/Reliability**

PREAMBLE:

Yukon Electrical would like details regarding all Whitehorse Rapids Hydro and Aishihik Hydro Generation facility outages impacting the WAF grid system from 2003 to 2008 inclusive.

QUESTION:

a) Please provide copies of all service interruption reports regarding generation outages at the Whitehorse Rapids and Aishihik Generating facility.

b) Please provide an excel spread sheet or equivalent summarizing the cause for each outage at each facility.

c) Please provide what actions or steps were taken to remedy or correct the cause for each of the outages listed.

d) Please list all O&M and capital expenditures that have been undertaken at the Whitehorse Rapids and Aishihik Hydro Generating facilities that specifically have improved reliability to customers. Please explain how each expenditure has contributed to service reliability.

ANSWER:

(a)

Please see Attachment 1 to this response.

(b) and **(c)**

Please see Table provided below**.**

Outages as Whitehorse and Aishihik

Unit	Failed Component	# of Occurances	Action to Prevent
WH4	Failed coil	1	Replaced coil
	Unknown	1	N/A
	Bus Bar Failure	2	Replaced bus bar
	Governor	7	Replaced hydraulic manifold
WH3	Governor	2	Plan to replace PLC
AH1	Cable failure	1	Replace cables
	Unknown	1	N/A
	High stator temp	1	Reset alarm levels
Transmission	Animal contact	1	None
S150	Incorrect wiring	1	Review with tradesman
	Unknown	1	N/A
L172	Unknown	1	N/A
	Vandalism - Broken Insulators	1	Review in media and with RCMP
L170	Lightning	1	None
S171	Incorrect relay reset	1	Review with tradesman
S167	Failed pot head	1	Replace pot head

(d)

Please see the table provided below.

Expenditures at Whitehorse and Aishihik ($000s)

YUKON ENERGY CORPORATION
EXPENDITURES at Whitehorse & Aishihiks
($000S)

	Actual			Forecast		
Description	**2005**	**2006**	**2007**	**2008**	**2009**	**comments**
P126 WD3 Re-build				1,100		Replace and refurbish parts for diesel
WH1 Trunion Bushing	370					Replace trunion bushing before failure
AH2 Rewind Stator		721				Increased output from the generator
AH2 Rewind Mechanical		305				will also improve life of the insulation
AH2 Rewind Rotor		268				and reliability of the unit.
Aishihik Cable Replacement		241				Replace failed cables
AH2 Protection Upgrade		88				Upgrade quality of protection equipment
WH4 Life Extension Project			550			
P126 Mirrlees Cooling System Upgrade			469			Upgrade cooling system
Underground Fuel Piping Remediation/Replacement			142			Improve fuel delivery system to diesels
WH3 & P125 Governor Upgrade			127			Improve governor control
AH1 Protection Upgrade			59			Upgrade quality of protection equipment
P126 Mirrlees Electrical Upgrades				150		Upgrade parts & equipment
P126 Mirrlees Cooling System Replacement				150		Upgrade parts & equipment
P126 Mirrlees Auxiliary Systems Replacement				150		Upgrade parts & equipment
AH0 Current Transformer Replacements				67		Replace current transformer before end of life
WH0 Improve Spill Regulation				25	200	Improve spill regulation so spill gates are more reliable since they won't operate as much
AH0 Deluge System					69	Fire extinguisher system
WD4 Control Upgrade					60	upgrade control equipment
Whitehorse Rapids Instrument Upgrade	99					Upgrade instruments
Electric Boiler Replacement P126	66					Improve heating in P126
Power Line Carrier Takhini - AH Replacement				155		Improve communications with Aishihik
TOTAL	**535**	**1,624**	**1,347**	**1,797**	**329**	

Yukon Energy Corporation

System Disturbance Report

Date: Aug 18 2005

System Operator: Steve Blysak

Weather: Cloudy light rain 12degs

Percentage of Grid: 34%

Pre-Disturbance Generation Setup

AH1	4.2mw
WH4	16 mw
WH1	5.27mw
WH2	5.42mw

Total Generation Online 30.89 Mw

Disturbance:

09:36:54	Wh4 Tripped	-16mw
09:36: 54	S6838 u/f trip	2.8mw
09:36:55	S150 52-17 u/f trip	2.70mw
09:37:14	S150 52-22 trip by op	2.73mw
09:37:34	S150 52-18 trip by Op	2.42mw
	Total Load Lost	**10.65**

Restoration

09:43	Started AH2 but unit failed to Sync cause still under investigation
09:47	WH3 ON
09:56	S150 52-22 Closed 4.3mw
09:58	S150 52-17 Closed 1.74mw
10:03	WD7 ON
10:04	S6817 Closed
10:05	FD7 ON
10:05	S150 52-18 Closed 2.74mw
10:06	WD6 ON
10:06	FD5 ON
10:08	S6838 Closed 2.06mw
10:09	S9403 Closed 1.44mw
10:10	S9402 Closed 1.08mw
10:11	Faro Mine load (pumps) .5mw

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S6838	09:36:54	10:08	31min 6secs
S150 52-17	09:36:55	09:58	21min 5secs
S150 52-22	09:37:14	09:56	18mim 46secs
S150 52-18	09:37:34	10:05	27min 26secs
S9403	09:36:55	10:09	32min 5secs
S9402	09:36:55	10:10	33min 5secs
Mine load (pumps)	09:36:55	10:11	34min 5secs

Target /Flags.

P127 #2 phase u/v, 5G, 5G1, 121XA

Comments:

The cause of the outage originated in P127 with a failed bus bar on #4 tripping the unit at 16mw causing system u/v and u/f.

Yukon Energy Corporation

System Disturbance Report

Date: August 20 2005

System Operator: Steve Blysak

Weather: Cloudy and Smokey 13deg C

Percentage of Grid: 100%

Pre-Disturbance Generation Setup

WH4	16mw
WH3	8mw
WH1	3.2mw
WH2	3.2mw

Total Generation Online 30.4 Mw

Disturbance:

11:15:48	WH4 Tripped	-16mw
11:15:50	S6838 Tripped u/f	3.1mw
11:15:51	S150 52-17 Tripped u/f	2.8mw
11:16:00	S150 52-22 tripped u/v	1.65mw
11:16:03	S150 52-21 Tripped u/v	5.95mw
11:16:50	S6837 Opened by Op	3.00mw
11:17:08	WH1 tripped	
11:17:11	WH2 tripped	
11:17:17	S150 52-18 Opened by Op	4.01mw
11:18:03	S164 52-3 Opened by Op	4.1mw
11:18:03	Faro 701 Open u/v	
11:18:06	WH3 tripped	
11:18:06	Black Out	

Restoration

11:20:23	S164 52-1 Open by Op	
11:21:00	AH1 Closed dead bus	L171 Energized
11:23:06	Faro 503 Opened	
11:23:18	Faro 506 Opened	
11:23:57	Faro 507 Opened	
11:24:00	S170 52-1 Open by Op	
11:24:22	S164 52-1 Closed	Energizing L172, L169, S150 and SCC
11:27:56	P132 52-FD7 Closed	Energizing FD0 SS and L356 (505)
11:29:19	Faro 506 Closed	Energizing Faro feeder #2

11:30:01	Faro 507 Closed	Energizing Faro Tfeeder #1
ALL Faro and Ross River Customers Restored with FD7		
11:33:47	S170 52-1 Closed	Energizing Mac Sub
11:35.01	S150 52-18	Energizing Arkell Sub 5.82mw *
11:36:52	AH2 ON	Synced Locally by Ron Kirkwood
11:38:42	S150 52-22	Energize 9L up to McRae Sub 2.21mw
11:39:26	S6838 Closed	2.45mw
11:42:30	S6837 Closed	4.59mw
11:46:42	S164 52-3	Energizing L170 up to Faro and the Mine
11:47:23	WH3 ON	
11:47:58	WH2 ON	
11:50:36	S150 52-17 Closed	1.69mw
12:08:03	701 Closed	
12:10:10	503 Synced Closed	
12:10:59	S150 52-21 Closed	
12:12:50	FD7 OFF	By Lloyd M.

Time Variance

Feeder	Opened / Tripped	Closed	Variance
Faro 505	11:18:03	11:27:56	9min 53secs
Faro 506	11:18:03	11:29:19	11min 16secs
Faro 507	11:18:03	11:30:01	11min 58secs
S150 52-18	11:17:17	11:35.01	17min 44secs
S150 52-22	11:16:00	11:38:42	22min 42secs
S6838	11:15:50	11:39:26	23min 26secs
S6837	11:16:50	11:42:30	25min 20secs
S164 52-3	11:18:03	11:46:42	28min 39secs
S150 52-17	11:15:51	11:50:46	34min 55secs
Faro 503	11:18:03	12:10:10	
S150 52-21	11:16:03	12:10:59	54min 56secs

Target /Flags.

Comments: WH4 tripped at 16mw Causing the system to Shed its u/f breakers then the system went unstable until WH0 units all tripped and there was no generation left on (Blackout)

Yukon Energy Corporation

System Disturbance Report

Date: September 2, 2005

System Operator: Mike Hannah

Weather: 12 degrees and cloudy

Percentage of Grid: 10%

Pre-Disturbance Generation Setup

WH1	3.4 MW
WH2	2.8 MW
WH3	8.0 MW
WH4	13.1 MW
AH1	3.0 MW

Total Generation 30.3 Mw

Disturbance:

15:55:22	WH4 trip
15:55:22	S6838 trip

Restoration

15:58:27	AH2 On line
16:18:32	S6838 Closed

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S6838	15:55:22	16:18:32	23 minutes 10 seconds

Target /Flags. WH4 > 51W1 Phase time over current
94T/L127
97S
52AX
86EG
27 Phase Under Voltage

WH4 Exciter > 27 FDG

Comments: The cause for WH4 tripping off line was due to a burnt busbar. SCC Operator had to wait for YECL to split the load on S6838 at Porter Creek Sub Before closing in S6838.

Yukon Energy Corporation
System Disturbance Report

Date: Jan 29, 2006

System Operator: Myles O'Brien

Weather: -25 Calm

Percentage of Grid: 100%

Pre-Disturbance Generation Setup

WH 3	7.0
WH 4	18.2
AH 1	11.9
AH2	11.9

Total Generation: 50.20 Mw

Disturbance:

Time	Event
13:32:43	AH1 ground over-current alarm (multiply times)
13:34:03	P130 52-F2 tripped (23.8 Mw loss of generation 48%of system)
13:34:03	S167 52-1 tripped
13:34:03	AH2 tripped – Over-speed
13:34:04	S6838 tripped - U/F
13:34:05	S150 52-17 tripped - U/F
13:34:14	S150 52-21 tripped - U/V
13:34:14	S150 52-22 tripped - U/V
13:34:14	S6837 tripped - U/V
13:34:15	Faro 701 tripped - U/V
13:34:16	WH4 tripped - Non-Lockout Over-speed
13:34:20	S150 52-18 tripped
13:38:15	Faro 503 opened
13:40:05	S164 52-R1 tripped (R1 reactor fault alarm)

Restoration

13:42:42	FD7 on
13:44:18	Faro 507 closed picking up Faro
13:44:31	Faro 505 closed picking up Ross River and 506 load
13:51:25	S150 52-1 opened (Split S150 from grid)
13:51:38	S150 52-15 opened (Split S150 from grid)

13:53:25	WH2 on line
13:55:56	S171 52-1 open
13:56:01	S171 52-3 open
13:56:31	S164 52-3 opened
13:58:45	WH2 tripped – 86 mechanical fault – low oil pressure shutdown
14:03:15	S167 52-1 closed
14:03:22	S150 52-17 closed (2.67 Mw pickup)
14:03:30	WH3 tripped - 86 electrical lockout
14:03:33	S150 52-17 tripped - U/F
14:04:58	P130 52-F2 closed (AH1 energized to S150)
14:05:27	S150 52-15 closed (AH1 energizes S150 & YEC SS)
14:05:37	S150 52-1 closed
14:06:42	P130 52-F2 tripped (closed 1 min 42 sec)
14:06:42	S167 52-1 tripped
14:06:42	AH1 tripped - lock out
14:07:19	S150 52-1 open
14:07:34	S150 52-15 open
14:29:42	S171 89-13 open – GOI point for WAP 06-27 P127 T9 inspection
14:32:21	WD7 placed on line
14:49:56	WH3 over-speed on start-up
Note	Could not sync hydro to WD7 Re: WD7 low voltage 3.3 kV, PLC problem.
15:37:50	WD7 off line – required to sync hydro on
15:39:14	WH3 on line
15:41:27	S150 52-17 closed (No load pickup, 19L sectionalized)
15:42:33	S150 52-17 tripped - U/F (estimated 2.5 Mw pickup)
15:46:30	WH2 on line
15:46:58	S150 52-17 closed (No load pickup, 19L sectionalized)
15:48:15	19L load pickup 2.56 Mw
15:49:41	S150 52-17 tripped via SCADA Re: System unstable WH2 and WH3 swinging
15:53:08	S150 52-17 closed (No load pickup, 19L sectionalized)
15:53:08	WH2 tripped – 86 Electrical fault
15:53:57	WH4 on - energized to S171 89-13
15:55:55	S150 52-17 U/F disabled
15:58:41	WH2 on line
15:59:51	S150 52-21 closed
16:00:50	WH4 off line - required to close S171 89-13
16:10:30	WH2 tripped - 86NC Low oil pressure shut-down
16:14:19	S171 89-13 closed
16:15:13	S171 52-1 closed
16:16:03	S171 52-3 closed
16:19:36	WH4 on
16:25:59	S150 52-15 closed
16:26:39	S150 52-1 closed

16:32:04	WD7 on line
16:43:38	WD1 on line
16:44:47	S6837 closed
16:45:52	S6838 closed
16:45:52	S6838 tripped - U/V
16:45:52	S6837 tripped -- U/V
16:48:31	S6837 closed
16:50:02	S6838 closed
17:00:01	WH2 on line
17:05:55	WD6 on line
17:07:26	WD4 on line
17:11:46	S150 52-18 closed
17:13:03	S150 52-22 closed
17:35:26	WD1 off line
17:35:26	WD7 off line
17:49:05	WD6 off line
17:54:03	AH1 on line - P130 bus and L355 energized
17:55:24	S167 52-1 closed
17:57:00	AH1 off line (L355 de-energized)
18:09:24	WD3 on line
18:22:12	AH1 on line
18:24:17	P130 52-F2 tripped
18:24:17	S167 52-1 tripped
18:24:17	AH1 tripped -- ground over current
18:28:11	WD1 on line
18:31:56	WD2 on line
20:00:21	S167 52-R1 failed to open (locally or remotely)
20:18:44	S167 89-R1 open
20:21:58	S167 89-LT3 open - S167 bus isolation
20:25:30	S167 89-1L open - S167 bus isolation
20:30:00	S167 89-1B confirmed open - S167 bus isolation
20:31:58	P130 52-F1 opened (false indication?)
20:38:04	AH2 on line (L355 energized)
20:52:41	AH2 off line (L355 de-energized)
21:05:10	S164 52-3 closed
21:36:26	AH2 on line (L355 energized)
22:19:09	S164 52-3 opened
22:21:56	S164 52-R1 closed
22:26:18	S164 52-3 closed
22:33:31	Faro 701 closed
22:33:55	Faro 503 closed
22:37:00	FD7 off line
22:47:03	P130 52-F1 closed (false indication?)

22:53:07	WD3 off line
23:30:17	WD6 on line
23:44:32	WD1 off line
23:48:49	WD6 off line

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S6838	13:34	16:50	3:16
S6837	13:34	16:48	3:14
S150 52-17	13:34	15:53	2:19
S150 52-21	13:34	15:59	2:25
S150 52-22	13:34	17:13	3:39
S150 52-18	13:34	17:11	3:37
Faro 505	13:34	13:44	0:10
Faro 507	13:34	13:44	0:10
S164 52-3 (L170)	13:51:25, 22:19:09	21:05:10, 22:26:18	7:20:54
L171	13:51:25, 14:05:27	14:06:42, 16:19:36	2:26:56
L355	14:06:42, 17:57:00, 18:24:17, 20:52:41	17:54:03, 18:22:12, 20:38:04, 21:36:26	7:10
Mendenhall	13:34	Jan 30/06 4:43	15:09 estimated

Target /Flags:

S6838	under frequency
S6837	under-voltage
S150 52-17	under – frequency
S150 52-18	under-voltage
S150 52-21	under-voltage
S150 52-22	under-voltage
WH4	over-speed
AH1	ground over current (did not trip)
AH2	over-speed
S167 Bus	bus differential

Comments:

The cause of this disturbance was found to be a faulted cable running from the switchgear to the transformer. There are 3 cables per phase totaling 9 cables, one of the A phase faulted.

The following issues were identified form the internal outage de-brief

1. **Overall Command**
   - In some situations it was felt that it would be beneficial to take the time to determine what the original issues were, have a meeting of key personnel to allow everyone to understand the problem and then assign tasks.

2. **Communications**
   - Phones failed in the diesel plant making communication with SCC impossible.
   - Radio etiquette – what should be said and how to say it on the radios should be discussed.

- The help line rang constantly until it was taken off the hook – perhaps in major outages it should be assigned to a non-operations person or at least the message should be changed to indicate the current conditions.
- Hand held radios should be available – Al plans to buy a few, there are two currently in SCC, and two in Brian's office that should be moved to SCC. They will then be available in one place and can be maintained by the SCC Operators.
- Tracking employees who are on site to assist (who comes in and who leaves) should be done.
- Phone number 5355 will become a recorded line.

3. **Stable Station Service**
   - The lack of station service created additional problems.
   - No AC power to louvers in spillway diesel, unit overheated.

4. **Response of Hydro Units**
   - Droop settings – would it be worthwhile to change the droop settings, would it give more control to the SCC operator.
   - Hydraulic governors – big time lapse with hydraulic governors.

5. **Response of Diesel Units**
   - Isoc load sharing on diesels needed
   - WD1 breaker issues
   - PLC WD7 issues
   - WD6 rad fans
   - WD4 low fuel alarms
   - No plant alarms
   - WD7 fuel valve

6. **Gates**
   - No communication at the gates
   - Needed local power to lift gates while station service was down – should there be a power supply set up permanently at the gates
   - Wasted time getting tools – should be left in the building
   - Couldn't see the elevation changes on the gates – poor lighting
   - Should a line be painted on the gate showing the optimum elevation if all the units are down
   - On an ongoing basis, should the OIC call SCC every morning to check on the gate level in case of emergency
   - Dedicated person assigned to gates in an emergency if there is enough resources

7. **Training**
   - It was suggested that on going training of emergency scenarios should be carried out for Operations staff

Yukon Energy Corporation

System Disturbance Report

Date: Feb 12 2006

System Operators: Mike Hannah and Rob Wells

Weather: -1 calm

Percentage of Grid: 18.1%

Pre-Disturbance Generation Setup

20.4	WH4
4.8	WH1
2.2	WH2
6.8	AH1

Total Generation 34.2 Mw

Disturbance

Time	Event
23:11:04	WH4 breaker tripped
23:11:06	S170 S6838 tripped
23:11:07	S150 52--17 tripped

Restoration

23:18:59	AH2 on
23:23:55	WH3on
23:25:40	S150 52-17 closed
23:27:12	S170 S6838 closed

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S170 S6838	23:11:17	23:25:40	14 minutes 23 seconds
S150 52--17	23:11:06	23:27:12	16 minutes 06 seconds

Target /Flags.

27 phase U/V, 5G, 5G1, 121XA,EM and 86 electrical lockout

Comments:

WAF outage caused by burnt bus bar at WH4

Yukon Energy Corporation
System Disturbance Report

Date: Feb 13 2006

System Operators: Mike Hannah and Rob Wells

Weather: -3 calm

Percentage of Grid: 15.1%

Pre-Disturbance Generation Setup

5.5	WH1
5.6	WH2
7.3	WH3
9.8	AH1

Total Generation 28.2 Mw

Disturbance

Time	Event
04:27:00	WH4 breaker tripped
04:27:03	S170 S6838 tripped
04:27:03	S150 52--17 tripped
04:27:31	WH1 tripped
04:27:32	WH2 tripped

Restoration

04:35:48	AH2 on
04:58:44	WH1 on
05:02:47	WH2 on
05:03:49	S150 52-17 closed
05:08:07	S170 S6838 closed
05:10:00	S9402 closed
05:12:00	S9403 closed

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S170 S6838	04:27:03	05:08:07	41 minutes 4 seconds

S150 52-17	04:27:03	05:03:49	36 minutes 46 seconds
S9402	04:27:03	05:10:00	42 minutes 57 seconds
S9403	04:27:03	05:12:00	44 minutes 57 seconds

Target /Flags.

Frequency-ROCOS 81-81R

Comments:

SCC requested a local start up of WH4. Immediately after the breaker closed for WH4 the unit went into reverse power to approx. -10 MW's knocking off WH1 and WH2 on overspeed and tripping S170 S6838 and S150 52-17 on under current.

Yukon Energy Corporation

System Disturbance Report

Date: April 26, 2006

System Operator: Steve Blysak

Weather: 5 c Light breeze

Percentage of Grid:

Pre-Disturbance Generation Setup

AH1	8.7
WH4	17.1
WH3	7.2

Total Generation 38.98 Mw

Disturbance:

Time	Event
21:30:22	u/v alarms at S170
21:30:25	Wh3 tripped elec lockout
21:30:25	Faro 701 open u/v
21:30:25	S150 52-22 open u/v
21:30:25	S150 52-21 open u/v
21:30:25	S150 52-17open u/v
21:30:25	S150 52-18 open u/v
21:30:26	Wh4 open overspeed
21:30:27	S6837 open u/v
21:30:27	S6838 open u/v
21:30:27	S164 52-1 0pen

Restoration

21:42:26	S164 52-1 closed energizing S170 and S150 with Ah1
21:44	FD7 on faro 505 and 507 closed faro Ross river energized
21:45	Ah2 on
21:46:45	S150 52-22 closed 4.44 mw
21:47:52	S150 52-18 closed 3.48 mw
21:50:16	Wh2 on
21:50:03	Wh4 on
21:53:05	S6838 closed 6.00mw
22:01:22	S150 52-17 closed 2.36 mw
22:05:55	S6837 closed 1.2 mw
22:16:24	S150 52-21 closed 2.5 mw

22:33:16	Faro 701 closed
22:33:35	Faro 503 closed Faro back on WAF grid
22:38	Fd7 off

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S150 52-22	21:30:25	21:46:45	16 min 20 secs
S150 52-18	21:30:25	21:47:52	17 min 27secs
S6838	21:30:27	21:53:05	22min 38 secs
S150 52-17	21:30:25	22:01:22	30 min 57 secs
S6837	21:30:27	22:05:55	35 min 38 secs
S150 52-21	21:30:25	22:16:24	45 min 59 secs

Target /Flags.
U/V

Comments:

Outage originated in lewes blvd sub squirrel in brkr bushings need breaker numbers and restoration times from yecl

Yukon Energy Corporation

System Disturbance Report

Date: July 14, 2006

System Operator: Steve Blysak

Weather: 17 degrees and scattered clouds

Percentage of Grid: 100%

Pre-Disturbance Generation Setup

WH4	17.35 Mw
WH2	2.62 Mw
WH3	7.08 Mw
AH1	3.75 Mw

Total Generation 30.80 Mw

Disturbance:

Time	Event
17:14:51	S150 52-15 Closed (by SCC)
17:14:51	S150 T7 Lock-out (Diff trip)
17:14:51	S150 52-1 Open
17:14:51	S150 52-23 Open
17:14:51	S150 52-15 Open
17:14:54	S150 52-17 tripped (u/f)
17:15:26	P130 52-AH1 open (reverse power)
17:16:11	S150 52-22 tripped (by SCC)
17:16:56	S170 S6837 tripped (by SCC)
17:17:02	S170 S6838 tripped (Under/Over Voltage)
17:17:12	S170 52-1 tripped (by SCC)
17:17:22	S150 52-21 tripped (by SCC)
17:17:33	S150 52- 18 tripped (by SCC)
17:17:53	WH3 tripped (elec lockout)
17:19:41	Faro 701 tripped (Under/Over Voltage)
17:21:16	S171 52-1 tripped (by SCC)
17:21:25	S171 52-3 tripped (by SCC)
17:21:41	S171 52-4 tripped (by SCC)
17:22:16	WH4 tripped (Reverse power)
17:22:38	WH2 tripped (by SCC) SCC SS
17:26:57	

Restoration:

17:28:00	FD7 on line
17:28:14	P125 52-WH2 closed (SCC station service back up)

17:28:20	505 closed
17:28:50	507 closed
17:36:47	S171 52-1 Closed (by SCC)
17:37:04	S171 52-3 Closed (by SCC)
17:37:27	S171 52-4 Closed (by SCC)
17:38:46	S150 52-23 Closed
17:38:59	WH2 tripped (elec lockout)
17:39:02	S150 52-1 Closed (by SCC)
17:40:21	WH4 Online
17:43:54	S170 52-1 Closed
17:46:56	S150 52-17 Closed
17:47:30	S150 52-17 (Opened by SCC)
17:51:06	P130 52-AH1 Closed
17:52:35	S150 52-17 Closed
17:54:18	S150 52-18 Closed
17:55:47	S150 52- 22 Closed
17:58:50	WH2 online
17:59:49	S150 52-21 Closed
18:02:32	S170 S6838 Closed
18:08:06	S170 S6837 Closed
18:20:00	WH3 online (locally)
18:20:07	Faro 503 Open
18:20:07	Faro 701 Closed
18:25:20	Faro 503 Closed (synced to System)
18:27:30	P132 52-FD7 Open

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S150 52-17	17:14:54	17:52:35	37 min, 41 sec
S150 52-18	17:17:33	17:54:18	36 min, 45 sec
S150 52- 22	17:16:11	17:55:47	39 min, 36 sec
S150 52-21	17:17:22	17:59:49	42 min, 27 sec
S170 S6837	17:16:56	18:08:06	51 min, 10 sec
S170 S6838	17:17:02	18:02:32	45 min, 30 sec
Faro 505	17:19:41	17:28:20	8 min, 39 sec
Faro 507	17:19:41	17:28:50	9 min, 9 sec
L355, L170 , L171	17:22:38	17:40:21	17 min, 43 sec

Target /Flags:
S164 Panel 171L AC fail relay 74 – 60 fm2 52-2
S164 Panel 172L AC fail relay 74 – 60 fm2 52-1
S164 Panel 170L AC fail relay 74 – 60 fm2 52-3
S150 52-17 Under-frequency
S6838 Under voltage
S6837 Under voltage
WH3 Reverse power
AH1 Reverse power
WH4 Reverse power

Comments: The cause of this disturbance was found to be an incorrect CT wiring on S150 52-15. The breaker had been replaced the week of July 10, 2006. On the return to normal switching one of the last steps was to close this breaker completing the circuit through S150 T7. However once the breaker was closed S150 T7 indicated a

differential trip resulting in breakers S150 52-1, S150 52-15 and circuit switcher S150 52-23 opening. As a consequence of these switches opening the WAF system was split; WH2 and WH3 feed the S150 load and WH4 and AH1 feeding the remaining WAF system. At the time of the disturbance there was approximately 5-6 Mw being imported to S150 through S150 T2. With insufficient generation to supply the load at S150, breaker S150 52-17 tripped on under-frequency, SCC then proceeded to open the remaining breakers at S150 in an attempt to stabilize the system. While opening the S150 breakers WH3 tripped off line on reverse power.

The operator was unaware that the system had been split and responded to the frequency indication in the control center, which was high as WH2 was on line supplying just station service and no S150 load. AH1 had tripped on reverse power at the start of the disturbance. SCC dropped the remaining load by opening S6837 and S170 52-1. The operator still not seeing any affect on the system frequency attempted to trip WH4 off, however the RTU hung up so the operator elected to trip S171 52-1, S171 52-3 and S171 52-4 resulting in WH4 going off line on reverse power.

When additional support arrived the SCC operator indicated that the west spill-gate was closing on its own. A local check of the gate indicated an opening of 4.5 feet with the gate stationary, staff took local control of the gate and raised it to 6 feet. Both the east and west spill gates lower limit alarms were activated, which may have led the operator to believe the gates were closing. WH4 was placed on line and an attempt to closed breaker S150 52-17 (partial 9L load pickup) was made due to poor response by WH4 the breaker was reopened. AH1 was added to the system and the restoration began with no further issues.

Outage Issues:

1. Spill gate closing indication.
2. WH4 load pickup.
3. Automatic front gate orientation
4. WH4 RTU control failures.
5. SCC situational awareness i.e. Split system review

Yukon Energy Corporation

System Disturbance Report

Date: August 1, 2007

System Operator: Myles O'Brien

Weather: 12 degrees scattered clouds

Percentage of Grid: 66%

Pre-Disturbance Generation Setup

WH1	2.56 Mw's
WH2	2.73 Mw's
WH3	6.3 Mw's
WH4	17.01 Mw's
AH2	0.98 Mw's

Total Generation: 29.58 Mw's

Disturbance:

Time	Event
21:37:59	WH4 Breaker Open (Speed Adjust Error of -22.49?)
21:38:01	S170 S6838 Open (U-F Trip)
21:38:02	S150 52-17 Open (U-F Trip)
21:38:08	S150 52-22 Open (U-V Trip)
21:38:12	S150 52-21 Open (U-V Trip)
21:38:14	WH1 Breaker Open (Emergency Stop 86 Electrical Fault)
21:44:50	S164 52-3 Opened by SCC Operator
21:44:54	Faro 701 Open

Restoration:

21:47:35	WD7 Online
21:53:35	FD7 Online
22:09:23	WD5 Online
22:10:04	WH1 Online
22:12:44	S150 52-21 Closed
22:15:28	S150 52-22 Closed
22:24:15	WD3 Online
22:29:44	WD2 Online
22:32:31	S150 52-17 Closed
22:36:57	S170 S6838 Closed
22:46:29	WD1 Online
22:56:59	WD4 Online
23:37:53	S164 52-3 Closed

23:58:19	Faro 503 Closed
00:49:27	L171 89-42-6 Closed (GOI 07-272)
00:54:55	Aish P130 52-F2 Closed (GOI 07-272)

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S170 S6838	21:38:01	22:36:57	58 Minutes 56 Seconds
S150 52-17	21:38:02	22:32:31	54 Minutes 29 Seconds
S150 52-22	21:38:08	22:15:28	37 Minutes 20 Seconds
S150 52-21	21:38:12	22:12:44	34 Minutes 32 Seconds
S164 52-3	21:44:50	23:37:53	1 Hour 53 Minutes 3 Seconds
Faro 701	21:44:54	23:58:19	2 Hours 13 Minutes 25 Seconds

Target /Flags: TBA

Comments: A Governor Speed Adjust error (hydraulic valve failure) caused WH4 to trip offline. WH1 tripped offline due to an electrical fault perhaps caused by voltage discrepancies of the WH4 breaker opening under full load conditions.

S164 52-3 was opened by SCC to gain system stability and aid in restoration. Whitehorse Diesel and WH1, 2 &3 were used for restoration until GOI 07-272 (L171) could be surrendered and returned to normal. Once L171 was returned to normal and AH2 was used to relieve P126 units.

Yukon Energy Corporation

System Disturbance Report

Date: August 27, 2006

System Operator: Myles O'Brien

Weather: 13 degrees and scattered clouds

Percentage of Grid: 50%

Pre-Disturbance Generation Setup

WH4	17.08 Mw
WH3	6.67 Mw
WH2	4.0 Mw
WH1	2.98 Mw

Total Generation: 30.73 Mw

Disturbance:

Time	Event	
11:34:09	S150 52-22	Open (Under voltage)
11:34:10	S170 S6838	Open (UV-OV)
11:34:11	S170 S6837	Open (UV-OV)
11:34:11	S150 52-17	Open (Under voltage)
11:34:15	WH4	Trip (Over speed)

Restoration:

11:39:34	AH1	52 Breaker Close		
11:43:58	S150 52-17	Close	3.87Mw	
12:08:47	S170 S6838	Close	2.57Mw	
12:11:52	S170 S6837	Close	2.08Mw	
12:15:00	S9403	Close	2.08Mw	(Porter Creek Sub #6)
12:17:00	S9402	Close	1.89Mw	(Porter Creek Sub #6)
12:21:00	S7191	Close	2.43Mw	(Services Sub #5)
12:23:00	S7192	Close	1.10Mw	(Services Sub #5)
12:24:00	S7193	Close	2.2Mw	(Services Sub #5)
12:27:00	S8358	Close	3.64Mw	(Mountain View Sub #28)
12:29:00	S8471	Close	1.02Mw	(Mountain View Sub #28)
12:31:00	S8354	Close	1.49Mw	(Mountain View Sub #28)
12:44:10	S150 52-22	Close	5.1Mw	
12:55:52	WD7	Breaker Close		
12:58:00	S6840	Close	0.56Mw	(Marsh Lake & Teslin)

Time Variance:

Feeder	Opened / Tripped	Closed	Variance
S150 52-22	11:34:09	12:44:10	00:10:01
S170 S6838	11:34:10	12:08:47	00:34:37
S170 S6837	11:34:11	12:11:52	00:37:41
S150 52-17	11:34:11	11:43:58	00:09:47

Target /Flags:

Comments:

Yukon Energy Corporation

System Disturbance Report

Date: June 10, 2006

System Operator: Gary McLaughlin

Weather: 14 C, Light breeze

Percentage of Grid: 88%

Pre-Disturbance Generation Setup

AH1	3.5
WH4	17.8

Total Generation 21.3 Mw

Disturbance:

Time	Event
02:19:40	S164 52-1 tripped
02:19:42	S150 52-21 tripped
02:19:42	S150 52-22 tripped
02:19:42	S150 52-17 tripped
02:19:42	S150 52-18 tripped
02:19:43	S6838 tripped
02:19:44	WH4 tripped
02:19:46	S6837 tripped

Restoration

02:28:07	S164 52-1 closed
02:29:24	AH2 on
02:30:39	WH1 on
02:31:07	S150 52-22 closed
02:33:54	S150 52-17 closed
02:34:58	WH3 on
02:35:25	S6838 closed
02:37:12	S15052-18 closed
02:51:46	WH2 on
02:59:27	S150 52-21 closed
03:09:19	S6837 closed

Time Variance

Feeder	Opened / Tripped	Closed	Variance (hh:mm:ss)
S150 52-22	02:19:42	02:31:07	0:11:25
S150 52-18	02:19:42	02:37:12	0:17:30
S6838	02:19:43	02:35:25	0:15:42
S150 52-17	02:19:42	02:33:54	0:14:12
S6837	02:19:46	03:09:19	0:49:33
S150 52-21	02:19:42	02:59:27	0:39:45

Target /Flags.

S150 52-17 under voltage trip
S150 52-18 under voltage trip
S150 52-21 under voltage trip
S150 52-22 under voltage trip
S6837 under voltage trip
S6838 under voltage trip

Comments:

The cause of this disturbance has to date not been determined. S164 52-1 tripped on a distance relay de-energizing L172, WH4 was unable to supply the load at S150 and S170 by itself resulting in an under voltage condition tripping the feeder breakers at each substation. L355, L170 and L171 remained energized and fed from AH1. A line patrol of L172 will be done Monday, June 12, 2006.

Update (June 12, 2006): YECL reports a possible high load contact over the weekend that may have caused this outage. They found a burnt primary conductor in the Marwell area fed from S7192 in the services substation.

Yukon Energy Corporation

System Disturbance Report

Date: June 17 2007

System Operator: Gary McLaughlin

Weather: 17C Thunderstorm with Rain

Percentage of Grid: 35%

Pre-Disturbance Generation Setup

WH1	5.5 mw
WH2	5.4 mw
WH3	8.2 mw
AH1	11.6 mw

Total Generation: 30.70mw

Disturbance:

Time	Event
15:31	Faro 701 Open
15:31	S164 52-3 Open
15:32	S6838 Open
15:32	S150 52-17 Open
15:32	WH2 Mechanical Fault 86N Trip
15:32	WH1 Mechanical Fault 86N Trip

Restoration:

15:36	Faro 507 Open
15:37	Faro 503 Open
15:42	P132 52-FD7 Closed
15:44	Faro 507 Closed
15:43	AH2 on
15:45	Faro 507 Closed
15:50	YECL Clearing Dist Breakers on S6838 and S150 52-17
15:56	WH1 on
15:58	WH2 on
16:12	S150 52-17 closed
16:12	YECL Closing Dist Breakers on S150 52-17
16:25	S6838 closed
16:25	YECL Closing Dist Breakers on S6838
18:18	L170 89-813 Open
18:19	S164 52-3 Closed
18:39	S164 52-3 Open

18:40	L170 89-813 Closed
18:40	S164 52-3 Closed
19:42	Faro 701 closed
19:48	Faro 503 Closed
19:53	P132 52-FD7 Open

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S164 52-3	15:31	18:19	2 hours, 48 min
S164 52-3	18:39	18:40	1 min
S150 52-17	15:32	16:12	40 min
S6838	15:32	16:25	53 min

Target /Flags

Line Distance relay on L170, 89.3 km (ABC instantaneous).
S6838 U/F trip
S150 52-17 U/F trip

Comments:

The cause of this event has been determined to be a lightning strike on L170. Due to the loss of load (U/F breakers) WH1 and WH2 tripped on over-speed, closing the head-gates and delaying the restoration process.

During the restoration the SCC operator asked YECL to clear their distribution breakers fed from S6838; they inadvertently cleared breakers in Mountainview sub fed from S6837 causing outage to their customers.

When L170 was normal YECL dispatch was unable to call CD1 and found out from staff at Carmacks Hotel that it was still running when should have already shut down. Dispatch asked SCC for some direction on what to do, if they should leave it run all night or send someone out.

Yukon Energy Corporation

System Disturbance Report

Date: July 14, 2007

System Operator: Mike Hannah

Weather: 21degrees scattered clouds

Percentage of Grid: 80%

Pre-Disturbance Generation Setup

WH1	5.25 Mw's
WH2	5.2 Mw's
WH3	7.7 Mw's
AH1	9.5 Mw's

Total Generation: 27.65 Mw's

Disturbance:

Time	Event
18:39:15	13L Load Pick Up (1.744 Mw) – Low Hz
18:40:01	AH1 tripped
18:40:03	S150 52-17 open
18:40:04	S6838 open
18:40:17	S150 52-22 open
18:44:03	S150 52-21 open
18:44:15	S6837 tripped by SCC Operator
18:50:38	WH3 tripped off line

Restoration:

18:47:22	AH2 on
18:47:37	S150 52-22 closed
19:10:30	WH3 on
19:17:51	S6837 closed
19:22:54	S150 52-21 closed
19:25:16	S150 52-17 closed
19:41:47	S6838 closed

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S150 52-17	18:40:03	19:25:16	45 minutes 13 seconds
S170 S6838	18:40:04	19:41:47	1 hour 1 minute 43 seconds
S150 52-22	18:40:17	18:47:37	7 minutes 20 seconds
S150 52-21	18:44:03	19:22:54	38 minutes 51 seconds

S170 S6837	18:44:15	19:17:51	33 minutes 36 seconds

Target /Flags: AH1 - 94 non lockout 86R and 1CS1. AH2 – 81R and 30AL

Comments: Cause has yet to be determined, YECL restoring power in Copper Ridge area when outage occurred.

Yukon Energy Corporation

System Disturbance Report

Date: Aug 14, 2007

System Operator: Mike Hannah

Weather: 24 degrees and sunny

Percentage of Grid: 100%

Pre-Disturbance Generation Setup

WH1	4.2 MW's
WH2	4.7 MW's
WH3	7.7 MW's
WH4	17.2 MW's

Total Generation: 33.80 MW's

Disturbance:

Time	Event
13:16:31	WH4 tripped off line
13:16:37	S150 52-22 open
13:16:37	S150 52-17 open
13:16:39	S170 S6838 open
13:16:40	S150 52-21 open
13:16:40	S170 S6837 open
13:16:45	S150 52-18 open
13:16:50	WH2 tripped off line
13:16:51	WH1 tripped off line
13:16:55	Faro 701 open
13:17:04	S167 52-2 open
13:17:05	WH3 tripped off line
13:19:43	S164 52-2 open by SCC
13:19:52	S164 52-3 open by SCC
13:20:09	Faro 503 open
13:24:58	S150 52-22 open

Restoration:

13:21:17	AH2 on line
13:22:03	S164 52-2 closed
13:23:30	P132 52- FD7 on line
13:24:56	S150 52-22 closed
13:27:26	AH1 on line
13:27:47	S150 52-22 closed

13:30:53	S170 S6838 closed
13:33:53	WH1 on line
13:34:24	S170 S6837 closed
13:35:28	WH2 on line
13:36:26	S164 52-3 closed
13:44:37	S150 52-17 closed
13:47:57	S150 52-21 closed
13:48:19	WH3 on line
13:55:43	S150 52-18 closed
13:57:26	Faro 701 closed
13:58:10	Faro 503 closed
14:00:11	P132 52-FD7 off line
14:54:31	S167 52-2 closed

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S150 52-22	13:16:37	13:24:56	8 minutes 19 seconds
S150 52-22	13:24:58	13:27:47	2 minutes 49 seconds
S150 52-17	13:16:37	13:44:37	28 minutes
S170 S6838	13:16:39	13:30:53	14 minutes 14 seconds
S150 52-21	13:16:40	13:47:57	31 minutes 17 seconds
S170 S6837	13:16:40	13:34:24	17 minutes 44 seconds
S150 52-18	13:16:40	13:55:43	39 minutes 3 seconds
Faro 701	13:16:55	13:57:26	40 minutes 31 seconds
S167 52-2	13:17:04	14:54:31	37 minutes 27 seconds
S164 52-2	13:19:43	13:22:03	2 minutes 20 seconds
S164 52-3	13:19:52	13:36:26	16 minutes 34 seconds
Faro 503	13:20:09	13:58:10	38 minutes 1 second

Target /Flags: Under frequency and under voltage is the primary reason that all of the feeders tripped open. Could not retrieve the flags/targets from WH4 as someone reset before the data could be down loaded.

Comments: The governor speed adjust motor for WH4 went to -20.54 causing the unit to trip off line. WH4 to stay out of service until speed adjust problems can be rectified.

Yukon Energy Corporation

System Disturbance Report

Date: September 15, 2007

System Operator: Mike Sage

Weather: 3 Degrees with scattered showers

Percentage of Grid: 100%

Pre-Disturbance Generation Setup

WH1	2.47
WH2	2.24
WH4	17.11

Total Generation: 21.82

Disturbance:

Time	Event
03:39:26	WH4 Open
03:39:28	S150 52-22 UV –Tripped - Open
03:39:29	S170 S6838 UV-OV – Tripped – Open
03:39:29	WH1 - Open
03:39:30	WH2 - Open
03:39:31	S170 S6837 – Open
03:39:31	S150 52-21 UV – Tripped
03:39:31	S150 52-17 UV – Tripped
03:39:30	Faro 701 - Open
03:39:32	S150 52-18 UV – Tripped
04:29:21	Faro 503 – Open (SCC)

Restoration:

03:50:47	SCC – Open – S164 52-2
03:51:03	SCC – Open – S164 52-3
03:57:31	AH1 – Closed
03:59:15	S164 52-2 – Closed
04:05:20	WH3 – Closed
04:07:54	AH1 - Trip (reverse power)
04:09:48	WH3 - Tripped SCC (system swinging)
04:12:07	S164 52-2 – Open (SCC)
04:12:31	AH1 - Closed
04:13:34	S164 52-2 – Closed (SCC)
04:14:10	WH3 - Closed
04:14:44	S150 52-18 – Closed

04:18:08	WH2 – Closed
04:21:11	WH1 – Closed
04:22:55	S150 52-22 – Closed
04:33:36	S150 52-17 – Closed
04:51:33	S170 S6838 – Closed
04:57:54	S167 52-2 – Closed
05:04:48	S164 52-3 – Closed
05:06:01	Faro 701 – Closed
05:06:40	Faro 503 – Dead Bus Closed
05:46:33	S167 52-2 - Closed

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S150 52-22	03:39:28	04:22:55	00:43:27
S170 6838	03:39:29	04:51:33	01:12:04
S170 6837	03:39:31	04:26:07	00:47:24
S150 52-21	03:39:31	04:41:30	01:01:59
S150 52-17	03:39:31	04:33:36	00:54:05
Faro 701	03:39:30	05:06:01	01:26:31
S150 52-18	03:39:32	04:14:44	00:35:12
Faro 503	03:39:21	05:06:38	01:27:17

Target /Flags:

S150 52-18 Under-Voltage
S150 52-17 Under-Frequency
S150 52-21 Under-Voltage
S150 52-22 Under-Voltage
S6837 Under-Voltage
S6838 Under-Frequency
WH1 Electrical Lockout - R6 Fault
WH2 Electrical Lockout – R6 Fault
WH4 - No Flags
701 Under-voltage

Comments:

The cause of this disturbance was found to be a failed coil in the WH4 creep detector resulting in a DC system fault taking the unit off line, with insufficient generation the system collapsed. During the restoration S164 52-3 and S164 52-2 were opened by SCC and AH1 dead-bus closed energizing the system. WH3 was synchronized to AH1, however without any load AH1 tripped on reverse power. WH3 began to swing and was tripped off line. The same steps were repeated and S150 52-18 was closed supplying sufficient load to stabilize the system; the restoration then proceeded. WH4 remained OOS during the restoration, the unit was returned to service and placed on line 8:54. AH2 was returned to service (annual PM) for system security.
The L355 Haines Junction line failed to hold during the restoration, there were reports of rain in the area at the time. On the third attempt the breaker held, however at YECL's discretion Haines Junction remained on diesel. The fault detectors were checked and where flashing on the north phase. The YECL serviceman later reported a blown arrestor on the load side of the metering tank. Repairs were made and Haines Junction synched back to the grid.

Outage Issues:

- The VFD on the east spill gate had problems with the resistors overheating, making the gate inoperable. A mobile diesel was brought on sight and the inch drive enabled. Could this be related to the voltage supply from the intake diesel? Is there still an issue with this gate jamming, because when the gate was tested it would not move remotely until a local operation was performed?

- WD7 started, but would not go on line. Problem was found to be a power supply issue, which was changed out. There were reports of odors from the control cabinet?

- WD6 was started remotely and placed on line but only loaded up to 1.66 Mw, the local operator was able to load the unit up. The unit failed to respond to a remote stop command and again had to be operated and shutdown locally.

- With the fuel line work at the Whitehorse diesel plant and the potential to have to run diesel if repairs could not be completed on WH4 (AH2 was under a WAP) fuel supply became a concern. Although not required attempts to contact the fuel supplier took time only to find there was only one driver available and he was delivering to Alaska from Dawson.

- 701 opened on under-voltage, however 503 was opened by SCC and should have opened with 701?

- The failure of a creep detector should not kill the unit DC causing the unit to shutdown!

Yukon Energy Corporation

System Disturbance Report

Date: November 15, 2007

System Operator: Steve Blysak

Weather: 0 Degrees and calm

Percentage of Grid: 67%

Pre-Disturbance Generation Setup

AH2	13.5 Mw
WH2	5.5 Mw
WH1	5.5 Mw
WH4	16.5 Mw

Total Generation: 41 Mw

Disturbance:

Time	Event
14:49:10	S171 52-1 Trip
14:49:10	S171 52-3 Trip
14:49:10	S171 52-4 Trip
14:49:14	S170 S6838 Open U/F - Trip
14:49:15	WH4 trip (86 Lockout) - Overspeed
14:49:15	S150 52-22 U/V - Trip
14:49:17	S150 52-21 U/V - Trip
14:49:17	S150 52-17 U/V - Trip
14:49:56	WH1 trip (Electrical lockout) - Overspeed
14:50:03	S150 52-18 Open (by Operator)
14:50:06	WH2 trip (Electrical lockout) - Overspeed

Restoration:

14:53:49	S171 52-3 closed
14:54:21	S171 52-4 closed
14:59:01	S171 52-1 closed
15:00:00	WH3 On
15:03:31	WH2 On
15:05:45	S150 52-17 closed 1.87mw
15:06:08	WH1 on
15:08:00	S6822 Closed 2 mw
15:09:00	S6817 Closed 1.87 mw
15:11:51	S150 52-18 Closed 1.85mw
15:14:00	S6838 Closed 2.65 mw

15:16:53	150 52-21
15:23:00	S1016 Closed 4.79 Mw
15:25:00	S1011 Closed 3 Mw
15:27:00	S150 52-22 Closed 5.41 Mw
15:30:00	S8615 Closed 3.18Mw
15:34:00	S9403 Closed 3.18 Mw
15:35:00	S9402 Closed 1.39 Mw

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S171 52-3	14:49:10	14:53:49	0:04:39
S171 52-4	14:49:10	14:54:21	0:05:11
S171 52-1	14:49:10	14:59:01	0:09:51
S170 S6838	14:49:14	15:14:00	0:24:46
S150 52-22	14:49:15	15:27:00	0:37:45
S150 52-21	14:49:17	15:16:53	0:27:36
S150 52-17	14:49:17	15:05:45	0:16:28
S150 52-18	14:50:03	15:11:53	0:21:50
S6822	14:49:17	15:08:00	0:18:43
S6817	14:49:17	15:09:00	0:19:43
S1016	14:49:17	15:23:00	0:33:43
S1011	14:49:17	15:25:00	0:35:43
S8615	14:49:14	15:30:00	0:40:46
S9403	14:49:14	15:34:00	0:44:46
S9402	14:49:14	15:35:00	0:45:46

Target /Flags:

WH1 – Overspeed
WH2- Over-Voltage
WH4-Over-Voltage and Overspeed

S150 52-17 – Under-Frequency
S150 52-18- Under-Voltage
S150 52-21- Under-Voltage
S150 52-22- Under-Voltage
S170 S6838 – Under-Frequency
EMDS – 4-5-6- All Reverse Power

Comments: Workers were commissioning the new RTU in S171 and reset a relay this caused S171 52-3 S171 52-4 and S171 52-1 to open causing a split system. Haines Junction,, Faro, and S6837 stayed energized by AH2 the 34.5 system collapsed from u/f and u/v do to a lack of generation when #4 went Down

Yukon Energy Corporation

System Disturbance Report

Date: May 04 2008

System Operator: Mike Sage

Weather: 4 c calm snow/ rain earlier in the evening

Percentage of Grid: 100%

Pre-Disturbance Generation Setup

AH1	5.89 Mw
AH2	6 Mw
WH1	5 MW
WH2	5.9 Mw
WH3	8.89 Mw

Total Generation: 31.6 mw

Disturbance:

Time	Event
22:49:24	S164 52-1-Tripped - Open
22:49:27	S170 6838-Tripped - Open U/F load shed stage #1
22:49:27	S150 52-17-Tripped - Open U/F load shed Stage #2
22:53:32	S170 6837 - Open
22:53:33	WH1 – Open Elec 86 lockout
22:53:58	AH2 52-1 – Open (SCC)
22:56:09	S150 52-18 – Open (SCC)
22:57:15	S170 52-1 – Open (SCC)
22:57:39	S164 52-3- Open (SCC)
22:57:39	Faro 701 Breaker – Open (SCC) (Faro Islanded Locally)
23:06:36	S150 52-17 – Tripped – Open
23:06:48	WH2 – Open (SCC) elect 86 lockout
23:06:57	WH3 – Open (SCC) elect 86 lockout
23:06:57	S150 52-22 – Tripped –Open
23:07:02	S150 52-21 – Tripped – Open
23:28:24	S171 52-3 – Open (SCC)
23:28:37	S171 52-4 – Open (SCC)
23:32:18	S170 S9815 – Open (SCC)
23:52:00	S150 52-1 – Open (SCC)
23:59:20	S150 52-13 – Open (SCC)
23:59:22	S150 52-11 – Open (SCC)
00:29:26	S150 52-12 – Open (SCC)
00:46:34	S170 52-2 – Open (SCC)

Restoration:

23:10:30	AH2 - On
23:26:57	Faro P132 52-FD7 – Closed (Faro Islanded)
23:40:42	S170 S6837 - Close
00:29:42	WH3 – On
00:32:28	S150 52-1 – Close
00:32:50	S150 52-15 – Close
00:54:14	WH2 – On
00:56:17	S150 52-21 – Close
01:03:47	WH1 – On
*01:04:02	Loop Close – S9530
01:04:19	S150 52-18 – Close
01:12:07	WD1 – On
01:12:23	S150 52-17 – Close
01:20:51	WD2 – On
01:48:42	S170 S9815 – Close
01:50:09	S170 S6838 – Close
01:59:03	WD6 – On
02:13:37	S150 52-22 – Close
02:16:26	WD5 – On
02:22:55	WD4 – On
02:26:03	S164 52-3 – Close
03:12:28	Faro 701 Breaker – Close
04:29:10	S171 52-3 – Close
04:49:09	S164 52-1 – Close
05:31:15	S170 52-2 - Close

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S164 52-1	22:49:24	04:49:09	5:59:44
S170 S6838	22:49:27	01:50:09	3:00:41
S150 52-17	22:49:27	01:12:23	2:22:55
S170 S6837	22:53:32	23:40:42	0:47:09
S150 52-18	22:56:09	01:04:19	2:08:09
Faro 701 Breaker	22:57:39	03:12:28	4:14:48
S150 52-22	23:06:57	02:13:37	3:06:39
S150 52-21	23:07:02	00:56:17	1:49:14
S170 S9815	23:32:18	01:48:42	2:16:23
S150 52-1	23:52:00	00:32:28	0:40:27
S150 52-15	23:52:03	00:32:50	0:40:46
S170 52-2	00:46:34	05:31:15	4:44:41

Target /Flags:

- S170 S6838 Under-Frequency
- S150 52-17 Under-Frequency
- WH1Electrical Lockout – R6 Fault
- WH2 Electrical Lockout –R6 Fault
- S150 52-22 Under-Voltage
- S150 52-21 Under-Voltage
- S150 52-18 Under-Voltage
- WH3 Electrical Lockout/Over speed

Comments:

The cause of this disturbance was found to be shot insulators on L172 transmission line between S171 and S164 substations. At this critical juncture of the system, it produced a split system and without insufficient generation from the Aishihik plant the system collapsed. Even after saving some of the grid with WH2 and WH3 it became unstable and was decided to open the breakers on the remaining two hydro's and start over. SCC tried to restore station service from Aishihik by closing S164 52-1 but failed, one unit remained online and the other running speed no load. Restored station service through P-125 with some switching involved.

- The VFD on the west spill gate failed while outage was in progress, it was reset twice. Not sure of the problem at this time.

- Lost RTU to Aishihik and operator had to look after units and local breakers during this outage.

Yukon Energy Corporation

System Disturbance Report

Date: May 16, 2008

System Operator: Myles O'Brien

Weather: 7C Cloudy

Percentage of Grid: 34%

Pre-Disturbance Generation Setup

AH1	8 Mw
AH2	8 Mw
WH4	12 Mw
WH1	4.3 Mw
WH2	2.2 Mw

Total Generation: 34.5 mw

Disturbance:

Time	Event
18:05:54	WH4 Governor Trouble Alarm
18:16:15	WH4 Breaker Open (Tripped)
18:16:17	S170 S6838 Open (Tripped U/F)
18:16:20	S150 52-17 Open (Tripped U/F)

Restoration:

18:08:05	WH1 Online
18:26:50	WH3 Online
18:35:14	S150 52-17 Closed
18:44:57	S170 S6838 Closed

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S170 S6838	18:16:17	18:44:57	28 min 40 sec
S150 52-17	18:16:20	18:35:14	18 min 54 sec

Target /Flags:

Comments: WH4 Governor Trouble Alarmed and load was immediately reduced by SCC while WH1 was brought online and Darrel Johnson (On-Call Mechanic) was called in. Ten minutes and twenty-one seconds later WH4 tripped offline with 12Mw. Restoration was conducted with WH3, WH1, WH2, AH1, AH2 and YECL in S170 and Riverdale Sub.

Yukon Energy Corporation

System Disturbance Report

Date: May 22, 2008

System Operator: Mike Hannah

Weather: 18 degrees and scattered cloud

Percentage of Grid:

Pre-Disturbance Generation Setup

WH1	5.75 Mw
WH2	6.00 Mw
WH3	8.90 Mw
AH1	6.30 Mw
AH2	6.40 Mw

Total Generation: 33.35 Mw

Disturbance:

Time	Event
18:10:00	S170 S6838 U/F trip
18:10:03	WH3 Breaker open

Restoration:

18:33:00	S9402 open (YECL)
18:34:00	S9403 open (YECL)
18:35:18	S6838 closed
18:35:30	S9403 closed (YECL)
18:36:30	S9402 closed (YECL)

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S6838	18:10:00	18:35:18	25 minutes and 18 seconds

Target /Flags: 32 on the Beckworth

Comments: At 18:09:56 WH3 began to shed load causing S6838 to trip on under frequency at 18:10:00. The cause of WH3 load shedding and eventual unit breaker trip was due to either a speed sensor issue or improper feedback from the LVDT to the ram.

Yukon Energy Corporation

System Disturbance Report

Date: Oct 05 2008

System Operator: Steve Blysak

Weather: Light Rain 5 c

Percentage of Grid: 100 %

Pre-Disturbance Generation Setup

WH4	17 Mw
WH1	3.3 Mw
WH2	2 Mw
AH 1	9 Mw

Total Generation: 31.3 Mw

Disturbance:

Time	Event
00:06:13	WH4 Gov Status Alarm
00:06:38	P127 52-WH4 Open (Gen 86 lockout)
00:06:40	S150 52-17 Open (U/F Trip)
00:06:42	506 Open
00:06:43	S6838 Open (U/F trip)
00:06:43	S150 52-22
00:06:44	WH4 Gen Nonlockout trip
00:06:45	S6837 Open
00:06:45	701 Open (U/V Trip)
00:06:46	P130 52- AH1 Open
00:06:46	AH1 Non-lockout Trip
00:06:46	S150 52-21 Open (U/V Trip)
00:06:46	S150 52-18 Open (U/V Trip)
00:06:47	WH1 52-1 Open (Elect fault 86E trip)

Restoration:

00:10:32	S164 52-2 Open (by sys op)
00:11:20	AH2 On
00:14:17	AH1 On
00:15:53	S164 52-3 Open
00:15:59	S164 52-2 Closed Energized 138 kv (except L170)
00:25:01	WH3 52-1 Closed
00:27:20	503 Open
00:27:32	AH2 nonlockout trip (reverse power)

00:28:09	507 Open by GJ
00:31:44	WH2 52-1 Closed
00:32:17	FD5 On
00:36:19	506 Closed
00:36:26	506 Open
00:36:39	507 Closed
00:38:02	S150 52-18 Closed
00:39:45	S150 52-17 Closed
00:42:08	S170 S6838 Closed
00:42:16	FD3 On
00:42:46	WH1 52-1 Closed
00:45:57	506 Closed
00:47:40	S170 S6837 Closed
00:49:59	S150 52-22 Closed
00:56:59	S164 52-3 Opened
00:59:40	S150 52-21 Closed
01:10:27	AH2 On
02:07:10	503 Closed (WAF Sys back to Normal)
03:56	All Yecl Customers restored

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S150 52-17	00:06:40	00:39:45	33 min 5 secs
S150 52-22	00:06:43	00:49:59	43 min 16 secs
S150 52-18	00:06:46	00:38:02	31 min 16 secs
S150 52-21	00:06:46	00:42:46	36 min
S170 S6838	00:06:43	00:42:08	35min 25 secs
S170 S6837	00:06:45	00:47:40	40 min 55 secs
Faro 505	00:06:45	00:32:17	25 min 32 secs
Faro 506	00:06:45	00:36:39	29 min 54 secs
Faro 507	00:06:45	00:45:57	39 min :12
S164 52-3	00:06:45	00:56:59	50 min 14 secs

Targets/Flags: WH4 5G 5G1 See Ed Chaplin for details

Comments: WH4 Gov status alarm.... WH4 trip 25 seconds later cause was a stuck proportional Valve.... the valve has been replaced unit placed back online on Oct 08 2008 WH1 tripped on over-current due to being last unit online and trying energize sys on its own. Yecl restored last customers at 03:56

Yukon Energy Corporation

System Disturbance Report

Date: Oct 12 2008

System Operator: Steve Blysak

Weather: sunny calm 7 c

Percentage of Grid: 100 %

Pre-Disturbance Generation Setup

WH4	19.3 Mw
WH1	5.5 Mw
AH 1	7 Mw
AH2	4 Mw

Total Generation: 35.8 Mw

Disturbance:

Time	Event
11:22:06	WH4 Gov Status Alarm
11:22:33	P127 52-WH4 Open (Gen 86 lockout)
11:22:35	S6838 Open (U/F trip)
11:22:38	S150 52-17 Open (U/F Trip) (U/F trip)
11:22:41	506 Open
11:22:42	P130 52- AH1 Open
11:22:42	P130 52- AH2 Open
11:22:45	S150 52-21 Open (U/V Trip)
11:22:45	S150 52-22 Open (U/V)
11:22:45	S150 52-18 Open (U/V Trip)
11:22:46	701 Open (U/V Trip)
11:22:51	WH1 52-1 Open (Elect fault 86E trip)
11:22:56	S9815 Open
11:22:?	S6837 Open (did not report when opened)

Restoration:

11:25:56	S164 52-2 Open (by sys op)
11:26:30	AH1 On
11:27:13	S164 52-3 Open
11:27:30	S164 52-2 Closed Energized 138 kv (except L170)
11:34:28	503 Open (by G Jones)
11:37:48	Fd 7 on
11:38:32	WH2 52-1 Closed
11:39:28	S170 S9815 Closed
11:39:44	506 closed by GJ
11:47:45	WH1 52-1 Closed
11:52:29	S150 52-17 Closed
11:58:33	AH2 On
12:01:43	S170 S6838 Closed
12:04:11	WH3 52-1 Closed
12:07:24	S170 S6837 Closed
12:11:22	S164 52-3 Closed
12:13:44	S150 52-21 Closed
12:25:03	S150 52-18 Closed
12:30:00	S150 52-22 Closed
12:58:26	701 Closed
13:05:00	503 Closed (WAF Sys back to Normal
13:05:04	Fd7 Off

Time Variance

Feeder	Opened / Tripped	Closed	Variance
S150 52-17	11:22:38	11:52:29	29 min 51 secs
S150 52-22	11:22:45	12:30	1 hr 7 min 15 secs
S150 52-18	11:22:45	12:25:03	1 hr 2min18 sec
S150 52-21	11:22:45	12:13:44	50 min 59 secs
S170 S6838	11:22:35	12:01:43	39min 8 secs
S170 S6837	11:22:36	12:07:24	44min 48 sec
Faro 505	11:22:41	11:37:48	15min 7sec
Faro 506	11:22:41	11:39:44	17 min 3 secs
Faro 507	11:22:41	11:37:48	15 min 7 secs
S164 52-3	11:22:41	12:11:22	48min 41 secs
S170 S9815	11:22:56	11:39:28	16min 32 min

Targets/Flags: WH4 5G 5G1 See Ed Chaplin for details
Comments: Wh4 Gov status alarm.... WH4 trip 20 seconds later cause was a stuck proportional Valve

Yukon Energy Corporation
System Disturbance Report

Date: Oct 13 08

System Operator: Steve Blysak

Weather: 3 C calm sunny

Percentage of Grid: +100%

Pre-Disturbance Generation Setup

AH1	8 Mw
AH2	8.5 Mw
WH1	5.6 Mw
WH2	5.5 Mw
WH3	8.2 Mw

Total Generation: 35.8 Mw

Disturbance:

Time	Event
09:11:13	S6838 Open (u/f)
09:11:14	S150 52-17 Open (u/f)
09:11:17	WH3 52-1 Open (86 E)
09:11:32	P130 52-AH1 open (non lockout)
09:11:32	P130 52-AH2 open (non lockout)
09:11:47	S170 S9815 Open
09:11:36	S150 52-22 Open (u/v)
09:11:38	S150 52-21 Open (u/v)
09:11:42	WH1 Open (86 E)
09:11:54	WH2 Open (tripped by sys op)
09:11:56	S150 52-18 Open (u/v)
09:11:57	S150 52-17 (u/v)
09:11:58	S170 S6837 Open (u/v)
09:11:35	506 Open (u/v)

Restoration:

09:13:34	S164 52-2 Open (by sys op)
09:13:42	S164 52-3 Open (by sys op)
09:15:29	AH1 On
09:15:46	S164 52-2 Closed (energizing S170 and S150 SCC SS)
09:18:57	503 Open (by Gary Jones)
09:22:19	FD7 Closed
09:23:40	506 Closed
09:25:22	WH1 52- 1 Closed
09:29:50	WH2 52-2 Closed
09:32:39	S150 52-22 Closed
09:34:28	S170 S6838 Closed
09:36:08	P130 52 AH1 Open (86E Lockout trip)
09:36:09	S170 S6838 Open
09:36:17	S150 52-22 Open
09:43:33	AH1 ON
09:43:44	S150 52-22 Closed
09:46:16	S6838 Closed
09:47:59	S6838 Open
09:48:00	P130 52 AH1 Open (86E Lockout trip)
09:48 :01	SCADA Down ups probs
09:48:07	WH1 52-1 Open (86E Lockout trip)
09:49:07	WH2 52-1 (trip by local op)
09:48:07	S150 52-22 Open (u/v trip)
09:50:00	P130 52 -AH2 Closed (by operator R.K.)
10:07:07	WH1 52-1 Closed
10:31:00	WH2 52-1 Closed
10:34:00	WH3 52-1 Closed
10:40:00	SCADA back up
10:45:03	S150 52-18 Closed
10:50:59	S150 52-22 Closed
10:52:24	S150 52-21 Closed
11:06:26	P130 52- AH1 Closed
11:14:16	P130 52 AH1 Open
11:15:02	S6838 Closed
11:16:31	S6837 Closed
11:17:17	P130 52- AH1 Closed
11:29:50	S164 52-3 Closed
11:47:23	S170 S9815 Close
12:15:00	S167 52-2 Closed (energizing L355)
14:18:12	503 Closed YEC sys back to normal

Time Variance

Feeder	Opened / Tripped	Closed	Variance hr/min/sec
S150 52-22	09:11:36	09:32:39	0:21:03
S170 S6838	09:11:13	09:34:28	0:23:15
S150 52-22	09:36:17	09:43:44	0:07:27
S170 S6838	09:36:09	09:46:16	0:10:07
S150 52-22	09:48:07	10:50:59	1:02:52
S150 52-21	09:11:36	10:52:24	1:40:48
S150 52-18	09:11:56	10:45:03	1:33:07
S150 52-17	09:11:14	10:35:36	1:24:22
S170 S6838	09:47:59	11:15:02	1:27:03
S170 S9815	09:11:47	11:47:23	2:35:36
505	09:11:35	09:22:19	0:10:44
506	09:11:35	09:23:40	0:12:05
507	09:11:35	09:22:19	0:10:44

Targets/Flags: AH1-94 non 86 -Neg seq o/c –phase u/v
AH2- Phase u/v-81 81R Freq o/u
WH1-WH2 -WH3 see attached target list

Comments: The WH3 digital governor lost its gate position indication causing the unit to shutdown, the unit breaker tripped on reverse power (timed). In combination with the loss of generation from WH3 and the reverse power (> 9 Mw) the unit absorbed, the system frequency dropped enough to initiate the under-frequency protected breakers to trip. This load loss was not enough to recover the system frequency, both Aishihik units tripped off line. The system restoration was longer than normal due to WH4

Yukon Energy Corporation

System Disturbance Report

Date: Nov 12 2008

System Operator: Steve Blysak

Weather:

Percentage of Grid: 100 %

Pre-Disturbance Generation Setup

WH4	17.00 mw
WH1	4.31 mw
WH2	5.2 mw
AH 1	7.00 mw
AH2	7.54 mw

Total Generation:

Disturbance:

Time	Event
15:28:50	WH4 gov speed adjust Lo Lo -21.538 ????
15:28:53	S170, S6838 Open u/f
15:28:55	S150, 52-17 Open u/f
15:29:00	P127 52-WH4 Open
15:29:11	WH1 52-1 Open
15:29:16	S170, 6837 Open
15:29:20	S170 9815 Open
15:29:26	P130 52-AH1
15:29:26	P130 52-AH2
15:29:26	Faro 506 Open u/v
15:29;26	S150 52-21 u/v
15:29:26	S150 52-22 u/v
15:29:26	S150 52-18
15:30:44	S164 52-3 Open tripped by op
15:31:01	WH2 52-1 Open tripped by op

Restoration:

15:33:16	AH1 On
15:38:01	WH1 On
15:38:41	S9815 Closed
15:42:16	WH2 On
15:45:13	S6837 Closed
15:53:13	S150 52-21 Closed
16:01:59	AH2 On
16:03:33	WH3 On
16:05:33	S150 52-22 Closed
16:06:52	S170 S6838 Closed
16:08:02	S150 52-18 Closed
16:09:40	S150 52-17 Closed
16:13:31	WD5 on
16:14:38	S164 52-3 Closed
16:16:39	Faro 503 Closed
16:16:54	Faro 506 Closed
16:16:39	Faro 507 Closed
16:19:40	WD6 On

Time

Feeder	Opened / Tripped	Closed	Variance
S170, S6838	15:28:53	16:06:52	0:37:59
S150, 52-17	15:28:55	16:09:40	0:40:45
S170, 6837	15:29:16	15:45:13	0:15:57
S170 9815	15:29:20	15:38:41	0:09:21
Faro 506	15:29:26	16:16:54	0:47:28
Faro 507	15:30:44	16:16:39	0:45:55
S150 52-21	15:29:26	15:53:13	0:23:47
S150 52-22	15:29:26	16:05:33	0:36:07
S150 52-18	15:29:26	16:08:02	0:38:36
S164 52-3	15:30:44	16:14:38	0:43:54

Targets/Flags:

Comments:

Yukon Energy Corporation
System Disturbance Report

Date: Dec 1/08

System Operator: Mike Sage

Weather: -8 degrees light snow

Percentage of Grid: 100%

Pre-Disturbance Generation Setup

WH4	Off
WH1	5.5 Mw
WH2	5.5 Mw
WH3	8.3 Mw
AH1	12.15 Mw
AH2	12.15 Mw
WD6	2.4 Mw

Total Generation: 46 Mw

Disturbance:

Time	Event
14:29:22	S167 T1 87 differential
14:29:22	P130 52-F2 – Open
14:29:22	S167 52-1 – Open
14:29:24	Faro Breaker 506 – Open
14:29:24	S170 S6838 – Tripped – U/F
14:29:26	S170 52-17 – Tripped – U/F
14:29:39	WH1 – Open – 86E
14:30:08	(SCC) Open – S150 52-18
14:30:17	(SCC) Open – S150 52-22
14:30:24	S170 S9815 – Open
14:30:27	WD6 – Open
14:31:32	(SCC) Open –AH1 52 Breaker
14:33:13	WH3 – Open -86E
14:33:19	S150 52-21 – Open – Under voltage
14:33:32	WH2 – Open – (Locally by Ed Peake)
14:33:32	Faro 701 Breaker – Open
14:35:24	Faro 503 Breaker – Open (Locally)
14:36:55	S164 52-3 – Open (SCC)
14:36:55	S2254 52-TR - Open

Restoration:

14:38:01	WH4 – Close
14:38:37	Faro P132 52-FD7 – Close
14:39:35	Faro 506 Breaker – Close
14:39:51	S150 52-17 – Close
14:41:50	S170 S9815 Breaker – Close
14:51:46	WD4 – Close
14:54:11	S170 S6837 – Close
14:58:49	S150 52-21 – Close
15:11:09	WD1 – Close
15:19:05	WD7 – Close
15:20:35	WH2 – Close
15:24:37	WH3 – Close
15:24:55	S164 52-3 –Close
15:25:20	Faro Breaker 701 – Close
15:26:55	S150 52-22 – Close
15:29:05	WD2 – Close
15:33:16	S150 52-18 – Close
15:37:29	Faro Breaker 503 – Close
15:41:53	Faro FD5 – Close
15:42:23	S170 S6838 – Close
15:45:12	WH1 – Close
15:45:43	WD5 – Close
21:00:00	S254 52-TR - Close

Time Variance

Feeder	Opened / Tripped	Closed	Variance hr/min/sec
Faro Breaker 506	14:29:24	14:39:35	0:10:11
S170 6838	14:29:24	15:42:23	1:12:59
S170 52-17	14:29:26	14:39:51	0:10:25
S150 52-18	14:30:08	15:33:16	1:03:08
S150 52-22	14:30:17	15:26:55	0:56:38
S170 S9815	14:30:24	14:41:50	0:11:26
S150 52-21	14:33:19	14:58:49	0:25:30
Faro Breaker 701	14:33:32	15:25:20	0:51:48
Faro Breaker 503	14:35:24	15:37:29	1:02:05
S164 52-3	14:36:24	15:24:55	00:48:31
S254 52-TR	14:36:55	21:00:00	6:23:05

Targets/Flags: S250 T1 back up protection relay, A phase fault/ground fault 51 over current at 15:39:25.
60.53 Hz
A Phase-364 amp
B Phase-12 amp
C Phase-17 amp
Neutral-369 amp\
Ground-370 amp
S167 T1- 87 differential
WH1 – over current/over speed

WH2 – negative sequence/over speed
WH3 – over current

Comments: The cause of this disturbance was found to be a failed pot-head from the bus work to the S167 reactor gang-switch, causing S167 52-1 and P130 52-F2 to trip separating the P130 generation from the rest of the grid. At the time of the event WH4 was off line under a permit for hydro testing. WH4, P126 and eventually P125 units were used for the system restoration. A Mayo serviceman was dispatched to S253 to record flags and close S253 52-T1 and S253 52-F1,

Yukon Energy Corporation
System Disturbance Report

Date: Feb 05, 2009

System Operator: Gary McLaughlin

Weather:-26 C

Percentage of Grid: 100%

Pre-Disturbance Generation Setup

WH1	5.32Mw
WH2	3.3Mw
WH4	19.59Mw
AH1	14.3Mw
AH2	15.5Mw

Total Generation: 57.91Mw

Disturbance:

Time	Event
08:54:20	AH1 non lockout trip (stator temp)
08:54:22	S150 52-22 open U/F
08:54:42	AH2 non lockout trip
08:54:45	WH1 tripped
08:54:49	S150 52-21 open U/V
08:54:49	S150 52-17 open U/V
08:54:49	S150 52-18 open U/V
08:54:50	WH4 tripped
08:55:00	Faro 701 tripped
08:56:20	S6837 open
08:56:20	S6838 open
08:56:20	S9815 open
08:59:42	S164 52-3 open

Restoration:

09:01:30	AH1 closed
09:01:44	Faro 503 opened
09:07:18	FD7 on line
09:09:34	WH2 on line

09:11:34	S150 52-17 closed
09:15:49	WH3 on line
09:17:50	S150 52-18 closed
09:19:45	S150 52-21 closed
09:20:59	S164 52-3 closed
09:21:01	S150 52-17 open
09:21:34	S164 52-3 open
09:25:52	WH4 on line
09:26:12	AH2 on line
09:28:30	WH1 on line
09:33:23	S6838 closed
09:35:51	S164 52-3 closed
09:37:04	S6837 closed
09:53:50	S9815 closed
09:54:41	S150 52-22 closed
10:07:04	S150 52-17 closed
10:25:20	Faro 701 closed

Time Variance

Feeder	Opened / Tripped	Closed	Variance hr/min/sec
Faro 701	08:55:00	10:25:20	1:30:20
S164 52-3	08:59:42	09:20:59	0:21:17
S150 52-17	08:54:49	09:13:35	0:18:46
S6838	08:56:20	09:23:33	0:27:13
S6837	08:56:20	09:37:04	0:40:44
S150 52-21	08:54:29	09:19:45	0:25:16
S150 52-18	08:54:49	09:17:50	0:23:01
S150 52-22	08:54:22	09:54:41	1:00:19
S9815	08:56:20	09:53:50	0:57:30

Targets/Flags:
WD7 was taken off line just previous
AH1 tripped off on high stator temp
WH4 tripped off on u/v and over-speed
WH1 tripped off on o/s and o/c
WH2 tripped off on ph o/c and stage

REFERENCE: **Pages 2-11 through 2-15; Page 2-19**

TOPIC: **Power Generation**

PREAMBLE:

The testing of YEC's forecast hydro, wind and diesel generation forecast as well as line losses.

QUESTION:

a) In excel format for the information provided in Table 2.5, please provide the monthly data for 2005 (Approved and Actual), 2006 Actual, 2007 Actual and 2008 and 2009 forecast that supports the annual totals. Please break out the diesel generation that is related to (1) system peaks, planned operation for such things as maintenance or exercising the units and (3) unplanned operation due to loss of hydro availability.

b) In excel format, please provide YEC's 1996/1997 351 GW.h long term monthly average hydro generation capability from its Whitehorse and Aishihik plants on the WAF system. If an update is available, please provide along with explanations for any changes. If an update is not available, please advise when it is expected to become available.

c) To better understand the quantum of hours the two systems are at operating at various loads, please provide a WAF system and MD system load duration curve for 2005 to 2007 actuals as well as for the 2008 and 2009 forecast. While YEC answered a similar question as part of its 2005 Application (YECL-YEC-1-46), it would be more helpful if YEC labeled the Y axis in "Load (MW)" and the X axis in "Duration (Hours)"

d) Given that YEC states that it does not track actual secondary peak usage. (Note 1 in Table 2.5), please explain how system planning as it relates to firm demand is to be accomplished without knowing the impact of secondary sales.

e) Since 2005, please detail all instances and reasons where YEC has called upon Yukon Electrical to dispatch Yukon Electrical's diesel units in Haines Junction,

Teslin, Carmacks, Ross River, Stewart Crossing and Pelly Crossing. What changes, if any, are expected during the test period?

f) Please provide a copy of the line loss study that was used to support the 2008 and 2009 generation forecast as well explanations as to why line losses increase to 8.66% in 2008 from 8.13% in 2007 and then decrease to 8.42% in 2009.

ANSWER:

(a)

Please see Attachment 1 to this response which sets out 2005 to 2008 actuals (note that sales values do not precisely agree with the values in Table 2.5, as the monthly values do not include year-end adjustments that arise out of the audit process). Reasons for diesel operation are not recorded in this format.

Forecast 2008 and 2009 are not available in this same format.

(b)

The breakdown of the 351 GW.h last used to set rates was from the 1996/97 GRA and still used in the calculations for the Diesel Contingency Fund, as follows:

Long Term Average Hydro Capability Totaling 351 GW.h as used in the 1996/97 GRA (MW.h)

January	30,407
February	27,722
March	26,992
April	23,818
May	24,702
June	30,960
July	30,772
August	30,872
September	31,800
October	32,503
November	30,765
December	29,775
Total	351,088

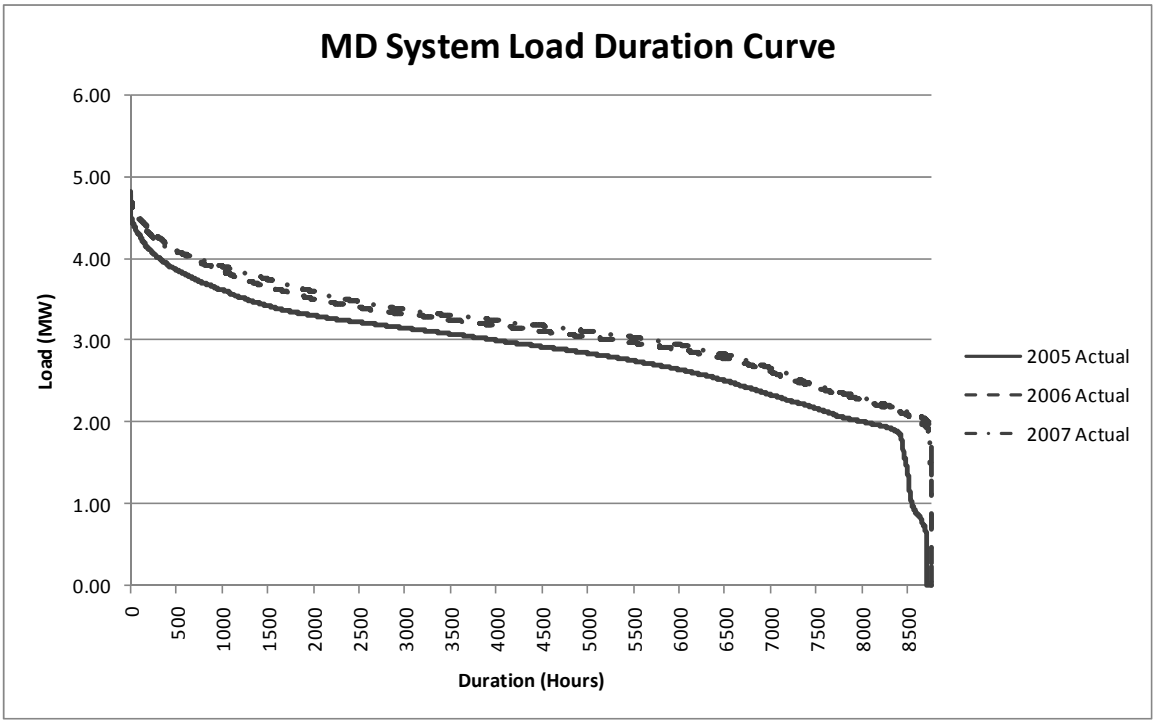
An updated approach to determining long-term average hydro values is available. The updated approach is able to address sensitivities related to load level as well as the full variability of hydrologic conditions, and as such does not develop a single number for all situations. At the approximate load level set out in the application (324 GW.h firm YEC load, net of wind generation), the results indicates that in over 90% of the possible flow scenarios, hydro generation can supply the full load (324 GW.h). In the remaining situations (extreme low flows) baseload diesel generation of up to 50 GW.h could be required. On average, this equates to a hydro supply of 321 GW.h and diesel generation of 3 GW.h.

The 351 GW.h value from 1996/97 does not include the Aishihik 3rd turbine at approximately 5 GW.h. With this system addition in place, a total YEC WAF load level of approximately 380 GW.h is consistent with a long-term average hydro capability of 356 GW.h (and an average diesel requirement of 24 GW.h).

(c)

For WAF, please see YECL-YEC-1-23 and YECL-YEC-1-50.

See chart below for Mayo-Dawson load duration curves for actual 2005-2007. Yukon Energy did not develop a Mayo-Dawson forecast load duration curve for 2008 and 2009.



(d)

Secondary sales customers are not firm customers and as such do not affect firm demand requirements. During critical times where diesel would need to be run secondary sales would be cut off per the requirements of Rate Schedule 32.

(e)

YEC does not keep records of times that YECL diesels were dispatched for grid support purposes, but estimates that it has occurred very few times in the past 5 years. It is not expected that this practice will change in the test period.

(f)

No line loss study has been performed.

Line losses for 2008 and 2009 were estimated using historical figures with adjustments for increases related to increased load with the connection of CSTP and higher loads on the Mayo-Dawson system.

These adjustments resulted in a slight increase in line losses compared to 2007. The Minto mine was forecast to be connected in October of 2008, thus the net impact for the year would be an increase as the new load would be served primarily from the Aishihik Hydro Plant as Whitehorse Hydro would be fully utilized as it is every winter.

Upon review, there is a small error in the 2008 line loss calculation provided in Table 2.1. Consistent with the approach to business planning in 2008, the loss factor should be 8.42%, the same as in 2009. Given the surplus hydro during 2008, there is no revenue requirement impact from this change.

Monthly Data for YEC Sales and Generation, per Table 2.5

		Total Sales KWh	Losses KWh	Losses %	Total - E.S.O. Total KWh	Hydro KWh	Wind KWh	Diesel KWh	Hydro - E.S.O. Whse KWh	Aishihik KWh	Mayo KWh	Diesel - E.S.O. Whse KWh	Faro KWh	Dawson KWh	Mayo KWh
2005	JAN	30,207,423	2,890,870	9.6%	33,098,293	33,051,633	-	46,660	16,359,843	14,040,000	2,651,790	43,930	2,730	-	-
Actual	FEB	25,454,913	1,869,635	7.3%	27,324,548	27,147,742	138,361	38,445	15,073,292	9,840,000	2,234,450	16,110	4,200	15,155	2,980
	MAR	24,339,746	2,916,271	12.0%	27,256,017	27,108,824	113,439	33,754	18,397,934	6,580,000	2,130,890	2,130	2,100	29,414	110
	APR	21,820,505	1,475,733	6.8%	23,296,238	23,126,616	59,534	110,088	14,091,476	7,280,000	1,755,140	-	840	109,248	-
	MAY	21,136,194	857,048	4.1%	21,993,242	21,902,622	74,087	16,533	16,359,512	3,590,000	1,953,110	-	1,680	14,793	60
	JUN	20,239,426	1,634,469	8.1%	21,873,895	21,807,072	58,492	8,331	17,915,242	1,910,000	1,981,830	-	-	8,331	-
	JUL	21,074,740	2,336,899	11.1%	23,411,639	23,334,318	45,373	31,948	18,424,488	3,040,000	1,869,830	-	-	31,848	100
	AUG	20,534,376	2,006,788	9.8%	22,541,164	22,419,880	100,587	20,697	19,046,220	1,210,000	2,163,660	2,360	12,390	5,947	-
	SEP	22,056,459	774,161	3.5%	22,830,620	22,706,466	121,513	2,641	13,697,996	7,100,000	1,908,470	30	1,890	721	-
	OCT	24,429,798	1,553,986	6.4%	25,983,784	25,658,019	104,890	220,875	17,466,179	6,480,000	1,711,840	7,920	-	212,475	480
	NOV	26,151,266	2,771,314	10.6%	28,922,580	28,881,545	-	41,035	16,653,225	9,960,000	2,268,320	5,650	2,730	32,605	50
	DEC	27,654,939	2,999,463	10.8%	30,654,402	30,572,057	73,552	8,793	18,504,327	9,620,000	2,447,730	2,100	5,880	813	-
	TOTAL	285,099,785	24,086,637	8.4%	309,186,422	307,716,794	889,828	579,800	201,989,734	80,650,000	25,077,060	80,230	34,440	461,350	3,780
2006	JAN	31,510,717	2,920,281	9.3%	34,430,998	33,693,798	-	737,200	19,438,698	11,600,000	2,655,100	311,120	425,880	-	200
Actual	FEB	25,270,462	2,131,926	8.4%	27,402,388	27,291,799	29,297	81,292	17,658,429	7,410,000	2,223,370	70,030	2,940	8,322	-
	MAR	28,162,245	2,852,622	10.1%	31,014,867	30,998,900	-	15,967	15,870,340	12,770,000	2,358,560	8,460	1,260	6,247	-
	APR	24,202,341	283,559	1.2%	24,485,900	24,391,527	70,919	23,454	14,510,457	8,000,000	1,881,070	2,100	1,890	19,464	-
	MAY	21,540,541	3,019,357	14.0%	24,559,898	24,212,980	120,820	226,098	14,617,880	7,350,000	2,245,100	99,610	121,170	5,318	-
	JUN	20,481,823	1,122,041	5.5%	21,603,864	21,511,417	26,405	66,042	16,543,367	2,920,000	2,048,050	18,100	12,600	35,342	-
	JUL	20,622,186	1,394,544	6.8%	22,016,730	22,004,900	10,600	1,230	19,450,230	500,000	2,054,670	600	630	0	-
	AUG	21,281,829	1,347,530	6.3%	22,629,359	22,531,979	91,690	5,690	20,055,159	400,000	2,076,820	840	1,428	1,952	1,470
	SEP	23,273,843	1,335,121	5.7%	24,608,964	24,410,306	136,740	61,918	20,696,606	1,800,000	1,913,700	50,151	-	10,297	1,470
	OCT	23,461,252	1,971,780	8.4%	25,433,032	25,050,338	86,200	296,494	19,544,228	3,440,000	2,066,110	45,724	91,812	158,958	-
	NOV	31,435,232	3,236,004	10.3%	34,671,236	34,517,610	9,010	144,616	19,273,450	12,480,000	2,764,160	73,184	68,880	2,552	-
	DEC	30,747,264	3,311,786	10.8%	34,059,050	34,006,570	18,260	34,220	19,107,170	12,020,000	2,879,400	9,946	840	23,014	420
	TOTAL	301,989,735	24,926,551	8.3%	326,916,286	324,622,124	599,941	1,694,221	216,766,014	80,690,000	27,166,110	689,865	729,330	271,466	3,560
2007	JAN	31,224,796	2,501,149	8.0%	33,725,945	33,511,510	-	214,435	19,446,640	11,671,920	2,392,950	11,795	66,360	133,760	2,520
Actual	FEB	29,363,947	2,757,563	9.4%	32,121,510	32,037,940	-	83,570	16,717,790	12,790,420	2,529,730	77,760	4,515	875	420
	MAR	29,473,804	2,469,139	8.4%	31,942,943	31,923,396	-	19,547	15,730,856	13,710,000	2,482,540	-	7,245	12,302	-
	APR	25,212,859	1,986,096	7.9%	27,198,955	27,034,910	111,240	52,805	16,576,910	8,370,000	2,088,000	11,545	-	41,260	-
	MAY	22,291,353	2,093,147	9.4%	24,384,500	24,243,500	86,430	54,570	14,497,550	7,670,000	2,075,950	52,470	2,100	-	-
	JUN	20,675,862	1,022,728	4.9%	21,698,590	21,642,829	41,640	14,121	12,697,579	7,000,000	1,945,250	-	2,520	11,601	-
	JUL	21,655,753	1,549,921	7.2%	23,205,674	22,874,544	42,280	288,850	15,879,184	5,150,000	1,845,360	80	-	288,770	-
	AUG	21,027,495	1,141,784	5.4%	22,169,279	22,054,681	-	114,598	16,872,911	3,040,000	2,141,770	55,967	5,040	53,591	-
	SEP	23,089,915	1,362,927	5.9%	24,452,842	24,236,295	62,970	153,577	20,434,575	1,750,000	2,051,720	99,830	2,100	43,037	8,610
	OCT	24,536,686	626,712	2.6%	25,163,398	25,017,918	-	145,480	19,752,038	3,230,000	2,035,880	8,026	12,600	124,854	-
	NOV	27,019,518	4,025,911	14.9%	31,045,429	31,012,391	-	33,038	18,961,981	9,660,000	2,390,410	30,938	2,100	-	-
	DEC	32,123,681	3,642,465	11.3%	35,766,146	35,676,508	17,120	72,518	18,820,848	14,100,000	2,755,660	15,013	1,260	46,795	9,450
	TOTAL	307,695,669	25,179,542	8.2%	332,875,211	331,266,422	361,680	1,247,109	206,388,862	98,142,340	26,735,220	363,424	105,840	756,845	21,000
2008	JAN	32,857,772	3,174,347	9.7%	36,032,119	35,991,138	-	40,981	18,285,928	14,880,000	2,825,210	35,643	1,680	3,658	-
Actual	FEB	29,857,854	2,431,033	8.1%	32,288,887	32,196,041	-	92,846	16,220,041	13,390,000	2,586,000	72,961	3,150	16,735	-
	MAR	27,131,922	2,171,945	8.0%	29,303,867	29,278,767	25,100	-	15,687,857	11,190,000	2,400,910	-	-	-	-
	APR	23,723,660	2,040,687	8.6%	25,764,347	25,644,456	-	119,891	14,596,146	9,070,000	1,978,310	-	-	119,891	-
	MAY	21,857,494	1,914,343	8.8%	23,771,837	23,408,535	174,790	188,512	13,085,165	8,260,000	2,063,370	175,228	11,130	2,154	-
	JUN	22,274,923	1,709,884	7.7%	23,984,807	23,905,766	39,760	39,281	19,350,016	2,440,000	2,115,750	-	-	39,281	-
	JUL	22,343,319	1,687,123	7.6%	24,030,442	23,955,219	70,500	4,723	19,515,269	2,230,000	2,209,950	-	-	4,156	567
	AUG	23,971,942	1,342,163	5.6%	25,314,105	25,292,910	18,900	2,295	19,700,550	3,240,000	2,352,360	-	840	1,455	-
	SEP	22,395,304	2,015,562	9.0%	24,410,866	24,389,523	-	21,343	16,617,493	5,690,000	2,082,030	-	-	21,070	273
	OCT	25,146,273	2,356,762	9.4%	27,503,035	27,176,763	-	326,272	13,830,823	11,250,000	2,095,940	170,788	47,880	107,604	-
	NOV	29,469,680	3,130,280	10.6%	32,599,960	32,443,510	101,390	55,060	20,152,970	9,680,000	2,610,540	12,776	18,480	23,804	-
	DEC	34,753,987	4,083,126	11.7%	38,837,113	38,059,418	6,450	771,245	19,346,068	16,000,000	2,713,350	652,488	11,130	107,627	-
	TOTAL	315,784,130	28,057,255	8.9%	343,841,385	341,742,046	436,890	1,662,449	206,388,326	107,320,000	28,033,720	1,119,884	94,290	447,435	840

REFERENCE: **Page 10 of Overview**

TOPIC: **Power Generation**

PREAMBLE:

YEC states "with ongoing load growth and expressed interest from other future industrial customers, the existing hydro generation is likely to be fully utilized within the next few years, necessitating new renewable supply sources in order to avoid reliance on high cost baseload diesel generation and the resulting GHG emission issues".

QUESTION:

a) Please provide all evidence, assumptions and scenarios that support YEC's position that existing hydro generation is likely to be fully utilized within the next few years and result in a reliance on baseload diesel generation. This evidence should quantify the amount of baseload diesel generation for the applicable time period.

b) Please comment on the impact of the worsening world and Canadian economic situation and outlook on this statement.

ANSWER:

(a)

Please see Yukon Energy's 20 Year Resource Plan and UCG-YEC-1-8(d).

(b)

Please see YECL-YEC-1-20(c).

REFERENCE: **Page 2-19 Line 10**

TOPIC: **Wind Turbine**

QUESTION:

a) Please provide details as to why the approved 2005 output from the wind turbines is overstated compared to 2005, 2006, and 2007 actuals.

b) Please provide the 2008 actual wind generation output and rational for the 2009 forecast.

c) Please explain what actions have been taken to increase the output of the wind generations in the test period.

ANSWER:

(a), (b) and **(c)**

See LE-YEC-1-26 in regards to operational and maintenance problems with the wind turbines, and plans for increasing output.

REFERENCE: **Major Projects Page 5-20**

TOPIC: **Capital Projects**

PREAMBLE:

Yukon Electrical is seeking more information on Mayo B hydro expansion.

QUESTION:

a) Please provide the detailed costs associated with the expenditures proposed and or expended in the test years. Please include a breakdown of all costs by labour, material, contractor and other. Please provide the details in regard to any contracts for work associated with these expenditures and the process used to select such vendors.

b) Please provide the detailed business case for the Mayo B Expansion, including all options considered? Please provide the anticipated financing arrangements for this project and identify any customer contributions that are expected to be received. Identify the source and the amount of all such contributions.

ANSWER:

(a)

The costs forecast in the GRA filing for Mayo B total $1.7 million in 2008 and a further $6.5 million in 2009.

For 2008, the $1.7 million was approved as an increase to capital budgets in place at that time for hydro investigation work. The increase to $1.7 million was comprised of:

- Pre-feasibility work to date - $0.068 million
- Mapping and Survey related work - $0.097 million
- Geotechnical investigations - $0.247 million
- Project management and coordination - $0.234 million

- Engineering - $0.405 million
- Environmental and socio-economic field studies - $0.195 million
- Environmental assessment, consultation and YESAB filing - $0.300 million
- Power system modelling - $0.100 million
- AFUDC and ES&G - $0.050 million.

The $6.5 million for 2009 is a high-level estimate that is oriented towards a project construction start date in early 2010, and an assumed planning stage budget to that time of approximately 10% of the overall capital cost. Specific budgets for each phase of Mayo B, similar to other major projects, are approved only once specific timelines and tasks are established and work from previous phases is largely addressed.

The capital budget approval and related GRA budgets were not based on specific contracts or vendors in place at that time.

(b)

YECL initially requested a detailed business case for the Mayo B Expansion, including all options considered, anticipated financing arrangements, and expected customer contributions (by source and amount). Available information regarding the rationale for this expenditure has been provided in the Application (see page 5-20) and in responses to interrogatory requests (see YUB-YEC-1-38 and UCG-YEC-1-89). Further information on the Mayo B Enhancement Project is available in the Project Proposal Submission filed with YESAB on February 27, 2009. This is available on Yukon Energy's website site at http://www.yukonenergy.ca/about/projects/mayob/.

The Mayo B Expansion was also discussed in Chapter 5 of the Yukon Energy 20-Year Resource Plan. Mayo B was included in the 2006 Yukon Energy 20-Year Resource Plan filing (at Appendix B) as part of an inventory of hydro project options. As noted at page B-1 of the Resource Plan, the projects included in Appendix B represented "the primary alternatives identified to date based on review of the numerous studies conducted in Yukon." Mayo B was specifically discussed as one of a group of small projects being considered (within the 5 to 10 MW range) at page B-10. This is also discussed in

response to UCG-YEC-1-89(c).[1] The Resource Plan noted that small hydro projects in the range of 5-10 MW were potential candidates for development under Chapter 5 forecasts under the 25 MW industrial scenario or larger. These projects could also potentially be part of a development plan under the larger 40 MW scenario.

Order 2009-4 directed Yukon Energy to provide further information related to risk for the project, the risk of not proceeding with the project, the alternatives to this project which were considered and the potential benefits to customers. The further information provided below in response to Order 2009-4 builds on the following information already provided in response to YUB-YEC-1-38:

- Yukon Energy is currently undertaking all required planning, consultation, environmental, engineering and other related activities in order to obtain authorizations and approvals necessary to allow for a decision to commence construction of the Project in 2010. At this time, Yukon Energy has made no final decision to proceed with the Project.

- Yukon government and Federal government regulatory approvals and decisions are required before any construction activities may be undertaken; however, these approvals and decisions may only be made after the required screening assessment by the Executive Committee of the Yukon Environmental and Socio-economic Assessment Board (YESAB) of the Project Proposal Submission (Project Proposal). On February 27, 2009, Yukon Energy submitted the Project Proposal to YESAB.

[1] The response to UCG-YEC-1-89(c) provides an excerpt from Appendix B of the 20-Year Resource Plan which notes as follows regarding Mayo B: The existing hydro site at Mayo has the potential to be enhanced by various changes in configuration, either to develop further head below the existing reservoir or an expansion of capacity utilizing the same head. This leads to multiple potential alternatives. However, as a supply option to WAF, these various projects are only of relevance if the Carmacks- Stewart transmission line is previously in service. The full capability of various potential Mayo enhancements to supply an interconnected WAF and MD system (as opposed to MD on its own) has not been fully studied, and should be re-examined in the event that the interconnection proceeds. One configuration alternative considered is a 10 MW, 48 GW.h, $101 million (2005$) variation based on a separate conveyance route from the existing reservoir to a new plant lower in elevation than the existing plant, which would be able to operate in parallel with the existing plant. This concept has an initial LCOE of 11.2 cents/kW.h. Various other concepts require further study. However, although work is still in preliminary stages, it must be recognized that it is possible no credible facility enhancements of this type exist at Mayo.

- The cost estimate at this time (Level 3-Feasibility stage of study) for Mayo B is $120 million, including contingencies of 15% to 25% depending on the project component.

- Selection of canal (versus tunnel) option likely reduces the degree of tender price risk, and future geotechnical risk to Project costs.

- At $120 million (and ignoring potential government infrastructure funding), the full assumed output of the plant of 38.4 GWh (under full long-term load conditions) yields a levelized cost of energy ("LCOE") for the capital cost of the project of $0.142/kW.h.

- In the near-term under reasonably foreseeable load conditions, integration of the Project into Yukon power systems would be expected to yield a somewhat smaller net firm energy benefit, potentially as low as approximately 30 GW.h of firm energy (plus up to 10 GW.h of enhanced potential secondary energy should there be loads available to purchase this supply). In such a case the levelized cost of energy would approximate $0.182/kW.h.

- By comparison, diesel costs per UCG-YEC-1-62 remain at $0.248/kW.h at today's fuel prices.

- In order to keep costs and risks to Yukon ratepayers within acceptable bounds (e.g., more in line with B.C green market power purchase costs of 8 to 10 cents/kW.h), it is anticipated that government infrastructure funding will be secured for a material portion of the project costs.

- No further details on the precise form and source of financing, including government funding are available at this time.

1. Project Risks

Risks for the Mayo B Expansion Project include:

- **Regulatory delay risks** such that earliest construction on land based activities cannot commence in summer 2010 as required to achieve earliest Project in-

service by late 2011 – risks of such delays may affect current Yukon applications for federal infrastructure funding, as well as result in YEC incurring added diesel generation costs for the period of any in-service delays. Most regulatory requirements are reasonably apparent, even if there is limited Yukon YESAB Executive Committee assessment process experience with related federal and Water Board permitting and/or licensing; Yukon Government directions have not been made to date as regards any YUB review requirements. Overall, due to the absence of any new dam or new flooding for the Project (as well as other factors addressed in the YESAB Project Proposal Submission), the Project is expected to receive all necessary regulatory approvals without material additions to cost (or reductions in output) for mitigation measures – and any potential regulatory delays are not expected to delay earliest in-service timing by more than one year.

- **Capital cost increase and other construction risks** typical to any project of this nature, location, scale and stage of development with some added risks related to tight timing if the Project construction in fact starts in summer 2010. Additional geotechnical field studies are planned in summer 2009 to reduce further the uncertainties affecting the canal, penstock and powerhouse geotechnical conditions YEC is reviewing options to manage and mitigate construction contractor risks, including risks related to lack of adequate contractor bid interest, inflated tender prices to cover potential project risks and final design uncertainties, adequate supervision and management during construction, and delays.

- **Other Project feasibility risks**, beyond regulatory and construction risks, include:
    - Delay in completion of Carmacks-Stewart Stage 2 beyond spring/early summer of the in-service year for Mayo B (would create need to use costly diesel generation [rather than surplus WAF hydro generation] when the existing Mayo plant is shut down briefly in that summer to complete connection of the new Mayo B powerhouse; if CSTP Stage 2 continues to be delayed, Mayo B generation would also be unable to be utilized as planned to displace diesel generation on the WAF as well as MD grids);
    - Further sustained diesel fuel price decline such that Mayo B costs exceed diesel generation costs; and

- Inadequate near-term system loads to utilize Mayo B generation as planned (including material delays in connection of new mine loads such as Carmacks Copper and Alexco); due to the relatively small scale of this development relative to the combined WAF/MD system, long-term loads adequate for effective use of the Project are not likely to be a material risk.

- **Project Funding risks,** particularly as regards securing federal funding as is currently being sought by the Yukon Government. Material federal infrastructure funding would assist in reducing Project feasibility risks as well as reduce the ultimate impact on ratepayers (through reducing impacts on YEC ratebase).

2. Risks of Not Proceeding with Mayo B Expansion

As noted, no decision has been made by Yukon Energy at this time to proceed with Mayo B. Prior to YEC's Board of Directors approving each major stage of Mayo B development, including any commitment to start construction, all material risks are reviewed to confirm that it is prudent to proceed. At this time, the largest single factor likely to affect the risk of not proceeding with Mayo B expansion at this time relates to securing adequate federal infrastructure funding on a timely basis.

Assuming that the above question addresses risks tied to the option of not proceeding with Mayo B expansion, the major risk is that YEC and Yukon ratepayers will be required to fund an extra 30 GW.h or more per year of diesel generation (i.e., the diesel generation that Mayo B would otherwise displace) with its related costs and GHG emissions.

By reducing the surplus hydro generation, new industrial loads advance the timing for potential renewed diesel generation. As noted at page 5-19 and 5-20 of the Application and in responses to IRs (e.g., CW-YEC-1-31):

- Ongoing resource planning activities indicate that the current hydro generation surplus (after CSTP Stage One and Minto connection, and before any secondary sales) at long-term average flows will likely now be fully utilized by firm sales on WAF sometime between 2011 and 2014.

- The connection of additional industrial loads, possibly as soon as 2010/2011, could lead to the requirement for 50 to 100 GWh of baseload diesel generation within the 2010-2015 time period.

As noted in response to CW-YEC-1-31(a) and (b) and in the Application (Section 2.2.2.2) Western Copper and Alexco are currently both expected to require service within the 2010 to 2011 time period. While forecast information provided by potential industrial customers is subject to change, the following forecast information remains current:

- **Western Copper** – An in service date of late 2011 is projected with an expected annual requirement averaging approximately more than 4 GW.h per month (50 GW.h per year), and a mine life of at least six years.

- **Alexco Resource Corp** – Plans to commence mining and milling operations at the Keno Hill property in early 2010. The response to CW-YEC-1-31 notes an expected requirement of 11.7 GW.h for the first 2 years of service, increasing to 16.5 GW.h for the next three years of service.

It is currently projected that by 2012 the combined Minto, Carmacks Copper and Keno Hill loads (along with other projected WAF/MD firm loads, including added Faro mine reclamation loads but excluding all secondary loads) would require over 70 GWh of new generation beyond that which could be provided under long term average water flows by the current WAF/MD hydro generation capability together with Aishihik 3rd Turbine and the completed CSTP Stage Two. As reviewed in response to the next section below, without Mayo B there is today no apparent renewable resource option that could be developed in at least the near term (2012-2015) to replace the additional renewable generation that Mayo B would provide. At even the recent 25 cents/kWh incremental cost, 30 GWh of diesel generation would incur added annual fuel and operating costs of approximately $7.5 million and increase CO2 emissions by approximately 21,000 tonnes per year.

3. Alternatives to Mayo B Project which were Considered

Mayo B has been identified as the largest single near-term renewable project opportunity (30 GWh/year of near-term incremental hydro generation) with the least risky timeline for

in-service between late 2011 and late 2012. Absent Mayo B, the current forecast load growth (see previous section) that Mayo B would serve would need to be supplied using diesel generation.

Alternatives to Mayo B were reviewed in YEC's 20-Year Resource Plan: 2006-2025, as well as in subsequent YEC studies.

Mayo B was reviewed as part of the 20-Year Resource plan as a potential small hydro project that could, in combination with other renewable resource projects, help to address various industrial development scenarios. Chapter 5 of the 20-Year Resource Plan noted that small hydro projects such as Mayo B (i.e., in the range of 5-10 MW), were candidates for development under the 25 MW industrial scenario or larger (up to 40 MW scenario). The Resource Plan's Appendix B noted that a number of utility "greenfield" hydro sites and alternative existing hydro project enhancements have been reviewed by Yukon Energy since 1987, and by NCPC or others prior to 1987, and provided summary information on the major options identified by these earlier studies.

In 2007, following the Yukon Utilities Board review of the 20 Year Resource Plan, Yukon Energy initiated an update to the studies of hydro sites and enhancements for near term development (2010-2015 in-service) previously identified as relatively promising, in the range of 20-50 GW.h per year (subsequently expanded to 50-100 GW.h per year). Based on this review, no greenfield hydro generation sites (e.g., Drury) were considered to be competitive with Mayo B or other enhancement options based on the load and timing factors specified. To meet the timing requirements in particular, it was apparent that Yukon Energy needed to focus on enhancements to current WAF and MD hydro generation facilities.

Other supply options examined by Yukon Energy (and included in Deferred Costs (Tab 5, Section 5.3 of Application) as Other Generation Feasibility) are discussed in the response YUB-YEC-1-38(b). Aside from Mayo B, other hydro generation enhancement projects currently being investigated include the Gladstone Diversion project (up to 18 GW.h/year), small scale Atlin winter storage[2] (up to 18 GW.h/year), and Marsh Lake fall-

[2] As noted in PWP/HML-YEC-1-41 "Yukon Energy is considering a much smaller development that would store water in Atlin Lake within its natural high water levels and release it over the winter, very similar to what is currently undertaken with regard to Marsh Lake".

winter storage[3] (up to 7.7 GW.h/year). These generation enhancements, each of which is much smaller than Mayo B, can be developed at an attractive cost and with relatively short construction periods (typically in the order of one year); however, the earliest feasible near-term in-service dates present specific risks that depend on the timeframes necessary to plan and licence each project. Each of these smaller enhancement options was considered to face today much greater regulatory risks than Mayo B, both as to securing ultimate regulatory approvals as well as to potential likely timing for nearest feasible in-service. Yukon Energy has noted, however, that Mayo B alone would not displace even half of the likely baseload diesel generation forecast for 2012 on WAF/MD grids, and therefore Yukon Energy (as noted in the Application) is actively pursuing near term development of these other enhancement projects as soon as is feasible, i.e., ultimately these project options are expected to complement rather than compete with near term Mayo B development.

Yukon Energy is also pursuing any other enhancements to its existing hydro generation capabilities; however, no set of such enhancements has the ability to displace Mayo B's forecast near term ability to displace diesel generation requirements on the WAF/MD grids.

The discussion in YUB-YEC-1-10(a) addresses results of studies undertaken regarding renewable generation and the focus on enhancements in the near term, and notes as follows:

> The main focus of recent studies has been to identify and assess near term options (i.e., in-service as soon as 2010 and up to 2015) to serve potential new load that may be connected during this time.
>
> At a high level, the conclusions indicate that the unit costs of enhancement to existing hydro generation (as well as timing requirements to develop) are below the costs (and development timing) that would need to be incurred for developing new "greenfield" hydro sites.

[3] YUB-YEC-1-27(a) notes the following with regard to the status of Marsh Lake "Yukon Energy has undertaken studies to confirm the hydrology related to Marsh Lake water levels, and the Yukon Government has completed a Flood Assessment and Abatement Study. Marsh Lake storage continues to be an attractive resource option, in the event it can be completed without any significant adverse effects on the local residents."

Further, while larger scale Hydro (such as Hoole, at 100-300 GW.h/year) remain under investigation for potential relevance by 2015, larger scale greenfield hydro generation cannot likely be developed in less than 5-6 years even on an expedited schedule.

Outside of enhancements to existing hydro facilities, renewable power generation for northern (i.e. has a wintertime electrical peak) climates not connected to the North American grid can be pursued from only a limited number of sources. A thorough review of Power Resource Technology Options is provided in Appendix A to Yukon Energy's 20 Year Resource Plan 2006-2025 ("20 Year Resource Plan").[4] Each of the generation technologies of notable promise (with respect to ability to effectively serve loads typical of Yukon), are under active investigation by Yukon Energy. In particular, both geothermal and further wind generation are currently being investigated as potential renewable generation options.

While geothermal and wind in Yukon are not considered near-term alternatives to the Mayo B project in terms of either timing or scale of development, each can in the future be developed to complement this project. Geothermal generation is not considered an alternative at this time as it remains in exploratory stages, while wind does not offer the same power characteristics as hydro enhancements (e.g., the type and degree of firmness provided by the Mayo B Project). Appendix A to Yukon Energy's 20 Year Resource Plan 2006-2025 provides a more detailed review of these options as well as other options that were reviewed at the time of the Resource Plan hearing, including biomass, coal, coal bed methane, nuclear, solar, natural gas, hydrogen and demand-side management.

Absent Mayo B or some other renewable resource option, baseload diesel would be required to meet growing system load requirements. As noted in Appendix A of the Resource Plan, diesel units are typically well-suited to meeting reserve capacity requirements and short-term capacity needs during system peaks. However, diesel is expensive for utility operations running to provide sustained energy on a regular basis throughout the year. As noted above, even at the recent 25 cents/kWh incremental cost, 30 GWh of diesel generation (equivalent to Mayo B near term added net grid generation) would incur added annual fuel and operating costs of approximately $7.5 million and increase CO2 emissions by approximately 21,000 tonnes per year. By comparison, the

[4] The resource plan filing and other materials are available on the Board's at the following link: http://yukonutilitiesboard.yk.ca/proceedings/yec_20/

levelized cost of near term energy related to Mayo B is approximately $0.182/kW.h even without any federal or other government infrastructure funding.

4. Potential benefits to customers

Similar to other hydro-based jurisdictions, Yukon's power system includes material assets with embedded costs well below the cost to bring on new generation today. Today, with anticipated load increases, both cost and environmental reasons provide strong incentives for Yukon Energy to expand the available complement of renewable generation, as well as transmission interconnections that support enhanced use of renewable generation in Yukon.

All utility ratepayers will realize benefits from the enhanced ability to serve both new industrial loads and on-going domestic load growth through additional renewable generation capacity available on the interconnected WAF/MD system. Long term benefits will be available due to lower cost (relative to diesel generation) renewable energy, as well as improved system reliability. OIC 1995/90 directs that the consolidated costs of Yukon Energy and YECL be used to set the same rates throughout Yukon for non-government retail customers[5] as well as Major Industrial customers, i.e., the benefits of Mayo B will accrue to all of these customers in Yukon and not only those in the vicinity of the Mayo B project.

YUB-YEC-1-38(a) notes the following with regard to Mayo B impacts over the near term:

> In the near term under reasonably foreseeable load conditions, integration of the Project into Yukon power systems would be expected to yield a somewhat smaller net firm energy benefit, potentially as low as approximately 30 GWh of firm energy (plus of up to 10 GWh of enhanced potential secondary energy should there be loads available to purchase this supply).

As noted above, even at the recent 25 cents/kWh incremental cost, 30 GWh of Mayo B near term added net grid generation will allow all retail customers in Yukon to benefit from the displacement of added annual diesel generation fuel and operating costs of

[5] Subject to run-off rate variations to reflect rate zone incremental generation cost variations.

approximately $7.5 million. By comparison, the levelized cost of near term energy related to Mayo B is approximately $0.182/kW.h prior to consideration of the lower costs resulting from the federal infrastructure funding currently being sought for Mayo B and Stage Two of the Carmacks-Stewart Transmission Project.

Long-term benefits to Yukon customers from Mayo B are expected to exceed those noted above for the near term, reflecting ongoing depreciation of Mayo B capital costs and enhanced net grid hydro generation from Mayo B associated with higher overall grid loads in the future[6].

The Mayo B Expansion expenditures included in the Application are all in Work In Progress, and will not materially affect the rate base or rates sought to be approved by the Board at this time. Yukon Energy is not seeking at this time approval from the Board for the addition of the Mayo B Expansion to rate base.

[6] Grid loads in 2012 will not yet be high enough to facilitate full use of the then existing WAF/MD hydro generation facility capability. For example, long-term average generation from Mayo B will exceed 34 GWh/yr (versus 30 GW.h/yr for 2012) when WAF/MD grid system load increases by about 100 GW.h/yr above the firm load s currently forecast for 2012 with Carmacks Copper (about 468 GWh/yr).

REFERENCE: **Major Projects Page 5-21**

TOPIC: **Capital Projects**

PREAMBLE:

Yukon Electrical is seeking more information on the Western Copper Grid Connection.

QUESTION:

a) Please provide the detailed costs associated with the expenditures proposed for 2009. Please include a breakdown of all costs by labour, material, contractor and other. Please provide the details in regard to any contracts for work associated with these expenditures and the process used to select such vendors.

b) Please provide the detailed business case for the Western Copper grid connection including anticipated load and energy use?

c) Please advise what rate YEC is proposing that Western Copper will be paying for its energy usage. Provide a breakdown of the calculations and determinants that will be used to make up the rate.

ANSWER:

(a) and **(b)**

As noted in the Application at page 5-12, it is expected that the Western Copper grid connection will occur with no cost to ratepayers. Costs are to be fully recovered from Western Copper, including the expenditures provided for in 2009 to address planning, engineering, permitting/YESAA review and negotiation of a PPA. These funds will be committed only after YEC has completed necessary discussion and arrangements with Western Copper whereby Western Copper commits to fund these expenditures. Such discussions have not yet occurred. No breakdown of these costs estimates is available at this time.

The overall business case for Western Copper gird connection remains as previously set out in review of the Minto PPA and the CSTP Part 3 Hearing, i.e., Western Copper will pay for all connection costs plus a contribution to the CSTP as required per the Minto PPA. Overall, on this basis, Western Copper will provide an added contribution to CSTP costs.

(c)

Western Copper will be a major industrial customer and, as such, will be subject to the Rate Schedule 39 tariff.

If Western Copper connects prior to December 31, 2012, it will pay the Rate Schedule 39 rate as provided for in OIC 2007/94 (and approved by Order 2008-13), which directs that the Board must ensure that "rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary," as attached as Schedule A to the OIC. The attached Schedule A provides for a Demand Charge of $15.00/kV.A of Billing Demand and an Energy Charge of 7.60 cents/kW.h for all energy used. A fixed charge is specified for Minto Mine, however, the Attachment to the OIC provides that "the Fixed Charge is to be adjusted to provide for fixed monthly charges as set out in any Power Purchase Agreement, or amendments thereto, between a Major Industrial Customer and either Yukon Energy Corporation or the Yukon Electrical Company Limited, as approved by the Board." The Rate Schedule provides for escalation of these rates after 2009; it also provides for Rider F for fuel price adjustments relative ot the fuel price forecast filed November 20, 2006.

REFERENCE: **Major Projects Page 5-23**

TOPIC: **Capital Projects**

PREAMBLE:

Yukon Electrical is seeking more information on the Alexco Mine Feasibility and permitting costs.

QUESTION:

a) Please provide the detailed costs associated with the expenditures ($300,000) proposed for 2009. Please include a breakdown of all costs by labour, material, contractor and other. Please provide the details in regard to any contracts for work associated with these expenditures and the process used to select such vendors.

b) Please advise what rate YEC is proposing that Alexco Mine will be paying for its energy usage.

c) Please confirm that Alexco will be paying the $300,000 feasibility costs for this project. Please advise what the total customer contribution is expected to be for the connection of the Alexco Mine should it occur and who will be paying the contribution.

d) Please provide a copy of the technical analysis conducted that shows the impact on existing customers in Keno Hill as a result of the connection of Alexco to the grid (voltage fluctuation, motor start studies, etc).

ANSWER:

(a) and **(c)**

As noted in the Application at page 5-23, the referenced Alexco Mine-related budget for 2009 provides for undertaking infrastructure planning, engineering, environmental and permitting work and other forms of due diligence as may be required to connect this customer in 2010. These funds will be committed only after YEC has completed

necessary discussion and arrangements with Alexco whereby Alexco commits to fund these expenditures and any additional customer contribution is also identified. Such discussions are underway, but have yet to be completed. No breakdown of these budget cost estimates is available at this time, and no estimate of the total customer contribution is available at this time.

(b)

Alexco will be a major industrial customer and, as such, will be subject to the Rate Schedule 39 tariff. Please see response to YECL-YEC-1-6(c).

(d)

This referenced technical analysis has not been carried out to date. Alexco are not sufficiently advanced in their engineering design to supply the information needed to conduct this analysis. It will be done at a later date. Alexco will be required to meet the technical interconnection requirements in the ESR's, Rate Schedule 39 and their PPA.

REFERENCE: **Introduction Page 1-7**

TOPIC: **WAF Hydro Surplus, Minto Industrial Load and CSTP Development**

PREAMBLE:

Yukon Electrical wishes to better understand the arrangements and cost benefits associated with the addition of Minto Mine and the CSTP expansion.

QUESTION:

a) Please provide a comparison of the forecast to actual costs of the Minto Mine spur line and phase 1 of the CSTP. Please indicate all contributions that were made and identify the source of the contribution.

b) Please provide the business case and regulatory models associated with Phase 2 of the CSTP. Please show the Net Present Value NPV analysis, with and without the addition of the Alexco Mine. Please provide details of the anticipated customer contributions that will be required. Please identify the party(ies) expected to make such contributions and when.

c) In regard to the connection of the two grids, the Mayo Dawson at 69kV and the CSTP at 138kV, what specific equipment is being proposed to transparently allow the grids to synchronize and support each other? Please provide the technical documentation for this equipment.

d) Please provide a copy of the recommendations provided by the Auditor General related to the Mayo Dawson Transmission line. Please detail the manner in which YEC has specifically implemented those recommendations with respect to the CSTP.

e) What is the maximum power (MW) that can be transmitted down the 69 kV line from Mayo toward the Grid tie point?

ANSWER:

(a)

Please see response to LE-YEC-1-46 and LE-YEC-1-47 which provide the detailed cost breakdown of the original budget and the current (not yet finalized) cost budget for both the CSTP Stage 1 and the Minto Spur.

A summary of contributions is provided as response to YECL-YEC-1-30.

(b)

YECL initially requested that YEC provide a business case and regulatory models associated with Phase 2 of the CSTP including Net Present Value analysis with and without Alexco Mine, identifying anticipated customer contributions required and parties expected to make contributions and when. Available information regarding the rationale for expenditure has been provided in the Application (see page 5-20) and in responses to interrogatory requests (see PWP/HML-YEC-1-27, UCG-YEC-1-74, YUB-YEC-1-3(c)). Further information on the CSTP Stage 2 is available in the CSTP Project Proposal Submission filed with YESAB in October 2006. This is available on Yukon Energy's website at http://www.yukonenergy.ca/about/projects/carmacks-stewart/. This project was also reviewed by the YUB during the Minto PPA hearing[1] and the Part 3 hearing.[2]

The CSTP Stage 2 was also discussed in the Yukon Energy 20-Year Resource Plan.[3] The revised response provided to YECL-YEC-1-11(d), notes the relevant portions of the 20-Year Resource Plan and other filings related to the CSTP, and the Board's recommendations in its related reports to the Yukon Government, which provided the justification for proceeding with Stage 1 of the project and which provides the rationale for completing Stage 2.

[1] Filings and Board Orders are available on the Board's website at http://yukonutilitiesboard.yk.ca/proceedings/PPA/.
[2] Filings and Board report are available on the Board's website at http://yukonutilitiesboard.yk.ca/proceedings/cstp/.
[3] Filings and Board report are available on the Board's website at http://yukonutilitiesboard.yk.ca/proceedings/yec_20/.

In Order 2009-4 Yukon Energy was directed to provide further information related to risks for the project, the risk of not proceeding with the project, the alternatives to this project which were considered and the potential benefits to customers. Each is discussed in detail below:

1. Risks for project

Timing to proceed with construction of CSTP Stage 2 is dependent on securing adequate new mine loads plus related funding contribution commitments (from mines and/or government) so as to prevent any net increase in retail rates (after consideration of new mine revenue impacts).

- CSTP Stage 2 might potentially proceed for in-service as early as late 2010 (to reduce diesel requirements related to Alexco mine loads), and would be required by spring/early summer of the final year of Mayo B construction (potentially 2011). The current planned timing for the Carmacks Copper mine in service in late 2011 supports near term development timing for both CSTP Stage 2 and Mayo B.

- CSTP Stage 2 development, however, is dependent on securing government and/or mine customer funding for almost all of its capital costs (in order to prevent any net increase in retail rates). On this matter, an application has been filed by Yukon for federal government infrastructure funding as part of an overall Mayo B/CSTP project proposal.

There are no apparent material regulatory risks today for the CSTP Stage 2 Project, beyond Yukon Energy securing Yukon Government approval to proceed. Prior to construction, and after confirmation as to federal government infrastructure funding, YEC needs to secure all required permits or other approvals from the Yukon Government, Selkirk First Nation and the federal government. However, this Project has received all required YESAB and Decision Body reviews and approvals[4]; the YEC Project

[4] The scope of the YESAB Executive Committee Screening, completed November 2, 2008, considered the entire transmission line project (i.e., both Stage I and II). Decision Documents from the Yukon Government, Little Salmon Carmacks First Nation, and the Selkirk First Nation were issued pursuant to the recommendation made by the Executive Committee at the conclusion of the assessment. These Decision Documents allow the responsible governments and their regulatory agencies to issue the permits required for Stage II, after their review and approval of the requisite permit applications having been made by Yukon Energy. As long as there are no significant changes made to the project route or substation locations/footprints, the Decision Documents should remain valid for Stage II permit issuance. Authorizations from the Responsible YG Minister and the YUB are also potentially required (i.e., Part III Energy Certificate).

Agreement with the Northern Tutchone First Nations also includes all agreements required to proceed with this Project on First Nation settlement lands. Timing to begin clearing and construction later this summer or fall will be constrained by the time needed to secure the required permits and approvals after Project funding is secured, including any related reviews that the Yukon Government may require by the YUB as regards the Energy Project Certificate for CSTP Stage 2.

Based on preliminary CSTP Stage 2 engineering done in 2007 and subsequent experience with CS Stage 1 construction, the preliminary updated project capital cost estimate for CSTP Stage 2 is $40 million.[5] This estimate is subject to risks related to final engineering requirements and receipt of construction contract tenders. Costs have been derived using those encountered in Stage One and are the most current available until the contracts are tendered. The Stage One project costs for the 138 kV line construction conformed generally with preliminary engineering cost estimates developed in spring 2007; however, final Stage One substation costs were materially higher than estimated prior to tendering.[6] CSTP Stage 2 cost estimates include the Stewart Crossing substation costs, which constitute a major component of the Stage 2 project and have been subject to escalation to reflect both enhanced preliminary engineering design assessments plus tendering cost escalation experienced from Stage One. Final engineering design will assess substation equipment needs for dynamic system flow stability, substation upgrades (if any) required at Carmacks and Minto Landing, and substation options to supply ongoing power to Pelly Crossing and the Carmacks Copper mine.[7]

[5] The current cost estimate is higher than initial estimates provided in the Resource Plan and CSTP Part 3 Application hearings ($17.5 million ($2007)), and as subsequently developed in spring 2007 with preliminary engineering ($29 million).

[6] See response to LE-YEC-1-46 which provides a detailed cost breakdown of the original CSTP Stage One budget and current (not yet finalized) CSTP Stage One budget.

[7] Final CSTP Stage One design and development has Pelly Crossing energy being supplied by Minto Landing substation facilities (138/25 kV step down) and operation of the 138 kV line from Minto Landing to Pelly Crossing at 25 kV during Stage One. For CSTP Stage 2, the least cost option will be assessed for ongoing Pelly Crossing energy supply (e.g., new 138/25 kV substation at Pelly Crossing versus continued use of Minto Landing substation facilities and development of a 25 kV distribution line from Minto Landing to Pelly Crossing within the current 138 kV line right-of-way). Similar options will be assessed for supply of power to Carmacks Copper (the spur line connection to Carmacks Copper, including any related substation developments, will be funded by the Carmacks Copper mine). Based on system stability considerations plus new substation costs, it is expected that distribution line options may prove superior for Pelly Crossing service and perhaps also for Carmacks Copper connection.

Stage Two feasibility and timing risks were discussed in the Part 3 CSTP Application, and addressed as part of that review process before the YUB[8]. It was noted at that time that Stage Two connection of 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 Mayo Dawson (MD) grid hydro generation (up to 15 GWh/year in 2012) plus surplus MD diesel capacity (up to 5.6 MW in 2012). Potential near-term ratepayer benefits associated with CSTP Stage Two were subject to the assumption of surplus generation resources on MD system, which (it was noted) would not be available to the extent that new industrial development (e.g. UKHM) occurs concurrently on the MD system[9]. Without new near term hydro energy generation supplies assumed in the Resource Plan from MD as well as Aishihik 3rd Turbine (and Marsh Lake in the initial Resource Plan), serving both Minto and Carmacks Copper mines would lead to new baseload WAF diesel generation even at earlier lower Minto mine loads.

Today, the near-term economics of the CS Stage 2 project (relative to what was estimated in the earlier Board hearings) is adversely affected by the higher capital cost estimates for this project and the current forecast of concurrent Alexco (MD grid) and Carmacks Copper mine developments (WAF grid) as well as other updated load forecasts for these two grids. As a previously noted, Yukon Energy's ability to proceed with CSTP Stage 2 requires government or mine customer funding of a material portion of the capital costs for the Project to proceed at this time. Based on current project cost estimates and forecast Alexco loads and sales revenues, government and/or mine funding of at least $35 million of the project capital cost is viewed as a pre-requisite to YEC being able to proceed at this time with CSTP Stage 2.

At the current time, minimal risks appear to apply regarding development of the Alexco mine loads; however, given current market condition uncertainties and the mine's need to secure financing to support capital costs for mine construction planned to start by

[8] It was noted that the funding commitment by Yukon, in combination with industry related funding, would enable Stage Two to proceed without direct costs to non-mine ratepayers as soon as industrial energy demands are sufficient to warrant this development. At that time the Yukon Government funding for Stage 2 was assumed to address the specific risks related to other concurrent mine developments on the Mayo-Dawson system (e.g., UKHM) combined with the potential impact of new added mine loads on renewed baseload diesel generation.

[9] It was noted at the Resource Plan hearing (trans refer 253 lines 4-14) that, "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."

spring/early summer 2010, material timing risks likely apply as regards the Carmacks Copper mine load development.[10]

In order to meet current in-service targets of no later than spring/early summer 2011, it is required that YEC be able to proceed this spring/summer with CSTP Stage 2 final engineering, permitting and early order of long lead equipment (e.g., transformers). This timing is subject to the timing and other risks of securing before summer the required federal and other government funding commitments, as well as Yukon Government approvals that will enable YEC to proceed at this time.

Long term feasibility of the CSTP Stage 2 will have minimal risks if the project is developed at this time based on the principles set out above. Although difficult to quantify in present value assessments, connection of the WAF and MD grids will enhance overall grid reliability and flexibility to utilize existing and future renewable generation resources.

2. Risks of not proceeding with CSTP Stage 2

No decision has been made by Yukon Energy at this time to proceed with CSTP Stage 2. Prior to YEC's Board of Directors approving each major stage of CSTP Stage 2 development, including any commitment to start construction, all material risks are reviewed to confirm that it is prudent to proceed. The largest single factor likely to affect the risk of not proceeding with CSTP Stage 2 at this time relates to securing adequate federal and other government infrastructure funding on a timely basis.

Assuming that the above question addresses risks tied to the option of not proceeding with CSTP Stage 2, the major risk is that YEC and Yukon ratepayers will be required to fund additional diesel generation with its related costs and GHG emissions. In the near term, such added diesel generation would reflect inability to use near-term WAF surplus hydro generation to supply Alexco loads plus the inability to use Mayo B generation (if developed) to supply growing WAF loads (including Carmacks Copper loads when connected). In the longer term, failure to connect the WAF and MD grids will reduce overall grid reliability and flexibility to utilize existing and future renewable generation resources in an efficient and effective manner.

[10] A PPA with Western Copper (regarding YEC service to the Carmacks Copper mine) would be required at least 24 months prior to start of YEC service in order to allow time required to secure YESAB review, permitting, engineering and construction of the mine spur connection. The PPA would include provision for a capital contribution to CSTP based on the principles set out in the PPA between YEC and Minto Explorations.

The response to PWP/HML-YEC-1-27 noted the following factors that remain relevant considerations regarding continued near term development for CS Stage 2:

- With potential connection of Alexco in 2010, there remains a need to ensure ability to reduce potential diesel usage due to that mine load connecting to the grid in that year.

- To the extent government infrastructure funds become available, the ability to be ready to advance and proceed with the project in the near term is critical.

Yukon Energy expects to require additional near term renewable power to help minimize the use of diesel to generation electricity. This reflects expected growth of existing non-industrial loads on each grid, expanded loads currently forecast at the Minto and Alexco mines, new Faro mine reclamation loads, and potential new mine loads such as Carmacks Copper.

The current Alexco mine development will connect new load to the Mayo Dawson grid in 2010, utilizing surplus hydro on this grid and leading to new diesel generation requirements (over 3 GW/h in each of the first two years of mine operation, increasing to about 10 GW.h/yr thereafter) if no new power resource developments or grid connections are initiated. Timely completion of the CS Stage 2 could potentially assist to displace such near term MD diesel requirements in late 2010 and 2011 through use of any remaining WAF surplus hydro generation.

Completion of CSTP Stage 2 to connect the two grids is also an important element supporting each new hydro or other renewable green development and particularly larger projects such as Mayo B on the Mayo Dawson grid, as the interconnection enables each new renewable generation project to help meet new load on both grids. Long term average annual baseload diesel generation requirements on WAF (without CSTP Stage 2 to allow Mayo B access, and without Carmacks Copper loads) are currently projected at about 14 GW.h/yr in 2011 and 23 GW.h/yr by 2013.[11]

[11] These WAF diesel generation requirement forecasts assume that current Aishihik Fish Act Authorization restrictions are resolved as these currently restrict average annual long term hydro generation at the Aishihik generation facility.

3. Alternatives to CSTP Stage 2 Project which were Considered

Exhibit B-16 filed during the Resource Plan hearing briefly discussed the two alternatives to the CSTP (Stage 1 and Stage 2). One alternative (a 35 kV line from Carmacks to Minto Mine) would not have supported future interconnection between the WAF and MD power grids and would have had limited long term benefits to Yukoners due to the expected requirement to decommission the line after service to Minto ended. The second alternative to the CSTP was not to proceed at all with any other option. It was noted that this alternative would provide the following outcomes:

- No grid power could be provided to future mine developments in this area, such as the Minto mine and the Carmacks Copper mine - this would adversely affect mine operating costs and economics, reducing royalties to government and potentially First Nations, and increasing diesel generation greenhouse gas emissions.

- Pelly Crossing would continue to be served by diesel generation.

- Interconnection of Yukon Energy's existing WAF and MD grids would not be realized, preventing this improvement to YEC's overall system reliability and efficiency.

- Economic development opportunities that could be realized with the CS/MS project in the Carmacks/Stewart Crossing region with access to grid power may not be encouraged.

Today, with CSTP Stage 1 already developed, the alternative remaining is not to proceed with CSTP Stage 2 at this time. This option would delay benefits from interconnection of the WAF and MD grids and restrict economic development opportunities facilitated by such interconnection of these grids.

The 20-Year Resource Plan identified near-term opportunities to utilize existing hydro surpluses on its WAF and MD hydro grids to displace diesel generation at new mine developments, as well as the immediate requirements to plan for new renewable generation to meet future industrial and other electricity load growth on these grids. Please see the revised response to YECL-YEC-1-5(b) for an updated review of the near-term (2010-2015) options that have been considered to develop new renewable

resources to meet projected load requirements in excess of current hydro generation capabilities. Without CSTP Stage 2, the limited near term renewable resource development opportunities to displace forecast diesel generation would be further constrained.

4. Potential benefits to customers

Similar to other hydro-based jurisdictions, Yukon's power system includes material assets with embedded costs well below the cost to bring on new generation today. Today, with anticipated load increases, both cost and environmental reasons provide strong incentives for Yukon Energy to expand the available complement of renewable generation, as well as transmission interconnections that support enhanced use of renewable generation in Yukon.

Benefits are expected to be realized by all utility ratepayers when Yukon Energy's grids become interconnected, as new industrial loads and on-going domestic load growth can be serviced through additional renewable generation capacity available from both the MD and WAF grids. Ratepayers will enjoy long term benefits due to available lower cost (relative to diesel generation) renewable energy as well as improved system reliability. OIC 1995/90 directs that the consolidated costs of Yukon Energy and YECL be used to set the same rates throughout Yukon for non-government retail customers[12] as well as Major Industrial customers, i.e., the benefits of CSTP Stage 2 will accrue to all of these customers in Yukon and not only those on the two grids.

The ultimate benefit of completion of Stage 2 and the interconnection of MD and WAF grids is the ability in future for any surplus hydro or other renewable generation resource on either system to be used to meet load requirement on either grid. There is also an added benefit of being able to use the reserve capacity on either grid to function as reserve capacity on the other grid. When CSTP Stage Two proceeds, the standby diesel generation at Mayo (2 MW) and Dawson City (5 MW), can be used as reserve capacity on the WAF grid, thereby helping to minimize the capital cost of adding new diesel or extending the life of old diesel generation on WAF to meet grid reserve capacity requirements. Similarly all reserve capacity on the WAF is available to function as reserve capacity on Mayo Dawson.

[12] Subject to run-off rate variations to reflect rate zone incremental generation cost variations.

Yukon Energy notes that the CSTP Stage 2 expenditures included in the Application are all in Work In Progress, and do not materially affect the rate base or rates sought to be approved by the Board at this time. Yukon Energy is not seeking at this time approval of the Board for the CSTP Stage 2 Project.

(c)

The design engineering for CSTP Stage II is not presently underway. Dynamic system studies are required to be able to identify any additional equipment that will be required for system stability. These studies have not been completed and therefore no details of the equipment required are known.

(d)

Please see report provided as Attachment 1 to this response. The recommendations are grouped as follows in the five main areas as described in the Main Points section of the report:

- **Shortcomings in definition of scope and costs:** YEC engaged experienced technical resources early in the process who frequently and in detail reviewed the outputs of design engineers to ensure outputs were reasonable. As well, the Board of Directors was provided frequent, detailed updates on cost, scope and progress.

- **Shortcomings in "design-build" approach:** YEC used traditional construction approach with separate contracts for design engineering, project management and construction.

- **Shortcomings in project management:** YEC hired a professional project manager to track schedules and budgets, monitor progress, report issues and act as liaison between engineers, constructors and YEC. In addition, an external project coordinator was hired to act as an owner's representative and monitor progress of all project construction activities (the individual hired is a former Vice President, Transmission for BC Hydro and advised the Office of the Auditor General as part of the review of the MDTS project).

- **Lack of contracting policies:** Since the MDTS project was completed, YEC conducted a comprehensive contracting policy project. This involved hiring an external consultant to help in the development of policies (see response to PWP/HML-YEC-1-42 for copies of these policies). In addition, YEC legal counsel was directly involved in the preparation of all major construction contracts to ensure proper mitigation of risk.

- **Inadequate financial management and project cost controls:** YEC devoted significant resources to the monitoring of project costs. At the construction approval stage, YEC's Board of Directors required management to commit to reporting back to the Audit Committee on cost and progress every 6 weeks (roughly twice as frequently as normally scheduled). As well, extra resources in financial administration and senior financial management were dedicated to the project to ensure satisfactory results.

(e)

Currently, if the Mayo load is average (1 MW) and the Mayo plant is at its maximum output (4.9 MW), than the maximum power that can be transmitted towards Stewart Crossing is 3.9 MW. The winter Dawson load is approximately this amount.

The transmission line between Mayo and Stewart Crossing is capable of carrying 11 MVA.



Mayo-Dawson City Transmission System Project

February 2005

Office of the Auditor General of Canada
Bureau du vérificateur général du Canada

All the audit work in this Report was conducted in accordance with the standards for assurance engagements set by the Canadian Institute of Chartered Accountants. While the Office adopts these standards as the minimum requirements for our audits, we also draw upon the standards and practices of other disciplines.

This Report is available on our Web site at www.oag-bvg.gc.ca.

Ce document est également disponible en français



Auditor General of Canada
Vérificatrice générale du Canada

To the Honourable Speaker of the Yukon Legislative Assembly:

I have the honour to transmit herewith my report on the Mayo-Dawson City Transmission System Project to the Yukon Legislative Assembly in accordance with the provisions of section 35 of the *Yukon Act*.

Sheila Fraser

Sheila Fraser, FCA
Auditor General of Canada

Vancouver, 7 February 2005

Table of Contents

Main Points 1

Introduction 3

Yukon Energy Corporation and its operating environment 3
The Mayo-Dawson City transmission system project 4
Focus of the audit 4

Observations and Recommendations 5

Feasibility and cost-benefit analysis 5

Project scope and costs not adequately defined 5
Substantial risks using the "design-build" approach 7
Project not subject to a comprehensive review prior to implementation 8

Overall project management 9

Lack of established project management policy and procedures 9
Roles, responsibilities, and accountability not clearly defined 10

Contracting practices 12

Lack of contracting policy and clear contracting procedures 12
Significant deficiencies in contracting for construction and services 12

Management of project implementation 16

Numerous problems encountered during project implementation 16
Significant claims in dispute despite agreement that project was complete 20

Financial management and project cost controls 21

Inadequate financial management and project cost controls 21
Significant cost overruns incurred 22

Adherence to original specifications 23

Deficiencies remain in final delivered product 23

Rate review by the Yukon Utilities Board 25

Need for a comprehensive examination of project costs 25

Conclusion 25

About the Audit 27



Mayo-Dawson City Transmission System Project

Main Points

1. The Yukon Energy Corporation recently completed the Mayo-Dawson City transmission system project to provide hydro power to Dawson City customers. The project was essentially justified on the basis of cost savings that would result from replacing diesel-generated power with hydro power. While savings may still be realized, the project was not well managed by the Corporation. This resulted in significant delays, cost overruns, and design and construction work that did not meet the Corporation's intent. In particular, the Board of Directors and management did not ensure that the Corporation established sound policies and practices or provided sufficient oversight and control over the implementation of this project. We identified

- shortcomings in defining the project scope and costs;
- substantial risks in using the chosen construction approach as the Corporation did not have the required experience and expertise;
- weak project management;
- significant deficiencies in contracting for construction and services; and
- inadequate financial management and project cost controls.

2. The Yukon Energy Corporation estimates that the total cost of the project is about $36 million, representing a cost overrun of about $7 million. However, this amount does not take into full account significant claims by the construction contractor and counterclaims by the Corporation that were still unresolved at the time of our audit.

Background and other observations

3. The Yukon Energy Corporation is the primary generator and transmitter of electrical energy in the Yukon. The Corporation serves customers living in and around Dawson City, Mayo, and Faro. It also sells power to another utility, which in turn distributes the energy to other Yukon communities, including Whitehorse.

4. In June 2000, the Corporation's Board of Directors approved the construction of a wood-pole transmission line to be completed before the end of 2002 and designed to transmit hydro power from Mayo to Dawson City, about 223 kilometres away. The scope of the project also included the construction of a new substation and modifications to two existing substations. Until this transmission system became operational in

September 2003, the Corporation supplied its customers in Dawson City (population about 2,000) with electrical energy generated from its local diesel engines. In replacing diesel with hydro power, the Corporation has almost eliminated its use of diesel generation.

5. Like any corporate body, the Corporation is expected to follow good management practices and employ sound project management principles. As a subsidiary of a government corporation, the Corporation operates at arm's length from the Yukon government. It is not subject to the same rules as government departments. However, government corporations and their subsidiaries are still a part of the government program family and subject to the same principles of corporate governance and accountability. This report provides an opportunity for the government to examine and, where necessary, strengthen the governance and accountability of government corporations and their subsidiaries.

Introduction

Yukon Energy Corporation and its operating environment

6. The Yukon Energy Corporation (YEC or the Corporation) is the primary generator and transmitter of electrical energy in the Yukon Territory, which has a population of about 30,000. The YEC is a subsidiary of Yukon Development Corporation, a government corporation owned by the Government of Yukon. The Yukon government appoints the members of the Board of Directors of the Yukon Development Corporation (who are also members of the YEC Board of Directors). The YEC Board of Directors delegates responsibility for the day-to-day business affairs to the President and Chief Executive Officer and to other senior managers. The YEC has about 66 employees.

7. Although the YEC was established in 1987 to take over electrical generation facilities previously owned by the federal government's Northern Canada Power Commission, it was not until 1997 that the YEC decided to operate and manage its own assets and hire its own staff. In its initial 10 years, the YEC contracted with the Yukon Electrical Company Limited—a private, investor-owned utility—to manage and operate all YEC facilities.

8. There are about 15,000 electricity customers in the territory. The Corporation directly serves about 1,700 of these customers—most of them living in and around Dawson City, Mayo, and Faro. Indirectly, the Corporation provides power to many other Yukon communities, including Whitehorse, through the Yukon Electrical Company Limited, which buys power from the Corporation and sells the energy to retail customers in the territory.

9. The Corporation has the capacity to generate 75 megawatts of power from its hydro facilities at Whitehorse (40 megawatts), Aishihik Lake (30 megawatts), and Mayo (5 megawatts). Its diesel generators can generate 39 megawatts. In addition, a small amount comes from wind turbines. As a public utility, its activities are governed by the territorial *Public Utilities Act*, the *Business Corporations Act*, and the *Waters Act*. The operations of the Corporation are also governed by the Yukon Development Corporation Regulation made under the *Yukon Development Corporation Act*. For example, to develop or acquire new transmission lines above a certain voltage, the Corporation is required to obtain approval from its parent corporation and the minister responsible for both the Yukon Development Corporation and the YEC.

10. Under the *Public Utilities Act*, the Yukon Utilities Board, a quasi-judicial board appointed by the Yukon government, is responsible for regulating utilities in the Yukon. The Yukon Utilities Board deals with issues that include rate changes and factors affecting rates, as well as customer service issues. For example, it may conduct a public review of general rate applications from utility companies. The review examines a utility's revenues and its costs of providing electricity, and the findings are used to establish rates. The current electricity rates were set in 1996–97, with several revisions in subsequent years.

The Mayo-Dawson City transmission system project

11. Since 1951, the Corporation's Mayo hydro facility has served customers in central Yukon. The facility originally supplied electricity to a mine and communities in Mayo, Keno City, and neighbouring areas. However, the mine was closed in 1989, leaving a surplus of about three megawatts of hydro power at the Mayo facility for a number of years. In 1991, the Yukon Electrical Company Limited assessed the feasibility of a transmission line to make use of the surplus power. In 1992, the Yukon Utilities Board held a hearing on the capital resource plan of the two companies, but recommended that no further studies on the proposed transmission line be performed unless there was a sufficient change in demand. From 1991 to 1997, electricity sales in Dawson City increased by about 29 percent. It was not until 1998 that the Board of Directors of the Yukon Development Corporation directed the YEC to undertake a full feasibility study of the proposed transmission line.



Workers mount a crossarm on a wood pole, which is used for the transmission line.

12. In June 2000, the YEC Board of Directors approved the construction of a wood-pole transmission line at a projected cost of $27,246,000 (2002 dollars). The project was to be completed before the end of 2002 and would transmit hydro from Mayo to Dawson City, a distance of about 223 kilometres. The transmission line, with a design capacity of 15 megawatts, would serve a population of approximately 2,000 and carry an initial peak electrical load of about 2.8 megawatts. In August 2000, the minister responsible for both the Yukon Development Corporation and the YEC approved the project. The scope of the project included the construction of a new substation at Callison (a subdivision of Dawson City) and modifications to two existing substations, one at Dawson City and another at Mayo. A key objective of the project was the long-term reduction of electrical rates through greater use of the existing hydro station in Mayo to replace expensive diesel generation in Dawson City.

Focus of the audit

13. We undertook this audit at the request of the YEC Board of Directors. We looked at key aspects and activities of the Mayo-Dawson City transmission system project. Our audit focussed on specific areas, including

- feasibility and cost-benefit analysis,
- overall project management,
- contracting practices,
- management of project implementation,
- financial management and project cost controls, and
- adherence to original project specifications.

While this report refers to various contractors, our comments and conclusions about management practices and actions refer only to those of the Yukon Energy Corporation. We did not audit the records of private sector contractors. Consequently, our conclusions cannot and do not pertain to any management practices that contractors followed.

For more information on our audit, see **About the Audit** at the end of the report.

Observations and Recommendations

Feasibility and cost-benefit analysis

Project scope and costs not adequately defined

14. YEC officials regard the Mayo-Dawson City transmission system as the single largest capital project the Corporation has ever undertaken. We found that the Corporation lacked the experience and expertise to carry out a project of this nature and magnitude. In total, it spent about $1.6 million on needs and feasibility analyses and preliminary engineering. While the need for the project and its feasibility and benefits were well justified, we found that the project scope and costs were not adequately defined in the feasibility study and cost estimates.

15. In May 1998, the Board of Directors of the Yukon Development Corporation authorized an amount of $400,000 to support the YEC's completion of a full feasibility study and a plan for the conceptual design, implementation, and financing of the proposed project. The YEC completed the feasibility study, which looked at different electrical options and economic conditions. The study identified an increase in demand for electricity in the Dawson City area, a decrease in interest costs, and an increase in diesel fuel prices. The study estimated that the project would cost $21 million (1998 dollars).

16. In April 1999, the Corporation hired an engineering firm to complete a peer review of the feasibility study. The review indicated that the estimated, overall project costs may have been understated by $2 million to $3 million. In April 2000, the Yukon Government's Department of Economic Development reviewed the economic assumptions and methodology used in the study and found them to be reasonable.

17. In July 1999, the YEC obtained approval from its board of directors to prepare preliminary engineering and to incur costs up to a maximum of $1.65 million, on the understanding that these expenses would become a cost of the project, should it proceed to completion. In late 1999, the Corporation selected an engineering firm to do the preliminary engineering and cost estimates.

18. In the spring of 2000, the engineering firm came up with an estimated cost of about $25.5 million (2000 dollars) for the project—$23 million for construction and $2.5 million for internal costs. On 27 June 2000, the YEC Board of Directors approved the construction of the project at $27,246,000 (2002 dollars)—$23,175,000 for construction, $1,825,000 for internal costs, and $2,246,000 for interest during construction and an inflation allowance.

19. According to the information submitted to the Board, the estimated $1,825,000 for internal costs would include a wide range of items such as

- project management,
- staff costs,
- tender preparation,

- evaluation and selection of contractors,
- costs for permits,
- financial and contract administration,
- accounting and reporting, and
- a legal survey.

The estimates appear to have been understated, given that the Corporation had already been authorized to spend up to $1.65 million to perform a feasibility study and initial design work. Nor did the estimate clearly identify as potential project costs other items such as legal and insurance costs during the construction phase.

20. A point-form project summary proposal was presented to the responsible minister in July 2000. It showed that the project was expected to save about $14 million over the life of the project (40 years) compared with the continued use of diesel. The project was also expected to generate about $4.5 million in employment opportunities for First Nations and local businesses. It would also reduce diesel emissions.

21. The YEC's analysis of cost savings showed that the present value of the costs associated with the continued use of diesel over 40 years was an estimated $42,184,000. In comparison, the Corporation estimated the present value of the costs of the transmission system over the same period at $27,964,000. Replacing diesel-generated power with hydro power would produce a net savings of about $14 million.

22. In this analysis, the YEC assumed the net capital cost for the project to be about $23 million instead of the estimated total of $27.246 million. This was done because its parent corporation (the Yukon Development Corporation) would provide $4 million in contributions. We believe that it would have been appropriate to consider the full cost in the analysis. We noted that the cost analysis did not include the capital costs needed to keep the diesel plant available as a standby operation. The YEC explained that this cost was not included in the project scope or budget because it was expected to be very modest. In the end, it amounted to about $285,000.

23. In June 2000, the YEC Board of Directors also requested the Yukon Development Corporation to provide a repayable contribution of up to $900,000 for the installation of a rural electrification infrastructure. In February 2001, the YEC Board of Directors authorized additional funding of up to $500,000 for conductor upgrades, subject to receiving a non-repayable contribution from its parent corporation. The Corporation subsequently received these contributions. With the $400,000 originally approved by the Yukon Development Corporation for a feasibility study and $27,246,000 for construction, the authorized costs associated with the project totalled $29,046,000.

24. In August 2003, the President of the Corporation at the time advised the YEC's Board of Directors that the break-even point for the project was about $40 million. However, we could not find any analysis to support this assertion. The Corporation provided us with data showing that projected over 40 years,

the estimated present value of revenues from the Dawson City area is about $44.6 million. The present value of operating costs of the transmission system projected over the same period is about $6.4 million. Our analysis suggests that the investment in this project could be justified if the capital costs did not exceed $38.2 million.

25. In summary, it appears that estimates of project costs were understated. In particular, potential internal costs were not clearly identified and budgeted for. Capital costs of keeping the diesel plant available as a standby operation were not included in the estimate. As we explain later in the report, many other changes were made to the scope of the project during the construction. It is important that the Corporation define the scope and identify the costs of capital projects adequately in seeking approval for projects.

26. **Recommendation.** To avoid underestimating total project costs, the Yukon Energy Corporation should ensure that the scope and costs of capital projects are adequately defined and identified when seeking project approval.

Management's response. The Corporation has recently improved its capital project processes. An interdepartmental Project Review Committee now reviews all capital project plans and makes recommendations to the board of directors for approval. Projects, especially larger ones, have detailed descriptions of scope and forecasted costs.

Substantial risks using the "design-build" approach

27. The proposal to the YEC Board of Directors in June 2000 suggested a single contract to construct the project using the "engineer, procure, construct, and manage" approach. The proposal also indicated that management planned to proceed with a small project management team that would include a term employee or contractor who would act as the project manager. The YEC selected this approach in the belief that it would reduce the time needed to complete the project and minimize the need for in-house staff involvement. However, it does not appear that the board of directors was fully briefed about the risks associated with using the "engineer, procure, construct, and manage" approach, later called the "design-build" approach.

28. In a June 2000 summary report, the engineering firm hired to do preliminary engineering and cost estimates identified three possible approaches to project delivery:

- design-build (turnkey);
- design, supply, and installation; and
- construction management.

29. The engineering firm cited many disadvantages and few advantages to using the design-build method for this project (Exhibit 1). For example, a disadvantage of the design-build method is that project risk is assigned to only one contractor. The engineering firm recommended that the project be delivered using the construction management approach, in which the detailed design is completed before contracts are issued, and the Corporation has direct control over the project schedule. However, despite the advice of

Exhibit 1 Key points in the engineering firm's analysis of advantages and disadvantages to using the design-build approach for the Mayo-Dawson City transmission system project

Advantages	Disadvantages
• Firm commitment to cost, time, and scope of construction • Single contract for the Corporation • Minimal need for YEC resources • No need for detailed technical input from the Corporation because the system is defined by a performance contract	• Design-build contractor not a local company • Total project scope not known (which can lead to cost overruns) • Limited opportunity to package work for small local contractors • Limited owner involvement once design-build contract is awarded • Project risk assigned to one contractor who must incorporate it in the tender price • Limited opportunity for First Nations involvement • Loss of design-build advantage because designer and constructor are not located together in the same area • Potential for conflict of interest, since designer and builder are from one company • Project bonding requirements will exclude medium-sized, but very capable contractors from participating • Large contractors could bring affiliated labourers, increasing overall cost

Source: Yukon Energy Corporation (based on a report prepared by the engineering firm hired by the Corporation)

the engineering firm, the Corporation's management recommended that the Board of Directors approve the design-build approach.

30. In this case, the YEC may have expected to benefit from the advantages of the design-build approach. However, it appears to have underestimated the associated risks as it lacked experience in using this approach. As we explain later in the report, the Corporation engaged more resources to manage the project than would normally be expected for a properly executed project.

Project not subject to a comprehensive review prior to implementation

31. Under the *Public Utilities Act*, the Commissioner in Executive Council may, by order, designate an energy project as a regulated project when the project is considered to be significant. An energy project includes any plant, smelter, refinery, or other undertaking or facility designed to use, convert, or process an energy resource. If an organization intends to construct a regulated project, it must apply to the appropriate minister for an energy project

certificate. The minister will then refer the application to the Yukon Utilities Board for a review.

32. When the minister responsible for the Yukon Development Corporation and the YEC approved the Mayo-Dawson City transmission system project in August 2000, the Yukon Development Corporation advised the minister that a transmission line did not qualify as an energy project as defined in the legislation. It also indicated that the YEC considered the risk of a problematic decision or an intervention by the Yukon Utilities Board to be low and manageable. As a result, the minister did not refer the project to the Yukon Utilities Board for review at that time. In January 2001, the Yukon Utilities Board indicated that it agreed with the YEC that there was no legal requirement for the board to approve the construction of the project or assess the prudence of any expenditure until such time as the Corporation sought to recover the costs of the project.

33. While there was no requirement for a review by the Yukon Utilities Board, such reviews are mandatory for capital projects in some other jurisdictions such as the Northwest Territories and British Columbia. They provide an independent assessment and critique of a proposed project, which can lead to improvements in the project. Such a review would have provided the Corporation with some assurance that the regulator would not raise major objections to the project after it had been completed—if it were carried out as approved.

34. In view of the significant expenditures and risks involved in major capital projects, we believe that it would be prudent for the YEC to request that the responsible minister seek an order to designate future projects of this nature and magnitude as regulated projects. This would provide for a review by the Yukon Utilities Board and, if necessary, a public hearing before the project can be implemented. The Corporation has advised us that if the projected cost of a capital project exceeds a specified threshold, it will voluntarily submit the project to the Yukon Utilities Board for review before the project proceeds.

35. **Recommendation.** The Yukon Energy Corporation should request that the responsible minister seek an order from the Commissioner of the Executive Council to designate future major capital projects as regulated projects, in accordance with the *Public Utilities Act*, so that such projects are reviewed by the Yukon Utilities Board and public hearings are held, if necessary, before the projects proceed. The minister may wish to consider proposing legislative amendments to require that all major capital projects be reviewed by the Yukon Utilities Board prior to approval.

Management's response. 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.

Overall project management

Lack of established project management policy and procedures

36. We expected to find a project management policy that established consistent standards for the designation, authorization, financial control, and

conduct of capital projects. However, the Corporation does not have a project management policy, and so it lacked clear standards and procedures to implement this transmission system project. It is important that the board of directors and management establish sound policies and practices and provide oversight and control over the management and operations of the Corporation.

Roles, responsibilities, and accountability not clearly defined

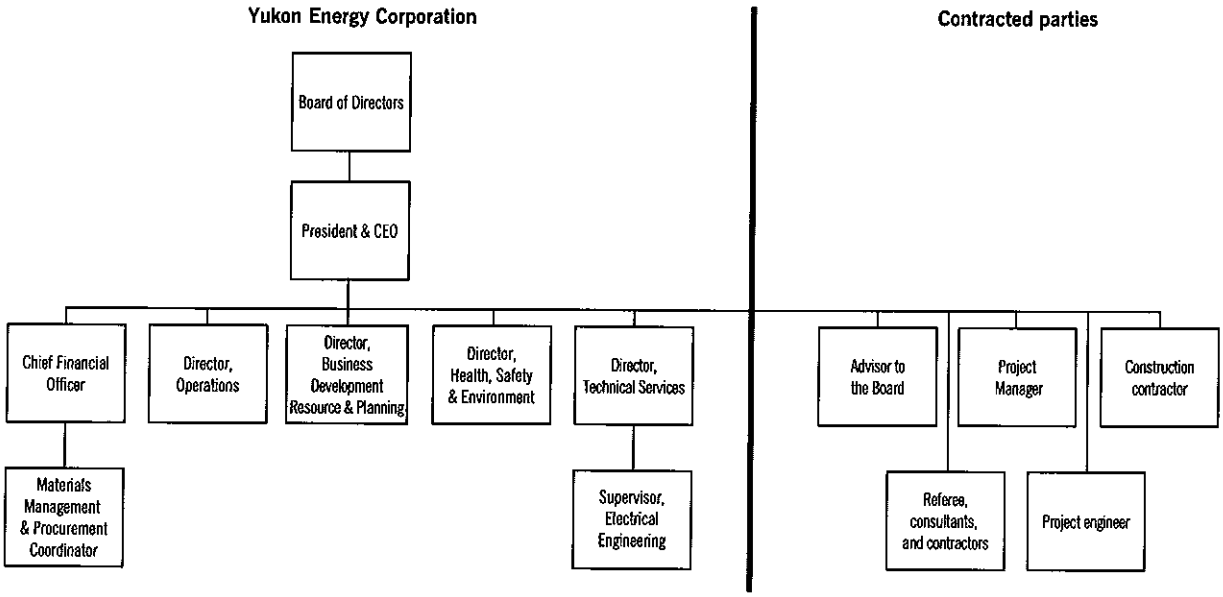
37. We expected to find a project brief with a statement of objectives that clearly defined roles, responsibilities, accountability, implementation approach, detailed budgets, and controls for this capital project. However, we did not find such a document. Instead, there were bits and pieces of information about the project management team and about lines of communication. The Corporation also referred to the responsibilities described in the construction and project manager contracts, but we found the descriptions to be inadequate.

38. We expected that there would be an initiator, a sponsor, and a project manager for a capital project. In a well-managed project, the project initiator—a manager at a senior level—is accountable for the success of the project and for ensuring that all necessary project management procedures, financial controls, and reporting requirements are in place. A project sponsor—also a manager at a senior level—is designated to support the success of the project by providing liaison with the board of directors or the senior management committee. A project manager is responsible for completing the objectives of the project.

39. It was not clear who was the initiator of the transmission system project. We found a continual change of leadership for the project between 1999 and 2004. The corporation president, who was there when the project was approved, left in September 2000. His replacement resigned in May 2001, soon after the award of the construction contract. The chief financial officer was made the next president, but he resigned in December 2003.

40. No sponsor was designated for the project. The president or the advisor to the board made progress reports to the Corporation's Board of Directors. From the beginning of the project, the Director, Technical Services (one of several key support staff to the president) was involved as a member of the project management team, which comprised several consultants and in-house staff. He prepared budgets and performed variance analysis from time to time, and he became actively involved in the project when problems arose. However, we could not find a clear description of his role. He retired in August 2003, but the Corporation retained him on contract immediately afterward to provide technical support services and to assist in resolving outstanding issues. We noted that the Corporation does not have established rules to govern post-employment contracts. The Corporation indicated that it needed to retain the services of this particular individual because his detailed knowledge of the project was critical to completing it. (Exhibit 2 shows the key players in the project.)

Exhibit 2 Key players in the Mayo-Dawson City transmission system project



41. The project manager (also referred to as the "consultant" under the construction contract called the design-build agreement) was hired on contract by the Corporation. However, it was not clear who the project manager reported to. The Corporation told us that he reported to the president during most of the project. We believe that, to successfully manage a project, a project manager must be seen to have a clear understanding of his/her role and authority. The construction contractor indicated that the project manager did not understand his role and authorities. Moreover, the project manager was not available on a full-time basis after April 2003, due to medical reasons. Although the firm acting as the project engineer provided support in the project manager's absence, the construction contractor did not view the engineering firm as the project manager.

42. **Recommendation.** The Yukon Energy Corporation should develop a project management policy to establish standards and procedures for the designation, authorization, financial control, and conduct of capital projects. In implementing capital projects, it should prepare a project brief that includes a statement of objectives and clearly defines roles, responsibilities, accountability, implementation approach, detailed budgets, and controls.

Management's response. The Corporation will undertake an audit of project management practices and procedures later in 2005. Upon completion of this review, a project management policy will be prepared. Where necessary, training will be provided to project managers. With respect to project briefs, expanded project descriptions are now prepared and reviewed by the newly implemented Project Review Committee.

Contracting practices

Lack of contracting policy and clear contracting procedures

43. The Corporation is not required to follow the general administrative policy directives issued by the Yukon Government when it contracts for construction and services. When its board of directors approved the project in 2000, the YEC only had a set of interim procurement guidelines in place. It drafted contracting guidelines in January 2002, but these guidelines had not been finalized when the project was implemented. As a result, there was no established contracting policy and no clear contracting procedures for YEC staff to follow. Specifically, we found that there were no established financial limits or thresholds above which contracts had to be awarded on a competitive basis.

44. Although the YEC did issue a request for proposals in a few cases, for this project we found that it awarded 12 contracts (each with payments over $50,000) on a sole-source basis. We found no explanation in the Corporation's files to justify this approach. The lack of a competitive process diminishes opportunities to identify the best contractor or get the best possible price for quality services. We are particularly concerned about certain contracts and payments discussed in the following sections of this report.

Significant deficiencies in contracting for construction and services

45. **Construction contract.** In October 2000, the YEC applied a set of criteria it developed to pre-qualify six firms to bid for the construction of the project. We found that the criteria were not specifically tailored to the requirements of a design-build project. Furthermore, we could not determine whether the values assigned to certain criteria were reasonable or appropriate and whether the Corporation had obtained sufficient information on the firms to make an informed decision.

46. Though in tendering the construction contract the YEC issued a request for proposals on 24 November 2000, it was not until about a month later that it sent out the design-build agreement, a key component of the proposal package. The invited firms raised many questions seeking clarification of the proposed work and, at their request, the closing date for the bids was extended from 23 January 2001 to 6 February 2001. The Corporation received three bids, but disqualified two of them for failing to comply with the mandatory requirements of the request for proposals. According to the Corporation, one disqualified firm failed to provide the required security and insurance information and to submit the exact proposal form; the other disqualified firm added conditions or qualifications to its proposal. As a result, there was only one valid bid. The YEC opted to negotiate with the firm rather than re-tender the contract. The selected firm (Chant Construction Company Inc.) was ranked lower than several other companies that had been evaluated at the pre-qualification stage.

47. At a meeting with the selected firm in February 2001, Corporation representatives identified a number of concerns about the firm's proposal. For example, they noted that it lacked several items in the scope of work set out in the proposal. They noted that the proposal had no procurement plan and

no formal safety program. In addition, some unit prices in the proposal were not consistent with the scope of the work.

48. During the construction contract negotiations in March 2001, the Corporation also became aware that the firm lacked experience in energy transmission and substation construction. For this project, the firm planned to rely on a series of individual specialists who were widely distributed throughout central Canada. It does not appear that the Corporation appropriately considered re-tendering the contract once these concerns came to light. It signed the construction contract (design-build agreement) on 11 April 2001, at a negotiated fixed price of $22,070,790.

49. Contracts for the project manager and project engineer. When the board of directors approved the project, the Corporation indicated that it would engage a contractor to act as project manager. The Corporation subsequently established an amount of $800,000 as the forecast cost of project management. It awarded a sole-source contract to one firm to act as project manager and another sole-source contract to another firm to act as the project engineer. The Corporation treated project engineering services as part of internal project management costs. By the time the project was completed, the Corporation had paid over $2.3 million in total to these two firms. It indicated to us that the project required a far higher level of project management support than had been expected. We identified significant deficiencies in these contracts—in particular, a lack of safeguards to protect the interests of the Corporation.

50. The project manager contract was not awarded on a competitive basis. In July 2000, the Corporation identified the project manager through a local human resources company, from a list of seven potential candidates. Only one candidate (Ian Hayward, principal of a firm called Windrush Engineering) was available and interested in the project. However, the Corporation did not look elsewhere for additional candidates. Initially, it contracted with the firm to provide consulting services relating to the invitation and selection of contractors for the construction of the transmission system project. The consulting work was scheduled to be from August to October 2000 and for a maximum of $30,000 (plus GST). The contract price was later increased to $70,190 for additional work, and the completion date was extended to 31 May 2001.

51. In September 2001, the Corporation entered into a project management contract with the same firm; the contract was retroactive to 1 June 2001. The Corporation would pay the project manager based on actual hours incurred in 2001 and 2002 (the project manager was expected to work an average of 150 hours per month), plus reimbursable expenses. We found that the contract did not specify a maximum price or ceiling and did not contain any provision for auditing claims.

52. Under the initial contract for consulting services and the subsequent contract with the same firm for project management, invoices submitted by the project manager show that the YEC paid a total of $424,455. Each invoice claimed a number of hours, but we did not find any detailed time

sheets submitted with the claims. We also noted that the Corporation reimbursed the project manager about $6,000 for entertainment expenses (on meals and alcoholic beverages with executives of the construction contractor and project engineering firm and with YEC staff and consultants) that were not provided for in the contract.

53. The contract with the firm acting as project engineer was also awarded without competition. It appears that no attempt was made to get competitive bids for this contract, and we found no explanation in the Corporation's files to justify this approach. We found no evidence that the board of directors approved a contract for engineering services on this project. We also noted that the project manager (Ian Hayward) was the founder of the engineering firm (Ian Hayward International Ltd.) and a director of this firm until 1995. The YEC knew of this relationship and issued the two sole-source contracts without raising any questions about it.

54. While the Corporation treated project engineering services as part of internal project management costs, using this engineering firm was contrary to the design-build concept as proposed by management—to employ a small project management team with only one contractor acting as project manager. According to the contract, under the direction of the project manager, the engineering firm's field office staff (one resident engineer and assistant, four field inspectors, and one field office manager) and staff at its head office and other locations (a resident engineer and assistant, field inspectors, principals, senior and junior engineers, draftsperson, technician, and secretary) would provide engineering services. The Yukon Energy Corporation would pay the project engineering fees, based on time spent, and reimbursable expenses. The agreement did not specify a maximum price or contain provisions for the Corporation to audit the claims if necessary. The agreement took effect on 3 May 2001, although the two parties did not sign it until September 2001. We found that the firm submitted an invoice for about $10,000 for services performed in April 2001, which indicates that it had begun work before the effective date of the contract. In our view, entering into contracts retroactively and allowing work to be performed before contracting arrangements have been completed is not an acceptable practice.

55. The contract was signed on behalf of the Director, Technical Services, by a Corporation employee at a supervisor level who did not have the authority to enter into the contract. This employee was not an officer of the Corporation. The Corporation's signing authority guidelines require one director (of the board of directors) and one officer of the Corporation to sign together to initiate expenditures of more than $500,000 for operations and maintenance (and for capital expenditures of more than $1,000,000), with the prior approval of the board of directors. At 31 May 2004, the Corporation had paid nearly $1.9 million to the engineering firm. The expenditures on this contract alone thus exceeded by far the $800,000 that the Corporation had budgeted for internal project management costs.

56. The YEC did not require the project engineer to submit any detailed time sheets to support the hours claimed, except for August 2001. For that month, concerned about the amount of time claimed for principals of the firm, the Corporation asked for a breakdown of the hours they had worked and on what matters. We also noted that in May 2002, the project manager wrote to the Corporation about the invoice submitted by the project engineer for April 2002. The project manager stated that he could support all charges except the charge for the principals' time ($10,290). He indicated that he had no yardstick by which to measure their input, other than a time sheet. Nonetheless, the project manager recommended that the claim be paid, and the Corporation paid the invoice without questioning it further. Corporation officials told us that the project engineer also provided information on the charges for two other invoices (October and December 2003) as requested by the Corporation.

57. Other contracts. We identified a number of deficiencies in other contracts related to this project. For example, in several contracts the Corporation paid the contractors more than the specified maximum contract price without having prepared formal contract amendments. In one other case, there was no written contract for goods and services involving payments of about $136,595. This was made solely on the basis of invoices submitted by the contractor.

58. In summary, we identified significant deficiencies in contracting for construction and services. The Corporation had no established contracting policy and no clear contracting procedures to provide for transparency and competition and ensure best value. It awarded many contracts on a non-competitive basis. We found that the contract for project engineering services was not properly planned for and authorized. In addition, the contracts for the project manager and project engineering services did not include adequate safeguards to protect the interests of the Corporation.

59. Recommendation. The Yukon Energy Corporation should establish and follow a contracting policy and clear contracting procedures that provide for transparency and competition and ensure best value. It should ensure that

- contracting requirements are properly planned for;
- contracts are entered into only by those who have the authority to do so;
- contracts clearly specify deliverables, maximum price, and cost ceilings;
- contracts include provisions for auditing claims, where appropriate; and
- payments are made only within authorized limits.

Management's response. The Corporation had its contracting and purchasing practices reviewed by a consultant in 2004. As a result, new contracting policies and guidelines have been developed and approved by the board of directors, which will address the points raised.

Management of project implementation

Numerous problems encountered during project implementation

60. Many problems arose during the implementation of the project. These included

- trespassing on First Nations lands,
- rerouting around the Dawson City Airport,
- disagreement over the survey data and soil conditions,
- timber removal,
- vibration problems with the transmission line, and
- unsatisfactory design documents and drawings.

As well, there were numerous disputes between the Corporation and the construction contractor. The Corporation alleged that the contractor failed to comply with certain contractual obligations, while the contractor alleged interference by the Corporation and the project manager. Some of these problems could not have been anticipated during the planning phase, but a number of them can be attributed to the Corporation's poor planning, communication, and project management. These problems resulted in additional costs, unresolved disputes between the Corporation and the construction contractor, and delays in completing the project.

61. **Violation of land use permit and trespassing on First Nations land.** The Corporation alleged that the construction contractor failed to get prior approval for temporary access to lands in the Mayo district and violated the land use permit. The Corporation also believed that the construction contractor did not apply responsible route planning practices, resulting in the trespassing on First Nations lands. Indeed, the YEC acknowledged that the contractor had cleared a parcel of First Nations land without proper authorization, and the First Nations concerned requested compensation for damages to their land. The construction contractor told us that it expected that the YEC would have obtained all necessary easements and rights-of-way as required under the contract. At the time of our audit, the Corporation was seeking an indemnification of about $119,000 from the construction contractor for the costs incurred as a result of trespassing.

62. **Rerouting around the Dawson City Airport.** The Corporation indicated that in the early planning stages (for example, during the feasibility study), it was not aware of any expansion plans at the Dawson City Airport. Shortly after design work had begun, the Corporation realized that airport expansion plans were underway and there were provisional zoning regulations introduced for the airport. This would require the rerouting of the transmission line around the Dawson City Airport. In August 2001, the Corporation considered several alternative routes and selected the Australian Mountain/Hunker Creek route to replace the original route. Based on a cost analysis prepared by the construction contractor, the Corporation estimated that the route change would cost about $600,000. In November 2001, the Corporation asked the construction contractor to price a change order for the route change. The contractor responded in May 2002 with a request for a change order of about $1.2 million, but the Corporation rejected the

contractor's estimates. By then, a substantial amount of work was already in progress. The construction contractor indicated to us that it proceeded with this change in the scope of work without insisting that all of the costs be identified and pre-approved in order to preserve the project schedule. The Corporation paid the contractor about $650,000, but it did not issue a formal change order; it felt that it would be difficult and time-consuming to assess a payment for work that had already been completed. The Corporation decided that claims by both parties would be assessed as a package after commissioning of the project. In October 2003, the contractor submitted two claims totalling about $1 million for rerouting work, in addition to the $650,000 already paid. At the time of our audit, the Corporation was disputing the two claims.



Soil conditions can affect the installation of wood poles.

63. **Survey data and soil conditions.** When the Corporation met with the construction contractor in February 2001 to negotiate the construction contract, its officials noted that the contractor's proposal did not make use of the remote survey information included in the request for proposals. The Corporation believes that this was largely because of the contractor's lack of knowledge of this type of information. Later, the project manager also indicated that, in his opinion, the construction contractor did not understand how to use the survey data. The contractor, however, claimed that the survey data were not as accurate as the request for proposals had indicated; it had therefore had to obtain the information by other means in order to complete the detailed design of the transmission line. The contractor also claimed that on-site conditions differed from the soil reports included in the request for proposal.

64. In October 2003, the contractor submitted a claim of $750,000 for costs related to inaccuracies in the survey data, and another claim of $612,630 for additional costs related to unforeseen soil conditions that affected the installation of the wood transmission poles. The Corporation is disputing these claims.

65. **Timber removal.** In March 2000, the Corporation entered into an agreement with two First Nations giving them the first right to take possession, at their own cost, of salvageable timber cut as part of this project, although they were not obliged to do so. Under the agreement, the timber had to be removed within two years after it was cut.

66. In the planning phase of the project, the Corporation did not anticipate any significant costs for timber removal and salvaging. As a result, the removal of cut timber was not included in the design-build agreement. During the construction phase, however, the Corporation had to pay about $400,000 to the contractor and the contractor's subcontractor to have timber removed to locations specified by the two First Nations. It did so to ensure that the project met the terms of the timber removal permit, which required it to clear the timber by 31 March 2002, and because the two First Nations were not satisfied with the amount of salvageable timber left for them. The Corporation claimed that the clearing methods used by the contractor's subcontractor had destroyed a lot of timber. The construction contractor, however, believes that its clearing methods were adequate and effective.



Workers install the transmission line.

67. **Line vibration problems.** After an earthquake on 3 November 2002, the Corporation investigated and analyzed vibration problems associated with the tension of the transmission line. The Corporation alleged that the line tensions are too high, leaving the transmission line susceptible to vibration under certain conditions and the possibility of premature failures. The Corporation believes that it is the construction contractor's responsibility to install dampers on the line to mitigate the effects of vibration. In October 2003, the Corporation submitted a claim of about $1 million for this alleged deficiency, which the contractor is disputing. The contractor believes that the tension of the transmission line met project specifications.

68. **Relationship between the Corporation and the construction contractor.** In April 2002, the Corporation's Advisor to the Board of Directors reported that the most serious issue at that time was the relationship between the Corporation and the construction contractor. Fundamental to this issue was a letter of March 2002 from the Corporation to the contractor's bonding company, in which the Corporation expressed concerns about how the contractor was performing relative to the contract. The contractor took exception to the Corporation's opinion and requested that the letter be withdrawn, but the Corporation refused. In October 2003, the contractor submitted a claim to the Corporation for $6 million, indicating that because of the Corporation's alleged misrepresentation to the bonding company, it had been unable to bid on several projects that would otherwise have been available to it.

69. In addition, the contractor submitted two claims to the Corporation totalling $1.65 million, alleging that the Corporation and the project manager had interfered with the means, methods, and scheduling of work by the contractor and subcontractors. At the same time, the Corporation submitted claims to the contractor totalling about $5.8 million for a late-completion penalty, costs resulting from late completion, and extra project management costs. All of these claims were unresolved at the time of our audit.

70. **Design and drawings.** Under the design-build agreement, the construction contractor was required to prepare and provide detailed construction documents to the Corporation for approval before beginning construction work at the substations. These documents were to include design drawings and specifications setting out all the requirements necessary for the proper construction of the transmission system project. But the Corporation had difficulty obtaining satisfactory design documents and drawings from the construction contractor. The construction contractor told us that a significant difference of opinion existed between the two parties as to the requisite standard to be met.

71. In some cases, the contractor asked that it be allowed to start construction before it had completed the designs and drawings. The Corporation told us it had agreed to these requests in the interest of trying to move the project forward. For example, in August 2002 it allowed civil construction work at the substations to proceed although the overall design drawings had not been completed and approved. The installation of

substation equipment followed, before concerns about the design drawings had been fully addressed. Later, having identified a number of problems, Corporation staff became concerned that the drawings being used on the work site were not accurate. When the Corporation found that there had been virtually no advancement in the drawings, it decided in early February 2003 to suspend work because of safety concerns and problems seen in the field. Meanwhile, there was no complete, detailed plan for commissioning the transmission system.

72. It took several months for the two parties to resolve the impasse over the adequacy of drawings and commissioning plans, deficiencies in construction, and other issues. In May 2003, they agreed to establish an action plan for completing the project. They also appointed an impartial referee to resolve disputes between them. On 27 May 2003, the minister responsible for both the Yukon Energy Corporation and its parent, the Yukon Development Corporation, appointed a new Chair to the Board of Directors of the Yukon Development Corporation (who also became the Chair of the YEC Board of Directors). A primary function of the new Chair was to resolve the issues surrounding the transmission system project.

73. While the original target date for project completion was 1 November 2002, the transmission system was only commissioned on 5 September 2003, which was set by the referee and agreed to by the parties. As of that date, the project achieved a substantial completion status (work was 95 percent complete) although drawings were still incomplete, and there appeared to be a number of deficiencies that remained outstanding. For example, there were issues related to improper cable terminations, inadequate building ventilation, and minor non-completed items. In January 2004, the Corporation accepted delivery of the "as built" drawings as they existed on 23 December 2003. In doing so, it agreed that the construction contractor would be deemed to have satisfied the contractual obligations with respect to the delivery of drawings.

74. In summary, we identified numerous problems during the implementation of the project. Many of them are due to the Corporation's poor planning, communication, and project management. They have resulted in additional costs, unresolved disputes between the Corporation and the construction contractor, and delays in completing the project. The construction contractor acknowledges that it bears responsibility for some of the problems encountered on the project. For example, it executed the design-build agreement without insisting on major changes to the contract knowing that there were problems with the contract documents. It believes that the design-build agreement was incoherent and did not properly articulate the expectations or responsibilities of the two parties under a conventional design-build protocol.

75. Recommendation. In implementing capital projects, the Yukon Energy Corporation should

- apply good project management practices,
- ensure compliance with contract provisions,

- issue formal change orders where necessary,
- ensure that work does not proceed unless authorized, and
- monitor work, so that when problems arise, appropriate action can be taken on a timely basis.

Management's response. The practices identified by the Office of the Auditor General are being addressed. While the deviations from the "best practices" listed are generally unique to the Mayo-Dawson project, management will ensure that the recommendations are applied to all future projects, regardless of size and complexity.

Significant claims in dispute despite agreement that project was complete

76. The design-build agreement contains dispute resolution clauses including the use of negotiation, mediation, and arbitration (with specified time limits outlined). However, we found that neither party relied on these provisions.

77. As noted already, construction work was suspended in February 2003. It was not until May 2003 that the two parties entered into a supplemental agreement in order to complete the project. As part of this agreement, they appointed the referee to resolve disputes between them. Under the design-build agreement, the two parties were expected to make all reasonable efforts to resolve disputes through negotiations. The resolution of a number of issues with the help of the referee led to the project's completion, but many claims remain unresolved.

78. On 2 October 2003, the referee directed both parties to submit their final list of claims by 15 October 2003. The construction contractor submitted a total of about $17 million in claims for numerous issues. The Corporation submitted a claim of $9.5 million for extra project management costs, delays in completion, and other issues. We make no comment on the merits of either of these claims.

79. On 16 January 2004, the two parties entered into an agreement that the project was complete and settled a number of issues. The referee's work also ended that month. At the time of our audit, there was no agreement between the two parties on how and when to settle the final claims. They did not use the provision in the design-build agreement that either party may refer a dispute to arbitration for final resolution.

80. We noted that the Corporation has incurred a significant amount of time, effort, and money engaging lawyers and consultants to assist in resolving the outstanding claims. While the Corporation has made efforts to move the claims process along, it has not had much success. Whatever the outcome, it is important that additional costs incurred by the Corporation are properly accounted for as part of the project costs.

81. Recommendation. In implementing capital projects, the Yukon Energy Corporation should make use of dispute resolution provisions in contracts and agreements to resolve disputes with contractors in an efficient and timely way.

Management's response. Management will use dispute resolution provisions where it is appropriate and in the best interests of the Corporation.

Financial management and project cost controls

Inadequate financial management and project cost controls

82. When undertaking a project similar in size and nature to the transmission system, we would expect an organization to have adequate financial management and project cost controls to ensure that the scope and costs of a project remain within budget and that all change orders and cost overruns are properly authorized. In this project, however, we identified shortcomings in these areas.

83. The Corporation's staff had difficulty reconciling the detailed budgets and variance analyses to the original cost estimates approved by the Boards of Directors of the Corporation and its parent corporation. While the YEC set up several codes in its financial accounting system to record the costs incurred on this project, we found them inadequate for monitoring and reporting project costs against budgets. In 2004, it took the Corporation several months to complete a reconciliation of the actual project costs with the original estimates and approved costs.

84. We found that internal costs were not properly controlled. According to the Corporation's data, expenditures on internal costs of this project totalled about $8.3 million although the original budget was estimated at $1,825,000 (Exhibit 3). These costs included such items as the feasibility analysis, tender preparation, internal project management, staff and travel costs, overhead costs, insurance and legal costs, consultants' and contractors' fees, and other related expenditures. For example, project management costs amounted to about $2.6 million, whereas the Corporation had budgeted $800,000; and staff and travel costs amounted to $1.1 million against the budget estimate of $50,000. The Corporation indicated that because of the numerous problems encountered during the project construction and commissioning, the project required a far higher level of staff involvement than expected.

85. Under the construction contract, the Corporation could make changes in the construction work through a change order or a change directive. A change order is a written order signed by the YEC and acknowledged by the construction contractor to authorize an addition, deletion, or revision in the scope of work or a change in project schedule or price.

86. A change directive is a written order signed by the YEC to direct an addition, deletion, or revision in the scope of work before the two parties agree on the adjustment to the contract. A change order would be recorded once both parties agreed on the contract adjustment.

87. We expected that change orders would have been formally issued for all changes in the work on which the Corporation and the construction contractor had initially agreed. The design-build agreement originally set a fixed price of $22,070,790. Subsequently, the Corporation approved nine change orders with payments amounting to about $1.3 million. However, as mentioned in paragraph 62, the Corporation paid the contractor a total of $650,000 without a formal change order. Moreover, several change orders

Exhibit 3 Summary of Yukon Energy Corporation's internal costs for the transmission system project ($ thousands)

	Original budget	Adjusted budget	Expenditures (31 May 2004)
Project management	150.0	800.0	2,567.0
Feasibility, tender preparation, licence, permits, etc.	1,525.0	1,737.5	1,649.0
Corporation staff costs	100.0	50.0	1,146.0
Legal	0.0	0.0	911.0
Contractors	0.0	0.0	818.0
Consultants	0.0	25.0	347.0
Insurance	0.0	0.0	344.0
Overhead	50.0	50.0	226.0
Materials	0.0	50.0	196.0
Other	0.0	0.0	75.0
Total	**1,825.0**	**2,712.5**	**8,279.0**

Source: Yukon Energy Corporation

were still in dispute after the project had been completed; the contractor is seeking an additional $1.1 million.

88. We noted that the Corporation paid $273,683 to the construction contractor for work performed pursuant to change directives, but no formal change orders for that work were ever made. An additional $780,371 claimed by the construction contractor for work performed pursuant to change directives was in dispute at the time of our audit.

Significant cost overruns incurred

89. We noted that the Corporation's Board of Directors received regular reports on the progress of the project, mostly through the president or the advisor to the board. Management identified potential cost overruns as early as March 2002. However, there were no controls or established procedures to authorize cost overruns and approve payments above the authorized limits for this project. There was no evidence that management ever asked the board of directors to approve any cost overruns and it never formally approved any.

90. At 31 May 2004, the Corporation had spent about $33.5 million on this project (Exhibit 4). This exceeded the authorized total costs by about $4.5 million, mainly due to scope changes (various change orders and directives), unforeseen construction contingencies (for example, earthquake investigation, trespassing on First Nations lands, and a referee to resolve contract disputes), extra project management costs, and underestimated and unbudgeted costs (for example, staff support, legal, insurance, and timber removal).

Exhibit 4 Mayo-Dawson City transmission system project—Authorized costs compared with expenditures ($ thousands)

	Authorized costs	Adjusted budget*	Expenditures (31 May 2004)
Feasibility study	400.0	0.0	0.0
Construction	23,175.0	23,865.5	23,676.0
Internal costs**	1,825.0	2,712.5	8,279.0
Interest and inflation	2,246.0	2,246.0	1,575.0
Additional items (rural electrification and conductor upgrade)	1,400.0	222.0	0.0
Total	**29,046.0**	**29,046.0**	**33,530.0**

*Adjusted budget reflects reallocations of money between categories.

**Internal costs included such items as the feasibility analysis, tender preparation, project management, staff and travel costs, overhead costs, insurance and legal costs, consultants' and contractors' fees, and other related expenditures.

Source: Yukon Energy Corporation

91. In November 2003, the Corporation indicated that the total cost of the project would be about $36.2 million, representing a cost overrun of about $7 million. However, this does not take into full account all the claims submitted by the construction contractor and counterclaims by the Corporation that were still in dispute at the time of our audit. As we indicated earlier in this report, the investment in this project could be justified if the capital costs did not exceed $38.2 million. We are concerned that the substantial cost overruns significantly reduce the savings that can be expected from this project. Coincidentally, because of recent large increases in diesel fuel prices the prospects for the benefits of this project look more promising.

92. **Recommendation.** The Yukon Energy Corporation should establish sound financial management and cost controls for implementing capital projects. Such controls should ensure that the scope and costs of projects remain within the approved budgets and that change orders and cost overruns are properly authorized.

Management's response. While the internal control systems at the Yukon Energy Corporation have generally been found to be free of material weaknesses, management acknowledges that the execution of the Mayo-Dawson project circumvented normal processes and controls. The situation should be prevented in the future as a result of process changes and improvements in corporate governance.

Adherence to original specifications

Deficiencies remain in final delivered product

93. The design-build agreement sets out in detail the requirements that the contractor must perform and adhere to in the design, construction, and commissioning of the project. It includes a statement that the intent of the agreement is to produce "first class design and construction work". It also stipulates adherence to standards of the electric utility industry.

94. As already noted, the design-build agreement clearly set out the contractor's obligation to submit drawings to the YEC for approval before commencing work. In a project of this nature, it is important that accurate, certified drawings be available before construction begins. This did not happen. Indeed, the problems encountered during commissioning and the deficiency list prepared by the Corporation showed design and wiring errors, equipment adjustment problems, and poor workmanship. The contractor, however, believes that its drawings met industry standards.

95. The design-build agreement also required the contractor to apply to the Corporation for a "certificate of total completion" once all the construction work had been completed to meet the requirements of the contract and all deficiencies had been rectified to the Corporation's satisfaction. The Corporation would then issue the certificate and pay the contractor the unpaid balance of the contract price including the performance holdback.

96. In January 2004, the Corporation issued the above certificate after the two parties had entered into the agreement mentioned in paragraph 79 of this report. The Corporation agreed to release the construction contractor from its warranty obligations under the contract in the transmission line component of the work. This release did not apply to the contractor's warranty obligations for any other component of the work, including the substation component. The Corporation also agreed that, except as otherwise indicated in the agreement made on 16 January 2004, the construction contractor would not be responsible for the deficiencies and incomplete work previously identified by the Corporation, agreed on by the two parties, or determined by the referee.

97. In agreeing on the completion of the project, the Corporation and the construction contractor came to a compromise on the drawings of the transmission system. The Corporation accepted delivery of the drawings as they had existed on 23 December 2003 and agreed to complete them itself.

98. The Corporation believes that there was a design deficiency in the transmission line, because it is susceptible to vibration as a result of the high conductor tension. This could increase the costs of maintenance and operations over the life of the project. In late 2004, the Corporation contracted with a company to install vibration dampers on the line at a cost of about $1 million.

99. The Corporation also claimed that the construction contractor did not meet contractual obligations to use certain "low loss" specifications for major pieces of electrical equipment (including transformers, reactors, and the synchronous condenser). The Corporation believes that this will result in higher costs of energy for the life of the project because the equipment installed consumes more power than was planned for and specified in the agreement. The Corporation submitted a claim of $530,000, which the contractor has disputed.

100. At the end of the audit fieldwork, the Corporation advised us that only a few outages had occurred since the transmission system became operational in September 2003. Although the design-build agreement specifically stated that the Corporation's intent was to receive "first class design and construction work," in light of the many deficiencies and problems encountered during construction and commissioning of the project it appears that this intent was not met.

Rate review by the Yukon Utilities Board

Need for a comprehensive examination of project costs

101. The YEC is committed to the position that this project will have no adverse impact on ratepayers. Considering the significant cost overruns incurred by the Corporation in implementing this project, we believe it would be important for the Yukon Utilities Board to undertake a comprehensive examination of the project's capital and operating costs as well as any outstanding problems when the Corporation seeks to recover the costs of the project. This would help to determine whether or not the project has any negative impact on electricity rates.

Conclusion

102. The Mayo-Dawson City transmission system project is the largest capital project the YEC has ever undertaken. However, the Corporation lacked the experience and expertise to carry out a project of this nature and magnitude. While the need, feasibility, and benefits of the project were well justified, the project scope and costs were not adequately defined. The YEC's Board of Directors was not fully briefed about the risks associated with using the design-build approach for this project without the required experience and expertise. Nor did the board of directors and management ensure that the Corporation established sound policies and practices or provided sufficient oversight and control over the implementation of this project.

103. The Corporation does not have a policy that establishes standards and procedures for project management. Project management was weak. Roles, responsibilities, and accountability were not clearly defined. Numerous problems and significant delays were encountered in implementing the project. Deficiencies remain in the final delivered product. It does not appear that the intent of the Corporation—to receive first class design and construction work—was met.

104. We identified significant deficiencies in contracting for construction and services. There was no established contracting policy to require that contracts be awarded on a competitive basis and no clear contracting procedures, including established financial limits or thresholds.

105. Financial management and project cost controls were inadequate. There were significant cost overruns in completing the project. We are concerned that the substantial cost overruns significantly reduce the savings that can be expected from this project. As the YEC is committed to the position that this

project will have no adverse impact on ratepayers, we believe it would be important for the Yukon Utilities Board to undertake a comprehensive examination of the project's costs when the Corporation seeks to recover them.

About the Audit

Objectives

To determine the extent to which the Mayo-Dawson City transmission system project

- was adequately defined in terms of scope, costs, and benefits;
- was subject to appropriate project management, control, and accountability; and
- resulted in a quality product that met original specifications.

Scope and approach

The audit examined key aspects of the Mayo-Dawson City transmission system project activities, including

- feasibility and cost-benefit analysis,
- overall project management,
- contracting practices,
- management of project implementation,
- financial management and project cost controls, and
- adherence to original project specifications.

We reviewed project files, financial management systems, and project cost control systems. We also interviewed program managers and corporation officials. We did not examine the records of the contractors.

Audit criteria

- The need for the project should be well defined and should be directly related to corporate objectives.
- Feasibility and options that could potentially fulfill defined requirements should be identified and analyzed.
- The selected option for developing and implementing the project should be translated into a project that clearly states objectives and contains work packages, schedule, budgets, organization, and controls.
- Contracting should
  - conform to established policies;
  - be based on requirements arising from the project definition;
  - incorporate authorized changes; and
  - be in keeping with well established principles including project organization, budgeting, scheduling, control, and reporting.
- The design-build process should be clearly defined in terms of design and drawing requirements, and those requirements should be communicated to the parties responsible for design.
- Overall project management should be in accordance with well established principles of project management.
- The project requirements should be satisfied and the project commissioned with minimum cost and disruption.
- The end product should meet the original specifications.
- Appropriate project accounting and financial controls should be in place.
- Responsibility and accountability should be clearly defined and communicated.

Audit team

Assistant Auditor General: Ronald C. Thompson
Principal: Eric Hellsten
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Lana Lin

For information, please contact Communications at (613) 995-3708 or 1-888-761-5953 (toll-free).

REFERENCE: **Page 8 of the Application**

TOPIC: **CSTP Connection of Minto Mine and Pelly Crossing Loads**

PREAMBLE:

"Net revenue losses due to delays in final connection, Minto Mine and Pelly Crossing. ($197,000 approximately).

QUESTION:

a) Please describe in detail what caused YEC to be delayed in connecting the Minto mine load.

b) Please describe in detail all scope changes in the construction of the CSTP to Minto Mines spur line and Pelly Crossing and the costs associated with each change. For each scope change indicate what alternatives were considered and ultimately selected and why.

c) Please provide a detailed explanation as to why customers through the Faro Dewatering Account should compensate YEC, due to YEC's inability to execute the planned Minto and Pelly connections on time.

ANSWER:

(a)

The CSTP Stage I/Minto Spur project was approved with a very aggressive in-service date of September 30, 2008. There was a high degree of risk due to weather factors, supply issues (over-heated economy at the time made sourcing of critical equipment on a timely basis uncertain), and regulatory matters (first project through Executive Committee screening of YESAB). The decision was made to proceed with this schedule because there was a significant upside to early completion (approximately $250,000 in new revenues per month to the benefit of ratepayers).

Right-of-way clearing and line construction were generally completed on time; however, the more complex work on substations took longer than anticipated. This was a result of key engineering personnel shortages during the detailed design phase. This resulted in some delays in the placement of orders for some of the major equipment. Also, some manufacturers were not able to meet their delivery dates. Wherever possible, management worked with suppliers to expedite delivery so as to maintain construction schedules. The shortage of personnel also caused a delay in the provision of some of the construction design details to the substation construction contractor which delayed the field work.

(b)

Scope changes addressed here related to changes made after the initial construction tenders and decision to proceed made in September 2007.

Material scope changes occurred due to the Final YESAB recommendation requirements for route adjustments at Tatchun Creek (CSTP) and the Yukon River crossing (MS). The final cost of these changes was $1.811 million and $0.218 million, respectively.

The original design called for a more complex substation at Carmacks. This was replaced by a simple switching station as a means to reduce project costs.

The original plan called for a 138kV to 25kV substation at Pelly Crossing to serve local load. Based on the modest load at Pelly and the high tendered cost of this installation ($2.5 million), the decision was made to energize the 138kV transmission line at 25kV and thereby defer the expense to Stage II.

(c)

Yukon Energy's test year revenue requirement comprises the costs to operate the system. Revenues that are not derived from secondary sales customers or the Minto mine must be recovered from other regulated ratepayers. Yukon Energy has proposed to use the residual amounts in the Faro Dewatering Account (which are effectively ratepayer funds that can only be applied under the direction of the Board) as opposed to adjusting the rate proposal to increase the requested rates. In the event the Faro dewatering account withdrawal is not approved as the source of these amounts, they

would necessarily be recovered the same as any other component of YEC's revenue requirement, through firm rates.

REFERENCE: **Tab 7, Schedule 2, Line 5**

TOPIC: **Working Capital**

PREAMBLE:

Yukon Electrical needs to understand the calculation of the lag days used in the working capital calculation.

QUESTION:

a) Please provide a complete copy of the lead lag study performed to develop the lag days of 27/365 used on Schedule 2.

b) Please confirm that the data used in this calculation was from 2005.

c) If confirmed, please explain why a more recent study using 2007 actual was not performed.

d) If not confirmed, please provide the date of the last study completed.

ANSWER:

(a)

Please see Attachment 1 to this response provided as Tab 10 to the 2005 Required Revenues and Related Matters Application.

(b)

Confirmed. The analysis used forecast 2005 data.

(c) and **(d)**

Yukon Energy has sought to maintain a simple and streamlined approach to GRA matters, to help keep regulatory costs down. For this reason, not every major analytical component of a GRA is intended to be thoroughly revised each GRA. For example,

given the recent (2005) work on depreciation and working capital, these items were not repeated for the present GRA.

There is no reason to expect a material change in revenue requirement would arise from completing another full review at this time.

Schedule 10.1
Yukon Energy Corporation
Working Capital Calculation

	Days
Average Lag in revenue collection	33
Less: average lag in payment of operating expenses	6
Net revenue lag	27

Schedule 10.2
Yukon Energy Corporation
Calculation of Average Revenue Lag

Revenue Type	2005 Budgeted Revenue ($000s)	Lag Days	Weighted Revenue ($000s)
Retail (incl Rider J)	4,783	47.84	228,811
Wholesale (incl Rider J)	20,681	30	620,430
	25,464	33	849,241

Yukon Energy's Revenue lag has decreased slightly since 1997 due to the elimination of industrial customers, which had a slightly higher than average lag, and the growth in wholesales, which have a slightly lower than average lag.

Schedule 10.3
Yukon Energy Corporation
Calculation of Operating Expense (Lead) Lag

	Expenses ($000s)	(Lead) Lag Days	Weighted Expenses ($000s)
Salaries and Wages			
Payments to Employees	5,476	7.50	41,071
Overtime and standby	438	22.50	9,855
Fuel	213	18.14	3,864
Purchased Power	38	30.00	1,140
Property taxes	250	(2.04)	(510)
Other Operating Expenses			
Insurance	910	(190.97)	(173,783)
Company benefits	943	30.00	28,288
Employee travel and expenses	475	20.00	9,506
Other	4,612	35.00	161,420
	13,355	6	80,851

The expense (lead) lag days has changed significantly from the 1996/97 GRA (14 days) due largely to a reduction in fuel expense, which had been a substantial expense that had a longer than average lag. In addition, insurance has a substantial lead, and has increased as a percentage of YEC's overall expenses.

REFERENCE: **Major Projects Over $1 million- page 5-3**

TOPIC: **Capital Projects**

PREAMBLE:

Yukon Electrical wishes to better understand the need and cost benefits associated with major capital projects proposed by YEC.

QUESTION:

a) Please fully explain YEC's capital approval process and authorities required to be obtained for its capital projects.

b) If not explained in (a) above, please explain YEC's internal reporting process for completed capital projects.

c) Please provide copies of all post completion reports for capital projects placed in service during 2005-2008. Please ensure that the final actual costs and approved costs are included in the reports.

d) Please provide detailed business cases for all projects in excess of $1M, as shown at lines 8-18 page 5-3 of the Application. Please include the cost of alternatives considered and an NPV calculation for each option. In addition, please provide copies of the tendering process used or proposed to be used for each project and identify which vendors were invited to submit a bid. Indicate what criteria were or will be used to evaluate the bids and how the final selections were made.

e) In relation to the above projects, please identify any actual or expected scope and or cost changes that have occurred and provide the reasons for these changes.

f) Please provide a list of contribution requirements for any of the above-mentioned projects and identify the party that is providing the contribution.

ANSWER:

(a) and **(b)**

The capital plan development and review process has recently been changed, and 2009 is the first year the new process will be used.

Items for future capital plans can be submitted by anyone within the Corporation. Submissions are provided to Engineering Services, and if deemed reasonable, are put in the "investigate" system. Engineering Services assigns a staff member to investigate the item. This process confirms the issue/problem and develops a range of solutions, undertaking a preliminary analysis of cost and benefits.

The item then goes into another list for consideration of inclusion in the next capital plan. A cross departmental team (the Project Review Committee (PRC)) reviews all submissions and prioritizes them according to their effect on the Corporation's goals and priorities. An initial cut is made taking into account the total resource requirements for the projects.

The remaining list is submitted to Senior Management. This list is amended or approved by Senior Management and then submitted to the Board of Directors for approval.

Upon approval by Board of Directors, projects are assigned to YEC staff and/or consultants to perform the detailed analysis including costing, scheduling and benefits. Once the best solution is selected, an Application for Expenditure is developed that includes the final project scope, estimate and schedule. This becomes the standard used to evaluate project execution. Any changes to the scope, estimate or schedule of the project must be approved by Management prior to any continued spending.

Progress on the all projects is reported on monthly, giving spending and commitments to date, schedule adherence, projected costs and any issues. Capital spending and execution updates are given to Senior Management and the Board of Directors every quarter.

(c)

For project completion reports please see Attachment 1 to this response.

(d)

As regards tendering processes used or proposed to be used for each project, as well as vendors invited and criteria to evaluate bids and how final selections were made, Yukon Energy has policies regarding competitive processes that it follows when awarding contract work to third parties; these policies are provided in response to PWP-YEC-1-42(a).

Business cases related to projects over $1 million are addressed in detail below.

Section 5.2.1 of the Application provides comprehensive information separately for each of the five projects over $1 million, and the response to CW-YEC-1-29 provides a discussion of business cases for each project over $1 million. Both the Application (at section 5.2.1) and the response to CW-YEC-1-29 note that business cases for four of the five projects over $1 million were extensively reviewed during the 20-Year Resource Plan hearing process as well as during subsequent regulatory review processes. Section 5.2.1.2 of the Application addressed the comprehensive business case for the Minto diesels, which were reviewed as part of the PPA hearing process, but which the Board has not previously recommended. Further discussion of the Minto Diesels was provided in response to to YUB-YEC-1-36.

Recommendations were provided by the YUB to government as part of the Resource Plan hearing process (e.g., CSTP, Mirrlees Diesel rebuilds at Whitehorse and Faro, and Aishihik 3rd Turbine), and as part of the Part 3 hearing process (e.g., CSTP Stage 1 and also Aishihik 3rd Turbine update). These extensive earlier reviews addressed the rationale, options, and initial cost estimates, as well as benefits and potential impacts of the projects on ratepayers. The recommendations of the YUB from each of these proceedings is part of the public record, and the updated information provided in Section 5.2.1 has not fundamentally changed the earlier rationale and business case for each of these projects.

In Order 2009-4, the Board directed YEC to provide the portions of the 20-Year Resource Plan that it considered relevant to answer this information request. The

following references from the Resource Plan hearing process are provided as support for the business case for each of the noted projects. (Note materials filed during the Resource Plan hearing process, including the 20-Year Resource Plan are available on the Board's website at http://yukonutilitiesboard.yk.ca/proceedings/yec_20/).

Pages 7-11 of the Summary section of the 20-Year Resource Plan provides an overview of near term options to address near term requirements and opportunities to 2012 and to provide for over 21 MW of new WAF firm winter capacity by 2012. These options included Whitehorse Mirrlees, Carmacks-Stewart Transmission Project and Aishihik 3rd Turbine. Chapter 4 of the Resource Plan addresses in detail the near term capacity requirements, including planning approach and timeline and a review of requirements, options, assessment of options and proposed actions. Each of the major projects over $1 million discussed in Tab 5 of the Application, except for the Minto Diesels, are discussed in detail in this chapter. Appendix C of the Resource Plan filing also provides a detailed assessment of Aishihik 3rd Turbine under various load scenarios.

Subsequent to filing the 20-Year Resource Plan, further supplementary materials were filed including the following:

- **Supplementary Materials** (filed May, 2006) – this filing provided an update on Resource Plan information related to the Whitehorse Diesels (Tab 1 of document), the Carmacks-Stewart Transmission Project (Tab 2 of document) and Other Topics (Tab 3 of document) which included a discussion of Aishihik 3rd Turbine Cost Estimates at S.3.1.1.

- **Exhibit B-16** (filed November, 2006) – provided updated information for the Whitehorse Mirrlees (pages 3-6), and for the Carmacks-Stewart Transmission Project (pages 6-12).
    - The discussion of the Mirrlees Extension Project included discussion of the Faro Mirrlees as "a suitable candidate for rehabilitation consistent with the Whitehorse Mirrlees" and an assessment of the benefits of proceeding with the Faro rehabilitation. Table 2 provided at page 5 of the document set out the capacity requirements and Yukon Energy's updated proposals to meet these requirements with Faro Mirrlees Rehabilitation in 2007, Whitehorse Mirrlees Life Extensions in 2008, 2009, and 2010, Carmacks-Stewart Transmission Line in 2009 and Aishihik 3rd turbine in 2009. The resulting system balance is shown in the second column from

the right of the sheet. The column to the far right describes the system in the event that the full interconnection of Carmacks-Steward does not occur in 2009 as planned.

- The discussion of the CSTP included an update on the YESAB filing and a discussion of alternatives to the project, as well as updates related to Minto and Carmacks Copper mines and project economics (page 9-12). This included a discussion of capital costs and ratepayer benefits.

Subsequent to the Resource Plan hearing the CSTP economics were reviewed as part of the Minto PPA hearing and as part of the Part 3 Hearing. The Part 3 Application related to this project included the following material relevant to the business case for the CSTP (See, Application for an Energy Project Certificate and an Energy Operation Certificate regarding the Proposed Carmacks-Stewart Transmission Project):

- Summary of project economics is provided at page 7.
- Assessment of justification and need for the project (pages 12-15).
- Assessment of risks (pages 15 – 19) including assessment of both Stage 1 risks and Stage 2 Risks.
- Assessment of effect of project on ratepayers (pages 19 – 20).

Exhibit B-9 (provided as Attachment 1 to UCG-YEC-1-17(a)) filed during the 2007 Part 3 hearing process provides a summary of updated Aishihik 3rd Turbine Assessment cases after consideration of the $5 million government contribution as then announced.[1]

Section 5.2.1.2 of the GRA Application also addressed the comprehensive business case for the Minto Diesels, which were reviewed as part of the Minto PPA hearing process, but which the Board had not previously recommended. Further discussion of the Minto Diesels was provided in response to YUB-YEC-1-36 filed during this GRA process.

[1] Specifically, Table 2 in Exhibit B-9 shows the costs and benefits of this project with in service in 2010 at a gross cost of $7.7 million, the $5 million government contribution, no CSTP Stage 2 in place, and only the Minto mine as a major new industrial load. NPV ratepayer savings from the project under these assumptions were estimated at approximately $8 million over the project lifetime.

The response to YUB-YEC-1-8 filed during the PPA hearing process notes the following:

> At the time that the initial 20-Year Resource Plan was prepared the potential acquisition of the Diesel Units was not considered; however, prior to the Resource Plan Hearing, YEC filed interrogatory responses (YUB-YEC-2-10(f)) which identified the potential option of purchasing four high speed diesel units (6.4 MW) from Minto at the Mine site as part of the PPA negotiations. During the hearing Yukon Energy clarified the basis under which it may, as part of the PPA, acquire control of these diesel units that will be surplus to the Mine's needs after YEC starts delivery of grid power.[2]

The Board provided specific comments and recommendations on the CSTP, Aishihik 3rd Turbine, the Whitehorse Mirrlees and the Faro Mirrlees in its Report to the Minister in Executive Council re: the YEC 20-Year Resource Plan filed January 15, 2007[3]. Further comments on the CSTP were provided in the Report on Application by Yukon Energy Corporation for an Energy Project Certificate and an Energy Operation Certificate regarding the proposed Carmacks-Stewart Transmission Project provided in May 31, 2007.[4]

(e)

These projects are described in section 5.2.1 of the Application. There have not been any scope changes to any of the projects since the Application was filed. Any cost changes that have occurred for these projects, beyond what is addressed in the Application (at section 5.2.1), have been reviewed in the following responses:

- **CSTP/MS** – See response to YECL-YEC-1-9(b).

[2] YEC clarified that any such arrangement would involve YEC control and ownership of the units, and not an IPP type of arrangement. See discussion with Mr. Pinard (transcript p. 96, line 1 to p. 97, line 22) and with Mr. Buonaguro (transcript p. 265, line 24 to p. 269, line 7). Evidence presented during the hearing reviewed potential benefits of mine site diesel generation at times when mine loads require use of diesel generation (e.g., reduced line losses, cost savings due to reduced diesel generation requirements, less pollution and less greenhouse gas emissions.

[3] See Section 6.3 and 6.4 (Pages 29-30) for discussion and recommendations related to Aishihik 3rd Turbine; Sections 6.7 and 6.8 (pages 31-33) for discussion and recommendations related to the CSTP; Section 6.9 and 6.10 (pages 33-35) for discussion and recommendations related to Mirrlees.

[4] The report and recommendations addressed the need for the CSTP, as well as risks facing the CSTP and alternatives to the CSTP Specific discussion and recommendations related to Aishihik 3rd Turbine were provided at pages 6-7. Specific discussion and recommendation related to CSTP Stage 2 were provided at pages 8-9.

- **Faro Mirrlees Diesel** – See response to YUB-YEC-1-36(d).

- **Whitehorse Mirrlees** – Costs for WD3 are still expected to approximate the amounts estimated in the GRA. (See YUB-YEC 36(e); business case for Mirrlees is discussed in YUB-YEC-1-34(e)).

- **Minto Diesels** – Since the GRA filing there have not been any scope or cost changes to the Minto Diesels. (See response to LE-YEC-1-52; the business case of the Minto Diesels is discussed in YUB-YEC-1-34(d)).

- **Aishihik 3rd Turbine** – See response to YUB-YEC-1-36(h).

(f)

Contribution requirements as currently known for these projects are listed in the Application, Section 5.2.1, and the relevant parties identified.

YUKON ENERGY

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Post-Completion Project Report

Project Title:	**L170 Line Assessment**		
Project Manager:	Albert Schwarz	**Business Plan $:**	$140K
PID #:	P05-039	**Pre-start Estimate:**	$188K
Work Order #:	C06032	**Project Final Cost:**	$214K
Project Start Date:	March 6, 2006	**WO Closed Out?:**	Yes
Project Completion Date:	Sept 30, 2007	**Turnover to?:**	Leo Poile
Planned Start Date:	Summer 2007	**Turnover Complete?:**	YES
Planned Completion Date:	Dec 2007		

Yr later to get costs in line.

1. **Project Description:**
   Description of problem and why this should be undertaken:

   This line is getting old; it is now about 30 years since it was built. We should have an assessment done for future planning and prioritizing of the work needed to maintain it. The best patrol that can be done is from the ground structure by structure.

   As part of the scope of the TX line assessment project, various stakeholders within YEC have different requirements which will need to be captured for the project tender. A preliminary list of stakeholders and associated needs that can be met by this project include:

   - Land Base (Roxanne S/W) – collection of UTM location data for each structure, as well as at least one digital photographs of each structure.

   - Operations/Transmission (Jack Weir) – Prioritized list of issues and maintenance requirements for the entire line, assessment of brushing for entire line, digital photo of each issue. Evaluate remaining life expectancy of TX line, structures, insulators, and components. Place/replace structure tags. Provide data for understanding effectiveness of past maintenance practices (Fixes that did not fix…)

   - Tech Services (Alex Love), Planning (Hector Campbell) – Infrastructure Plan Report – Details 20 year life-cycle plan for the TX line, including upgrading and major repair or replacement options. Evaluate remaining life expectancy of TX line, structures, and components. Data to be used for capital project planning.

2. **Outstanding Deficiencies** (description & responsibility)
   None. Reports and data accepted by operations as meeting their stated needs.

3. **Components that went well?**
   We chose and hired an excellent contractor who was able to work with us, and understand and anticipate our needs as the project progressed.

   Excellent quality of work.

   Expanded the scope of the project to assess L170 to riverside and L172 to Mac Sub with contract change orders, as the contractor completed the original scope of work earlier than expected.

4. **Problems encountered?**
   Cost of entire line assessment out of budget.

   Tried to hire a contractor on a fixed charge basis where the scope of the difficulties that the contractor might encounter are largely unknown – bidders were either very high to cover contingency, or reluctant to bid.

   Timing of tender documents needs to be early enough in the year to allow contractors to arrange for the years work ahead of time…tenders in 2006 went out too late for a successful year.

5. **Reasons for cost and/or time variances?**
   Timing of tenders in 2006 was too late to solicit competitive bids for that year.

   Ballpark estimate for costs was far too low (by about half).

YUKON ENERGY

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Post-Completion Project Report

Project Title:	South Fox Lake PT Substation		
Project Manager:	Albert Schwarz	**Business Plan $:**	$92K ✓
PID #:	P05-076	**Pre-start Estimate:**	$92K ✓
Work Order #:	C05111	**Project Final Cost:**	Approx $100K ✓
Project Start Date:	Oct 2005	**WO Closed Out?:**	Yes
Project Completion Date:	Sept 2007	**Turnover to?:**	Leo Poile
Planned Start Date:	Oct 2005	**Turnover Complete?:**	Yes
Planned Completion Date:	Dec 2006 (power to the community).		

1. Project Description:

Scope A's continues - phase ⇒ added unnecessary work required.

The following is taken verbatim from the PID:

1) ***Description of problem and why this should be undertaken:***

Design and Construction of a PT Substation is required at South Fox Lake to provide service to NWtel, as well as future service to the community. This substation/customer connection project has been requested by NWtel, and they have agreed to carry the bulk of the costs of the project put forward in our estimate to them.

Associated with this PT Substation is the construction of distribution to the NWtel site under project C04079 (about $40k).

An $8K YEC investment per customer under RESP is included in the budgeting of the projects (C04079, C05111, C06037).

Update, Nov. 3, 2006

The scope and budget for this project have changed now that the community of South Fox Lake (SFL) has decided to purchase power distribution from Yukon Energy.

The cost of the PT Sub is expected to increase to $200K with the changes required to support power distribution to the community. These changes involve the upgrade to a 100 KVA transformer (from 25KVA), and addition of step-up transformer, disconnect switch, splitter box (for YM-2 connection), and associated plumbing, labor, and electrical wiring.

The cost of the project includes an estimated $25k in costs to pay for the actual station service voltage transformer used at the PT sub. This is an estimated cost of the salvage value of the PT sub salvaged from Takhini sub earlier this year – this piece of equipment will be re-used in the South Fox Lake project to help keep costs down.

Costs for the project are now expected to be as follows:

Total PT Sub Construction Cost	*$200k*
RESP Contribution (23 Lots)	*$ 92k*
NWTel Contribution	*$ 16k (taken from $55k total NWtel contribution)*
YEC Investment	***$ 92k***

Thus the total project cost to YEC for this project will be an RESP investment of $92k. *(Cont'd next page)*

The remainder of the NWtel investment ($55k - $16k = $39k) will be applied to the cost of the distribution projects to supply power to the community. Should the cost of the PT sub be lower than expected, more funds will be available to reduce distribution infrastructure costs. The intent is that the cost of the PT sub is fully covered by either Customer, RESP contributions or company RESP investments.

2. **Outstanding Deficiencies** (description & responsibility)
   None.

   PID P07-xxx has been submitted for the construction of a fence to protect the PT-Sub from the public (And vise-versa).

3. **Components that went well?**
   Able to supply power by committed dates to NW-tel and Community.

   Budget surprisingly close, considering the way the project was implemented (initial construction of 2400V secondary, later PPT replacement and cutover to 14.4 secondary).

   Reasonably good PT Sub and platform design.

4. **Problems encountered?**
   Scope change (and associated budget and schedule issues, not to mention stress) is a continuing issue.

   When defining the work to be done for a project of this size, a list should be included in the PID defining the specific items to be included in project scope, and those specifically excluded. More up-front work should be done to define the (internal) customer's needs, and the work to be done before starting such a project.

   Also, when construction is split into various phases, or rework is performed, costs quickly escalate beyond reasonable estimates. In this case, we took this path because of time constraints and parts availability, but the budget impact of breaking up a job is higher than it looks on paper, because of extra planning and setup time, mod/demob costs, and so on.

5. **Reasons for cost and/or time variances?**
   Primarily changes in scope.

YUKON ENERGY

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Post-Completion Project Report

Project Title:	Purchase and Installation of Time Synchronizers		
Project Manager:	Craig Church	**Business Plan $:**	$27,000 ✓
PID #:	P04-055	**Pre-start Estimate:**	$32,000
Work Order #:	C07009	**Project Final Cost:**	$48,500 ✓
Project Start Date:	March 2007	**WO Closed Out?:**	Yes
Project Completion Date:	August 2007	**Turnover to?:**	Al Porter
Planned Start Date:	November 2006	**Turnover Complete?:**	Yes
Planned Completion Date:	August 2007		

Installation — longer
Ravi → Craig — D's idea

1. **Project Description:**
   No accurate time sequencing of events or actions from different relays or equipment, especially during disturbances. Since different relays record different times, events are almost impossible to relate each other in time domain. Such time sequencing is extremely helpful in analyzing problems and to implement corrective measures. Lack of such corrective measures results the problems remaining without addressing and causes repetitive system disturbances. When all the relays have same exact time on them, the events can be correlated and analyzed to suggest corrective measures. This enables YEC to improve system reliability.

2. **Outstanding Deficiencies** (description & responsibility)
   The alarm contacts on the SEL-2401 and SEL-2407 are not connected at any of the sites because currently they do not act as intended. The alarm contacts only operate (open) when power is lost to the unit, and will close when power is restored or when satellite lock is re-established (depending on the setting). However, if the satellite lock is lost without power being lost the unit will not alarm regardless of the setting, therefore the alarm connections to SCADA were not connected because they did not provide any new alarm. (Ie. If power was lost to the unit it would mean that DC power had been lost and the DC system would alarm)

   It was the intent to connect the Hathaway 1200 DFR in Mayo to the time synchronizer system, however, the required card needed for that connection did not exist nor was it easy to track down/purchase. Therefore we were unable to connect it.

3. **Components that went well?**
   Installation went very smoothly, great job done by electrical maintenance.
   Timeline was accurate.
   The background research done on the various types of relays (and corresponding connection types) saved time during on site installations.

4. **Problems encountered?**
   Availability of parts, specifically RG-58 connectors (T-connectors and BNC terminations) were not as easily obtained as originally expected. Similarly RG-6 terminations (TNC connectors) for the GPS antennas were not readily available.

YUKON ENERGY

COPY

Post-Completion Project Report

Project Title:	Office Space Renovations		
Project Manager:	Bill Haydock	**Business Plan $:**	$0 in 2007
PID #:	P06-048	**Pre-start Estimate:**	$60,500 ✓
Work Order #:	C06109	**Project Final Cost:**	$72,387.49 ✓
Project Start Date:	December 2006	**WO Closed Out?:**	Yes
Project Completion Date:	July 2007	**Turnover to?:**	Ken Sawyer
Planned Start Date:	October 2006	**Turnover Complete?:**	Yes
Planned Completion Date:	March 2007		

1. **Project Description**

YEC was running out of space for its employees in 2006. As part of a recent re-organization, plans were made and carried out under this project to free up some space by utilizing the file storage double-wide to house the electrical section. The electrical leadhand also moved over there. This work involved demolition of some walls and the construction of others. A separate section was built for the Purchasing department, but was later used for two other employees.

The office section of P126 was renovated to contain the mechanics and the power line technicians, including the construction of two offices for their respective leadhands.

Most of the files were moved off site, but some that need to be regularly accessed were moved up to the single-wide trailer at the WH4 turnaround (This movement/storage of files did not form part of this project).

2. **Outstanding Deficiencies** (description & responsibility)

There is a potential issue with heating/cooling in the two offices in P126. The extent of this issue, if there is one, will not be known until next year, after a complete winter and summer has gone by. Some system re-design may be required.

One office in P126 does not have baseboards. The baseboard is here, and has been given to Ken, but the office occupant doesn't want it installed. It has been agreed that Ken will ensure baseboard installation occurs when this occupant moves out.

3. **Components that went well?**

The actual construction components. Wall construction, mechanical and electrical components went well, although in a fairly piece-meal fashion as new requests or requirements popped up.

4. **Problems encountered?**
   There were far too many "participants" in this project, and too many people looking at too many alternatives during the initial phase. Even during construction, people were changing their minds or requesting extras that were not part of the original scope.

5. **Reasons for cost and/or time variances?**

   The project went approximately 20% over budget. The major reason for this was the length of time the planning process took. There were new variations of walls and cubicles/pods/workstations that had to be developed at a rate of about one a week, every time somebody wanted to see how something new would work. This all took time and money. (the last straw was when somebody asked me to take down an existing wall and build a new one 12" away because somebody's office was too big. I declined to do this change).

   The other reason for the delay is that the files didn't actually get moved out of the doublewide until the middle of December 2006. This effectively meant that no work could start until January due to the Christmas season.

   I can honestly say that this was the least fun project I have done in the last few years.

YUKON ENERGY

COPY

Post-Completion Project Report

Project Title:	**Portable Diesel Gen Set**		
Project Manager:	A. Love	**Business Plan $:**	$80,0000
PID #:	P05-070	**Pre-start Estimate:**	$87,300 revised to $61,300
Work Order #:	C06102	**Project Final Cost:**	$60,084 ✓
Project Start Date:	Oct 01, 2006	**WO Closed Out?:**	Yes
Project Completion Date:	Dec 31, 2006	**Turnover to?:**	Elect Maint
Planned Start Date:	Aug 01, 2006	**Turnover Complete?:**	Yes
Planned Completion Date:	Dec 31, 2006		

1. **Project Description:**
   To purchase a mobile Gen Set of about 100 kW rating for use at YEC substations and PT sites. The Gen Set will help to provide good customer service by providing power to remote sites during planned and un-planned line outages.

2. **Outstanding Deficiencies** (description & responsibility)
   Secondary containment – this has been addressed as a deficiency that Elect maint will address by installing a spill kit.

3. **Components that went well?**
   The gen set purchased is much lighter and hence easier to tow than the previous unit.

   The purchasing dept. did an excellent job of soliciting 10 competitive bids for evaluation.

   Elect Maint did a very good job on testing and commissioning the unit – this included setting up a load bank to test it.

4. **Problems encountered?**
   The secondary containment was difficult to deal with. A unit with built in double wall tanks was very long delivery so we had to take a single wall tank unit. For secondary containment there are options such as belly pans and insta berms, but each of these pose their own problems. In the end we settled on including a spill kit with the gen set to deal with any leaks.

   At light loading (< 10 kW) the engine spits oil into the exhaust and poses an operational and fire risk. This problem will be alleviated when the new small gen set is received in the fall of 2007.

5. **Reasons for cost and/or time variances?**
   Project came in under budget. Once the project was started the cost estimate was revised to $61,300 based on budgetary estimates, and the final costs are $60,084.

   Final Cost Breakdown
   Gen Set $43,000 (72%)
   Labour $3,500 (6%)
   Materials $5,000 (8%)
   ES&G $5,300 (9%)

YUKON ENERGY

COPY

Post-Completion Project Report

Project Title:	Marshall Creek and Dimok Timber Metering Transformers		
Project Manager:	Albert Schwarz	**Business Plan $:**	C06131 – $0 C07027 - $0
PID #:	P04-199	**Pre-start Estimate:**	C06131 $48K – Contrib. C07027 $37k – Contrib.
Work Order #:	C06131 Marshall C07027 Dimok	**Project Final Cost:**	Not All costs In Yet.
Project Start Date:	Dec 2006	**WO Closed Out?:**	C06131 -Yes C07027 -Yes
Project Completion Date:	Dec 2007	**Turnover to?:**	Leo Poile
Planned Start Date:	Dec 2006	**Turnover Complete?:**	Yes
Planned Completion Date:	Oct 2007		

Service @ Haines Jct could have saved $

1. Project Description:
Installation of Metering transformers and bypass switches at two new YEC-YECL POS locations

2. Outstanding Deficiencies (description & responsibility)

'A' Ground was not installed at transformer pole due to the cost of digging and excavating in frozen soil. Transformers are grounded through MGN and single ground rod – OK until spring, when this deficiency will be rectified.

3. Components that went well?

- Purchasing worked well with engineering to arrange for timely tendering and purchasing of equipment.
- Linemen and Electricians, and metering tech worked well together on the installation. Good feedback to engineering from the field r.e design.

4. Problems encountered?

- A unique structure had to be designed for these installations – not in our current distribution standard. However, we have no current process to handle managing unique updates or changes to our standard…
- A purchasing spec was created including a technical specification for purchase of metering transformers and spares – can we not qualify a vendor an use them for future purchasing instead of re-tendering for purchases of 1-2 units, which is expensive and time consuming for all?

5. Reasons for cost and/or time variances?

Construction took longer than expected due to short days/cold weather. We should have housed linemen at Haines Junction instead of driving daily to/from Whitehorse.

YUKON ENERGY

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Post-Completion Project Report

Project Title:	Metering 2006 Blanket WO		
Project Manager:	Albert Schwarz	**Business Plan $:**	$25K
PID #:	P04-189	**Pre-start Estimate:**	$28K
Work Order #:	C07026	**Project Final Cost:**	$25K
Project Start Date:	Jan 2007	**WO Closed Out?:**	Yes
Project Completion Date:	Dec 2007	**Turnover to?:**	Gary Jones, Leo Poile
Planned Start Date:	Jan 2007	**Turnover Complete?:**	No
Planned Completion Date:	Dec 2007		

1. Project Description:
Upgrade to specific metering sites to provide for collection of power quality data from all YECL POS locations. Includes installation of communications facilities, new meter installations, etc.

2. Outstanding Deficiencies (description & responsibility)

Handover – Though the meters themselves are the responsibility of the metering tech (Gary Jones), the ION energy management database system is still the responsibility of Technical Services.

3. Components that went well?

Managed to establish physical connection to Callison, Mayo, and Dawson meters through IT, though actual connectivity will be commissioned in 2008.

Developed a meter reading screen for operations, and need to expand on this in 2008 to create usable tool for operations month-end reports.

4. Problems encountered?

- Could not get NWtel service connected at Ross River or Haines Junction Subs. Did purchase Meters for these sites, though these can be considered active spares for the time being.
- Need to understand PQ reporting requirements in 2008 – suggest instead of collecting data indefinitely, we create year-end PQ reports for each POS, and file these for use at later rate hearings.
- Raw data takes up much server space – a standard report may be more accessible, and allows for benchmarking and comparison…

5. Reasons for cost and/or time variances?

YUKON ENERGY

COPY

$10,000 in disposal costs

Post-Completion Project Report
December 4, 2007

Project Title:	Keno Transformer (S257 T1) Replacement		
Project Manager:	T. Allan Hammond	**Business Plan $:**	$85,000
PID #:	P05-081	**Pre-start Estimate:**	$85,000
Work Order #:	C07022	**Project Final Cost:**	$65,000
Project Start Date:	May 2007	**WO Closed Out?:**	In progress
Project Completion Date:	Sept 2007	**Turnover to?:**	EM (88), T&D (82)
Planned Start Date:	March 2007	**Turnover Complete?:**	No
Planned Completion Date:	Nov 30/07		

YECL D distr system & used existing transformer from Mayo / Dawson

1. **Project Description:**
   Replace 2300V/200 kVA transformer with 14.4 kV/200 kVA transformer; modify substation to accommodate, including: constructing a platform to house the new transformer, installation of a new metering structure, testing and commissioning of the new equipment, and re-gravelling the substation.

   YECL upgraded Keno distribution to 14.4 kV prior to substation rebuild.

2. **Outstanding Deficiencies** (description & responsibility)
   Cable guard for #2/0 ground on pole required (to be addressed by Mayo T&D);
   Modify ground grid to suit extended rear fencing (to be addressed by Project Manager in 2008).

3. **Components that went well?**
   Installation by YEC employees; assembly of parts at Kulan warehouse; non stock materials ordered well in advance of projected start date.

   Technical assistance from Technical Services, EE Team was very helpful in completing this project.

   Mayo T&D Team able to secure special equipment locally.

4. **Problems encountered?**
   Difficult to get date commitment by T&D. Original date for install was August 27 and was changed to Sept 21 (almost 1 month). This date was also in danger of being changed on very short notice.

   The meter installation overseen by YEC employee. When parts arrived, they required modification as it was not clearly communicated to the vendor what was required.

5. **Reasons for cost and/or time variances?**
   Initial budget (for a new transformer) included $10,000 for transformer disposal in 2007. The outgoing transformer was not part of the Yukon Government waste round up. These funds cannot be carried over for this purpose.

YUKON ENERGY

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Post-Completion Project Report

Project Title:	Rocky Point Remediation		
Project Manager:	R. Gee	Business Plan $:	$250,000
PID #:	P05-009	Pre-start Estimate:	$256,000
Work Order #:	C06089	Project Final Cost:	$206,482
Project Start Date:	July 1, 2006	WO Closed Out?:	Yes
Project Completion Date:	Aug 29, 2007	Turnover to?:	n/a
Planned Start Date:	Jan 1, 2006	Turnover Complete?:	n/a
Planned Completion Date:	July 31, 2007		

Challenger Construction — Ice Roads started to weaker

1. Project Description:

The construction project component of the project involved rehabilitating the Rocky Point berm with larger, angular rip rap material. This involves developing a new quarry site, carrying out a drill and blast operation in order to produce suitable size material, trucking the rip rap to site, excavating and placing the material. Other aspects of the project included:

- Regulatory approval and permitting: YESAA approval, YTG Quarry permits, YTG Land Use permit, CAFN Land Use permit, DFO discussions
- Engineering design: specifications, drawings
- Contractor tendering
- Permit close outs

2. Outstanding Deficiencies (description & responsibility)

n/a

3. Components that went well?

The construction contractor on the project was Challenger Construction. This was my first time working with them and they proved to be organized, cost effective, and fair.

4. Problems encountered?

The weather is always a wild card factor in a project that is in a remote area and utilizes ice roads for hauling. Construction began in March 2007 and the weather was cold. However, by the end of the project in April, the weather had warmed considerably and the ice roads where getting in very poor condition.

The original berm design section was not obtained due to the inability of the excavator to reach the design elevation. A field decision was made to not bring out a concrete breaker but rather to extend the berm further out into the lake.

The contractor had trouble finding the bedrock. As they began stripping, what was thought to be a large bedrock knob was actually only a thin tip. Fortunately, the rock was just large enough to provide the sufficient quantity of rip rap.

5. Reasons for cost and/or time variances?

Total cost was under budget. Time was close to as planned.

Reasons for cost difference:

- Permitting and approvals performed internally rather than contracted out
- Total construction days was shorter than planned
- Contractor costs were below estimated

6. Recommendations to Improve Project

When ice roads are required for a project, plan for a completion date of March. Then if the inevitable delays of a project start to creep in, there is adequate time to complete the project even in the event of a warm spring. The problem with this is that if you plan the construction for February and March, it could be very cold and result in additional costs. However, at least the project will be completed if the weather turns warm.

REFERENCE: **Distribution Projects Page 5-14**

TOPIC: **Capital Projects**

PREAMBLE:

Yukon Electrical wishes to better understand the specific tasks and type of expenditures that are associated with Land Management and Easement Projects shown at line 15-19 on page 5-14.

QUESTION:

a) How much was spent on this type of activity by YEC in each of the years 2005, 2006, and 2007?

b) In relation to the above projects, what were the specific tasks that were undertaken with respect to this project? Please provide a breakdown by labour, material contractor, and other costs associated with these expenditures. Does YEC pay for easements and if so at what level? For all of the above information please separate this information between land tenure for Crown land and that for private lands.

c) Please identify any easements YEC is seeking for existing facilities. Please explain why such easements are required.

d) What are the estimated costs associated with completing this project? What is the estimated cost per kilometer of distribution line for this activity once the project is completed?

ANSWER:

(a) and **(b)**

For assessment of spending on Land Management and Easement Projects in each of the years 2005, 2006, and 2007, please see chart provided below:

Land Management and Easement Project – spending by year and by land type

($000s)	**2005**	**2006**	**2007**	**Crown Land**	**Private Land**
Labour	59	80	78	22	195
Material	0	1	0	0	1
Contractor	31	19	0	7	42
Other	18	13	12	5	38
Total	108	113	90	34	276

YEC does not pay for easements.

(c)

YEC seeks easements from property owners in order to allow ready access by utility employees for construction and maintenance of equipment owned by the utility.

The following table notes the registered easements YEC has for existing facilities:

Registered Easements

	Dawson	**Mayo**	**Faro**	**Total**
2005	0	0	8	8
2006	79	65	239	383
2007	71	67	18	156
Total	150	132	265	547

(2008 to date – 164 Total registered Dawson, Mayo, Faro)

The table below notes the outstanding easements YEC is seeking:

Outstanding Easements

	Dawson	Mayo	Faro	Total
Primary	733	238	103	1,074
Secondary	827	154	134	1,115
Total	1,560	392	237	2,189

(d)

The estimated final cost of this project is approximately $1 million. The estimated cost per kilometer of distribution line for this activity is not known and cannot be provided.

REFERENCE: **Distribution Projects Page 5-15**

TOPIC: **Capital Projects**

PREAMBLE:

Yukon Electrical wishes to understand the improvements that may be required on the Whitehorse Dam.

QUESTION:

a) Please provide a copy of the study undertaken in 2008 for the Whitehorse dam, as shown on lines 3-7 on page 5-15? What process was undertaken to select a vendor to do this study? In providing this response, identify how many vendors were invited to bid and the respective bid amounts.

b) What have been the costs associated with the excessive wear on the gate hoist machinery?

c) For each of the years 2005 to 2009, provide the amount of extra labour costs incurred to ensure the gates do not freeze in the winter.

ANSWER:

(a)

The requested information cannot be provided. Due to changes in priorities, this project was deferred until 2010.

(b)

Costs are not tracked to a sufficient level of detail to identify the cost of the excessive wear.

(c)

The only extra labour costs relating to the gate hoist equipment are overtime that may have been required. Overtime is not tracked to this level of detail and therefore this number is not available and cannot be provided.

REFERENCE: **Distribution Projects Page 5-15 Vehicle Purchases**

TOPIC: **Capital Projects**

PREAMBLE:

Yukon Electrical wishes to understand the costs associated with vehicle purchases.

QUESTION:

a) For 2005 - 2009, please provide a detailed breakdown of the costs for each service body unit.

b) Was a tendering process used in the purchase of the units? If so how many bids were received and what were the various prices provided by vendors? If not, why not?

c) Did YEC dispose of the old service bodies being replaced? If so, please provide the salvage value or expected salvage value of each unit and where is the salvage value recorded?

ANSWER:

(a)

Details on the costs related to each unit are provided below:

2005 Descriptions		Actual Spending ($000)
Unit 67 1 ton 4X4	Service body	60
Unit 68 1 ton 4x4	Service body	60
Unit 69 1 Ton 4x4	Service body	60
Unit 70 1 ton 4x4 no winch	Service body	58
Unit 71 1/2 ton 4x4	Operator pool	34
Unit 72 1/2 ton 4x4	Operator pool	34
Unit 73 Midsize 4dr sedan	Pool	26
Unit 74 1 ton 4x4	Service body	61
Misc Accessories		13
Total		**404**

2006 Descriptions		Actual Spending ($000)
Unit 76 1 ton 4x4	Service body	65
Unit 77 1 ton 4x4	Service body	65
Misc Accessories		7
Total		**137**

2007 Descriptions		Actual Spending ($000)
Unit 78 1 ton 4x4	Service body	63
Unit 79 1 ton 4x4	Service body	63
Unit 801 ton 4x4	Service body	63
Unit 81 1/2 ton 4x4	Pool	30
Unit 82 4x4 SUV	Pool	34
Unit 83 3/4 ton 4x4	Distribution Tech	34
Unit 84 1 ton 4x4	Service body	70
Unit 85 1 ton 4x4	Service body	66
Misc Accessories		19
Total		**442**

2008 Descriptions	Budget ($000)
Service Vehicle	76
Service Vehicle	76
Pool Vehicle	56
Total	**209**

2009 Descriptions	Budget ($000)
Service Vehicle	77
Service Vehicle	77
Pool Vehicle	57
Pool Vehicle	57
Total	**268**

Note that 2008 actual spending is provided in response to UCG-YEC-1-83(a).

(b)

Yukon Energy tenders for the purchase of all units. The number of bids varies depending on timing of tender (i.e. manufacturers tend not to bid when they are re-tooling for next year's models) and type of unit.

(c)

Salvage proceeds received in 2005 were $51,641, and are as noted in the table below:

G/L Date	Amount	Description	Asset Number
12/8/2005	(15,517)	1998 Dodge Pick up	50
12/8/2005	(6,150)	1996 Dodge 3/4 Ton Pick Up	29
12/8/2005	(1,600)	1992 Plymouth Acclaim Car	25
12/8/2005	(13,788)	1996 Dodge 3/4 Ton Service Body	43
12/8/2005	(14,586)	1996 Dodge 3/4 Ton Service Body	48
Salavge Proceeds received in 2005	**(51,641)**		

No vehicles were sold from 2006 through 2008.

The proceeds from these sales are included in Other Revenues (see Tab 7, Page 7-15 line 50). See also response to YECL-YEC-1-34(a).

REFERENCE: **Distribution Projects Page 5-18- line assessment phase 2 Carmacks- Faro**

TOPIC: **Capital Projects**

PREAMBLE:

Yukon Electrical is seeking more information on the Carmacks- Faro Phase 2 project.

QUESTION:

a) Please provide the detailed costs associated with the line assessment being the Phase 2 Carmacks-Faro transmission line. Please include, labour, material, contractor and other costs. Please explain how this study differs from the study that was undertaken in 2004 by YEC.

b) Please provide copies of YEC's Asset Management program as well as all end-of-life studies performed by YEC since 2004.

ANSWER:

(a)

The costs for this project are as follows:

Item	**Cost**
YEC Labour & Expenses	$ 6,566
Contractors	$ 176,041
Materials	$ 3,637
ES&G/AFUDC	$ 20,475
Total	$ **206,720**

The study performed in 2004 was completed on the line to Aishihik (L171), MacIntyre Connection (L169) and the Takhini – Riverside line (L172). The study performed in 2008 was on the Takhini – Carmacks – Faro line (L170).

(b)

Yukon Energy has not completed any end-of-life studies since 2004 (outside of the Mirrlees Life Extension project which was filed and reviewed extensively the 20 Year Resource Plan hearing). During the 2005 Required Revenues and Related Matters hearing, Yukon Energy filed three extensive condition assessment reports on its key assets. These reports remain the guiding documents in use in respect of asset assessment.

REFERENCE:

TOPIC: **Transmission Standards**

PREAMBLE:

Yukon Electrical would like to better understand the rational for the standards adopted by YEC for transmission infrastructure.

QUESTION:

a) Please list the third party consultant YEC engaged when selecting the design standard for the Mayo/Dawson 69KV line and the costs associated with this vendor.

b) Please provide the rational for the type of structures and transmission voltage selected for the Mayo/Dawson 69KV transmission line.

c) Please provide the same detail as in (b) above for the structures selected for the CSTP.

d) Please provide a list of the external consultants procured by YEC to design, construct, and site manage the CSTP project. In addition, please provide the costs associated with each of the external consultants.

e) Please provide all contracts that YEC established for the construction of the CSTP/Minto Mine Spur, including contracts with First Nations and Valard Construction.

ANSWER:

(a)

YEC used BC Hydro International (BCHIL) as its design consultant on this project. The costs are not relevant to this proceeding as the project costs were extensively reviewed

at the 2005 Required Revenues and Related Matters hearing and accepted into rate base as part of $1.649 million in feasibility studies.[1]

(b)

Issues relating to design, construction and costs of the Mayo Dawson line were fully canvassed at the 2005 Required Revenues and Related Matters hearing and therefore not relevant to this GRA.

(c)

The CSTP Stage I was the first phase of a possible two phase project to connect the WAF grid with the MD grid. This entailed a new transmission line approximately 250 km in length for both phases. This length at any lower voltage would have resulted in unacceptable line losses. Any higher voltage would have resulted in capital costs which were too high. Since the connection was to the existing WAF grid at 138 kV, it was determined that this would be the best choice.

The choice of structure design was made based on industry practice. This design is a standard for utilities in Canada

(d)

Consultants and contractors retained to design, construct and site manage the CSTP/MS are listed below. Contract costs as provided are current YEC Board approved amounts for Stage One CSTP/MS [design costs exclude preliminary engineering costs allocated to Stage Two CSTP] and are not necessarily final amounts resolved with each contractor.

[1] See YUB-YEC-1-19, filed during the Required Revenues and Related Matters hearing.

Role	Consultant/ Contractor	Contract Cost (000's)
Design*	Wardrop	1.372
Survey	Challenger	0.810
Line Construction	Valard	19.844
Substation Construction	F&M Installations	4.684
Site Management	Wardrop	1.348
Commissioning	Magna Electric	0.349
Clearing	Pelly Construction	3.465

(e)

Contracts with third parties are treated by Yukon Energy as confidential. Yukon Energy is prepared to provide the Board with copies of the contracts on a confidential basis if the Board believes they are relevant or necessary to allow the Board to gain a satisfactory understanding of the matters that need to be considered in this Application.

REFERENCE: **Table 3.6 and Table 3.7**

TOPIC: **Transmission and Distribution Costs**

PREAMBLE:

Yukon Electrical needs more information in order to fully understand costs.

QUESTION:

a) For each of Transmission and Distribution, please provide details of costs for 2005-2009 by activity such as:
   i Supervision and Engineering;
   ii Overhead line maintenance;
   iii Underground line maintenance;
   iv Substation maintenance.
   v Brushing;
   vi Meter and meter testing;
   vii Service to outside parties;
   viii Transformer repair and maintenance; and
   ix Street light maintenance.

b) For each of Transmission and Distribution, please provide year end actual and forecast details for 2005-2009 of:
   i Km of line; and
   ii Number of Substations
   iii Number of customers served off of each line.

ANSWER:

(a)

Please see tables below for each of non-labour expenses and labour expenses.

Transmission and Distribution Costs - Non-Labour

$000s	2005 Approved Non-labour	2005 Actual Non-labour	2006 Actual Non-labour	2007 Actual Non-labour	2008 Foecast Non-labour	2009 Forecast Non-labour
Trans Supervision	3	0	1	1	1	1
Trans Line Brushing	100	158	117	239	257	377
Trans Overhead Lines	126	89	153	161	127	132
Trans Lines Substation	104	93	83	69	122	102
Transmission	**333**	**340**	**354**	**470**	**507**	**612**
Distribution Supervision	8	1	1	1	5	5
Distribution Brushing	31	14	72	1	40	46
Distribution Lines/Substations	108	127	200	66	65	63
Distribution Meter/Meter Testing	16	12	33	18	21	47
Distribution Transformer	0	0	0	3	0	0
Distribution Street Lights	8	9	4	8	17	17
Distribution	**171**	**163**	**310**	**97**	**148**	**178**

Transmission and Distribution Costs - Labour

$000s	2005 Approved Labour	2005 Actual Labour	2006 Actual Labour	2007 Actual Labour	2008 Forecast Labour	2009 Forecast Labour
Trans Supervision	32	21	20	20	33	34
Trans Line Brushing	23	8	5	5	4	5
Trans Overhead Lines	104	74	116	123	123	127
Trans Lines Substation	271	191	167	145	306	316
Transmission	**430**	**295**	**307**	**293**	**466**	**482**
Distribution Supervision	37	41	30	38	48	49
Distribution Brushing	21	16	10	8	18	19
Distribution Lines/Substations	286	266	299	359	397	409
Distribution Meter/Meter Testing	35	26	28	31	38	38
Distribution Transformer	2	0	0	1	2	2
Distribution Street Lights	14	5	5	9	3	4
Distribution	**395**	**354**	**372**	**446**	**505**	**521**

(b)

Year end actual and forecast details for each of Transmission and Distribution for 2005-2009 are as follows:

(i) Km of line - approximately 600 kms
(ii) Number of Substations – 17
(iii) For the number of customers served off of each line and substation please see chart below.

Substation	Substation Description	Approximate Number of Customers Served
S146	Faro Reactor Substation	
S150	Whitehorse Substation at Hydro Site	YECL 13 YEC Customers
S162	Faro Mine Substation	1 YEC Customer
S163	Carmacks Substation	YECL
S164	Takhini Substation (Mayo Road, near Whitehorse)	YECL L170 29 YEC Customers L171 77 YEC Customers
S167	Aishihik Hydro Substation	YECL L355 5 YEC Customers
S170	McIntyre Substation (Whitehorse area)	YECL
S171	Riverside Substation (Whitehorse area)	
S249	Mayo Hydro Substation	351 YEC Customers
S250/P158	Callison Substation / Dawson Diesel (Dawson)	1230 YEC Customers
S251	Stewart Crossing Substation	YECL
S252	Pelly Crossing Substation	YECL
S253	Minto Landing Substation	
S254	Minto Mine Substation	Minto Mine
S255	Carmacks Substation	
S257	Keno City Substation	YECL
870S	Faro Substation	YECL 318 YEC Customers

1

REFERENCE: **Pages 5 -18 & 5 - 19**

TOPIC: **Transmission Projects**

PREAMBLE:

Transmission Projects $100,000 to $1 million over the test period

QUESTION:

Yukon Electrical would like to better understand the types of activities and process YEC uses to complete transmission maintenance.

a) Please provide details (labour, material contractor and other) of the $155k spent in 2008. Outline the specific tasks undertaken.

b) Please provide the details (labour, material contractor and other) of the $220k planned in 2009. Outline the specific tasks undertaken.

c) Lines 14 through 30 on page 5-18 and lines 1 through 15 on page 5 -19 suggest various patrol, inspection and testing procedures to be executed on various components of the transmission system. Please provide copies of YEC's transmission maintenance procedures and programs and the associated cost of each program. (Pole test and treat, Insulator sample test program, etc.)

d) What problems have been experienced on the transmission system since 2005? How were they rectified?

ANSWER:

(a) and **(b)**

A breakdown of the capital projects is provided in the table below:

Transmission Projects under $100k

$000s	2008 Forecast	2009 Forecast
Mayo - Dawson Transmission Line Drawings	50	
Transfer Trip S171 / P127	45	
Ross River Upgrades	30	
S170 Transformer Protection Upgrade	25	
L174 Protection Coordination	5	
Transmission Line Assessment and Repairs		75
S164 Reactor Replacement		75
Blocking Switches		50
PT Substation Fencing - South Fox Lake		20
Total	155	220

A description of the projects is as follows. All of the projects are estimated based on all-in costs, and detailed breakdowns of the cost components are not available except where noted:

- **Mayo Dawson Transmission Line Drawings:** Project objective involves use of consultant to update marked-up site drawings and have internal draftspeople update electronic drawings.

- **Transfer Trip S171/P127:** Installation of transformer trip protection scheme between substation S171 and hydro plant P127 – prevents transformer damage under certain fault scenarios. Internal Labour estimated at $30k, Materials at $10k, other expenses at $5k.

- **Ross River Upgrades:** Replace deficient structures on L356 Ross River transmission line.

- **S170 Transformer Protection Upgrade:** Replace obsolete protection relays in substation S170.

- **L174 Protection Coordinator**: Implementation of revised protection settings to improve customer service.

- **Transmission Line Assessment and Repairs**: Line patrol and assessment of identified deficiencies.

- **S164 Reactor Replacement**: Preventative maintenance testing of oil indicates equipment could be end of life – at minimum oil requires reclamation or equipment may need to be replaced.

- **Blocking Switches**: Addition of equipment to allow for protective relay testing without the need for service interruption to customers. Internal labour estimated at $28k, materials at $8k, and other costs at $14k.

- **PT Substation Fencing – South Fox Lake:** Addition of fencing around PT substation to discourage vandals/protect the public. Internal labour estimated at $12k, materials at $6k, and other costs at $2k.

(c) and **(d)**

Please see LE-YEC-1-60, LE-YEC-1-34, YUB-YEC-1-37 (d) and (e).

YEC does not have specific written procedures for transmission maintenance. Broken cross-arms / sway-braces, insulation failures and tree contacts are the primary cause of transmission interruptions on the YEC grid.

Beyond emergency repairs and the noted capital projects, each line has an aerial patrol once per year, followed by a ground patrol of areas of concern identified by the aerial patrol. YEC's practice has been to isolate and effect repairs identified from these patrols. Danger trees are removed as soon as reasonably possible.

REFERENCE: **Page 2-3 lines 9-11; Page 2-5 Table 2.1; Page 2-16 Table 2.2**

TOPIC: **Primary Wholesale Sales to Yukon Electrical**

PREAMBLE:

Absent Pelly Crossing, wholesale sales are forecast at 238,439 MW.h in 2008 and 264,626 MW.h in 2009, with percentage growth rate of approximately 1.38% in 2008 over 2007 actuals, and 2.39% in 2009 over forecast 2008.

Difference in "ongoing sales" forecast (MW.h) between YEC and YECL (-1,293 MW.h (2008); 3,164 MW.h (2009))

QUESTION:

a) In excel format for each of the WAF and MD grids, please provide the forecast monthly wholesale sales for 2008 and 2009 as compared to actuals for 2005, 2006 and 2007.

b) Other than adjusting for the impact of YEC changing its secondary sales forecast from that originally provided to Yukon Electrical and YEC using actual wholesale sales for the period January 1 - June 30, 2008, please confirm YEC is relying on Yukon Electrical's 2008 wholesale purchased power forecast for purposes of its own 2008 wholesale sales forecast. If not, please explain why.

c) Please confirm that YEC's 2008 "ongoing sales" wholesale sales forecast is 1,293 MW.h lower than what was forecast by Yukon Electrical. If so, please explain why.

d) In excel format, please provide the details of the wholesale sales WAF load growth for the 2001-2004 period averaging 2.2% per year as well as the more recent experienced growth rate in WAF wholesale sales from 2004 - 2007 of 2.5% per year. Please explain what YEC believes have been the major underlying drivers of this growth.

e) Please provide the annual average wholesale sales growth rate and associated details for the period 1996 to 2007 as well as the annual average growth rate for the period 1986 - 2007. Please explain the underlying reasons for the differences in these longer term growth rates relative to the 2.39% ongoing WAF and MD sales (excluding Pelly) growth rate used by YEC for 2009.

f) Other than simply looking at historical averages for the period 2001 -2007, please detail all other work YEC has performed to understand the underlying load drivers of the recent historical growth rate and why these factors are reasonable to use on a go forward basis to determine a wholesale load growth for 2009 and beyond. More specifically, please detail and provide an analysis of the new load that is driving the 6,157 GW.h of ongoing WAF and MD load growth between 2008 and 2009.

g) Did YEC discuss its wholesale sales forecast assumptions with Yukon Electrical prior to the filing of its own Application? If not, why not?

h) Did YEC consider adjusting its 2009 wholesale growth forecast, that appears to be based on simply trending recent past growth, to reflect past “one of” load growth changes experienced in the Whitehorse area including government commercial customers such as the Canada Games Centre, the Copper Ridge Extended Care Facility, the Athletes Village at Yukon College or non-government commercial customers such as Wal-Mart, Superstore and Canadian Tire? If yes, please quantify. If not, please explain why not.

i) Please confirm YEC uses temperature forecasts to forecast its sales load for purposes of determining surplus hydro availability for secondary sales customers. If not, please explain why not If yes, please detail what YEC has learned with respect to the relationships between WAF and MD loads and temperature.

j) Did YEC prepare its 2008 and 2009 wholesale sales forecast on a temperature normalized basis? If not, please provide.

k) Please provide 2001 - 2007 actual wholesale sales and annual growth rates on a temperature normalized basis.

l) Please comment on the impact of the worsening world and Canadian economic situation and outlook on YEC's wholesale sales forecast and, more specifically, on current and new forecast retail customers served off the WAF grid.

ANSWER:

(a)

Please see table below.

WAF Grid Monthly Wholesale Sales for the Years 2005-2009

MW.h

Month	Actual 2005	Actual 2006	Actual 2007	Forecast 2008	Forecast 2009
January	26,230	26,359	25,517	27,529	28,445
February	21,632	21,188	24,331	25,303	26,128
March	20,503	23,851	24,450	22,760	23,512
April	17,498	19,818	20,328	19,402	20,058
May	17,818	17,844	18,304	18,371	18,982
June	16,452	17,017	16,680	18,537	19,142
July	17,281	16,799	17,685	18,100	18,677
August	16,358	17,544	17,524	17,900	18,475
September	17,640	19,010	19,105	19,600	20,243
October	20,323	19,317	20,278	20,860	21,377
November	21,743	26,921	22,383	23,883	24,476
December	23,549	25,340	27,473	25,854	26,496
Total	237,028	251,007	254,059	258,098	266,011

MD Grid Monthly Wholesale Sales for the Years 2005-2009
MW.h

Month	Actual 2005	Actual 2006	Actual 2007	Forecast 2008	Forecast 2009
January	33	100	98	83	100
February	30	83	97	79	98
March	26	92	99	72	100
April	23	63	76	55	77
May	14	56	61	46	62
June	10	40	46	128	47
July	11	46	52	52	53
August	15	46	54	46	46
September	17	50	52	50	51
October	19	69	60	69	70
November	100	109	71	109	110
December	93	100	87	100	102
Total	390	854	855	891	916

(b)

Confirmed, on an annual basis. However, Yukon Energy does not necessarily use the same monthly distribution of wholesale sales forecast as YECL.

(c)

Confirmed. Please see Table 2.1 in Tab 2. Yukon Energy's forecast is different than YECL's as Yukon Energy's filing was able to incorporate actual sales from January to June of 2008.

(d)

Please see table below. Note that the 2.2% growth rate for 2001-2004 was provided in the 20 year Resource Plan hearing, at a time when Yukon Energy had Fish Lake generation readily available, and this value reflects YECL "native" load (i.e., with Fish Lake generation added back). The 2.5% value was calculated for this GRA at a time when YEC did not have YECL Fish Lake generation readily available, and thus was

calculated off of simple WAF wholesale sales (i.e., YECL WAF native load net of Fish Lake generation). With the Fish Lake generation included, as noted in the table below, the YECL native load growth over the period 2004 to 2007 is 2.9% per year, and over the period 2004 to 2008 is 2.8%.

WAF Grid Wholesale Sales for the Years 2001-2008

MW.h

With Fish Lake	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Sales								
Wholesale Primary	217,138	220,647	229,731	235,718	237,028	251,007	254,059	262,951
Fish Lake	9,165	8,576	4,948	6,034	6,900	8,200	9,030	6,551
Total	226,303	229,223	234,679	241,752	243,928	259,207	263,089	269,502
Average growth rate 2001-2004				2.2%				
Average growth rate 2004-2007 and 2004-2008							2.9%	2.8%

w/o Fish Lake	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Sales								
Total	217,138	220,647	229,731	235,718	237,028	251,007	254,059	262,951
Average growth rate 2001-2004				2.8%				
Average growth rate 2004-2007 and 2004-2008							2.5%	2.8%

Yukon Energy noted, in its April 1 response to YECL's request for additional information that it is not in a position to usefully comment on "major underlying drivers" for the growth reviewed above. As noted in the response to CW-YEC-1-3(c), Yukon Energy is not provided the data by YECL to track YECL's retail loads in a manner that permits identification of the reasons for such variances. Yukon Energy forecasts are based on the best information available to it.

Notwithstanding the above response, Order 2009-4 has directed YEC to "to respond to what it believes are the underlying drivers to its wholesale sales forecast."

YEC's wholesales sales forecasts for the Resource Plan, the 2005 a Required Revenues application and the current Application have been prepared based on adoption of average growth rates as noted in each instance which appear to be reasonable in light of information available to YEC. These forecasts have proven to be useful for YEC planning purposes, keeping in mind that actual individual annual wholesale loads are subject to considerable variability due to weather, Fish Lake generation, and other factors not captured in any forecast for specific year sales.

In preparing its average growth rate assessments, YEC is not able to provide meaningful temperature normalized analysis of wholesale loads because it does not have access to

detailed information on the individual customer class information underlying the wholesale loads. Accordingly, YEC is aware that the growth rate trends it is assessing include material weather impacts affecting each year's data – for this reason, YEC has focused on longer-term trends rather than specific year-to-year comparisons.

As reviewed in response to YECL-YEC-1-19(e), YEC has reviewed longer-term wholesale sales growth trends since 1987 and concluded that since the 5 year hiatus on growth in Yukon after closure of the Faro mine, the loads have been steadily climbing at a rate that more readily approximates the levels shown in YEC's GRA, and slightly above that used in the 2006-2025 Resource Plan (which applied 1.85% as the annual average growth rate). YEC has not attempted to assess specific underlying factors accounting for this ongoing growth, but believes that such growth reflects overall Yukon growth related to a combination of population, government service sector and business sector activities sustaining Yukon development after a recovery period following closure of the Faro mine

Based on review of the recent YECL GRA filings which set out a range of WAF customer class temperature normalized assessments far beyond what is available to YEC, YEC does not believe that overall wholesale forecasting, at least for the current Application, would necessarily be improved through prior access to such additional information.

Based on review of the recent YECL GRA filings which set out considerable additional sales and customer information beyond what is normally available to YEC, it is also not apparent that overall wholesale forecasting at least for the current Application would necessarily be improved through prior access to such additional information.

By way of example, as YECL's GRA information suggests, principal drivers for recent WAF wholesales may reflect growth in big box retail stores as well as growth in office buildings, restaurants, recreational facilities, new house and condominium construction. However, based on YEC's review of the ongoing wholesales sales growth trends, references to the nature of recent "one-off" general service load increments in Whitehorse do not appear to explain why the higher growth rates that these customers help to drive have become the norm rather than the exception.

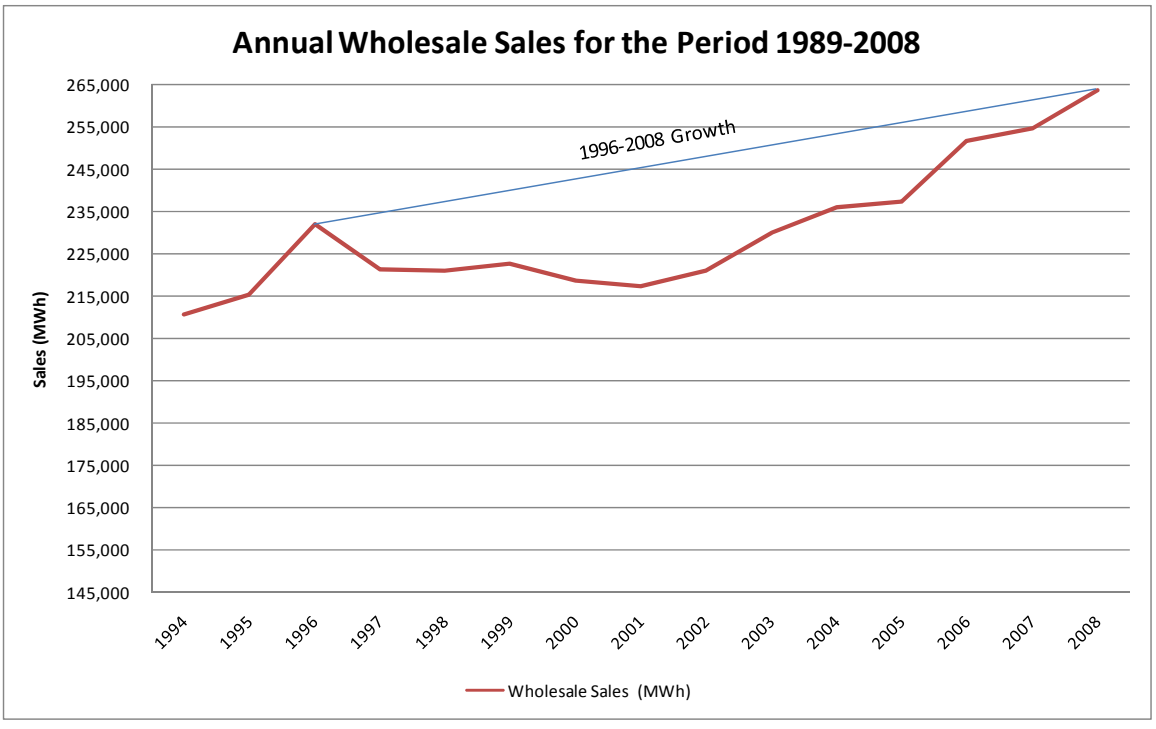
The current world wide recession may introduce new dampers on recent Yukon growth trends that affect wholesale sales. However, the impact of such "drivers" are similar to

weather and Fish Lake sales variances, i.e., beyond the ability of YEC to forecast at the time that its Application was prepared.

(e)

The long-term compounded growth in wholesales as requested, from 1986 (fiscal year ending March 31, 1986, when the assets were owned by NCPC) to 2008 actuals is 2.71% (from 146.6 GW.h to 263.8 GW.h).

The period from 1996 to 2008 is not representative of a reasonable data set for Yukon. The mathematics show a growth rate over this period of 1.07% per annum (from 1996 at 232.1 GW.h to 2008 at 263.8 GW.h). However, as shown in the chart below this is heavily skewed by the closure of the Faro mine and the massive impacts on Yukon that occurred between 1996 and 2001 (when, as noted in the YEC Resource Plan, approximately 10% of Yukon's population left the territory). Since that 5 year hiatus on growth in Yukon, the loads have been steadily climbing at a rate that more readily approximates the levels shown in YEC's GRA, and slightly above that used in the 2006-2025 Resource Plan (which applied 1.85% as the annual average growth rate).



(g)

No. Yukon Energy's GRA load forecast was not completed as of the date of YECL filing its GRA. YEC's basic WAF load forecasting approach, and concerns with YECL's past wholesale forecasts tending to be too low, have been reviewed in the past during the Resource Plan Hearing. Once YEC's current wholesales forecast for 2009 was prepared for its own Application, YEC was not aware of any useful basis to review this forecast with YECL in the midst of YECL's own GRA review.

(f), **(h)**, **(j)** and **(k)**

YEC's WAF forecasts for the Resource Plan Hearing as well as for the current Application have focused on wholesale loads, and have been prepared based on adoption of average growth rates as noted in each instance which appear to be reasonable in light of information available to YEC. These forecasts have proven to be useful for YEC planning purposes, keeping in mind that actual individual annual wholesale loads are subject to considerable variability due to weather and other factors.

As noted above (YECL-YEC-1-19(f)), Yukon Energy is not provided with YECL's customer specific data and therefore cannot carry out (even if it so wanted to) detailed assessments of the underlying customer class growth underlying wholesale growth. Based on review of the recent YECL GRA filings which set out considerable information beyond what is available to YEC, it is not apparent that overall wholesale forecasting at least for the current Application would necessarily be improved through prior access to such additional information. By way of example, references to the nature of "one-off" general service load increments in Whitehorse do not appear to explain why the higher growth rates that these customers help to drive have become the norm rather than the exception.

YEC has not prepared its wholesale forecasts on a temperature normalized basis. Please see CW-YEC-1-3(d) which sets out the 2.5% wholesale growth that YEC used to determine the forecast 2009 wholesale loads. Please see YECL-YEC-1-19(d) in regards to the justification for the 2.5%. YEC cannot provide meaningful temperature normalized analysis of wholesale loads without access to detailed information on the individual customer class information underlying the wholesale loads. Based on review of the recent YECL GRA filings which set out a range of WAF customer class temperature normalized assessments far beyond what is available to YEC, YEC does believe that

overall wholesale forecasting at least for the current Application would necessarily be improved through prior access to such additional information.

(i)

Not confirmed. YEC does not have temperature forecasts for the test years. YEC's approach to forecasting secondary sales interruptions is set out in detail in YECL-YEC-1-23(b) which uses 8 years of monthly load duration curves to represent an average of the overall load response that has been experienced in each specific month of the year. Incorporated into this actual load response is the effects of weather. In short, by using a long term average load shape for each month YEC's approach to forecast availability of secondary sales does in effect consider weather conditions over a long period of time (i.e. normalized). In respect of surplus hydro the relevant consideration for forecasting secondary sales in the test years is the surplus hydro capacity that exists or is constrained from time to time over the course of a year. This factor is the fundamental basis for the analysis contained in YECL-YEC-1-23(b).

(l)

Please see response to PWP/HML-YEC-1-29.

REFERENCE: **Pages 2-5 to 2-7 of Application; Page 2-16 Table 2; Schedule A Industrial Primary Rate Schedule 39**

TOPIC: **Major Industrial Sales**

PREAMBLE:

YEC is forecasting 6,845 MW.h of major industrial sales in 2008 and 29,023 MW.h in 2009. This is slightly lower than the 32,500 MW.h per year assumed in the Power Purchase Agreement ("PPA") Application for Minto filed in February 2007, and reflects the fact that several loads included in the original assumptions provided by Minto Explorations were not ultimately required

QUESTION:

a) On a monthly basis for 2008 and 2009, please provide all the billing determinants for industrial sales (Demand Charge, Energy Charge, Fixed Charge) that result in total forecast revenues of $709,000 in 2008 and $3,142,000 in 2009.

b) Please detail the due diligence and analysis performed by YEC to prepare the industrial sales forecast including an analysis of the underlying load assumptions used in the preparation of the GRA forecast as compared to the underlying load assumptions used in the preparation of the PPA. Please comment on the factors that would result in actual sales being higher or lower than forecast.

c) Please comment on the impact of the worsening world and Canadian economic situation and outlook on YEC's industrial sales forecast.

d) Please confirm that YEC is holding a security deposit for its new industrial customer per Section 4.9 of the Electric Service Regulations. If not, please explain why and detail the security that YEC has in place with respect to collection risk on energy sales to Minto Explorations.

e) Using the same load forecast in 2010 as used for 2009 as well the most recently available chain price index, please provide the forecast revenue increase for

2010 as a result of the escalation of demand and energy charges based on the 12 month implicit chain price index for gross domestic product at market prices for Canada as reported by Statistics Canada.

f) Please provide a copy of the YEC / Minto Explorations PPA that was signed off by representatives of YEC and Minto Explorations, filed with the Board on May 14, 2007 and approved by the Board in Board Order 2007-6.

g) Further to YEC stating it expected to commence PPA discussions with Western Copper later in 2008 (page 2-7), please provide an update on the status of these PPA discussions and the impact on YEC's longer term load forecast relating to this customer.

h) Further to YEC stating it expected to discuss a PPA with Alexco Resource Corp. (Alexco) later in 2008 (page 2-7), please provide an update on the status of these PPA discussions and the impact on YEC's longer term load forecast relating to this customer.

i) Further to YEC stating there are other near-term mine developments in the next 4 to 7 years, please provide an update on these near-term mine developments and the impact on YEC's longer term load forecast.

ANSWER:

(a)

Please see the tables below.

Revenue from Industrial Sales (2008 Forecast)

Month	Demand Charge @ $15.0 / kv.a	Energy Charge @ $ 0.076 / kW.h	Total Revenue
Jan	-	-	-
Feb	-	-	-
Mar	-	-	-
Apr	-	-	-
May	-	-	-
Jun	-	-	-
Jul	-	-	-
Aug	-	-	-
Sep	-	-	-
Oct	63,000	175,286	238,286
Nov	63,000	169,632	232,632
Dec	63,000	175,286	238,286
Total			709,205

Revenue from Industrial Sales (2009 Forecast)

Month	Demand Charge @ $15.0 / kv.a	Energy Charge @ $ 0.076 / kW.h	Total Revenue
Jan	78,000	187,337	265,337
Feb	78,000	169,208	247,208
Mar	78,000	187,337	265,337
Apr	78,000	181,294	259,294
May	78,000	187,337	265,337
Jun	78,000	181,294	259,294
Jul	78,000	187,337	265,337
Aug	78,000	187,337	265,337
Sep	78,000	181,294	259,294
Oct	78,000	187,337	265,337
Nov	78,000	181,294	259,294
Dec	78,000	187,337	265,337
Total			3,141,746

(b)

Yukon Energy prepared the GRA industrial load forecast based on input from Minto. With respect to variance from PPA loads, please see YUB-YEC-1-2.

(c)

Based on conditions as currently understood the Minto operations are expected to generally evolve as previously assumed. Alexco operations are still assumed to be connected as an industrial customer in 2010. It is possible other potential new industrial connections may experience delays related to accessibility of financing and to allow for recovery of commodity prices. However, YEC has been focusing on essential requirements and to date has not had opportunities to discuss these issues with potential other new industrial connections.

(d)

Not confirmed. Security for collection risk on sales to the Mine is covered by section 6.5 of the Power Purchase Agreement.

(e)

The requested information is not relevant to the current Application.

(f)

Please see response to CW-YEC-1-1.

(g)

Please see response to LE-YEC-1-62.

(h)

Please see response to LE-YEC-1-8. Current information on industrial loads is provided in CW-YEC-1-31(a).

(i)

The information provided at Tab 2 of the Application (pages 2-6 and 2-7) remains current.

REFERENCE: **Page 2-8, Page 2-16 through to Page 2-18**

TOPIC: **Residential and General Service Sales Forecast**

PREAMBLE:

Residential sales are forecast to be 11,155 MW.h in 2008 and 11,183 MW.h in 2009 and General Service sales are forecast to be 18,193 MW.h in 2008 and 19,543 MW.h in 2009.

QUESTION:

a) Please confirm if YEC believes its Residential and General Service retail sales are impacted by temperature? If so, please quantify. If not, please explain why not.

b) Please confirm YEC prepared its Residential and General Service sales forecast on a temperature normalized basis. If not, please explain why.

c) Please provide an update on YEC forecasted sales with Alexco and the due diligence it has done with respect to forecasting the load.

d) Please provide the forecasted peak demand for Alexco and the due diligence YEC completed to confirm this forecast.

ANSWER:

(a)

Yes. However, these impacts are not considered material since Residential and General Service retail sales make up the minority of YEC's sales. It is noted that approximately 90% of YEC's sales are to wholesale and industrial customers.

The forecast methods applied by YEC are discussed in LE-YEC-1-7.

(b)

No. Please see response to LE-YEC-1-7 as to approach adopted.

(c)

Please see response to LE-YEC-1-7.

(d)

For 2009 Alexco is not an industrial customer, but rather a General Service Non-Government customer, and as such its peak demand is not forecast individually.

REFERENCE: **Introduction to application page 11**

TOPIC: **System Bulk Power Supplies**

PREAMBLE:

Under b. Firm Electric Heating YEC states "it is imperative that customers today do not receive price signals that encourage the installation of inefficient baseboard electric heating…."

QUESTION:

a) Please provide copies of any analysis undertaken by YEC to support the view that the use of baseboard heating contributes significantly to system load in the Yukon.

b) Please provide copies of all meeting minutes or notes whereby YEC consulted with Yukon Electrical, as the primary distributor and customer contact in the Yukon, as it relates to energy planning for the Yukon.

ANSWER:

(a)

Yukon Energy has not conducted any analysis that indicates the extent of baseboard electric heating load. Yukon Energy has conducted analysis that, at present run out rates, the economic incentive for baseboard heating is out of step with the principles of economy and efficiency as set out in OIC 1995/90, as illustrated at pages 4-10 to 4-14 of the Application.

(b)

Please see YECL-YEC-1-26(c).

REFERENCE: **Page 2-9 to Page 2-10**

TOPIC: **Secondary Sales Forecast**

PREAMBLE:

Secondary sales are forecast to be 20,557 MW.h in 2008 and 16,613 MW.h in 2009.

QUESTION:

a) Please confirm that YEC prepared the secondary sales forecast based on normalized temperatures. If not, why not.

b) In excel format, please provide and supporting data that was used to prepare the daily and monthly secondary sales forecasts that total 20,557 MW.h and 16,613 MW.h for 2008 and 2009 respectively.

c) In excel format, please provide the load and supply data that resulted in YEC determining there would be 1,740 hours of secondary sales interruption in January, February and December of 2009.

d) In excel format, please explain and detail how YEC determined the maximum potential secondary sales in 2009 is forecast to be 22,000 MW.h reflecting the sum of connected loads, less an unavailability factor related to customer equipment.

e) Please explain and detail the work done by YEC when it advised Yukon Electrical in early 2008 that forecast secondary sales for 2008 and 2009 were 16,853 MW.h and 6,954 MW.h respectively as compared to YEC's October 2008 GRA forecast of 20,557 MW.h and 16,613 MW.h respectively. Please ensure this response highlights the major changes in assumptions and the associated reasons.

f) Please confirm which secondary sales customers were SCADA connected customers in 2005, 2006, 2007 and which customers are forecast to be SCADA connected in 2008 and 2009. What is the forecast impact, if any, of the additional customers being SCADA connected?

g) In a manner similar to YECL-YEC-1-46 (2005 YEC Application IR response), please prepare a chart that compares monthly 2005 WAF surplus hydro availability to the forecasts for 2008 and 2009.

ANSWER:

(a)

YEC does not prepare its secondary sales forecast based on analytical "normalized" temperatures for the following reasons:

- Many secondary sales customers do not use their boilers as their sole heating source. In larger installations the electric boiler often operates at a designated level (i.e. 85 to 90% of its capacity) with a primary heat source picking up the difference. Therefore temperature fluctuations are addressed by the primary heat source boiler.

- One factor driving secondary sales is whether the owner operates the unit to its full operating potential. There are many instances observed over the past 4 years where secondary sales have not been at the levels Yukon Energy would expect based on the installed capacity of customers. It is not apparent to YEC why these installations were not operating near their full levels, but Yukon Energy has been asked by YECL to not contact these customers when such situations are evident, and Yukon Energy has complied with this direction.

- Many secondary sales customers in fact have an inverse relationship with temperature. There are two heat pumps that use less secondary sales when it gets colder, while there is a process operator that uses more secondary sales as the weather gets warmer.

Based on the above factors, YEC is of the view that historic averages by customer, adjusted for availability factors, are the best indicators of secondary sales potential.

(b) and **(c)**

Please see Attachment 1 to this response. This Excel files summarizes the data used to derive "standard" monthly load duration curves, using actual hourly loads from two datasets – February 1998 to January 2003, and January 2004 to December 2007. For each month, the standard load duration curve is a composite of 9 years of past data. The file also shows the estimates prepared on the basis that for each hour where secondary sales must be interrupted, due to actual peaking diesel use had it not been interrupted, it is assumed 4 hours of secondary would be interrupted to deal with notification periods, day/night load variance, and other interruptions not forecast in this model related to diesel required for other purposes, such as unscheduled hydro outages.

Secondary sales forecast data provided in the attachment are for the WAF grid, which combined with secondary sales for MD grid, total to 20,557 MW.h and 16,613 MW.h for 2008 and 2009 respectively.

It is noted that there is a misprint in the Application. The correct hours of secondary sales interruption is 1704.

YEC does not assume that these hours of interruption will be in January, February and December of 2009 only. As noted on page 2-10 of the Application (footnote 10), the hours of interruption are concentrated in January, February and December of 2009, but they happen in other months of the year as well.

(d)

The 22 GW.h reflects an approximate cumulative value of historic monthly averages for established customers plus an estimate for the newest customer to connect to secondary sales. It is assumed that the historic averages by customer reflect an element of unavailability for breakdowns or maintenance as this should be an annual or intermittent event that would impact sales in past years. It is not possible to accurately forecast what level of unavailability will occur as we cannot forecast equipment breakdowns. So in some years the actual sales will exceed the forecast sales while in other years they fall short.

There is no Excel format analysis for this adjustment.

(e)

The forecasts provided in early 2008 to YECL were based on an early assumption that all WAF secondary sales would have to be interrupted once CSTP was in service, with the exception of the months of May through September 2009, as set out in the following table:

YEC 2009 secondary sales forecast as of early 2008

	Secondary sales kW.h
May 2009	1,890,050
June 2009	1,543,250
July 2009	971,800
August 2009	1,118,800
September 2009	1,430,150
total	6,954,050

(f)

Only the Whitehorse General Hospital was SCADA connected for 2005 through 2008. It represents an approximate load of 1 MW. There is one other government building in discussions regarding becoming SCADA connected in 2009. If connected, it would represent a load of approximately 0.4 MW.

The benefit of SCADA connected customers is that they can be dropped off or reconnected to the system on very short notice as the need arises.

(g)

It is not possible to provide a chart at the present time that outlines surplus energy availability as requested. The availability of surplus energy is not specifically linked to any given month, but rather to the quantity of water in storage and otherwise required to be spilled, as well as the relative water conditions on the system at any given point in time.

As noted at page 2-9 to 2-10 of the Application, the key constraint at the present time with respect to secondary sales is peaking diesel which is set out in detail in response to YECL-YEC-1-23(b).

REFERENCE: **Page 2-19**

TOPIC: **Line Losses**

PREAMBLE:

Line 3 losses %. Yukon Electrical would like more information on line losses

QUESTION:

a) Please provide a breakdown of the line loss total into the Mayo Dawson versus WAF grids.

b) Please comment on the difference in loss percentages and any plans in the test periods to improve upon the efficiencies in the respective systems.

ANSWER:

(a)

The requested information is provided below.

Breakdown of the Line Loss Total for the Years 2005-2009

	Actual 2005	Actual 2006	Actual 2007	Forecast 2008	Forecast 2009
WAF Grid Losses - MWh	18,669	18,747	19,542	21,915	22,337
MD Grid Losses - MWh	5,288	6,137	5,489	5,440	6,608
Total Losses	23,957	24,884	25,031	27,355	28,945
WAF Sales - MWh	264,975	280,728	285,820	293,618	319,107
WAF Losses - %	7.05%	6.68%	6.84%	7.46%	7.00%
MD Sales - MWh	20,254	21,305	22,022	22,412	24,474
MD Losses - %	26.11%	28.80%	24.92%	24.27%	27.00%

(b)

Please see response to YECL-YEC-1-2(f). There are no specific plans for reduction in losses at this time.

REFERENCE: **Page 12 - Workshop Presentation Faro Dewatering Account**

PREAMBLE:

Yukon Electrical wishes to understand the customer impact of using the Faro Dewatering Account to pay for unrelated YEC costs.

QUESTION:

a) Please provide the details of all of the withdrawals / inputs that YEC has made on the dewatering account since its inception.

b) Please provide a continuity schedule demonstrating a) above.

c) Please provide the percentage of rate increase that each withdrawal represents to customers had it been provided through traditional regulatory means.

ANSWER:

The preamble to the question is not clear. The Faro Dewatering amounts have not been used to pay for "unrelated YEC costs". Amounts in regulatory liabilities held by YEC (including the deferred Faro dewatering revenues) are funds held for the benefit of ratepayers and only applied pursuant to a specific direction of the YUB.

(a) and **(b)**

Please see table provided below. Amounts indicated as "sales to ARM" are sales to the party in charge of site maintenance at the Faro mine site from time to time over the period 1998-2004 (when the total amount of these sales was being deferred).

Continuity Schedule of the "Faro Dewatering Account"

Year	Opening Balance	Invoice	Labour charges	Year End Flex Note Adjustment	Faro Mine Trust Transfer	Ending Balance	
1998	0.00	(297,924.00)	3,153.79			(294,770.21)	
1999	(294,770.21)	(171,204.00)	655.84			(465,318.37)	
2000	(465,318.37)	(257,440.00)		124,883.00		(597,875.37)	
2001	(597,875.37)	(559,944.00)	2,726.96	94,875.00		(1,060,217.41)	
2002	(1,060,217.41)	(442,200.00)	3,067.85	73,329.00		(1,426,020.56)	
2003	(1,426,020.56)	(421,053.60)	2,074.16	70,725.74		(1,774,274.26)	
2004	(1,774,274.26)	(353,324.40)	1,090.64	58,623.31		(2,067,884.71)	
2005	(2,067,884.71)				292,000.00	(1,775,884.71)	
2006	(1,775,884.71)				292,000.00	(1,483,884.71)	
2007	(1,483,884.71)				292,000.00	(1,191,884.71)	
2008	(1,191,884.71)				0.00	(1,191,884.71)	note 1

Note 1:
There is no YUB Board Order to enable YEC to make an annual withdrawal from the Income Stabilitation Trust account for 2008

(c)

There have been no withdrawals from the account related to imposing rate increases on customers, whether "traditional" or otherwise. Yukon Energy has not had a rate increase since 1998 (related to the closure of the Faro mine) which pre-dates any deferred Faro dewatering revenue amounts.

On the basis of total base rates, such as Rider J is applied, the $0.292 million annual withdrawal allowed Yukon Energy to avoid the need for a rate increase of approximately 0.8% through each of the years 2005 to 2007.

REFERENCE: **Introduction Page 1-3**

TOPIC: **20 Year Resource Plan**

PREAMBLE:

Throughout its application YEC refers to the 20 Year Resource Plan.

QUESTION:

a) Has the 20 Year Resource Plan been approved for implementation? If so under which authority has it been approved? Please provide a copy of the approval.

b) What aspects of the 20 year plan have been implemented and what have been the costs associated with implementing each aspect of the Plan?

c) Did YEC consult with Yukon Electrical on the 20 Year Plan? If not, why not? If so, please provide all documentation in YEC's possession regarding such discussions.

d) Does YEC support ongoing consultation with Yukon Electrical on system planning matters, as Yukon Electrical serves the majority of the customers in the Yukon? If not, why not? If so, please provide the details of how YEC plans to include Yukon Electrical and its customers in the system planning process?

e) Will the proposed 3rd wheel at Aishihik increase the maximum amount of MW that YEC will be able to supply to the grid? If so, how many additional MWs will be generated? How long would this increased amount of MW be sustained?

ANSWER:

(a)

The 20 Year Resource Plan was reviewed in detail by the Board and interested parties and the YUB provided its views and recommendations relative to all sections of the report to the government.

(b)

The 20 Year Resource Plan Recommendations and Proposed Actions have been pursued as follows:

- Chapter 3: Yukon Energy operates with updated Capacity Planning Criteria. No specific costs are associated with this item.

- Chapter 4 Proposed Actions (costs as noted for capital projects in Tab 5)
  - Item 1: Aishihik 3rd turbine is being pursued – see YUB-YEC-1-27(b).
  - Item 2: Marsh Fall/Winter Storage remains an attractive project as noted in YUB-YEC-1-27(a).
  - Item 3: Carmacks-Stewart Transmission Project Stage I is now in service, and Stage II remains a project under active planning.
  - Item 4 and 5: Mirrlees Life Extension Project is underway, with units at Faro and Whitehorse in service in the test years, and two additional units at Whitehorse scheduled for beyond the test years.
  - Item 6: Ongoing monitoring of loads, including industrial, is an active YEC assignment. Major loads including Alexco, Western Copper, the Faro reclamation activities, and other potential customers are tracked. No specific cost for this activity is identified.
  - Item 7: Other small enhancement projects have been pursued – the Southern Lakes study is complete largely in relation to Marsh Lake. Re-runnering hydro units is an active opportunity YEC continues to review, and will implement in the event economically feasible. YEC has rejected the concept of a 1 MW diesel at Carcross as new capacity is not required on the WAF system at this time.

- Chapter 5 Proposed Actions (costs as noted in Tab 5)
  - 10 MW scenario:
    - Aishihik Diversions and Atlin Storage are projects that are being considered for advancement (see page 5-20).
    - System-wide water and load dispatch model development is completed
    - Assessment of the Southern Lakes has been initiated with hydrology studies; the potential for water control structures has an initial focus on Atlin Lake.
    - Mayo Hydro enhancements are in active planning.

- WAF new small hydro has been investigated (e.g., Drury), with the conclusion that Mayo B is preferable in the near-term.
- DSM: Activities focus on support for Yukon Government initiatives.

- 25 MW scenario: In addition to 10 MW scenario
  - Update WAF hydro information for larger potential generation (e.g., Hoole Canyon).
  - Prepare initial pre-feasibility concept on major wind generation development.
- 40 MW and 120-360 MW Scenarios – no activity.
- Pre-commitment activities:
  - Monitoring industrial load developments – see above.
  - Southern Lakes Hydrology – see above.
  - Other existing Hydro Facility Enhancements – see above.
  - Level 1 and 2 assessments to identify preferred 5-30 MW scale Yukon hydro sites – see above.
  - Ongoing monitoring of hydrology – being undertaken at this time in conjunction with potential resources in the Aishihik area.

(c)

Yukon Energy sought the involvement of YECL in Resource Plan activities, both prior to and during the regulatory hearing. From July 2005 through November 2005, Yukon Energy provided both written requests and in person discussions requesting YECL's cooperation in the exercise of developing a 20-Year Resource Plan. Attached (attachments YECL-YEC-1-26(c) 1-4) is all correspondence YEC could readily locate in regards to those attempts at consultation.

In regards to the regulatory review, in its September 25, 2006 letter to the YUB, YECL noted that it would "…no longer actively participate in the current review of YEC's 20 Year Resource Plan; but will focus its attention on the significant regulatory projects that are expected to be brought before the Yukon Utilities Board under Part 3 of the Act."

(d)

Yukon Energy routinely works with YECL on distribution planning matters where the two utilities interface. As part of any next update to the major Resource Plan, Yukon Energy

expects opportunities for involvement of YECL and customers, in the event they elect to participate.

As the primary generator and transmitter of power in Yukon, Yukon Energy is required to maintain day-to-day responsibility over ongoing system planning activities in these functions.

(e)

The proposed third wheel at Aishihik is 7 MW. Yukon Energy has not yet proposed an operational plan for the unit. Opportunities to generate will be sustained as long as there is water in Aishihik Lake above the minimum level of Yukon Energy's licence.

Details regarding the expected Aishihik 3rd Turbine impacts on displacing diesel generation under various load and timing scenarios were reviewed during the Resource Plan Hearing and the CSTP Part 3 Hearing. See UCG-YEC-1-17(a) for further information.

YUKON ENERGY CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 5L6
(867) 393-5300

0310-03-04

July 18, 2005

Doug Tenney
The Yukon Electrical Company Limited
100, 1100 First Avenue
Whitehorse, YT
Y1A 3T4

Dear Doug,

Yukon Energy is currently undergoing planning with respect to major generation and transmission infrastructure. This planning process is intended to determine the bulk power requirements of the WAF and Mayo-Dawson systems, as well as potential for future interconnection to isolated systems.

In this regard, given the large part of our load accounted for by Yukon Electrical, we have identified below specific information from YECL that would assist with respect to our current planning for bulk power supply in Yukon. We have attempted to address these requirements in a form that we assume is readily available from Alberta Power as it was produced in past YUB hearings (and is expected to be required in future for YUB proceedings). However, if the same data is more easily produced in a different format using today's computer systems, that would be acceptable as well.

1. ***Actual Loads:*** The actual loads and customer numbers by customer class and community for the last 3 fiscal years. It may be helpful if it can be produced in the form of CI-YEC/YECL-23 from the 1993/94 GRA as it relates to YECL, particularly Tables 5 to 7 (energy loads, losses and supply by rate schedule), Tables 8 to 10 (showing demand loads, losses and supply by rate schedule; please confirm that these are coincident peak values), Tables 11 to 13 (showing customer numbers by rate schedule), and Table 17 (losses and supply by community).
2. ***Forecast Loads:*** Please provide any current forecasts of the loads and customer numbers similar to the actuals provided in bullet 1 above, to the extent that this information is available within YECL. Please also provide any long-term load growth assumption used by YECL in its planning exercises to ensure consistency between the two utilities.
3. ***Generator Complement:*** Please provide an update of the interrogatory response UCG-YEC/YECL-1-73 from the 1996/97 GRA indicating the YECL diesel generator inventory and planned retirement dates (we do not require the data in the final column on book value). Please also indicate any planned additions or replacements to any of the diesel units on each system.

4. ***Fish Lake Hydro:*** Please provide the actuals for Fish Lake hydro for the last three years. In addition, please provide any new assumed long-term average output, any planned improvements to change the average output, any assumed low flow reliable winter period output at time of WAF peak, or if there are any established retirement dates. This would include any impacts on the reliable low flow peak to increase or decrease the currently assumed 1 MW of peak winter capability.

We are attempting to deal with this bulk power planning exercise expeditiously. If some material can be provided easily, while other material will require some time, we would appreciate receiving what is readily available as soon as possible, preferably within the next two to three weeks. Please let me know if there is anything we can do to help clarify and deal with the above.

Sincerely,

David Morrison
President

YUKON ENERGY

COPY

YUKON ENERGY CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 5L6
(867) 393-5300

September 12, 2005

Doug Tenney
The Yukon Electrical Company Limited
100, 1100 First Avenue
Whitehorse, YT
Y1A 3T4

Dear Doug,

On Wednesday August 24th, 2005 during our meeting at Yukon Energy's offices, you indicated that YECL was not willing, for reasons of commercial competition (as I understood your position), to share any of the YECL load and generation information that YEC had requested in its letter of July 18th. I have reviewed this matter further and I would like you to reconsider your position. I sincerely hope with the further explanation provided below YECL will better understand why Yukon Energy is seeking YECL's cooperation in YEC's bulk power planning exercise and as a result will provide the information requested.

As originally noted in our July 18th letter, YEC is attempting to deal with its generation and transmission resource planning exercise in an expedited manner hence the reason why we were requesting the information be provided quickly. However, given your initial reaction to YEC's request I think it would be helpful to explain in more detail why YEC needs the information requested.

As was indicated in our July 18th letter, Yukon Energy has undertaken a major review of its present and future generation and transmission infrastructure systems needs including a complete condition assessment of our major infrastructure and a review of the capacity planning criteria presently in use for Yukon's grid systems. It is our expectation that this exercise will ultimately lead to a review by the YUB of Yukon Energy's twenty year resource use plan.

The last time that the YUB reviewed such major capital plans and projects, it recommended in its December 7, 1992 Report to Commissioner in Executive Council (in the Load Forecasts section) that the Utilities provide detailed support for their load forecasts:

> *... the Board agrees with the position of the City of Whitehorse, and recommends that a more rigorous approach to forecasting use per customer be taken by the*

Companies. In future general rate applications or review of capital plans, the Companies should be able to provide detailed support for such forecasts.

Obviously, we are interested in ensuring that such "detailed support" is available for any YUB review of our capital plans that involves forecasting use per customer and other similar planning elements relevant to Yukon bulk power system planning.

Given that YECL represents the majority of Yukon Energy's load on WAF and is also a regulated utility, necessary information that would be provided in the normal regulatory review process was accordingly requested from YECL to assist in Yukon Energy's planning. Cooperation with Yukon Electrical is a critical precondition if we are to provide the "detailed support" recommended by the YUB. Our request focused on the integrated WAF and Mayo-Dawson grids and potential for future interconnection to isolated systems, specifically requesting typical information that YECL would provide in any GRA (and in fact, as indicated in the letter, is based on requests from the 1993/94 GRA and the 1996/97 GRA, which YECL fully responded to at that time). With regard to loads, we attempted to focus our request on customer class information. We were not attempting to obtain confidential information on any individual customers.

Hopefully with this further explanation Yukon Electrical will reconsider its decision. However, if you have any further questions or concerns in this regard, please let me know as soon as possible so that we can assist in moving forward in a timely way.

On a related note, before we conclude our current planning exercise, Yukon Energy would like to meet with you to brief Yukon Electrical on the matters being discussed as part of this resource planning process. Such a meeting would also allow us to obtain YECL's input on these matters. Please let me know about Yukon Electrical's interest and availability for such a session.

Sincerely,

David Morrison
President



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0310-03-04

November 25, 2005

COPY

Mr. Doug Tenney
The Yukon Electrical Company Limited
100, 1100 First Avenue
Whitehorse, YT
Y1A 3T4

Dear Doug,

I am writing to remind you of the September 12th, 2005 letter I sent you as a follow-up to our Wednesday August 24th, 2005 meeting at Yukon Energy's offices.

At our August 24th, 2005 meeting, you indicated that YECL was not willing, for reasons of commercial competition (as I understood your position), to share any of the YECL load and generation information that YEC had requested in its letter of July 18th. In my September 12th, 2005 letter, I asked you to reconsider this position and to cooperate with our current generation and transmission resource use planning by providing readily available information that historically has been provided by YECL in past GRAs.

As noted, Yukon Energy's request was consistent with the YUB's recommendation from its December 7, 1992 Report to Commissioner in Executive Council (in the Load Forecasts section) that the Utilities provide detailed support for their load forecasts. As I also indicated in my September 12th, 2005 letter, with regard to loads, we attempted to focus our request on customer class information. We were not attempting to obtain confidential information on any individual customers.

We have obviously carried on without the YECL data. However, I would still appreciate a response to clarify Yukon Electrical's position on these matters before we finish our current work and any filings with the Yukon Utilities Board, and in particular to confirm if YECL is now taking the position that any such data will no longer be made available and/or to clarify under what conditions it will be provided in future.

Yours truly

David Morrison
President

The Yukon Electrical Company Limited
An ***ATCO*** Company

December 7, 2005

Mr. David Morrison
President
Yukon Energy Corporation
PO Box 5920
Whitehorse, Yukon
Y1A 5L6

Re: Generation and Transmission Planning in Yukon

Dear Mr. Morrison:

On July 18, 2005, you wrote to Yukon Electrical requesting a variety of information including actual load, forecast load, generation inventory and generation planned retirement dates for both grid and non-grid communities for use in "our current planning for bulk power supply in Yukon." On August 24, we had an opportunity to meet face to face to discuss this request. During this meeting, I believe that I informed you that given the current structure of the electric industry in the Yukon, that Yukon Electrical wanted to have an opportunity to participate in any new generation or transmission facilities required in Yukon. To allow for this and to serve the public interest, Yukon Electrical believes that planning should be conducted jointly rather than by only one utility. As such the provision of all of the information requested by Yukon Energy would put Yukon Electrical at a competitive disadvantage.

It should also be remembered that on an annual basis, Yukon Electrical does provide Yukon Energy with a three year forecast of our purchase power requirements on the Whitehorse-Aishihik-Faro grid as well as actual and forecast Fish Lake Hydro generation.

On September 12, Yukon Energy wrote back in response to the August 24th meeting. Yukon Energy reiterated that it was in the midst of "a major review of its present and future generation and transmission infrastructure system needs including a complete condition assessment of our major infrastructure and a review of the capacity planning criteria presently in use for the Yukon's grid systems." (emphasis added) Again, Yukon Electrical took this to mean that Yukon Energy alone was planning the system requirements.

The September 12th letter went on to state, as justification for why Yukon Electrical should now provide the data requested, that the YUB in its December 7, 1992 Report to Commissioner in Executive Council regarding sales forecasts stated "In future general rate applications or review of capital plans, the Companies should be able to provide detailed support of such forecasts." It should be remembered, that at the time that the YUB made this comment, the two companies were jointly managed and thus had joint

THE YUKON ELECTRICAL COMPANY LIMITED
An ***ATCO*** Company

system planning. Effective January 1, 1998, the joint management ceased and to-date, no process for joint planning has been implemented. As well, as YEC intends on filing its capital plan with the YUB, it should be ready and able to defend its sales forecast no differently than it did in its 2005 Required Revenues and Related Matters Application.

It should be clear that Yukon Electrical believes that joint planning of the generation and transmission requirements of Yukon needs only to address:

- the current and forecast load,
- the current capacity of the system including planned retirements, and
- the planning criteria to be used in determining the need for new generation and transmission on the system.

The companies' specific plans to satisfy these requirements do not need to be shared as part of joint planning but rather will be the subject of review by the YUB as part of any energy project certification application by either company.

Yukon Energy, in its September 12th letter, offered to meet with Yukon Electrical prior to the completion of its exercise in order to obtain "Yukon Electrical's input" on these matters. At that time, Yukon Electrical believed, correctly or incorrectly, that the offer, should have taken place when the terms of reference and scope of the exercise were being developed. However, it is important that the planning of the Yukon's electrical requirements moves forward. To this end, Yukon Electric would like to meet with Yukon Energy so that both companies can share customer class actual and forecast sales data by community as well as generation capacities and planned retirement dates. Further discussion will be required for customer class coincident peak data as this information is not readily available and must be estimated in any event.

I trust that this clarifies Yukon Electrical's position and I want to inform you that Yukon Electrical is available to meet at your earliest convenience. Please call if you require any further clarification or wish to set a time to meet.

Yours truly,
THE YUKON ELECTRICAL COMPANY LIMITED
An **ATCO** Company

Doug Tenney
General Manager

Cc Sett Policicchio, President ATCO Electric

Printed on recycled paper

REFERENCE: **General**

TOPIC: **Accounting Policy**

PREAMBLE:

Yukon Electrical needs to understand YEC's accounting and regulatory practices.

QUESTION:

a) Please provide details, rationale, and support for, all changes to accounting policies since 2005.

b) Please provide details, rationale, options considered and support for all changes to regulatory practice since 2005.

ANSWER:

(a)

Please see response provided to CW-YEC-1-35.

(b)

The only change to regulatory practice since 2005 is the recent practice of the Board with respect to regulatory hearing costs. Previously, Yukon Energy had either expensed costs related to regulatory proceedings, or began amortizing the amounts over the period to which the hearing related. In recent Board Orders (CSTP Part 3, Resource Plan, and Minto PPA) the Board has directed YEC to maintain all costs in a hearing cost reserve account for amortization beginning at the next YEC GRA. This has been followed by YEC, as shown in Tables 5.3 to 5.7.

REFERENCE: **Page 4**

TOPIC: **Rate Case Expense**

PREAMBLE:

"c. **Depreciation and Amortization Expenses** of $6.403 million for 2008 and $6.930 million for 2009 including approval to amortize the following regulatory costs: i. An estimated "placeholder" expense of $0.800 million related to costs for the current GRA (Phase I) Application, anticipated to be incurred over 2008 and 2009 for preparation and review of the Application and reimbursement of related intervenor and YUB costs, to be amortized over the 2 test years (2008 and 2009). The intensity and duration of the regulatory process cannot be determined at this time. Accordingly, Yukon Energy seeks approval to adjust the above amount to reflect the full actual amounts incurred or Ordered to be reimbursed at the time of the final refiling in the current GRA process, following receipt of all final Orders from the Board. No amounts have been estimated for any future Phase II GRA activities related to further rate design and/or cost of service study matters."

QUESTION:

a) Please provide complete details of all components of $800,000 estimate for rate case costs, including estimate for internal costs and external costs.

b) If estimate for costs includes use of consultants, please provide:
   i engagement letter and terms of reference;
   ii description of services being provided; and
   iii hourly rate being charged and hours estimated.

c) Please confirm that amortization of rate case costs of $400,000 is included in YEC's revenue requirement for each of 2008 and 2009.

d) Please provide a continuity schedule of this deferral account for the period 2005-2009 showing:
   i opening balance;
   ii rate case costs;
   iii amortization of rate case costs; and

iv closing balance.

e) Please confirm that YEC's intent is to continue to include $400,000 in revenue requirement and amortization expense in 2010 and beyond if there is no rate case for 2010 and 2009 rates continue into 2010. If not confirmed, please fully explain why not.

ANSWER:

(a) and **(b)**

Yukon Energy's initial response, and its response to YUB-YEC-1-4, noted that the $800,000 estimate in the Application is only a top-down, "placeholder" estimate (as noted at page 4 of the Application) and YEC did not have available any specific estimated amounts for consulting versus other services (such as travel or legal). YEC's initial response also noted that all costs charged to the regulatory account are incremental costs (supplies, consultants, overtime, travel) and do not include normal staff salaries.

Board Order 2009-4 directed Yukon Energy to respond in terms of total costs and the portion it expects to occur due to the use of its own consultants.

The initial estimate provided when the Application was being prepared was based on the assumption that, given the previous review in 2005, the process would be more efficient and costs would be less than experienced at that time. This assumption did not bear out. Based on current information the present forecast cost of the current GRA hearing process is now $1,100,000 determined as follows:

Consulting	$480,000
Legal	220,000
Misc Internal	50,000
Board/Intervenor Costs	350,000
	$1,100,000

As previously noted, subsequent to the hearing, Yukon Energy will be filing actual costs for the Board's review and approval.

(c)

Confirmed.

(d)

Please see Tables 5.3 to 5.7.

(e)

Not confirmed. If the hearing costs are fully amortized by the end of 2009, they will not be amortized in 2010.

Yukon Energy has not determined if 2010 will be a test year with its own revenue requirement being set by the Board. Absent such a process (such as a GRA), the 2009 rates will continue until such time as there is need to revise the rates for a future test year.

REFERENCE: **Page 3-13, Lines 5-6 and Page 4**

TOPIC: **Reserve for Injuries and Damages (RFID)**

PREAMBLE:

Page 3-13 The Reserve for Injuries and Damages ("RFID") is an account maintained as approved by the Board, in order to address uninsured and uninsurable losses as well as the deductible portion of insured losses.[7]

[7] Yukon Energy noted during the 2005 rate review process that it applies the following corporate accounting practice with respect to the Reserve for Injuries and Damages (RFID):

• It is a contingency reserve set up to address the cost of uninsured/uninsurable losses.

• Uninsured losses are defined as losses that could be covered by insurance but which Yukon Energy has chosen not to insure because the probability, frequency and/or dollar value of losses do not justify the premium.

• Uninsurable losses are those losses for which coverage is not available in the conventional insurance market.

• The RFID is also used to pay the insurance policy deductible in the event of a claimed loss.

Page 4: To increase the annual appropriation to the RFID to $150,000 from the current $50,000 starting in 2009.

QUESTION:

a) Please provide details of the process that is followed when charging items to the RFID, including an outline of all approvals required prior to charging items to the RFID.

b) Please provide a continuity schedule for the period 2005-2008 of the RFID showing:
   i Opening balance;
   ii Claims (itemize all claims to reserve);
   iii Provision charged to O&M;
   iv Other (itemize all transfers, etc.; and
   v Closing RFID balance.

c) For all claims itemized above please provide:
   i Description of claim;
   ii Date when incident happened;
   iii Explanation of why it qualified to be charged to RFID; and
   iv Evidence of appropriate sign offs and approvals for incident to be charged to the reserve.

ANSWER:

(a)

Charges to the RFID are at the discretion of the CFO. Generally, after the CFO authorizes, a work order is set up in the financial system for tracking costs associated with a given event.

(b)

Continuity Schedule – YEC Reserve for Injuries and Damages

	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)
Opening Balance	**797**	**-33**	**500**	**463**
Additions				
Computer Stolen	4			
Third Party Vehicle Damage - Mayo	1			
Service Truck Fire Loss	1			
Dawson Hse H20 Damage	6			
Marsh Lake Dam Repair	2			
YUB Board Order 2005-12 transfer from Reg Liability	-743			
Takhini Substn Break-In		15		
Kulan Break In		32		
L171 Lightning Arr Failure		11		
L171 Insulator Failure		35		
Whitehorse Hydrant Leak		36		
Unit 63 Vehicle Theft		2		
WH1 Hub and Blade Repair		302		
Aishihik Cable Repair		200		
L174 Broken Pole			39	
Marsh Lake Water Damage			17	
Kulan Warehouse Water Damage			7	
L172 Insulator Failure				40
Rock Creek Crossing				11
Polaris Ranger & Trailer Replacement				9
Repair Outage Damage				25
Streetlight damage				1
Total	**-730**	**633**	**63**	**86**
Annual Provision	**-100**	**-100**	**-100**	**-50**
Closing Balance	**-33**	**500**	**463**	**500**

(c)

2008

L172 Insulator Failure

- ***Description of Claim*:** Vandalism damage to line insulation.
- ***Date of Incident*:** Night of May 4, 2008.
- ***Explanation:*** Loss to uninsured asset.
- ***Sign offs and approvals:*** There was approval from the CFO.

Rock Creek Crossing

- ***Description of Claim:*** The line crossing at Rock Creek got washed away due to high water.
- ***Date of Incident:*** May/June 2008.
- ***Explanation***: This incident was not an insured event.
- ***Sign offs and approvals:*** Approved by the CFO.

Polaris Ranger & Trailer Replacement

- ***Description of claim:*** Two miles south of Moose Creek a company truck pulling a trailer with a Ranger ran into some icy conditions. The trailer with the Ranger broke free from the vehicle and rolled into the ditch, resulting in both the trailer and the Ranger being completely destroyed.
- ***Date of Incident:*** April 17, 2008.
- ***Explanation:*** This loss was claimed under insurance. RFID was charged for loss of use and replacement cost above insurance proceeds.
- ***Sign offs and Approvals:*** There was sign off from the CFO on the proof of loss.

Repair Outage Damage

- ***Description of Claim:*** Outage caused by problems with the WH-4 governor.
- ***Date of Incident:*** October 12, 2008.
- ***Explanation:*** Insured loss (sudden, accidental breakdown of insured property), not claimed due to insurance policy deductible exceeding total value of loss.
- **Sign offs and Approvals:** Approval by the CFO for all charges to this work order.

Streetlight Damage

- ***Description of Claim:*** YEC line vehicle struck a streetlight and knocked it down (this streetlight owned by YECL).
- ***Date of Incident:*** August, 2008.
- ***Explanation:*** Cost of damage was below deductible for liability insurance policy.
- ***Sign offs and Approvals:*** Approved by CFO.

2007

L174 *Broken Pole*

- ***Description of Claim:*** There was a broken pole on the Aishihik Transmission Line.
- ***Date of Incident:*** First two weeks of February, 2007.
- ***Explanation:*** Uninsured event.
- ***Sign offs and Approvals:*** There was approval from the CFO.

Marsh Lake Water Damage

- ***Description of Claim:*** High water damaged the Lewes Control Structure.
- ***Date of Incident:*** July/August, 2007.
- ***Explanation:*** Insured loss (sudden, accidental breakdown of insured property), not claimed due to insurance policy deductible exceeding total value of loss.
- ***Sign offs and Approvals:*** There was approval from the CFO.

Kulan Warehouse Water Damage

- ***Description of Claim:*** A water tank at the Kulan Warehouse broke causing water damage.
- **Date of Incident:** September 9, 2007.
- ***Explanation:*** Insured loss (sudden, accidental breakdown of insured property), not claimed due to insurance policy deductible exceeding total value of loss.
- ***Sign offs and Approvals:*** There was approval from the CFO.

2006

Takhini Substation Break-In

- ***Description of Claim:*** Persons unknown broke into substation building and vandalized equipment.
- ***Date of Incident:*** January, 2005.
- ***Explanation:*** Below deductible.
- ***Sign offs and Approvals:*** Approved by CFO.

Kulan Break-In

- ***Description of Claim:*** Persons unknown entered YEC yard in Kulan industrial park; broke into storage container and stole various line maintenance tools and equipment.
- ***Date of Incident:*** April, 2005.
- ***Explanation:*** Loss below deductible limit.
- ***Sign offs and approvals:*** Approved by CFO.

L171 Lightning Arrestor Failure

- ***Description of Claim:*** Line arrestor prematurely failed, required emergency repair.
- ***Date of Incident:*** August, 2005.
- ***Explanation:*** Loss below deductible.
- ***Sign offs and Approvals:*** Approved by CFO.

L171 Insulator Failure

- ***Description of Claim:*** An insulator on the L171 line prematurely failed.
- ***Date of Incident:*** May 19, 2006.
- ***Explanation:*** Uninsured Loss.
- ***Sign offs and Approvals:*** There was approval from the CFO.

Whitehorse Hydrant Leak

- ***Description of claim***: Leak in underground piping for hydrant system at Whitehorse Rapids Generation Station.
- ***Date of Incident:*** Late July 2006.
- ***Explanation:*** Insured loss (sudden, accidental breakdown of insured property), not claimed due to insurance policy deductible exceeding total value of loss.
- ***Sign offs and Approvals*****:** There was approval from the CFO.

Unit 63 Vehicle Theft

- ***Description of Claim*****:** Unit was stolen and successfully recovered; claim is for damages incurred.
- ***Date of Incident:*** December, 2006.
- ***Explanation:*** Insured loss (sudden, accidental breakdown of insured property), not claimed due to insurance policy deductible exceeding total value of loss.
- ***Sign offs and Approvals:*** Approved by CFO.

WH1 Hub and Blade Repair

- ***Description of Claim:*** Hub failure in adjustable turbine blade.
- ***Date of Incident:*** March 20, 2006.
- ***Explanation***: The amount of the loss was unknown at the time of the incident; insurer was advised of a potential loss. Subsequent to the repair, the total loss was determined to be $302,000. At that time, the deductible on YEC's property insurance policy was $250,000; our broker advised against making a claim for the $50,000 differential as this would have a negative effect on future premiums (insurers look at claimed losses in five previous years when pricing policies).
- ***Sign offs and Approvals:*** There was approval from the CFO.

Aishihik Cable Repair

- ***Description of Claim:*** A Failure in cable leading from turbine to switchgear.
- ***Date of Incident:*** January 2006.
- ***Explanation***: Insured loss (sudden, accidental breakdown of insured property), not claimed due to insurance policy deductible exceeding total value of loss.
- ***Sign offs and Approvals:*** There was approval from the CFO.

2005

Computer Stolen

- ***Description of Claim:*** Computer Stolen.
- ***Date of Incident:*** Q1 2005.
- ***Explanation:*** Insured loss (sudden, accidental breakdown of insured property), not claimed due to insurance policy deductible exceeding total value of loss.
- ***Sign offs and Approvals:*** There was approval from the CFO.

Third Party Vehicle Damage - Mayo

- ***Description of Claim:*** YEC employee struck a third party vehicle while backing out of a parking spot.
- ***Date of incident:*** May 2005.
- ***Explanation:*** Insured event under automotive liability insurance policy; not claimed as total value of loss was below the policy deductible.
- ***Sign offs and Approvals*****:** There was approval from the CFO.

Service Truck Fire Loss

- ***Description of claim:*** Electrical short in winching mechanism caused fire and total loss of vehicle.
- ***Date of Incident:*** October, 2004.
- ***Explanation:*** Costs for uninsured contents lost in fire.
- ***Sign offs and Approvals:*** There was approval from the CFO.

Dawson Hse H20 Damage

- ***Description of Claim:*** Water line failure damages.
- ***Date of Incident:*** May 2005.
- ***Explanation:*** Insured loss (sudden, accidental breakdown of insured property), not claimed due to insurance policy deductible exceeding total value of loss.
- ***Sign offs and Approvals:*** There was approval from the CFO.

Marsh Lake Dam Repair

- ***Description of Claim:*** Repair vandalism damages to Marsh Lake Structure.
- ***Date of Incident:*** October, 2005.
- ***Explanation:*** Insured loss (sudden, accidental breakdown of insured property), not claimed due to insurance policy deductible exceeding total value of loss.
- ***Sign offs and Approvals:*** There was approval from the CFO.

REFERENCE: **General**

TOPIC: **Affiliate Agreements**

PREAMBLE:

Yukon Electrical is interested in understanding the relationship between YEC, YDC and YTG.

QUESTION:

a) Please provide a copy of all agreements that exist between YEC and YDC as well as YTG pertaining to affiliate transactions, governance, code of conduct, etc. Also, please provide a breakdown of any funds that YEC has received or anticipates receiving from or paying to YDC and or YTG for the years 2005 to 2009 and provide the details of each transaction.

ANSWER:

(a)

YEC has an agreement to provided corporate and financial services to YDC on a cost-recovery basis. See Attachment 1 to this response. The table below covers payments to and from YEC and YDC and YG.

	2005	2006	2007	2008	2009
Payments from YDC					
Services	244	216	157	- [1]	-
Rate Stabilization Fund	358	432	310	216	110
Other contribution agreements	34	25	25	-	-
Rural Electrification Support		86			
Debt financing - Minto Mine contributions				16,081	1,919
Contributions to CSTP [1]			4,000	2,957	
Settlement of MDTS outstanding claims				3,000 [4]	
Payments to YDC					
Interest	3,780	4,164	4,311	5,612	5,386
Principle	861	1,001	977	1,254	3,649
Financial system lease	177	177	177	177	150
Payments from YTG[2]					
Contributions to CSTP [1]		450		10,000 [3]	
Contributions to Aishihik Third Turbine				1,500 [3]	3,500

NOTES

1. YEC does not in practice forecast Services provided as all services are billed at full cost - therefore no financial impact to the organization.

2. YEC engages in normal commercial transactions with YTG as part of operations (e.g. new services, WCB premiums, etc). These payments are not included in this analysis.

3. Contributions received from YTG via YDC.

1 4. Settlement paid by YDC on YEC's behalf.

INTER-COMPANY ARRANGEMENTS ON SERVICES

THIS ARRANGEMENT is made effective as of September 1, 2005:

BETWEEN:

YUKON ENERGY CORPORATION

("YEC")

AND

YUKON DEVELOPMENT CORPORATION

("YDC")

RECITALS

A. YEC is engaged in the generation, transmission and distribution of electricity in the Yukon Territory and owns and controls certain assets in connection therewith;

B. YDC is engaged in assisting in the sustainable energy development of the Yukon and owns all of the shares of YEC ;

C. YDC requires certain financial, accounting and corporate services;

D. YEC has agreed to provide those services to YDC on the terms set out below, and

E. It is understood that this agreement replaces the original Inter-company Agreement on Financial Services effective January 1, 2002.

ARRANGEMENT

The parties wish to confirm their understanding of their arrangement as follows:

1 **Description of Services.**

1.1 YEC will provide financial, accounting and corporate services ("Services") for YDC as specified in Schedule A, and may provide or facilitate the provision of other financial management systems and services as required by YDC on a mutually acceptable and full cost recovery basis.

1.2 The Services will be performed by appropriately qualified personnel coordinated through the Chief Financial Officer (YEC) and the Chief Executive Officer (YDC) and/or their delegates.

2 **Facilities and Equipment.**

2.1 Unless otherwise agreed, the Services will be performed and provided from the offices of YEC.

3 **Relationship of Parties.**

3.1 YEC will at all times be an independent contractor and will be solely responsible for paying the salary, wages and related benefits of its financial services personnel and for withholding and remitting all statutory deductions relating thereto.

4 **Termination**

4.1 This Arrangement will commence as of the effective date and continue indefinitely, but either party may terminate this Arrangement by providing to the other party not less than 6 months notice in writing to that effect or full equivalent payment in lieu with such termination being effective at the beginning of YDC's next fiscal year.

4.2 This Arrangement may be terminated by either party immediately if the other party fails to adequately perform any of its material obligations under this Arrangement, provided that the deficiency has been brought to the other party's attention in writing and the deficiency has not been remedied to the first party's satisfaction within 3 months after the delivery of the notice.

4.3 If this Arrangement is terminated, YEC will deliver forthwith to YDC all books, documents, records, manuals and all other relevant documentation, including all electronic files and data that are maintained either in whole or in part relating to the performance of the Services.

5 **Payment of Fee**

5.1 YDC will pay YEC a fee for the Services provided (the "Fee"). The amount of the Fee will be equal to the full cost incurred by YEC in providing the Services, it being agreed that YEC shall not suffer a loss or realize a profit as a result of providing the Services.

5.2 YEC will invoice YDC for the Fee, with sufficient and appropriate documentation to support the amount of the Fee, and YDC will pay the Fee to YEC within 30 days after it receives the invoice plus interest thereafter at an agreed upon rate on overdue amounts established annually. In the event of any dispute regarding the amount of the Fee, the parties will endeavour to resolve the dispute by mutual agreement, but failing agreement the Fee will be determined by arbitration pursuant to Article 8.

5.3 For greater clarity, the amount of the Fee will include an appropriate share of YEC's costs of salary or wages and related benefits, insurance, office overhead, and other similar costs that relate to provision of the Services, but YEC shall not include any costs in the Fee more than one time.

5.4 Invoicing for Services provided will occur at least quarterly being March 31, June 30, September 30 and December 31.

6 Indemnities

6.1 YDC will indemnify and save harmless YEC from and against all liabilities, claims, and demands arising out of the performance of the Services by YEC personnel.

6.2 YEC will indemnify and save harmless YDC from and against all liabilities, claims and demands whatsoever to the extent they are caused by the negligence of YEC or any of its personnel in the provision of the Services.

6.3 In performing the Services, YEC will, at all times, exercise the standard of care, skill, diligence and timeliness normally provided in the performance of services for work of a similar nature internal to YEC to that contemplated by this Arrangement.

7 General

7.1 YDC's published financial statements will at all times be in accordance with Canadian Generally Accepted Accounting Principles. YDC shall take responsibility for the contents of the financial statements. Any accounting questions that arises in the provision of the Services may be referred to the coordinators referred to in section 1.2 for resolution.

7.2 YDC is responsible for compliance with the *Financial Administration Act* (Yukon), *Yukon Development Corporation Act* and any other legislation governing its financial affairs.

7.3 Subject to prior notice from YEC and section 5.1, YDC agrees it will not unreasonably withhold consent to YEC implementing any order made by the Yukon Utilities Board or any regulation that affects the provision of the Services, and the order or regulation will take precedence in the event of inconsistency with the terms of this Arrangement.

7.4 The parties agree that this agreement may be amended from time to time by mutual consent and in writing.

8 Arbitration

8.1 **Procedure.** In the event of any dispute as to the rights or obligations of any party hereunder, either party may by notice to the other submit the dispute to arbitration as follows:

(a) within ten (10) days from the date of such submission, the parties shall agree on the appointment of a single arbitrator who shall hear and determine the matter in dispute. If the parties are unable to agree on a single arbitrator within ten (10) days of such submission, then either party may apply to the Supreme Court of the Yukon Territory for appointment of the arbitrator.

(b) the arbitrator shall proceed immediately to hear and determine the matter in dispute. The determination of the arbitrator shall be made within thirty (30) days after the appointment of the arbitrator subject to any reasonable delay due to unforeseen circumstances; and

(c) the arbitrator's determination shall be in writing, and shall be final and binding on the parties, and the parties shall abide by the determination and perform in accordance with the terms and conditions thereof.

8.2 **Cost of Arbitration.** The costs of arbitration (other than internal costs of the parties) shall be paid as directed by the arbitrator.

8.3 **Applicability of Arbitration Act.** The provisions of this Article shall be deemed to be a submission to arbitration within the provisions of the *Arbitration Act* (Yukon) except that any limitation on the remuneration of the arbitrators imposed by such legislation shall not be applicable.

9 Applicable Law

9.1 This Arrangement shall be construed and interpreted in accordance with the laws of the Yukon Territory and the laws of Canada applicable therein.

10 Confidentiality

10.1 Any information given to or reviewed by YEC as a result of performing the Services, including all information relating to the Services or other business and affairs of YDC, their investments, affiliates, co-venturers, or the Yukon Government, shall be considered as confidential and privileged by YEC personnel and consultants (the "Confidential Information"), except information falling into one of the following categories:

(a) information that YEC demonstrates was in its possession on a non-confidential basis prior to receipt or acquisition of such information from YDC; and

(b) information that is lawfully in the public domain at the time of receipt by YEC of such information from YDC.

10.2 Except where required by an order of the court or by law or the professional standards or rules referred to in section 1.3, YEC shall not use or disclose the Confidential Information, without the prior written consent of YDC.

10.3 YEC may disclose the Confidential Information to those of its employees, consultants or suppliers and their respective employees to whom disclosure is required for YEC to perform the Services provided that YEC shall use best efforts to ensure that its employees, consultants and suppliers keep Confidential Information in confidence and shall not disclose it to others, except as required by section 10.2, without the prior written consent of YDC.

10.4 The provisions of this Article 10 shall survive termination of this Arrangement.

11 Notice

11.1 Any notice or other communication required or permitted to be given under this Arrangement shall be in writing unless otherwise specified and shall be effectively given if mailed in Canada by first class mail, postage prepaid, delivered or sent by telecopier or other electronic means of communication which results in a printed signed document, addressed or directed as follows:

To YEC at:

Yukon Energy Corporation
Box 5920
Whitehorse, Yukon
Y1A 6S7

Attention: Chief Financial Officer

To YDC at:

Yukon Development Corporation
Box 2703 (D-1)
Whitehorse, Yukon
Y1A 2C6

Attention: Chief Executive Officer

or to such other person or address or number as a party may specify by notice given as set out above.

11.2 Any notice or other communication will be deemed to have been received as follows:

(a) if delivered or sent by telecopier or other electronic means, on the day of delivery or transmission if it is a business day and otherwise on the next succeeding business day;

(b) if mailed, on the fifth business day following the date on which it was mailed.

11.3 If at the time of the giving of notice there is a postal dispute, all communications shall be delivered or sent by telecopier or other electronic means of communication which results in a printed signed document.

12 **Assignability**

12.1 Neither party may assign any of its rights hereunder to any other party without the prior written consent of the other.

IN WITNESS WHEREOF the parties hereto have confirmed this inter-company Arrangement as of the day and year first written above.

SIGNED AND DELIVERED BY **YUKON DEVELOPMENT CORPORATION** IN THE PRESENCE OF:

Susan Rousseau
(Witness Signature)

Susan Rousseau
(Witness Name)

Sept 28/05
(Date)

Blaine R. Anderson
(Signature of Authorized Representative)

BLAINE ANDERSON
(Name of Authorized Representative)

CHIEF FINANCIAL OFFICER
(Title)

SIGNED, SEALED AND DELIVERED BY **YUKON ENERGY CORPORATION** IN THE PRESENCE OF:

Shelley Dixon
(Witness Signature)

Shelley Dixon
(Witness Name)

Sept 30/05
(Date)

(Signature of Authorized Representative)

DAVID MORRISON
(Printed Name of Authorized Representative)

PRESIDENT + CEO
(Legal Name)

SCHEDULE "A"

FINANCIAL, ACCOUNTING AND CORPORATE SERVICES

YEC agrees to provide the following financial, accounting and corporate services:

1. General ledger accounting and maintenance including account reconciliation
2. accounts payable processing and payments
3. accounts receivable processing and payments
4. cash monitoring
5. preparation of financial reports and analysis as required
6. support for year end audit purposes, including preparation of working papers.
7. Where appropriate, provide payroll services to YDC BOD members.
8. Provide legal services
9. Provide management consulting services
10. Provide support to the Board of Directors including the services of a Corporate Secretary, the services of a Chairman and advice on governance issues (and related training as deemed necessary)
11. Provide corporate communications services including the preparation of an annual report
12. Provide Information Systems services including support for software and hardware
13. Provide advice on strategic and financial planning
14. Provide general administrative support
15. Purchase insurance, where cost-effective to do so, on behalf of YDC in conjunction with the insurance program for YEC and charge a proportionate share of the costs

REFERENCE: **Page 5-23, Lines 11-16**

TOPIC: **International Financial Reporting Standards (IFRS)**

PREAMBLE:

QUESTION:

a) Please provide details of the costs that comprise the $46,000 in 2008 and $105,500 in 2009 required to investigate IFRS.

b) If any of the cost components in (a) above include payments to external consultants, please provide:
   i engagement letter and terms of reference;
   ii description of the services being provided; and
   iii the hourly rate being charged.

c) Please provide a status on what steps YEC has taken to date to be compliant with IFRS and provide YEC's detailed plan, including timelines, on what YEC is required to do to become compliant effective 2011.

ANSWER:

(a)

Yukon Energy appointed outside consultants to provide assistance with the required future conversion to International Financial Reporting Standards (IFRS) in 2008. Several conference calls were undertaken to discuss where the utility's progress with regard to the implementation of accounting standards as well as areas of potential concern.

Yukon Energy requested that the consultants perform a high level diagnostic and qualitative assessment designed to identify the main IFRS areas that the Utility needs to address.

The costs associated with 2009 relate to having the consultants visit Yukon Energy and provide the following services:

- Detailed assessment of identified areas;
- Training to staff and board members; and
- Assistance with the implementation of IFRS requirements on the new FIS system.
- To assist in the preparation and design of IFRS-compliant financial statements and business processes.

(b)

Please see response provided to **(a)** above. Yukon Energy has an engagement with KPMG on this matter. Details of specific contract terms are confidential.

(c)

Yukon Energy has completed a Quick Scan of the utility (high level diagnostic). The consultants have visited the site and collected information about YEC's system and processes. A shared site has been developed to allow direct communications between the Utility and the consultant. The consultant provided assistance with specifications for the new FIS system.

YEC is currently working on a more detailed plan, to meet the target implementation timing.

REFERENCE: **Page 3-12, Table 3.10**

TOPIC: **Insurance**

PREAMBLE:

QUESTION:

a) For 2005-2009, please provide details of insurance coverage. Include information on the amount being covered, a description of each component of the coverage, as well as, the deductible and forecasted premiums for each policy for the coverage.

b) Please explain all changes to either the insurance coverage or the deductible since 2005.

c) Please discuss the interrelationships between coverage, deductibles and premiums and why the specific levels were arrived at for each policy included in (a) above.

ANSWER:

(a) and **(b)**

Please see table below.

Details of Insurance coverages, by year – part I

Year	Type	Description	Limits	Premium	Deductible
2008-2009	Property	Property and Equipment Breakdown	$250,000,000	$585,000	$100,000 except $250,000 equipment breakdown and $50,000 inland transit and course of construction
	Liability	Automobile Liability	$5,000,000	$79,022	$10,000 for Ford F800 and Crane Truck, $2,500 for all other vehicles and $1000 for trailers, snowmobiles and ATV's
	Liability	Excess General Liability	$50,000,000	$110,696	$250,000 for all losses except $500,000 for Pollution
	Liability	Non-owned Aviation	$5,000,000	$3,715	Nil
	Other	Directors' and Officers Liability	$10,000,000	$17,928	$50,000 Self Insured retention
	Other	Crime	$1,000,000	$3,255	$20,000
2007-2008	Property	Property/Inland Transit	$230,000,000	$499,100	$200,000 all Losses except $100,000 building and $50,000 Inland Transit. 48 hour waiting
	Property	Boiler & Machinery	$100,000,000	$100,000	$250,000 property damage.
	Liability	Auto Liability	$5,000,000	$77,646	$10,000 for Ford F800 and Crane Truck, $2,500 for all other vehicles and $1000 for trailers, snowmobiles and ATV's
	Liability	Excess General Liability	$50,000,000	$106,275	$250,000 all losses except $650,000 gradual pollution
	Liability	Non-owned Aviation	$5,000,000	$3,715	Nil
	Other	Directors' and Officers Liability	$10,000,000	$15,238	$20,000 each loss
	Other	Crime	$1,000,000	$3,255	$100,000

Details of Insurance coverages, by year – part II

2006-2007	Property	Property/Inland Transit	$230,000,000	$499,814	$200,000 except inland transit of $50,000
	Property	Boiler & Machinery	$100,000,000	$68,575	$250,000 except $500,000 for WD1, WD2 and WD3
	Liability	Auto Liability		$75,794	
	Liability	Excess General Liability	$50,000,000	$109,013	$250,000
	Liability	Non-owned Aviation		$3,910	
	Other	Directors' and Officers Liability	$10,000,000	$32,000	$100,000
	Other	Crime		$3,255	
2005-2006	Property	Property/Inland Transit	$230,000,000	$645,263	$200,000 except inland transit of $50,000 and $100,000 main office building
	Property	Boiler & Machinery			
	Liability	Auto Liability	$5,000,000	$71,084	$5,000 for Ford F800, $2,500 for all other vehicles and $1000 for trailers, snowmobiles and ATV's
	Liability	Excess General Liability	$50,000,000	$107,747	$250,000 except $650,000 pollution liability
	Liability	Non-owned Aviation	$5,000,000	$3,258	Nil
	Other	Directors' and Officers Liability	$10,000,000	$33,688	$100,000
	Other	Crime	$1,000,000	$3,100	$20,000

(c)

Yukon Energy has a professional broker who, among other things, provides management with recommendations on optimal coverage for a given cost given the industry sector and corporate risk profile. On any given renewal, pricing for coverage will fluctuate year over year. The broker reviews these changes and management assesses on a case-by-case basis how to balance premium cost vs. coverage.

REFERENCE: **Page 3-11**

TOPIC: **Information Systems**

PREAMBLE:

Since 2005, there has been a significant increase in software license fees.

QUESTION:

a) Please provide details of each fee, including what system fee is required and who fee is paid to.
   i. If fee is paid to an 'affiliate' organization external to YEC, please provide a copy of service agreement that governs service levels and associated costs.
   ii. If there is no service agreement, please explain why not.

ANSWER:

(a)

There are no fees paid to affiliates. Fees are paid to either the reseller or the vendor for all products.

The table below reports the Software licence renewals costs contained in the Information Systems line reported in Table 3.9 Administration on Page 3-10 of the Application.

Software or Service	'2005 Actual	'2006 Actual	'2007 Actual	'2008 GRA	'2009 GRA
Website hosting & domain name fees for yukonenergy.ca			75	1,450	1,450
TDG & WHIMIS software				2,000	2,000
HR Mgr	1,856	1,895	1,935	2,000	2,000
Bentley Microstation	745	1,830	3,173	2,500	3,400
Dell Canada	808				
T4 Timesaver			240	250	250
Entrust SSL certificates			383		
Entrust SSL certificates				500	500
Genesis				850	850
Genesis - Phone call accounting system	750	750	750		
Ecolog OH&S				2,500	2,500
Ecolog OH&S	1,515	2,238	2,147		
Dell Canada		700	1,922		
Checkpoint / NOKIA		10,093	13,086		
Domain name registration (yec.yk.ca)			50		
Checkpoint / NOKIA				12,550	12,550
MS systems center configuration manager				3,000	3,000
Dell Canada		1,313	3,232		
PolarGroup ICT - Domain Name	1,032	4,557	905	80	80
PLS-CADD				1,600	1,600
McAfee			3,745	11,250	11,250
VMWare Infrastructure Enterprise for 2 processors				3,500	3,500
VMWae Virtual Center mgmt server				1,500	1,500
Symantec Corp - Veritas Backup Exec				4,600	4,600
Microsoft Bulk Licenses			36,586	27,000	31,000
Sharepoint 2007 for search				6,400	6,400
Symantec - Veritas Enterprise vault				2,300	2,300
Adobe Acrobat		832		2,000	2,000
Cisco Smartnet Support				10,000	10,000
Symantec			2,199		
Platinum support for 2 ESX servers			2,268		
Backup Exec software 1 BE servers			890		
Sharepoint					43,020
PSS/sincal				4,000	4,000
Solar Winds - Orion				2,000	2,000
Surf Controll & Web filter/monitoring	4,527	2,761	8,105		10,000
Snag it Software			423		
Dell Canada	1,515				
Veritas Software		2,892			
Org Plus					
Dell Canada		75			
Zone Alarm			509		500
	12,749	29,935	82,622	103,830	162,250

Note, in addition to the above which are recorded as IT department licences, approximately $10,000 per year is spent on JD Edwards licencing for the finance department, and approximately $3,000 to $10,000 for electrical system testing software licencing for technical services.

REFERENCE: **Schedule 11 line 50**

TOPIC: **Other Revenues**

PREAMBLE:

Other revenue decrease from $161,000 in 2006 to forecasts of $125,000 in each of 2008 and 2009.

QUESTION:

a) On annual basis from 2005 through to 2009, please provide details on Other Revenues and provide reasons for variances.

ANSWER:

(a)

Please see table provided below.

Other Revenues 2005 -2007 Actual and 2008 - 2009 Proposed

Other Revenue	2005 Actual	2006 Actual	2007 Actual	2008 Proposed	2009 Proposed
House/Office Rent	22	29	29		
Misc Revenue	57	103	8		
Stock Sales	2	3	0		
(Gain)Loss Disposition on F/A	(15)	(3)	(49)		
Revenue from YDC	225	204	146		
Revenue from ESC	181	73			
Cost of Services to YDC	(225)	(201)	(142)		
Cost of Services to ESC	(179)	(73)	(3)		
Cost of Goods	(55)	(98)	(5)		
Office Rent/Yard Rent	(14)	(1)	4		
Reconnection Fee	12	12	10	11	11
Penalty Charges	0	0	1		
Joint Pole Use	108	111	115	115	115
Total	**118**	**161**	**115**	**126**	**126**

REFERENCE: **Page 5-17**

TOPIC: **Capital Expenditures – JD Edwards Replacement**

PREAMBLE:

Yukon Electrical wishes to understand the business needs for replacing the current Financial System

QUESTION:

a) Please provide the year acquired and total cost JD Edwards was acquired for.

b) Please provide the annual upgrade details and costs to JD Edwards since inception and the current version of the software.

c) Please provide the current yearly licensing and maintenance fees for JD Edwards.

d) Please provide the business case used in the decision to replace this system.

ANSWER:

(a)

Please see table provided below. JD Edwards was acquired in 1999. The total cost is approximately $1.413 million.

1999	FIS System	739
2001	Inventory System	466
2001	Fixed Assets	106
2001	Fixed Assets	11
2001	JDE report writing	91
	Total ($000):	**1,413**

(b)

YEC has not completed a full upgrade since 2003. Annual operating costs (excluding fees addressed in (c) below are limited to external consulting resources for periodic

programming and reporting fixes. These costs are included in Administration. The version of the software is JDEdwards OneWorld, version B7333, Service pack 22.

(c)

Yukon Energy paid $9,429 in 2008 to Oracle for the JD Edwards annual license fee; it is anticipated that the fee will increase slightly for 2009. Yukon Energy conducts most of its maintenance on JD Edwards internally and seeks external consultation when required.

(d)

The issue of replacing YEC's present financial system has been reviewed extensively by senior management over the last couple of years.

Unfortunately the present system simply cannot be maintained or upgraded given the age of the software program, the inability of the system to support operational requirements and the changing needs of the Company.

At a basic operational level the current software package is old and out of date -- it is approximately 10 years old, is very unstable and the developer/vendor of the system has not supported the software for over two years. These realities have created serious problems in efficiently using the system during that time. Even ignoring the material difficulties of using a 10 year old key financial system without vendor support, other problems relating to more functional issues are also being experienced including the following:

- Key fundamental configurations e.g. chart of accounts simply preclude any real option of upgrading the current system. The only possible alternative is re-implementation of the system which has the same effect from a cost perspective as a completely new implementation.

- Critical management reporting in such areas as project commitment reporting is not economically feasible under the current system.

In addition the poor configuration of the present system requires significant manual intervention in key processes, for example invoice payment – hard copy paper has to be

handled by 5 different people before a payment can be made. Enhanced functionality is required to eliminate these inefficient manual systems.

There is also a very urgent need for an electronic maintenance management system. The current manual job card system has proven ineffective at ensuring important maintenance activities occur on operational assets. An electronic system will allow management to program maintenance schedules by asset, employ automatic notification features to ensure tasks are completed on a timely basis, and provide enhanced tracking and reporting capabilities by asset. All of these features are absolutely critical to improving system reliability, which is a key strategic initiative for the corporation.

Given these factors and to ensure that the most efficient and cost effective solution was found --during 2008, management completed a comprehensive analysis of the business needs of all key areas expected to be served by a new system including the following:

- General ledger
- Accounts payable
- Accounts receivable
- Fixed assets
- Inventory
- Procurement
- Project accounting
- Maintenance management.

These needs were incorporated into a Request for Proposal competitive bid package. A copy of the package is provided as Attachment 1 to this response.

This bid process was closed at the end of February 2009. Four bids were received. A comprehensive evaluation process is underway, including price comparison and fit to required business needs. This “fit” is tested via live demonstration executing very detailed scripts developed by Yukon Energy. Once this process is complete and a vendor selected, a detailed implementation plan with timelines, resource requirements and deliverables will be assembled along with a project budget. This package will then be presented to the Yukon Energy Board of Directors for their review and approval.

The project is scheduled for completion in 2010. From a regulatory perspective, the costs will be in work-in-process until that time, so that approval to add to rate base will be sought at the next revenue requirement process.

Please see also response to YUB-YEC-1-37(c).

REQUEST FOR PROPOSAL (RFP) #2008-040

for

Enterprise Software System

YUKON ENERGY CORPORATION
Box 5920,
Whitehorse, YT Y1A 6S7
Phone: (867) 393-5302

TABLE OF CONTENTS

SECTION 1: INTRODUCTION 4

1.1 Corporate Overview 4
1.2 Project Purpose 4
1.3 Project Intent 4
1.4 Request for Proposal (RFP) Terminology 5
1.5 Time-Frames 6

SECTION 2: INSTRUCTIONS/INFORMATION TO PROPONENTS 7

2.1 Delivery of Proposals 7
2.2 Proposal Submission Requirements 7
2.3 Closing Date and Time 7
2.4 Verification of Receipt of Proposal 7
2.5 Questions and Queries 7
2.6 Proposal Withdrawals 8
2.7 Pricing Information 8
2.8 Amendments 8
2.9 Proposal Details 8
2.10 Innovative Processes / Value Added Elements 8
2.11 Right of Acceptance / Rejection 8
2.12 Disputes 9
2.13 Opening of Proposals 9
2.14 Addenda 9
2.15 Extensions 9
2.16 Waiver of Irregularities 10
2.17 Negotiations 10
2.18 Assignment / Affiliation 10
2.19 Incurred Costs / Expenses 10
2.20 Irrevocability 10
2.21 Clarification 10
2.22 Ownership of Proposals 11
2.23 Publicity 11
2.24 Confidential and Proprietary Information 11
2.25 No Collusion 11
2.26 References / Searches / Contacts 11
2.27 Full Disclosure 11
2.28 Bidder's Responsibilities 12
2.29 Joint Proposals and Subcontracting 12

SECTION 3: TERMS AND CONDITIONS 13

3.1 Insurance 13
3.2 Indemnification 13
3.3 Payment 13
3.4 Warranty and Guarantee 14
3.5 Termination 14
3.6 Laws, Permits and Licenses 15
3.7 Independent Consultant 15
3.8 The Workers' Compensation Act 15
3.9 Health and Safety 15
3.10 Environmental Protection 16
3.11 Confidentiality 16

SECTION 4: EVALUATION CRITERIA & PROCESS 17

4.1 Evaluation Methodology and Process 17
4.2 Evaluation Committee 17
4.3 Evaluation Criteria 17
4.4 Evaluation Process 17

SECTION 5: SUMMARY 19

SECTION 6: RESPONSE FORMAT 20

6.1.1 Title Page 20
6.1.2 Letter of Introduction 20
6.1.3 Table of Contents 20
6.1.4 Executive Summary 20
6.1.5 Proponent Information 20
6.1.6 Full Disclosure 20
6.1.7 Product Information 20
6.1.8 Implementation Approach & Methodology 20
6.1.9 Client References 20
6.1.10 Pricing 20
6.1.11 General Product Requirements 20
6.1.12 Data Conversion Requirements 20
6.1.13 Business Area Requirements 20

SECTION 7: CURRENT ORGANIZATION & PROCESSES 21

7.1 Organization Chart 21
7.2 Business Systems 22
7.3 Technical Platforms 25
7.4 Transaction Volumes 26
7.5 User Base 27

SECTION 8: PROPONENT RESPONSES 28

8.1 Proponent Information 28
8.2 Product Information 28
8.2.1 Third-Party Products 29
8.3 Implementation Approach & Methodology 29
8.4 Clients 29
8.5 Pricing 29
8.6 General Product Requirements 30
8.7 Data Conversion Requirements 31
8.8 Business Area Requirements 32

SECTION 9: INTENT TO RESPOND 33

SECTION 1: INTRODUCTION

1.1 CORPORATE OVERVIEW

Established in 1987, Yukon Energy Corporation ("the Corporation") is a publicly-owned electrical utility that operates as a business, at arms length from the Yukon government. We are the main generator and a transmitter of electrical energy in the Yukon and we work with our parent company Yukon Development Corporation to provide Yukon residents with a sufficient supply of safe, reliable electricity and related energy services.

The Corporation is regulated by the Business Corporations Act, the Public Utilities Act and the Yukon Water Act. Our headquarters are located near the Whitehorse Rapids hydro plant in Whitehorse with community offices in Mayo, Faro and Dawson City.

Additional Corporation information and annual reports can be viewed on the Corporation's website at: http://www.yukonenergy.ca

1.2 PROJECT PURPOSE

Yukon Energy Corporation ("the Corporation") is inviting submissions (Bids) for an enterprise-wide business system to replace its current system. The current system is an old release of Oracle's EnterpriseOne system which was formerly known as J.D. Edwards OneWorld. The modules in use are primarily the Finance modules (namely, General Accounting, Accounts Receivable, Accounts Payable and Project Accounting), Inventory Management and Procurement. ADP is used for Payroll and transactions are manually uploaded to the General Ledger. A replacement system for Payroll is not included in this initiative. However, interfaces between ADP and the replacement system will be required. Included in this initiative is also the sourcing of a Maintenance system. The preference is to find a product that has a 'built-in' Maintenance module which meets the Corporation's requirements. Other alternatives that will be considered include a strong enterprise product that has pre-built interfaces to another 3rd party Maintenance product or a solution of two products with the development of the required interfaces.

The Corporation's search for a replacement system does not preclude the Corporation's review of the latest release of Oracle's EnterpriseOne product. As the Corporation's current release is so far behind the latest release of the EnterpriseOne product, any consideration of the EnterpriseOne product will be reviewed as another potential competitive product.

The purpose of this Request for Proposal (RFP) is to find the best-fit solution to support the Corporation's requirements for functionality fit, process improvements, ease of use and including ease of support and maintenance in support of the Corporation's limited technical resources.

This Request for Proposal (RFP) is of two parts, namely, this document which is referred to as the "main document" and an attachment of worksheets referred to as "Attachment A".

1.3 PROJECT INTENT

It is the intent of the Corporation to obtain the best overall solution, services and value through a bidding process that provides a high level of responsiveness, quality Proposals, and a proponent that has a proven track record of meeting their client's needs.

1.4 REQUEST FOR PROPOSAL (RFP) TERMINOLOGY

Below is a list of terminology used throughout this RFP.

ADP - Refers to the software Payroll vendor, Automatic Data Processing Inc
AP - Accounts Payable
AR - Accounts Receivable
BOM - Bills of Materials
Business Unit - Refers to a department or a cost centre or a profit centre
CIS - Customer Information System; 3rd party software used for electric utility billing.
Corporation, the - Refers to Yukon Energy Corporation (YEC).
Customization or Custom - Refers to software programming to change existing program logic.
EM - Electrical Maintenance
FA - Fixed Assets
FIS - Financial Information System
GL - General Ledger
GST - Canadian Goods and Services Tax
IFRS - International Financial Reporting Standards
JDE - Refers to Oracle's enterprise applications system currently in use by Yukon Energy.
LPO - Local Purchase Order; small dollar (<$5,000) purchase orders manually written up on pre-printed forms.
MM - Mechanical Maintenance
O&M - Operations and Maintenance
PID - Project Identification
PM - Preventive Maintenance
PO - Purchase Order
PRC - Project Review Committee
Proposed Product or Proposed Solution - The terms "proposed product" and "proposed solution" are used interchangeably where applicable to refer to a proponent's proposed solution for Yukon Energy. The solution proposed can be one of a single product or a mixed of products including any third-party products.
Proprietary Product - The term "proprietary product" is used to refer to Proponents' primary suite of products in references to relationships with third-party products.
PST - Canadian Provincial Sales Tax
UOM - Units of Measure
WCB - Workers' Compensation Board
YEC - Refers to Yukon Energy Corporation
YTG - Refers to the Yukon Territory Government
YUB - Refers to the Yukon Utilities Board

1.5 TIME-FRAMES

The estimated time-frames shown below are anticipated schedules for events pertaining to this RFP and may vary at the sole discretion of Yukon Energy.

Event	Date
Request for Proposal (RFP) Issued	December 19, 2008
Deadline for "Intent to Respond" submission [1]	December 26, 2008 4:00pm PST
Last day for submission of questions relating to RFP	January 23, 2009 4:00pm PST
Last day of Corporation's responses to questions related to RFP	January 27, 2009 4:00pm PST
Deadline of proponent RFP submission to Corporation	January 30, 2009 4:00pm PST

[1] An "Intent to Respond" form is provided at the end of this RFP for Proponents to respond accordingly.

SECTION 2: INSTRUCTIONS/INFORMATION TO PROPONENTS

2.1 DELIVERY OF PROPOSALS

Proposals must be submitted in a sealed envelope and delivered in original form by hand or Courier to:

Yukon Energy Corporation ("the Corporation")
Attn: Purchasing
#2 Miles Canyon Road, P.O. Box 5920
Whitehorse, YT Y1A 6S7

Electronic copies of proposals are to be emailed to:

purchasing@yec.yk.ca
Subject: Yukon Energy RFP #2008-040

2.2 PROPOSAL SUBMISSION REQUIREMENTS

The proponent shall clearly identify on the envelope containing the proposal, the name and address of the bidder, the name of the tender, the tender number and the date and time of the proposal closing.

Two copies of the proposal must be submitted. One copy must be in hardcopy form, originally executed and include original signatures of duly authorized signatory(s) of the proponent. The second copy must be in electronic form and emailed to the email address indicated in *section 2.1, Delivery of Proposals*.

Proposals must be submitted in the format as documented in *Section 6: Response Format*.

2.3 CLOSING DATE AND TIME

The date and time of Proposal closing is **January 30, 2009 at 4:00 p.m. PST** (As per the Corporation time clock located at the Reception Area**).** In order to be considered, a Proposal must be received at the location specified herein on or before the Proposal closing time. Proposals received after the Proposal closing time will be rejected.

2.4 VERIFICATION OF RECEIPT OF PROPOSAL

Proponents may verify that their Proposal has been received prior to closing date and time by calling (867) 393-5302. The proponent must identify the company name before this information will be released. No other information concerning the Proposal will be released prior to Proposal Closing Date and Time.

2.5 QUESTIONS AND QUERIES

Proponents are required to submit their questions, including questions relating to specifications, discrepancies, omissions, or any apparent ambiguities, in writing, by fax, not less than three (3) working days before Closing Date and Time to:

Attention: **Lynda Harlow**, Procurement & Contractor Administrator
Yukon Energy Corporation
Telephone: 867-393-5302 Fax: 867-393-5301
E-mail: purchasing@yec.yk.ca

Proponents shall not contact or ask questions of any other Corporation personnel unless so directed elsewhere in this document. Information obtained from any person or source other than the Corporation's designate will not be considered as valid to this RFP process and cannot be considered or incorporated into

the proponent's Proposal submission. The Corporation reserves the right to disqualify any proponent who solicits information from any person other than the Corporation's designate.

The Corporation shall review the questions and where the information is not already clearly provided, will issue either a memorandum or an addendum to all proponents. The Proponent that submitted the question will not be identified in the Corporation's response. All memorandum and/or addenda become part of the RFP documents. Receipt of all addenda issued should be acknowledged by the proponent, on the Proposal form(s) provided for submission.

2.6 PROPOSAL WITHDRAWALS

Proposals may be withdrawn at any time prior to the Closing Date and Time by submitting a written withdrawal request to the same address to which the Proposal was submitted.

2.7 PRICING INFORMATION

Proposal prices shall be in Canadian dollars, and shall include all applicable duties and taxes, and all costs of performing the work, except the Canadian Federal Goods and Services Tax (GST). All prices listed in the submitted Proposal should exclude the GST costs and should be identified as a separate price to all or any requested pricing items.

2.8 AMENDMENTS

Where a Proposal has been received by the Corporation before the Proposal Closing Date and Time, amendments by e-mail or facsimile are acceptable provided that such amendments are received in writing at the location specified herein prior to the Proposal Closing Date and Time.

Amendments to a Proposal must clearly state the name of the Proposal, date and time of Proposal closing, the name and address of the Proposal in accordance with these Instructions to Proposal. Any amendment must be duly signed by an authorized signatory of the Proposal.

Any amendment to the Proposal price shall state only the amount by which the Proposal price is increased or decreased and shall not indicate the revised total Proposal price.

2.9 PROPOSAL DETAILS

Proponents should provide complete and accurate information and details for all aspects of their Proposals. Failure to respond to any requests for information, costs, qualifications or clauses will be deemed to be a negative response, and may disqualify the Proposal.

2.10 INNOVATIVE PROCESSES / VALUE ADDED ELEMENTS

Proponents wishing to submit other innovative methods or operational Proposals that they feel will benefit the Corporation are encouraged to do so. However, it is requested that all alternative Proposals be shown separately and submitted as an 'alternate Proposal' and accompanied by their initial Proposal that meets the service requirements stated in the RFP document. It is also requested that the proponent identify their preference of alternatives in order from first preference on.

2.11 RIGHT OF ACCEPTANCE / REJECTION

The Corporation, at its sole discretion, reserves the right at any time prior to selection of the successful proponent(s), to accept in whole or in part all Proposals it has received, to withdraw any portion of this RFP and/or to cancel this RFP in its entirety. Upon evaluation of all valid Proposals received, the Corporation will select the Proposal which offers the most effective and beneficial package. The Corporation reserves the right to award the work to one or more proponents. The lowest or any Proposal

will not necessarily be accepted. No act of the Corporation, other than a notice in writing signed by a Corporation's procurement employee, shall constitute an acceptance of a Proposal. In the event that all the Proposals exceed the budget set by the Corporation, the Corporation reserves the right not to accept any Proposals and to close the RFP process without award.

From the information submitted under this Request for Proposal, the Corporation shall determine the successful Proposal, which in the sole judgment of the Corporation, provides the best value to the Corporation in accordance with the requirements and criteria set out in this document. Further, the selection of the successful Proposal will be made on the basis of the Proposal which meets the Corporation's needs and the established deliverables stated in the specification section of this document including any addendums or memorandums.

This RFP should not be construed as an agreement to the identified service. The Corporation is not bound to enter into a contract with the proponent that submits the lowest price and/or fee structure, or with any proponent. Proposals will be assessed and evaluated in accordance with the evaluation criteria. The Corporation is under no obligation to receive further information, whether it is oral or written, from any proponent.

The Corporation will have no liability in any manner whatsoever to any of the proponents as a result of this RFP.

2.12 DISPUTES

If a dispute arises that cannot be resolved immediately by the Corporation's decision or negotiation between the parties, the dispute may be:

a) referred by either party for mediation before an independent project mediator ten (10) days after commencing negotiations; and,
b) referred to arbitration ten (10) days following the end of such mediation

If neither party requires mediation or arbitration within ten (10) days after a written notice that negotiation or mediations are at an end, either party may refer the dispute to the courts or both agree to proceed to mediation or arbitration notwithstanding that other necessary parties will not be bound by any resolution of this dispute.

2.13 OPENING OF PROPOSALS

The opening of Proposals will be closed to the public. Information on Proponent's names and/or prices received may be released at the Corporation's sole discretion. In the event proponent's names and/or prices are released, this information may be released in a timely fashion and only to qualifying proponents after responses are opened and a Contract is awarded to the successful proponent.

2.14 ADDENDA

All addenda issued during this RFP will become part of the RFP. The Proponent should identify all addendum received in their Proposal as requested in Section 7, Proposal Form 1, of this RFP.

2.15 EXTENSIONS

The Corporation may extend the Closing Date and Time of the RFP by issuing a written addendum to all proponents.

2.16 WAIVER OF IRREGULARITIES

The Corporation reserves the right to and may, in its sole discretion, waive any minor irregularity or non-compliant issues in the Proposals received. Failure to comply with any item(s) of this RFP may be deemed sufficient cause to reject all or part of any Proposal.

2.17 NEGOTIATIONS

Not withstanding any other provision in this RFP, the Corporation reserves the right in its sole and absolute discretion at any time and from time to time after submission of Proposals and before award of a contract(s) to negotiate any or all terms and conditions of a contract(s) or otherwise in respect of the work for which a contract may be awarded, including negotiating terms and conditions that are or may be different from those contained in the RFP documents, with one or more proponents but not necessarily with all proponents. The Corporation also reserves the right not to enter into negotiations with one or more proponents; to terminate negotiations with any proponent(s); not to offer the same or substantially the same negotiated terms and conditions of a contract(s) to more than one proponent; and to award a contract(s) by acceptance of any Proposal so negotiated.

2.18 ASSIGNMENT / AFFILIATION

In the event of an agreement, neither party shall assign or subcontract any part of the contract or any monies to become due there under without the prior written consent of the other. Written consent shall not be unreasonably withheld.

Proponents will disclose any and all business relationships that may impact the project or any component of the work, including but not limited to joint ventures and partnerships.

2.19 INCURRED COSTS / EXPENSES

Proponents are solely responsible for their own costs and expenses in preparing and submitting a Proposal and for any subsequent negotiation costs and expenses with the Corporation, if any.

If the Corporation elects to cancel this RFP or rejects all Proposals received, the Corporation will not be liable to any proponent for any costs or expenses of preparation and/or presentation of their Proposal.

The Corporation will not be liable to any proponent for any claims, whether for costs, expenses or damages incurred by a proponent in preparing its Proposal, loss of anticipated profits in connection with any final contract, or any other matter whatsoever.

By submitting a Proposal, the Proponent agrees that it will not claim damages, for whatever reason, relating to the RFP or in respect of the competitive process and agrees that it waives any claim for loss of profits if no contract is entered into with the proponent.

2.20 IRREVOCABILITY

Proposals shall be irrevocable for a period of ninety (90) days from the closing date, and the proponent shall not have the option of revoking its Proposal until the expiry of the irrevocable period.

2.21 CLARIFICATION

The Corporation reserves the right at any time to seek clarifications of, or any additional information in connection with, or modifications of, any Proposal from any one or more proponents, but not necessarily all proponents, either serially or concurrently, and in any manner including through written correspondence, interviews or presentations by proponents.

Any clarifications, additional information or modifications received in connection with this RFP may form part of the RFP and may be considered by the Corporation in its sole discretion in its RFP evaluation and decisions including without limitation as to acceptance, rejection, negotiation or award, and the Corporation will be entitled to accept any Proposal as clarified, supplemented or amended through this process.

2.22 OWNERSHIP OF PROPOSALS

All responsive Proposals including any documents submitted to the Corporation by a Bidder become the property of the Corporation and shall not be returned to the Bidder.

2.23 PUBLICITY

The proponent shall not issue any press release or make any public announcement or disclosure concerning the Proposal Documents, the Contract or the Proposal without the prior written consent of the Corporation.

2.24 CONFIDENTIAL AND PROPRIETARY INFORMATION

The Proposal documents are the property of the Corporation, and Bidders and/or any persons who have obtained a copy of the Proposal documents shall keep confidential and shall not use, reproduce or distribute any information, drawings or specifications included in or provided with the Proposal documents except for the purpose of preparing a Bid for the RFP.

The Corporation shall comply with all applicable privacy laws in respect to any Proposal to this RFP. Each Bidder shall clearly identify any information and/or records that it is providing in its Proposal that constitutes confidential information that is supplied in strict confidence and/or the release of which could significantly harm them.

2.25 NO COLLUSION

Proponents shall not discuss or communicate, in any form, with any other proponent or any representative or agent of any other proponent regarding the preparation or presentation of their Proposal. Proposals shall be submitted without any connection, knowledge, comparison of information, or arrangement, with any other proponent or any agent or representative of any other proponent.

If a proponent contemplates using the same Subcontractor or supplier for a particular part of the deliverables, the proponent shall put into place appropriate ethical walls and other safeguards to protect the confidentiality of their information and to ensure collusion does not take place.

2.26 REFERENCES / SEARCHES / CONTACTS

Proponents responding to this RFP, authorize the Corporation to contact any identified clients (current and past) and references regarding the information provided in their Proposal.

2.27 FULL DISCLOSURE

Proponents are to provide a written statement of full disclosure addressing the following particulars:

- any personal relationship to any employee of the Corporation who makes recommendations concerning the award of the Proposal contemplated within this RFP, or any employee (or immediate relative of an employee) of the Corporation with any direct, or indirect pecuniary interest, ownership or directorship with respect to the Proponent;

- any business relationship with the Corporation, any of its staff, employees, officers, directors or board members;
- any matter involving a dispute with a claimed value in excess of $50,000 which is the subject of any current, pending or threatened mediation, arbitration or litigation proceeding; and
- particulars of any proceedings involving the proponent under the Bankruptcy and Insolvency Act (Canada), the companies Creditor Arrangement Act (Canada) or similar legislation.

Proponents should specifically address the requirements of this section by either providing appropriate disclosure or by indicating that they have nothing to disclose in respect of the matters listed above.

Proponents must advise the designated contact of any change in the foregoing throughout the RFP process or intended negotiation period.

The Corporation reserves the absolute right to eliminate any Proposal or terminate any resulting agreements without prejudice for failure to disclose the information required in this section, and/or for disclosure at any time of proceedings in the nature of bankruptcy or insolvency by or against the proponent.

2.28 BIDDER'S RESPONSIBILITIES

If the Corporation accepts a Bid, the Bidder will be bound by the Proposal Documents, the Bidder's submission, the General Conditions and any subsequent negotiations, and will commence the Work within the time specified and complete all the work by the date for substantial performance of the Work.

2.29 JOINT PROPOSALS AND SUBCONTRACTING

The proposal may be submitted where more than one company or organization will be providing the solution, either through a joint bid, or through a subcontracting arrangement. In these cases:

- All companies or organizations must be identified in the proposal;
- The solution to be provided by each company or organization has to be clearly identified;
- One company must be specified in the proposal to assume overall responsibility for the solution; and
- No other companies or organizations may be added or substituted without the prior written consent of Yukon Energy Corporation.

SECTION 3: TERMS AND CONDITIONS

Below is a list of "Terms and Conditions" that the successful proponent will be requested to accept and comply with within the contract negotiations. Proponents are requested to review the items listed below and advise as to which "Terms and Conditions" they would agree to and those they cannot agree with Proponents may provide alternatives to terms and conditions they cannot agree with.

3.1 INSURANCE

The successful bidders shall be required to provide satisfactory certificates of general liability insurance to the Corporation. Certificates should show the types of coverage, the dollar amounts and the effective dates which shall not be less than $2,000,000.00 and shall include a standard form cross liability clause. Failure for any reason to furnish this proof shall be a breach of the agreement, allowing the Corporation to terminate the agreement or at the Corporation's option, to supply such insurance and charge the cost to the bidder.

3.2 INDEMNIFICATION

The proponent shall indemnify and save harmless the Corporation, its successors, assigns, agents, employees and authorized representatives and each of them from and against any and all claims, demands, losses, costs, damages, actions, suits or proceedings whether directly or indirectly caused or incurred, related to or occasioned by, arising or resulting from any error, omission or negligent act of the proponent, any sub-proponent, and their respective servants, agents and employees in the performance of this Contract, excepting liability arising out of any error, omission or negligent act of the Corporation, its successors, assigns, agents, employees and authorized representatives.

The Corporation shall indemnify and save harmless the proponent, its successors, assigns, agents, employees and authorized representatives and each of them from and against any and all claims, demands, losses, costs, damages, actions, suits or proceedings whether directly or indirectly caused or incurred, related to or occasioned by, arising or resulting from any error, omission or negligent act of the Corporation and the Corporation's respective servants, agents and employees in the performance of this Contract, excepting liability arising out of any error, omission or negligent act of the proponent, its successors, assigns, agents, employees, and authorized representatives.

The indemnity provided by the proponent in this Section will survive the expiration of this Contract for no longer than two (2) years.

3.3 PAYMENT

The Corporation shall pay the Consultant and the Consultant shall accept, as full consideration for the Deliverables and executed in accordance with the Contract, the Contract price, plus any other amounts, if any, agreed in writing by the Corporation and payable to the Consultant under the Contract, less the amounts, if any, payable or owing by the Consultant to the Corporation under the Contract or any other agreement between the Corporation and the Consultant, and less any holdbacks retained hereunder.

As defined in the Contract, the Consultant may submit invoices for goods or materials supplied, and upon such invoice being approved by the Corporation, the Corporation shall pay the Consultant as per the term of the Contract, less the amount of any outstanding liens or claims or any other indebtedness which may have been incurred by the Consultant and for which the Corporation might in any way be held responsible.

The Consultant may be required to submit a statutory declaration with each invoice in a form acceptable to the Corporation stating that all accounts for Subcontractors, products and material suppliers and other

indebtedness which may have been incurred by the Consultant relating to the Contract have been paid in full and are fully discharged.

The Corporation will pay the Consultant within 30 days after receipt and approval of the Consultant's invoice, unless otherwise agreed between the parties in the Contract, and in the following manner:

a. 90% of the amount payable, 30 days after delivery in good order at the point delivery, or
b. the balance of the amount payable 30 days after the Corporation has accepted ownership of the Deliverables, in writing.

The Corporation may set off against any amount payable or debt due by the Corporation under this Contract the amount of any debt due to the Corporation by the Consultant under this Contract or any other agreement between the Consultant and the Corporation.

3.4 WARRANTY AND GUARANTEE

The Consultant warrants and guarantees that the Deliverables are free from all defects from faulty materials or workmanship which appear within the period specified in the Contract Documents, or if no such period is specified, then the later of:

a. twelve (12) months from the date Total Performance; or
b. eighteen (18) months from the date of delivery of the Deliverables to the specified delivery point(s);
c. or such other date as specified in the Contract documents.

The Consultant shall, at its own expense, upon receiving written notice from the Corporation, remedy immediately and to the satisfaction of the Corporation, any defect in or deficiency to the Deliverables and any other work arising from that defect, deficiency or unsatisfactory Deliverables.

The Corporation shall provide the Consultant with access, at all reasonable times, to the location of any defective, deficient or unsatisfactory Deliverables to enable the Consultant to perform the remedial work and the Consultant shall be responsible for:

a. exposure of the defect, deficiency or unsatisfactory Deliverables in order to perform the remedial work;
b. the restoration of the Deliverables disturbed or damaged in the course of exposing the defect, deficiency or unsatisfactory Deliverables, and in performing the remedial work; and
c. any and all risks and costs associated with exposing the defect, deficiency, or unsatisfactory Deliverables and performing the remedial work.

The Consultant warrants and guarantees that all remedial work is free from defects to the same extent provided herein, except that the warranty period shall commence on the date that the Corporation provides to the Consultant written acceptance of the remedial work performed by the Consultant.

The Consultant's obligations under this general condition shall not be affected by the completion or termination of the Contract, suspension or withdrawal of the Contract, or rejection of the Deliverables under the Contract.

3.5 TERMINATION

The Corporation, at its sole discretion and with or without cause, reserves the right to terminate without penalty, any or all agreements arising out of the RFP.

The Corporation will provide thirty (30) days prior written notice on the event of termination without penalty. The Corporation shall be relieved of any further obligations hereunder, except for payment for the balance outstanding for the work performed by the successful proponent up to the time of termination.

In addition, the Corporation may immediately terminate the agreement upon the occurrence of any of the following:

a) where the proponent, despite notice thereof, persists in rendering services unacceptable to the Corporation: and/or
b) where the proponent becomes insolvent, is declared bankrupt, or commits an act of bankruptcy.

If in the event that the selected proponents(s) become insolvent, partner or merge with another firm(s), and/or change their business models, the Corporation, at its sole discretion may, with notice in writing, remove said proponent(s) from the list of proponents approved to provide such described services to the Corporation. The Corporation, at its sole discretion may add and/or remove proponent(s) from time to time in order to maintain a competent list of proponent(s) for legal services.

3.6 LAWS, PERMITS AND LICENSES

The laws of the Yukon and Canada shall govern the agreement. The successful proponent shall obtain and pay for all permits and licenses required either by the Government of Canada, the Yukon Government, the City of Whitehorse, or any other authority. Compliance with all requirements, permits, licenses and laws must be in place prior to the successful proponent initiating any provisions of the agreement to be in compliance with the terms and conditions of the agreement.

3.7 INDEPENDENT CONSULTANT

The Consultant is an independent Consultant. Under no circumstances shall the Consultant, its employee or Subcontractors be considered to be agents, partners, representatives or employees of the Corporation. The Consultant shall not represent itself as an agent of the Corporation.

3.8 THE WORKERS' COMPENSATION ACT

If the Consultant is to perform any work on the Corporation's site, including but not limited to delivery, assembly and/or unloading of Deliverables, before commencing work on site and at any time on the request of the Corporation's Representative, the Consultant shall, within ten (10) days of the award of a Contract and at any time during the term of the Contract when requested by the Corporation, supply evidence of certification by the Yukon Workers Compensation Board that the Consultant and all Subcontractors are registered and in good standing, and all workers performing the work are covered by the Consultant's or Subcontractor's Workers Compensation.

The Consultant and the Corporation agree that the Consultant is, for the purposes of the Workers Compensation Act, the prime Consultant, and holds all liability and responsibility of the prime Consultant.

3.9 HEALTH AND SAFETY

If the Consultant is to perform any work on the Corporation's site, including but not limited to delivery, assembly and/or unloading of Deliverables, the Consultant shall comply with all applicable safety provisions of the Workers Compensation Act and safety regulations issued by the Corporation's Representative. For the purpose of this general condition, the term "safety regulations" includes any and all operating order, work protection practices, lockout procedures, and any other safety requirements that may be required or regulated whether municipally, provincially, federally, or otherwise. The Consultant

shall be solely responsible for the safe performance of all the work and the safety of all persons engaged in the work and shall ensure all safety laws, regulations and requirements are implemented and adhered to through the performance of the Contract.

The Consultant shall immediately notify the Corporation's Representative in writing of any incidents or circumstances described herein, and about any claims made, and the Consultant shall obtain a release in the names of the Corporation and the Consultant.

The Consultant shall ensure that the persons engaged in the work comply with all requisite safety procedures, regulations and laws, as applicable to the Delivery Point.

Notwithstanding anything stated herein, the Consultant shall be solely responsible to ensure that every person is properly trained in safety procedures applicable to the Contract and the Delivery Point, and any bodily injury or death of any of those persons as a result of the failure of the those persons to comply with those procedures or the Consultant's failure to provide appropriate training to them.

The Corporation may refuse to permit any workers employees, agents, vehicles, equipment and/or Subcontractors on the Corporation's site if the Corporation determines that such personnel or equipment do not comply with the rules and regulations relating to safety.

3.10 ENVIRONMENTAL PROTECTION

The Consultant shall demonstrate that it is environmentally responsible, including but not limited to complying with all applicable environmental legislation and regulations as applicable to the Deliverables.

The Consultant shall comply with any direction given by the Corporation to protect and preserve the environment.

3.11 CONFIDENTIALITY

The Corporation and the Consultant shall keep confidential all matters respecting technical, commercial and legal issues relating to or arising out of the Contract, or the performance of the Contract and shall not, without the prior written consent of the other, disclose any such matters, except in strict confidence to its professional advisors, or as required by a governmental or legal authority.

The Consultant shall not publish any statement in any paper or document or issue any press release or public announcement or disclosure concerning the award of the Contract without prior written consent of the Corporation, which consent may be unreasonably withheld, except as required by law.

SECTION 4: EVALUATION CRITERIA & PROCESS

4.1 EVALUATION METHODOLOGY AND PROCESS

Proposals will be evaluated on the information received in the Proposal submission, only if received by the Closing Date and Time. Further, the evaluation may be made on any subsequent telephone interviews or meetings with any short listed proponents.

4.2 EVALUATION COMMITTEE

An evaluation committee comprised of the owner's designate and other Corporation staff will evaluate the Proposals received.

4.3 EVALUATION CRITERIA

Proposals will be evaluated by the Evaluation Committee on the overall best value to Yukon Energy based on the following criteria.

Criteria
Proponent's qualifications and experience
Proponent's product exposure in the market-place
Product fit to Yukon Energy's requirements
Price
Quality of submission
Quality of product demonstrations
References

4.4 EVALUATION PROCESS

The evaluation process is a five-step process as listed below. Two of the steps, steps two and three, are Proponent's demonstration of the product functionality and a presentation of the product's technology platform respectively.

Step 1: Evaluation of Proponent's Proposed Solution

This step delves into a detailed evaluation of the proposed solution based on submissions in *Section 8: Proponent Responses*.

A short-list of the top-ranked proposals will be established at the end of this step. Short-listed proponents will be advised accordingly and Yukon Energy will work with proponents to formulate and schedule product demonstrations.

Step 2: Product Demonstrations

Demonstration requirements and scripts will be provided to Proponents prior to the demonstration sessions. Demonstrations will be evaluated based on

- Product and solution features and processes
- Applicability and fit to Yukon Energy requirements

- Quality of demonstrations

Step 3: Technical Presentation

This step evaluates the technical architecture and, support and maintenance requirements of the proposed solution. Proponent's will present the following for evaluation:

- The technology architecture and platform(s) on which the solution operates.
- Procedures for implementing upgrades and fixes
- On-going and periodic maintenance procedures; backup options, disk and file re-organizations
- Administration and change control procedures
- Customization capabilities and methods
- Report Writing tools and/or Data Warehousing functionality
- Data import and export capabilities and procedures
- Ease of building interfaces to other systems
- Data conversion tools
- Web capabilities
- Security features

Step 4: Reference Checks

This step involves the evaluation of client feedback and experiences with the Proponent and the proposed product. Site visits might be requested by Yukon Energy if deemed required.

Step 5: Final Selection

A final selection will be made based on the overall score from all the above steps. Yukon Energy, at its discretion, reserves the right to defer or not proceed with executing a final selection.

SECTION 5: SUMMARY

The Corporation thanks all proponents for responding to the RFP. We recognize the time, resources and energy that it takes to provide a Proposal for our consideration. We do not take lightly the work and effort made to provide a Proposal and appreciate your responding to our RFP.

In no way or manner should this RFP be considered a repudiation or statement of dissatisfaction with any current company providing services to the Corporation. This RFP is an ongoing business commitment and demonstration ensuring that the Corporation undergoes scrutiny and diligence that can withstand review and audit. The Corporation is committed to the highest standards of business practice and services. We appreciate your company helping us achieve these goals.

We thank you in advance for your participation in this RFP.

SECTION 6: RESPONSE FORMAT

In order for Yukon Energy to effectively expedite the evaluation of RFP submissions, proponents are requested to submit responses with adherence to the format documented in this section. All copies of responses are to include the following items and sequenced as laid out in the sections below.

6.1.1 Title Page

The title page must include the RFP number and title, closing date and time, Proponent's company name and address including telephone number and Proponent's contact person and contact information.

6.1.2 Letter of Introduction

A one-page letter of introduction and signed by a duly authorized representative or officer of the Proponent.

6.1.3 Table of Contents

The table of contents itemizing major sections of the response with corresponding page numbers indicated.

6.1.4 Executive Summary

A one to two page summary on the key elements of the proposal as it relates to Yukon Energy's requirements.

6.1.5 Proponent Information

Complete submission requirements in *section 8.1 Proponent Information*

6.1.6 Full Disclosure

Complete disclosure requirements in section 2.27.

6.1.7 Product Information

Complete submission requirements in *section 8.2 Product Information*

6.1.8 Implementation Approach & Methodology

Complete submission requirements in *section 8.3 Implementation Approach & Methodology*

6.1.9 Client References

Complete submission requirements in *section 8.4 Clients*

6.1.10 Pricing

Complete submission requirements in *section 8.5 Pricing*

6.1.11 General Product Requirements

Complete submission requirements in *section 8.6 General Product Requirements*

6.1.12 Data Conversion Requirements

Complete submission requirements in *section 8.7 Data Conversion Requirements*

6.1.13 Business Area Requirements

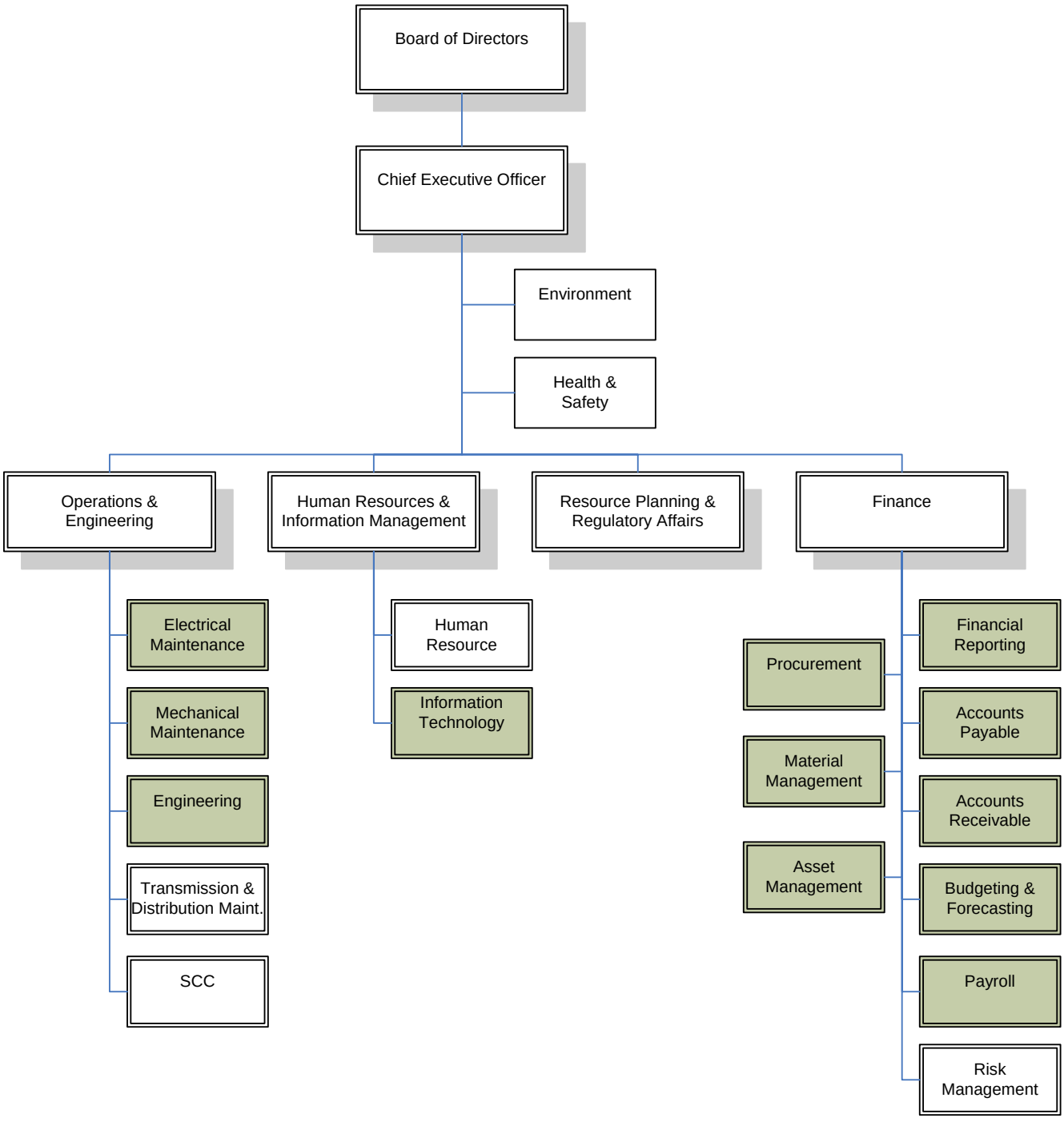
Complete submission requirements for Business Areas indicated in *section 8.8.*

SECTION 7: CURRENT ORGANIZATION & PROCESSES

This section is intended to provide Proponents with an overview and a better understanding of Yukon Energy's organization structure, business areas, processes and current business systems.

7.1 ORGANIZATION CHART

Referring to the schematic below, Yukon Energy is structured with four major areas reporting to the Chief Executive Officer who in turn reports to the Board of Directors. The business areas affected by this RFP are shaded as shown.



7.2 BUSINESS SYSTEMS

Below is a high-level overview of key functionality of each business module that is relevant to this RFP.

Accounts Payable

- JDE Accounts Payable is used to expedite all aspects of invoicing from vouchering through to payment and including cash requirements forecasting.
- Automatic system tolerance checking is enabled at voucher match to alert of quantitative and dollar amounts exceeding pre-set tolerances.
- A Supplier Master is maintained on all pertinent information including payment terms, payment methods and tax applicability for automatic defaults into transactions.
- The Accounts Payable module is automatically integrated to the General Ledger, to Procurement for matching of purchase orders and receipts, and to Inventory Management for the restatement of unit costs from price variances at voucher match.
- Accounts Payable batches are approved prior to posting.
- Vouchers are grouped by different criteria and combinations of, for example by bank account, currency, due dates, for automatic system generated cheques. Manual cheques are issued as required.
- Contract holdbacks are manually tracked on spreadsheets whereby the holdback amounts are manually calculated and the corresponding account allocations manually journalled into the General Ledger.
- System integrity reports are used to supplement internal balancing procedures to locate balancing problems and data inconsistencies between detail transactions (vouchers and payments) to batch totals and between the Accounts Payable Ledger and General Ledger.

Accounts Receivable

- The stand-alone CIS system is used for the processing of all aspects of electric utility billing including the processing of cash receipts, generation of aging reports and monthly control reports and statements.
- CIS transactions are captured on spreadsheets, summarized and manually journalled into the JDE General Ledger.
- All non-electric utility billing including wholesale generation billing and customer extensions for the installation of distribution lines are done manually. Invoices are manually prepared on MSExcel spreadsheets and corresponding journal entries made into the JDE General Ledger. The journal entries are entered with a customer number reference from the JDE Customer Master. Cash receipts are expedited via the JDE bank reconciliation facility and allocated back to the original invoice journal entry. Statements are not produced for non-electric utility billings.

Budgeting & Forecasting

- Budgets are prepared on Excel spreadsheets with approved budgets entered/uploaded into the JDE Financial System.
- Sales Forecast: Details itemizing customers, energy requirements and forecasted demand are captured on spreadsheets. The calculations are complex with varying degrees of data manipulations and hence the use of excel. This is a manual process of collecting and collating data.
- Operations & Maintenance (O&M) Expenses Forecasting: The information is extracted out of JDE quarterly onto spreadsheets for forecasting.

- Capital Plan: Capital Plan is also undertaken in excel spreadsheets. This is a manual business process where Project Identification Document (PID) is used to initiate planned projects and derive the final capital plan. This is a re-iterative process until the PID is approved and finalized into the budget process.
- Payroll Costs: Some of the information is extracted from the ADP Payroll System onto an excel spreadsheets including manual entry of some additional information. The information is then consolidated and uploaded into JDE.
- Reports of actuals versus budgets are generated from the JDE system and information maintained on spreadsheets for reporting and monitoring purposes. Monthly reports are distributed to individual managers, quarterly reports to the Board of Directors and on request only to Yukon Utilities Board using spreadsheets.
- Budgets are closed and rolled over to the following year by company with the exception of capital budgets which are carried forward where applicable.

Financial Reporting

- Financial Reporting is a critical part of YEC's accountability and is categorized into Transactional Reporting, Monthly Reporting, Variance Reporting, Annual Reporting, Statutory Reporting and Management Reporting.

Asset Management

- All aspects of asset management are processed on the JDE Fixed Asset module.
- The Straight Line Method of depreciation is used and is configured by asset classes.
- Depreciation entries are system generated from the Fixed Assets module and posted into the General Ledger.
- Asset splits can be expedited by a manual journal entry or generated by the system based on a specified percentage, specified monetary values and specified quantities.
- Grants and customer contributions for the development of assets are tracked separately in accordance with specific grants and contribution rules.

General Accounting

- All financial transactions are captured on the JDE General Accounting system.
- Yukon Development Corporation is the only other company that is supported out of the JDE system.
- Transactions in the General Ledger are populated via manual journal entries and system-generated entries from source feeder JDE modules such as Accounts Payable, Fixed Assets, Job Cost, Procurement and Inventory Management.
- Calendar year is the fiscal date pattern used.
- The interface from the CIS billing system to the JDE General Ledger is manual via spreadsheets.

Inventory Management

- The Inventory Management function provides support for inventory at 1 main and 4 satellite warehouse locations.
- Inventory is purchased into the main warehouse and transferred to satellite warehouses.
- Items stocked in warehouses primarily serve maintenance requirements and any requirements for new development projects.

- Inventory counts are done weekly in the main warehouse based on pre-defined count cycles by item and a yearend complete count is done for the satellite warehouses.
- All inventory activities are processed through the JDE Inventory Management module which interfaces to the JDE Procurement and General Ledger modules.
- Traceability of serial numbers for serialized items are manually maintained and tracked.

Maintenance

- Maintenance is expedited by the Operations and Maintenance Department on all serviceable plant equipment including distribution lines.
- Electrical maintenance, mechanical maintenance, and line maintenance is expedited by three separate departmental groups with each group responsible for tracking their own maintenance schedules and requirements.
- The MainBoss System was implemented in 2003 and 2004 for electrical and mechanical maintenance respectively. The system has been under utilized or not been used since May of 2005.
- Repositories of spare parts inventory exist at different plants to service maintenance requirements. This inventory is not tracked on any system.

Payroll

- The staff complement of YEC comprises of seventy employees, with forty-six union employees and twenty-four exempt staff.
- ADP is used for Payroll processing specifically using the “people at work” module. The processing of bi-weekly and monthly payrolls is executed through ADP payroll system (pay at work). This payroll payment process and service provider is not expected to change in the foreseeable future.
- ADP offers time and labour distribution integrated computing solutions which currently is not in use.
- The interface between ADP and the JDE General Ledger is manual. Journal entries are manually compiled on spreadsheets and uploaded into the General Ledger.

Procurement

- Procurement is segregated into purchasing for inventory items and purchasing for non-inventory items (goods, services and equipment).
- All inventory purchasing is expedited by the warehouse manager in the main warehouse and are captured in the JDE Procurement system and electronically routed for approval based on dollar amount thresholds.
- Non-inventory purchases greater than $5,000 are expedited by YEC’s buyer and are captured in the JDE Procurement system.
- Purchases less than or equal to $5,000 are expedited using Visa or a Local Purchase Order (LPO) which is a manual purchase order. LPO’s are not entered in the JDE Procurement system.
- Service contracts (or standing/blanket orders) are manually compiled and maintained.
- Requisitions for non-inventory purchases are initiated on requisition forms for manual approvals.
- Quotations are processed manually.

Project Accounting

- The Engineering Department manages capital projects such as the construction of a new substation and installing new distribution lines including feasibility studies such as the feasibility of building a new transmission line.
- Business plans for projects are manually initiated on a Project Identification Document (PID) hardcopy form with an initial planned budget amount and manually routed to applicable signing authorities for approval.
- Project cost estimates, both internal and external, are manually compiled on spreadsheets. Quotations/tenders for external labour/services, materials and equipment are obtained from suppliers and included in estimates.
- Approved budgeted and estimated costs are manually uploaded/entered into the JDE system.
- Work Orders for approved projects are initiated on a Work Order Job Description Form and are manually tracked.
- Actual costs captured from invoices are downloaded from the JDE system onto spreadsheets and further manipulated for tracking and reporting of actuals against estimated costs.

Customer Extensions

- Customer extensions are customer requests for installation of new distribution lines or run-offs from existing lines.
- Manual work orders are created to expedite requests.
- Customer deposits and payments are collected and manually processed. Journal entries are created and entered into the JDE General Ledger accordingly.
- Work order inventory requirements are manually submitted (via email) to the warehouse manager. An inventory issue is created in the JDE system for the release of materials
- Procurement of required materials, services and equipment rentals are processed via the JDE system. A manual requisition is submitted to the buyer for a purchase order or contract to be expedited.
- Refunds to customers for projects under the estimated cost are manually calculated and submitted to Accounts Payable for a cheque to be processed via the JDE Accounts Payable module.
- Customer Extension System: This is a standalone custom-built system that is currently being developed on the MSAccess platform to support various aspects of customer extension projects such as estimations, work order generation and derivations of cost sharing apportionment amongst customers. Portions of this system have been developed and are currently in use. Additional functionality is planned to be added as per ongoing development. Feedback on this system has been positive. Interfacing of applicable transactions such as project costs (both estimates and actuals), procurement and customer payments/deposits/refunds to and from this system and the JDE system is manual. Only interfaces to this system are to be considered in this RFP.

7.3 TECHNICAL PLATFORMS

The technical platforms used in support of the current business modules are documented as follows.

JDE System (Oracle EnterpriseOne)

- Windows 2003 SP2 Operating System.
- Microsoft SQLServer database 8.00.760 (SP3).
- Windows Terminal Server is used for remote (Kulan location) and mostly local user access.

- Remote access network protocol – the remote user is assigned a VPN tunnel through the firewall. Kulan is permanent and accesses the Terminal Server and others are User-Password and access a test computer as required.

Microsoft Access

- Windows 2003 SPI Operating System.
- Read only ODBC link to JDE database for data extracts and generation of reports.

7.4 TRANSACTION VOLUMES

To assist Proponents in ensuring that the proposed solution is able to support the transactional throughput required by Yukon Energy, below are current average annual volumes by business areas. A 25% 5-year projected growth can be expected.

Yukon Energy Transaction Volumes (Annual)	
	Record Count
Accounts Payables	
Vouchers	4500
Debit Memos	20
Automated (system generated) Cheques	2700
Manual Cheques	80
Recurring Voucher	0
Accounts Receivables	
Invoices (JDE)	0
Deposits (JDE)	0
CIS	0
Fixed Assets	
Asset Disposal	300
Asset Split	10
Asset Transfer	30
Depreciation Journal Entries	23000
Engineering	
Projects	150
Work Orders	300
General Ledger	
Budget or Cost Allocation Journal Entries	500
Journal Entry	6000
Payroll Journal Entries	9000
Inventory	
Issues	3500
Transfers	300
Inventory Adjustments	150
Receipts	150
Physical Inventory Count Adjustments	600
Maintenance	
Work Orders (Preventive and Corrective)	300
Procurement	
Purchase Orders – System Generated	120
Service Contracts – System Generated	30
Purchase Orders Line Items	450
Service Contracts Line Items	100
Local Purchase Orders	1000

7.5 USER BASE

The table below shows the number of system users by business area at each of Yukon Energy's location. Users within Finance have cross-functional responsibilities for Accounts Payable, Accounts Receivable, Budgeting & Forecasting, General Accounting, Project Accounting, Financial Reporting and the manual capture of Payroll entries into the General Ledger.

Number of Users by Business Area by Geographical Location					
	Head Office	**Remote Locations**			
Yukon Energy Business Area	***Whitehorse***	***Kulan***	***Dawson***	***Mayo***	***Faro***
Finance	8				
Inventory Management		1	2	2	1
Maintenance/Engineering	7				
Procurement	2				
Total	**17**	**1**	**2**	**2**	**1**

SECTION 8: PROPONENT RESPONSES

8.1 PROPONENT INFORMATION

Proponent profile information on the following items should be provided in the same sequence as listed below.

1. Company profile and history.
2. Location of offices in Canada and internationally.
3. A copy of proponent's most recent annual report.
4. A statement of confirmation that Yukon Energy, if deemed necessary, may review the Proponent's financial statements for the last two years and/or conduct a credit check on its business.
5. Company's growth over the past two years.
6. Profitability over the past 2 years - if public information.
7. Total number of employees.
8. Total number of employees focussed on Research and Development.
9. Total number of support employees.
10. Location of support offices in Canada and internationally.
11. A list of certified and trained implementation partners in Canada and internationally. Include locations of certified partners.
12. A brief summary of future corporate directions and strategies.

8.2 PRODUCT INFORMATION

Yukon Energy's objective is to source a solution that efficiently and effectively meets business requirements and therefore is open to looking at "best of breed" proposals whereby a proposed solution could include third-party product complements. In order to assist Yukon Energy in evaluating proposals, Proponents are encouraged to provide as much detail as possible, including any third-party product recommendations, on the information requested in this section.

Product information on the following items requested should be provided in the same sequence as listed below.

1. A brief introductory overview of Proponents' product offering. Include product brochures where applicable.
2. Future product directions.
3. Date of initial and current product release.
4. Length of time that the current release has been available in the market-place.
5. Number of major product releases from the initial release to the current release.
6. Frequency of product releases and the average time between upgrades.
7. Number of clients operational with the proposed solution in Canada and internationally.
8. Reporting tool(s) for custom/adhoc reports. List any third-party reporting tools supported.
9. Scheduler facility to schedule periodic jobs to run unattended.
10. Operating systems supported; server and clients.
11. Database systems supported.
12. Minimum hardware requirements for the server and for client PCs.
13. Support for workflow functionality and specify email products supported where applicable.
14. Communications and/or network protocol supported for local and remote access.
15. Hardware platform most commonly used and recommended for Yukon Energy.
16. Software platform (operating system and database system) most commonly used and recommended for Yukon Energy.

8.2.1 Third-Party Products

Any third-party product complements are to be indicated in the "Third-Party Products" worksheet in Attachment A of this RFP.

8.3 IMPLEMENTATION APPROACH & METHODOLOGY

Responses to the items below are requested to provide Yukon Energy with a high-level overview of implementation requirements. It is recognised that further detailing of implementation requirements will be required should Yukon Energy proceeds with the implementation of the proposed solution.

1. Outline the implementation approach and methodology that has been successfully used for the delivery of the proposed solution.
2. Provide a high-level project plan and timeline based on Yukon Energy's requirements and sizing. Identify the key phases and activities to be included as part of the implementation.
3. Define key success factors and project deliverables to implementing the proposed solution.
4. State the expectations and resource requirements from Yukon Energy.
5. Indicate the Proponent's resources required for the implementation of the proposed solution. Indicate the use of any third-party implementers where applicable and include a list of pre-qualified implementers with supporting information on the number of implementations executed and an overview of each implementation.
6. Specify any special facilities that Yukon Energy may have to provide for the implementation.

8.4 CLIENTS

1. Provide the number of completed installations and fully operational clients for the proposed solution in Canada. Include a sample list of operational clients, location and modules installed including 3rd party software complements implemented.

2. Indicate the number of electrical utility client sites operationally functioning with the installed proposed product and modules used. Include a sample list of similar utility, preferably electric utility clients.

3. List at least three client references that can be contacted by Yukon Energy. Include company name, contact name, contact's title, e-mail address, telephone number, software versions and relevant modules installed, installation dates and 3rd party software complements where applicable.

4. List references of electrical utility clients, if any, that can be contacted by Yukon Energy. Include company name, contact name, contact's title, e-mail address, telephone number, software versions and relevant modules installed.

8.5 PRICING

All prices are to be quoted in Canadian dollars and net of taxes. Pricing should be based on Yukon Energy's sizing as indicated in *section 7.4 Transaction Volumes* and *section 7.5 User Base*. Please specify any key exceptions to pricing including any assumptions that would influence the final price. Prices should be broken down by software costs, hardware costs and implementation costs.

If there are any other ancillary products that typically are bundled with your software, for example, report writer tools, please indicate pricing separately.

Please anticipate concurrent users of between 25-30 users.

Software Costs should be broken down by module in accordance to Yukon Energy's business areas. If modules are bundled and not priced individually, please indicate components of bundles and corresponding pricing. Indicate the number of client and server licences where applicable. If third-party products are proposed, indicate prices separately including product name, vendor name and whether interfaces are in place (or are not) with the proprietary product. If interfaces to third-party products are not in place, include estimates for building the required interfaces.

Hardware Costs should also include costs of database and operating systems with the number of licences indicated where applicable. Include any other ancillary costs required for remote access.

Implementation Costs should include all hardware implementation, software implementation and training costs.

Software Maintenance Costs should include annual support costs and where applicable specify the types of support levels and corresponding costs.

8.6 GENERAL PRODUCT REQUIREMENTS

In addition to the specific business area requirements defined in latter sections, Yukon Energy is also looking for a proposed solution with overall features listed below. As such features vary in design and availability from product to product, please provide a brief synopsis of how the proposed solution provides for each feature. If accommodations for a feature are not in place, please indicate not available.

1. Online Help functions
2. Security function
3. Audit trails for transaction or master file maintenance; who, when and what
4. Scalability in terms of additional users and modules
5. Web Capabilities
6. Data import and export capabilities
7. Reporting Toolset including Data Warehousing capabilities
8. Full system integration of all modules required by Yukon Energy

Along with other Canadian publicly orientated enterprises, Yukon Energy is currently reviewing the implications of converting our current reporting framework from Canadian Generally Accepted Accounting Principles ('GAAP') to International Financial Reporting Standards ('IFRS'). It is anticipated that this accounting conversion may require a systems solution for reporting under both sets of GAAP. As such the proposed solution should also be able to handle both IFRS and Canadian GAAP in parallel.

8.7 DATA CONVERSION REQUIREMENTS

Provide a brief explanation of how data conversion is to be expedited and the availability of conversion tools to convert or migrate Yukon Energy's existing data to the proposed solution. The table below provides a sample sizing of Yukon Energy's data conversions requirements.

Data	Number of Records
Chart of Accounts	47,000
Supplier Master	3,500
Employee Master (active and inactive)	200
Customer Master JDE	80
Facilities	20
Item Master	3,000
Warehouses	4
Asset Master	3,000
Work Orders	1,200
General Ledger	1,100,000
Item Ledger	60,500
Projects	150

8.8 BUSINESS AREA REQUIREMENTS

Responses to product functionality fit are required for the following areas:

1. Accounts Payable
2. Accounts Receivable
3. Budget and Forecasting
4. Financial Reporting
5. Fixed Assets
6. General Ledger
7. Inventory Management
8. Maintenance
9. Payroll Interfaces
10. Procurement
11. Project Accounting

Attachment A of this RFP consists of worksheets indicating Yukon Energy's requirements and for the Proponent to respond to these requirements accordingly. Proponent's responses are to be entered directly into these worksheets and emailed to the email address indicated in *section 2.1, Delivery of Proposals*.

Further instructions on "How To" fill-in worksheets are indicated within Attachment A.

SECTION 9: INTENT TO RESPOND

If the proponent intends to respond to this Request For Proposal RFP #2008-040, complete this page and fax or email to the contact below on or before December 26, 2008.

Yukon Energy Corporation
Attention: Lynda Harlow
Fax Number: 867 393-5301
Email: purchasing@yec.yk.ca

Proponent Organization

Name: _____

Address: _____

_____

_____

_____

Proponent Contact

Name: _____

Title: _____

Phone: _____

Signatures

Name *(Please Print)*: _____

Signature: _____

Title *(Please Print)*: _____

Date: _____

Yukon Energy Corporation Enterprise Software System RFP #2008-040 Attachment A

This document is referred to as Attachment A in Yukon Energy's RFP #2008-040 main document. It consists of 2 types of worksheets for proponents to fill-in to complete responses to Yukon Energy's Request For Proposal #2008-040.

1. Third-Party Products Worksheet - *1 worksheet*
This worksheet is for Proponents to indicate any third-party complements to Proponents' proposed main solution.

2. Business Area Requirements Worksheets - *10 worksheets*
These are a set of worksheets, one per Business Area as listed below, for Proponents to indicate their Product Fit to Yukon Energy's requirements.

- Accounts Payable
- Accounts Receivable
- Budgeting&Forecasting
- Financial Reporting
- Fixed Assets
- General Ledger
- Inventory Management
- Maintenance
- Payroll Interfaces
- Procurement
- Project Accounting

Yukon Energy's prioritization of requirements is indicated in the **Priority** column of each Business Area Worksheet as follows:

Priority: **1** = Must Have
2 = Must Have for Future Implementation
3 = Nice to Have for Future Opportunity

Proponents are to indicate responses to each requirement in the **Fit to Product** column using only one of the key response values listed below. The **Fit/Gap Explanation** column is provided for any additional notes or comments for Proponents to further qualify the "Fit to Product" response.

Fit to Product F ***Y*** *= Yes, within standard functionality*
P *= Partially within standard functionality, achievable with customizations*
N = No, not in product functionality
F *= Planned for future release.*

Third-Party Products					
Third-Party Vendor Name	**Third-Party Product / Module Name**	**Interface Exists (Y/N)**	**Brief description of the third-party interface to proponent's proprietary product.**	**Number of years that interface has been in place.**	**List clients that are operational with this interface.**

LEGEND

Priority: **1**=Must Have **2**=Must Have for Future Implementation **3**=Nice to Have for Future Opportunity

Fit to Product Responses: ***Y*** *=Yes, within standard functionality* ***P*** *=Partially within standard functionality, achievable with customizations*
N *=No, not in product functionality* ***F*** *=Planned for future release.*

Business Area: **Accounts Payable**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
A1.0	**Supplier Master Information**			
A1.1	Unique identification of suppliers with the ability to enter supplier name of a minimum of 30 characters including full mailing address information (Street Address, City, Province/State, Postal Code, Country)	1		
A1.2	Categorization of supplier by line of business.	2		
A1.3	Supplier's payment method. For example, cheque or electronic funds transfer.	1		
A1.4	Supplier's payment terms and discount terms with the ability to default YEC's standard term (Net 30) if no special supplier terms.	1		
A1.5	Supplier's currency code for purchasing and payments. For example, the specification of USD for US suppliers.	3		
A1.6	Tax applicability (applicable or exempt) and tax rate by location. For example, GST and PST tax applicability and rates for British Columbia and HST in Atlantic provinces.	1		
A1.7	Supplier Bank Account Information such as Bank Transit Number and Bank Account Number for electronic payments.	2		
A1.8	Supplier contact for Accounts Payable inquiries. Contact information should include Contact Name, Job Title, Address, Telephone Number(s) and email Address.	1		
A2.0	**Accounts Payable Trade Accounts**			
A2.1	Ability to have different trade accounts for the booking and segregation of different types of expenses and costs. For example, Regular Accounts Payable Trade, Employee Trade, Board Trade.	2		
A3.0	**Approvals**			
A3.1	Option for management approval of A/P transaction batches for posting to the Financial System.	3		
A4.0	**Voucher Processing**			
A4.1	Ability to capture various voucher information such as invoice number, invoice value, invoice date, service date, GL date, GL allocation accounts including additional descriptive text for explanations and remarks.	1		
A4.2	Ability to match a voucher to a purchase order with the options to expedite a complete match, a partial match for partial delivery of goods and services and a partial match and the cancellation of any remaining outstanding goods and services.	1		
A4.3	Ability to match a voucher to a receipt voucher for purchase orders with receipts entered into the system.	1		
A4.4	Configuration of Recurring Vouchers, such as monthly rent payments, to be automatically generated with the ability to manually make changes for exceptions as required.	1		

LEGEND

Priority: **1**=Must Have **2**=Must Have for Future Implementation **3**=Nice to Have for Future Opportunity

Fit to Product Responses: ***Y*** *=Yes, within standard functionality* ***P*** *=Partially within standard functionality, achievable with customizations*
N *=No, not in product functionality* ***F*** *=Planned for future release.*

Business Area: **Accounts Payable**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
A4.5	Entry of voucher prepayments without references to invoice. For example, supplier initial deposits before delivery of goods.	1		
A4.6	Disallow entry of duplicate invoice number from the same supplier.	1		
A4.7	Specification of a pay status for a voucher. For example, "Hold Payment", "Pending Approval", "Approved for Payment", "Paid".	1		
A4.8	Specification of a manual purchase order number at voucher entry for non-system generated purchase orders.	1		
A4.9	Automatic default of supplier payment terms at voucher entry with the ability to override payment terms for exceptions.	1		
A4.10	Automatic calculation of discount due dates based on supplier or voucher specific payment terms.	1		
A4.11	Ability to override voucher due dates as required.	1		
A4.12	Automatic default of tax applicability and tax rates into vouchers based on pre-configured tax rates by supplier and/or ship to location.	1		
A4.13	Automatic default of payment bank accounts at voucher entry with the ability to change payment bank accounts as required.	1		
A4.14	Automatic retrieval, at voucher entry, of supplier information from purchase orders. For example, special payment terms negotiated for a specific purchase order.	1		
A4.15	Specification of payment handling codes such as courier cheque, pickup, mail.	1		
A4.16	Ability to void/reverse vouchers.	1		
A4.17	Ability to identify the department originating the voucher.			
A4.18	Ability to override defaulted tax applicability and taxes at voucher entry.	1		
A4.19	Ability to distinguish between a debit voucher and a credit voucher by transaction type.	1		
A4.20	Electronic routing of vouchers, as required, for approvals prior to payment.	1		
A5.0	**Holdbacks**			
A5.1	Specification of a holdback percentage at invoice entry for automatic calculation of holdback amount.	3		
A5.2	Entry of a holdback percentage at purchase order to be automatically calculated when invoice is matched to purchase order.	3		
A5.3	Automatic booking of holdback amounts to pre-defined accounts at voucher processing.	3		
A5.4	Partial release of holdback amounts as required and tracking of remaining holdback amounts.	3		
A5.5	Reversal of released holdback amounts when required.	3		
A5.6	Option to specify holdback amounts to be automatically calculated inclusive or exclusive of taxes.	3		

LEGEND

Priority: **1**=Must Have **2**=Must Have for Future Implementation **3**=Nice to Have for Future Opportunity

Fit to Product Responses: ***Y*** *=Yes, within standard functionality* ***P*** *=Partially within standard functionality, achievable with customizations*
N *=No, not in product functionality* ***F*** *=Planned for future release.*

Business Area: **Accounts Payable**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
A6.0	**Voucher Match Tolerances**			
A6.1	Configuration of quantity tolerances by percentage or by units to be effected at voucher match.	1		
A6.2	Configuration of unit cost tolerances by percentage or by dollar amount to be effected at voucher match.	1		
A6.3	Configuration of extended amount (unit cost * quantity) tolerances by percentage or by dollar amount to be effected at voucher match.	1		
A7.0	**Taxes**			
A7.1	Set up tax rates for GST and PST base on effectivity dates.	1		
A7.2	Automatic calculation of GST amount and automatic allocation of tax amount to pre-defined GST account.	1		
A7.3	Automatic calculation of PST amount and automatic allocation of tax amount back to corresponding expense account.	1		
A8.0	**Cash Forecasting**			
A8.1	Ability to show cash requirements based on a specified number of aging days as required.	1		
A8.2	Ability to forecast cash requirements by due dates and invoice dates.	1		
A9.0	**Payment Processing**			
A9.1	Grouping of vouchers for payment by method of payment (cheque, EFT). For example, generate payments only for suppliers to be paid by cheque.	1		
A9.2	Grouping of vouchers for payment by Currency. For example, generate payment for all USD vouchers.	3		
A9.3	Grouping of vouchers for payment by account code. For example, generate payment for all A/P Trade Account vouchers.	2		
A9.4	Grouping of vouchers for payment by dollar value. For example, vouchers greater than $2.00 and less than $100,000.00.	2		
A9.5	Grouping of vouchers for payment by payment due dates. For example, generate payments due on December 25th, 2008 or up to and within the next 5 business days.	1		
A9.6	Grouping of vouchers for payment by discount due dates.	1		
A9.7	Grouping of vouchers for payment by company.	1		
A9.8	Grouping of vouchers for payment by one or more suppliers. For example, generate payment for supplier ABC only or for suppliers ABC, PQR and XYZ.	2		
A9.9	Grouping of vouchers for payment by any combination of requirements listed in *A11.1 to A11.8* inclusive. For example, generate payment for USD invoices to be paid by cheque for suppliers ABC and XYZ.	1		

LEGEND

Priority: **1**=Must Have **2**=Must Have for Future Implementation **3**=Nice to Have for Future Opportunity

Fit to Product Responses: ***Y*** *=Yes, within standard functionality* ***P*** *=Partially within standard functionality, achievable with customizations*
N *=No, not in product functionality* ***F*** *=Planned for future release.*

Business Area: **Accounts Payable**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
A9.10	Ability to preview (in proof mode) a group of payments to be generated, make any changes such as removing a voucher from the group and subsequently submitting the group for actual payment generation.	1		
A9.11	Inclusion of remittance detail, for printed cheques, such as supplier ID, supplier invoice number, invoice amount paid, discount amount taken, purchase order reference and any explanation/remarks field entered for the voucher.	1		
A9.12	Ability to reset the cheque printing process to re-print one or more cheques in the event of printer problems encountered.	1		
A9.13	Ability customize cheques and remittance stubs to include company logo and electronic signatures.	1		
A9.14	Ability to capture manual cheques issued "after the fact".	1		
A9.15	Support for electronic payments and funds transfers.	2		
A10.0	**Periodic & Annual Close**			
A10.1	Ability to run monthly close by fiscal date periods.	1		
A10.2	Ability to close A/P period ahead of G/L period close if required.	1		
A10.3	Allow posting to a future period if required. For example, if the calendar month is July and the June monthend has not been closed off, allow postings to both June and July.	1		
A11.0	**Inquiries & Reporting**			
A11.1	Drill-through to voucher and corresponding purchase order details from account inquiry.	1		
A11.2	On line “as off” supplier balances.	1		
A11.3	Unvouchered purchase orders and/or receipts.	1		
A11.4	Supplier profile information showing Supplier Name, Supplier ID, Address, Email Address, Contact Name, Payment terms, taxes.	1		
A11.5	Vouchers by pay status inquiry showing all pending payment approval, on hold, approved for payment and paid vouchers including information such as invoice number, supplier ID, voucher valud, invoice date, due date, open value, discount available/taken and cheque reference if paid.	1		
A11.6	Ability to provide for supplier history retrieving vouchers, payment references and purchase orders. (This should include current history and prior years)	1		
A11.7	A/P Summary Aging showing Supplier ID, Supplier Name, Phone Number, Company Number, Balance Open, Current , Aging days 31-60, Aging Days 61-90, Aging Days 91-120, Aging Days Over 120	1		
A11.8	A/P Detail Aging showing Supplier ID, Supplier Name, Phone Number, Company Number, Invoice Number, Invoice Date, Due Date, Balance Open, Current , Aging days 31-60, Aging Days 61-90, Aging Days 91-120, Aging Days Over 120.	1		

LEGEND

Priority: **1**=Must Have **2**=Must Have for Future Implementation **3**=Nice to Have for Future Opportunity

Fit to Product Responses: ***Y*** *=Yes, within standard functionality* ***P*** *=Partially within standard functionality, achievable with customizations*
N *=No, not in product functionality* ***F*** *=Planned for future release.*

Business Area: **Accounts Payable**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
A11.9	A/P"As-of" Open Detail Aging showing Supplier ID, Supplier Name, Company Number, Invoice Number, Invoice Date, Due Date, Balance Open, Balance Original, Current , Aging days 31-60, Aging Days 61-90, Aging Days 91-120, Aging Days Over 120.	1		
A11.10	A/P Payments Register showing Payment Number, Payment Date, Supplier ID, Supplier Name, Voucher Number, Company Number, Amount Paid, Supplier Invoice Number.	1		
A11.11	A/P Payment History showing Supplier ID, Supplier Name, Invoice Number, Invoice Date, Due Date, Payment Amount, Voucher Number, Cheque Remark.	1		
A11.12	A/P Voucher Report showing Supplier ID, Supplier Name, Phone Number, Company Number, Invoice Number, Invoice Date, Due Date, Invoice Amount, PO Number, GL Date, Batch Number, User ID, Batch Date, GL Account Distribution, Department, Account Description.	1		
A12.0	**Audit Checks & Integrity Reporting**			
A12.1	Report to show any discrepancies or out-of-balance accounts between Accounts Payable and the General Ledger.	1		
A12.2	Report to show out-of-balances between batch totals and detail transactions within a batch.	1		
A12.3	Ability to track and report on changes made to supplier profiles.	1		
A13.0	**Interface 3rd Party Software**			
A13.1	EDI functionality for EFT payments and specifically to TD Bank.	3		
A13.2	Automatic email notifications to suppliers for EFT payments.	3		

LEGEND

Priority: **1**=Must Have **2**=Must Have for Future Implementation **3**=Nice to Have for Future Opportunity

Fit to Product Responses: ***Y*** *=Yes, within standard functionality* ***P*** *=Partially within standard functionality, achievable with customizations*
N *=No, not in product functionality* ***F*** *=Planned for future release.*

Business Area: **Accounts Receivable**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
B1.0	**Customer Information System (CIS)**			
B1.1	Interface to the Customer Information System (CIS) to capture Sales, Revenue and unbilled Receivables into the General Ledger. The Customer Information System is a stand-alone software used exclusively for a customer service billing. The customer master and all related billing information resides in the CIS system. This is includes customer name, customer ID, billing address, tax information, payment terms and bank information.	1		
B2.0	**Customer Master Information**			
B2.1	Unique identification of customers with the ability to enter customer name of a minimum of 30 characters including full mailing address information (Street Address, City, Province/State, Postal Code, Country)	1		
B2.2	Reference field for a hold code for the ability to flag a customer that should not be supplied services possibly a delinquent customer.	1		
B2.3	Customer specific payment terms with the ability to default the minimum of net 30 days.	1		
B2.4	Customer credit limit dollar amount.	1		
B2.5	Customer contact for Accounts Receivale inquiries. Contact information should include Contact Name, Job Title, Address, Telephone Number(s) and email Address.	1		
B2.6	Customer email address for the ability to use email for invoice delivery.	3		
B2.7	Customer's tax applicability (applicable or exempt) and tax rate by location. For example, GST and PST tax applicability and rates for British Columbia suppliers and HST suppliers in Atlantic provinces.	1		
B3.0	**Approval Process**			
B3.1	Option for management approval of A/R transaction batches for posting to the Financial System.	1		
B4.0	**Billing Processing**			
B4.1	Ability to generate invoices showing the following:			
B4.2	1. "Bill To" company name and address	1		
B4.3	2. "Ship To" (service location) address	1		
B4.4	3. Work order reference	1		
B4.5	4. Invoice date	1		
B4.6	5. Service date	1		
B4.7	6. Discount due date	1		
B4.8	7. Quantity, Unit of Measure	1		
B4.9	8. Unit price	1		

LEGEND

Priority: **1**=Must Have **2**=Must Have for Future Implementation **3**=Nice to Have for Future Opportunity

Fit to Product Responses: ***Y*** *=Yes, within standard functionality* ***P*** *=Partially within standard functionality, achievable with customizations*
N *=No, not in product functionality* ***F*** *=Planned for future release.*

Business Area: **Accounts Receivable**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
B4.10	9. Extended amount (unit price * quantity)	1		
B4.11	10. Discount amount	1		
B4.12	11. Tax amounts	1		
B4.13	12. Payment terms	1		
B4.14	13. Department field reference	3		
B4.15	14. Company field reference	1		
B4.16	15. Explanatory field(s) for any additional comments or notes to be included in the invoice	1		
B4.17	Automatic system generation of unique invoice numbers.	1		
B4.18	Ability to set up recurring invoices to be automatically generated based on specified period intervals, for example monthly, bi-monthly.	1		
B4.19	Ability to review and make revisions to invoices prior to issuance.	1		
B4.20	Approval option for invoices (or batches) prior to posting to the General Ledger.	1		
B4.21	Ability to reverse invoices after posting to the General Ledger.	1		
B4.22	Automatic calclation of GST and PST based on pre-configured tax applicability and rates.	1		
B4.23	Support for the ability to distinguish different transaction types, namely, invoices and credit notes.	1		
B5.0	**Cash Receipts**			
B5.1	Entry of cash receipts with the ability to enter receipt dates which are separate from the current General Ledger period date.	1		
B5.2	Ability to support the selection of bank accounts to be debited.	1		
B5.3	Ability to review and the option to approve receipts prior to posting to the General Ledger.	1		
B5.4	Ability to reverse posted receipts with automatic system reversal of amounts booked to various accounts.	1		
B5.5	Ability to automatically match invoices with cash receipts amounts or manually select invoices that are being paid.	1		
B5.6	Ability to offset invoices and credit note entries, this is required so that debit and credit entries are not shown in the aged accounts receivable report.	1		
B6.0	**Credit Collections**			
B6.1	Ability to print statements and delinquency notices	1		
B6.2	Ability to set up interest rates and have the system automatically generate interest charges on overdue accounts	1		
B7.0	**Period & Annual Close**			
B7.1	Ability to run monthly close by fiscal date periods.	1		

LEGEND

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Business Area: **Accounts Receivable**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
B7.2	Allow posting to a future period if required. For example, if the calendar month is July and the June monthend has not been closed off, allow postings to both June and July.	1		
B7.3	Ability to close A/R period ahead of G/L period close if required.	1		
B7.4	Ability to define "allowed" posting periods and disable posting to "disallowed" periods.	1		
B7.5	Ability to restrict postings to closed periods.	1		
B8.0	**Inquiries & Reporting**			
B8.1	Customer information detailing all open, paid, pending invoice information.	1		
B8.2	GL accounts with the ability to drill-through to applicable invoice details and payments.	1		
B8.3	Details of items paid with corresponding cheque number	1		
B8.4	On line “as off” customer balances	1		
B8.5	Un-posted A/R Batches	1		
B8.6	Customer Master information showing Customer ID, Customer Name, Billing Address, Taxes, Payment Terms, Contact Information	1		
B8.7	Invoice information details showing Invoice Number, Customer Reference Number, Invoice Date, Due Date, Discount Due Date, Invoice Description, Invoice Amount, Amount Outstanding.	1		
B8.8	AR Open Summary Report showing Customer ID, Customer Name, Customer Phone Number, Invoice Date, Invoice Number, Aging days 31-60, Aging Days 61-90, Aging Days 91-120, Aging Days Over 120 and totals by Aging Day Range.	1		
B9.0	**Audit Checks & System Integrity Reporting**			
B9.1	Report to show out-of-balances between batch totals and detail transactions within a batch.	1		
B9.2	Ability to show discrepancies between any Accounts Receivable batch posted into the General Ledger	1		
B9.3	Ability to show that all the General Ledger Accounts Receivable Trade accounts are in balance with the Accounts Receivable Subledger.	1		
B9.4	Ability to track and report on changes made to customer profiles.	1		
B10.0	**Interfaces 3rd Party**			
B10.1	Interface to the Customer Information System (CIS).	1		

LEGEND

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Business Area: **Budgeting & Forecasting**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
C1.0	**Budgeting and Forecasting**			
C1.1	Ability for budgets to be entered into the system by different budget owners as required.	1		
C1.2	Ability to export budgets to spreadsheets for further analysis and reporting (graphical) as required.	1		
C1.3	Ability to capture budgets by month or by fiscal year.	1		
C1.4	Ability to capture budget by department and within which a further breakdown by at least two additional levels of details.	1		
C1.5	Ability to budget in units and dollars.	1		
C1.6	Ability to support the use of budget spread patterns such as seasonal spread patterns, regular 1/12 budget pattern and percentage based spreads. This is based on an annual budget amount entered whereby the system automatically spreads the amounts to the months based on the spread pattern specified.	1		
C1.7	Ability to provide history of prior year expense and revenue. This should ideally span a seven-year period. This would be used for budget comparisons in the budgeting module.	1		
C1.8	Ability to roll up budgets into departments, account codes and any further categorization of account codes.	1		
C1.9	Ability to identify budgets by original budget, approved budget, final budget and revisions for the tracking of amendments.	1		
C1.10	Ability to prevent unauthorized changes to original and approved budgets.	1		
C1.11	Ability to perform budget tracking by capital project.	1		
C1.12	Ability to perform budget reallocation by specified percentages.	1		
C1.13	Ability to generate initial forecasts from prior year expenses and revenues. For example Operating & Maintenance expenses and Payroll Costs.	1		
C1.14	Support for 12 month rolling forecasts; with 12-month total displayed.	1		
C1.15	Ability to make adjustments to forecasts.	1		
C1.16	Ability to generate automatic, low intervention forecasting methods such as the use of percentage based changes or indexed changes.	1		
C1.17	Ability to attach documents/notes to support budget details.	1		
C2.0	**Forecast Evaluation Tools**			
C2.1	Ability to download forecast data onto spreadsheets.	1		
C2.2	Ability to save different versions of forecast for accuracy analysis.	1		
C2.3	Support for “what if” analysis tool.	1		
C3.0	**Approval Process**			
C3.1	Ability to route budgets for approvals based on various approval authorities.	1		
C4.0	**Managing Budget Overages**			

LEGEND

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Business Area: **Budgeting & Forecasting**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
C4.1	Ability to restrict postings to accounts which exceeds the budget amount and the option to route postings for approvals.	2		
C4.2	Ability to generate an exception report for overages where actual amounts exceed budgeted amounts.	1		
C5.0	**Annual Budget Close**			
C5.1	Ability to selectively rollover specific budgets to the following year.	1		
C5.2	Ability to carry forward capital budgets if applicable.	1		
C6.0	**Mass Updates**			
C6.1	Ability to carry out mass updates to budget spread patterns as required.	1		
C7.0	**Inquiries & Reporting**			
C7.1	The ability to compare actual amounts with budgeted amounts and display the variances as follows:	1		
C7.2	Comparison of budgets verus actuals including reported variances by department, by account code, by various levels of account code categorizations, and combinations thereof.	1		
C7.3	Monthly budget report by departments and account codes showing Department, Department description, Account Code, Account description, Total Budget Amount, Monthly Period(1-12) Amounts.	1		
C7.4	Annual Budget Reports showing Department, Department description, Account Code, Account description, Total Budget Amount.	1		
C7.5	Budget Worksheet showing Account Description, Prior Year YTD Actual, Current Year YTD Budget, Current Year YTD Actual, Projected, Next Year Requested Budget, % Change, New Year Final Budget, % Change and the ability to enter supporting comments.	1		
C8.0	**Interface from Third Party Software**			
C8.1	Interface to ADP (Payroll) for the extrapolation of payroll costs for forecasting.	1		
C8.2	Interface to CIS (Customer Information System) for the extrapolation of sales and revenues for forecasting.	1		

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Business Area: **Financial Reporting**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
D1.0	**Reporting**			
D1.1	Account balance and detail by Month	1		
D1.2	Journal Entry Details prior to Posting	1		
D1.3	Journal Entry Posting Report	1		
D1.4	Monthly Trial Balance Report	1		
D1.5	Income Statements by business function, type of expenditures, by department and by different user groups (Board of Directors, Yukon Utilities Board, Audit, Management, Budget Owners).	1		
D1.6	Income Statements by various levels of detail such as:			
D1.7	1. Admin vs Operations	1		
D1.8	2. Admin by Function (Type of Activity)	1		
D1.9	3. Admin by Type of Expenditure by Activity	1		
D1.10	Ability to generate monthly, quarterly and yearly statements.	1		
D1.11	Balance Sheet for different user groups and different levels of detail. Eg: Board of Directors vs Auditors and by details of all accounts that make up cost and roll-up to cash.	1		
D1.12	Cash Flow Statements	1		
D1.13	Lead Sheets (Balance Sheet & Income Statement) for yearend audits; supporting the numbers in the audit financial statements.	1		
D1.14	Project cost tracking reports showing Actuals vs Approved Project Budget vs Projected Project Budget for 1 year and multi-year projects.	1		
D1.15	Support for reporting both IFRS (International Financial Reporting Standards) and Canadian GAAP (Generally Accepted Accounting Principles) in parallel.	1		
D2.0	**Reporting Security/Access**			
D2.1	Financial Reporting security is required to selectively restrict access by type of report and suppression of specific sensitive/confidential data fields by user group.	1		

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Business Area: **Asset Management**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
E1.0	**Asset Profile**			
E1.1	Ability to uniquely identify each asset with a system generated number and/or a unit number and a serial number.	1		
E1.2	Support for alphanumeric unit numbers with a minimum of 6 characters long.	1		
E1.3	Support for serial numbers (for the capture of Manufacturer's reference numbers) with a minimum of 30 charaters long.	1		
E1.4	Ability to set up parent/child relationships to define hierarchical relationships of asset components.	1		
E1.5	Ability to capture the following data elements for an asset:			
E1.6	1. Asset description of a minimum of 60 characters.	1		
E1.7	2. Asset company reference	1		
E1.8	3. Physical location of asset	1		
E1.9	4. Department that owns the asset	1		
E1.10	5. Acquisition Date	1		
E1.11	6. Disposal Date	1		
E1.12	7. Reference field to store an authorization number, for example, Project Identification number that is initiated for a capital expenditure.	1		
E1.13	8. Reference field for tracking easements	1		
E1.14	9. Licences reference field.	1		
E1.15	10. Status of the Asset. (Eg: Active, Inactive, Scrapped)	1		
E1.16	Ability to categorize assets into the following classes and/or with the following elements:			
E1.17	1. Accounting Class. (Eg: Land, Building, Furniture & Fittings, Computers, Roads, Vehicles)	1		
E1.18	2. Equipment Class. (Eg: Land Operations, Software, Hardware, Trucks, Vans, Cars)	1		
E1.19	3. Manufacturer Information. (Eg: Caterpillar, Ford Co, Honeywell)	1		
E1.20	4. Model Year	1		
E1.21	5. Usage. (Eg: Hydro, Diesel, Wind)	1		
E1.22	6. Vintage Year. (Used for splitting and transfer of assets)	1		
E1.23	7. Iowa Curve field reference. The codes for the Iowa curve and the corresponding rates are entered. (This is unique to YEC where the assets are re-valued for useful life and assigned new depreciation rates based Iowa Curve rate study). The ability to support this is mandatory.	1		
E1.24	8. Asset condition. (Eg: New, Used)	1		
E1.25	9. Financing Methods. (Eg: Lease, Bank, Owner Finance)	1		
E1.26	10. Investment Tax Credit field (Amounts received as grants or sponsors for development of assets)	1		
E1.27	11. Current Item Quantity (Eg: number of poles, number of structures)	1		

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Business Area: **Asset Management**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
E1.28	12. Original Item Quantity	1		
E1.29	13. Remarks/explanation fields (preferrably a minimum of 60 characters) for the entry of an additional notes pertaining to an asset.	1		
E1.30	Ability to set up the following Depreciation information for an asset:			
E1.31	1. Asset Cost Account	1		
E1.32	2. Accumulated Depreciation Account	1		
E1.33	3. Depreciation Expense Account	1		
E1.34	4. Depreciation Method (Eg: Straight Line)	1		
E1.35	5. Asset Useful Life (in months or years)	1		
E1.36	6. Depreciation Start Date	1		
E1.37	7. Salvage Value	1		
E1.38	8. Site Restoration Account (the ability to expense secondary depreciation and have the offset entry in the balance sheet as site restoration account)	1		
E2.0	**Ledgers - Multiple Books of Records**			
E2.1	Ability to support multiple books of records such as:			
E2.2	1. Actual Ledger	1		
E2.3	2. Units Ledger	1		
E2.4	3. YEC Depreciation Ledger (This is used to calculate depreciation based on the Iowa curve revaluation)	1		
E2.5	4. Creation of additional ledgers as required. (Possible requirement for IFRS)	1		
E3.0	**Depreciation Rules**			
E3.1	Support for Straight Line Method with defined months	1		
E3.2	Ability to create own depreciation rules. (This is a deviation from the straight line calculation. This requirement is driven from the Iowa curve study where new/different depreciation rates and rules are required).	1		
E3.3	Over-depreciation of an asset must be allowed for pooled assets. This is unique to the YEC.	1		
E3.4	Different depreciation start dates is required (Eg: 1st day following in service date).	1		
E4.0	**Fixed Asset Splitting**			
E4.1	Ability to automate asset splitting by specification of a percentage.	1		
E4.2	Ability to automate asset splitting by specification of monetary values.	3		
E4.3	Ability to automate asset splitting by specification of quantities/units.	3		
E4.4	Ability to split by manual journal entry. (Creation of a new asset and manually transfer the cost and accumulate depreciation as required).	1		
E5.0	**Transferring Fixed Asset**			

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Business Area: **Asset Management**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
E5.1	Ability to transfer assets by criteria specification accounts, such as, Costs, Accumulated Depreciation and/or Expense Accounts. Eg: If an asset was created with a wrong account code, a transfer is needed to the correct account code.	2		
E5.2	Ability to transfer assets by categories such as by Accounting Class and/or Equipment Class.	1		
E5.3	Ability to transfer assets by criteria specification such as location and owner.	2		
E6.0	**Fixed Asset Disposal**			
E6.1	Support for various disposal methods such as Simple Disposal, Disposal with Cash Proceeds, Disposal with Trade In, Disposal with Trade In and Cash Proceeds.	1		
E6.2	Ability to specify mass disposals of assets by Accounting Class and/or Equipment Class.	2		
E7.0	**Monthly Depreciation Calculation**			
E7.1	Ability to run monthly depreciation calculations in a preliminary mode for review before running in a final mode whereby amounts are posted into respective depreciation accounts.	1		
E7.2	Ability to automatically calculate depreciation based on an “as off “date.	1		
E7.3	Ability to reverse depreciation calculations if required.	1		
E8.0	**Approval Process**			
E8.1	Ability to support Management Approvals prior to posting of asset costs and depreciation.	2		
E9.0	**Mass Updates of Assets Set Up**			
E9.1	Ability to change asset categorizations on mass without having to change each asset individually. Eg: Change all computers classified under the "Hardware" category to "Equipment".	2		
E9.2	Ability to change asset life on mass without having to change each asset individually. (Eg: Change all computer hardware equipment to depreciate from 60 months to 72 months)	2		
E9.3	Ability to attach assets to a ledger. (Eg: Attach assets to a new ledger defined for IFRS requirements)	2		
E10.0	**Grants**			
E10.1	Ability to track different grants per asset. (Eg: contributions by the Yukon Government, contributions by Customers, contributions by YDC)	1		
E11.0	**Period and Annual Close**			
E11.1	Closing a fiscal year with the automatic carry forward of asset cost and accumulated depreciation balances to the new year.	1		
E11.2	Ability to post Fixed Asset entries into "allowed" future periods.	1		

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Business Area: **Asset Management**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
E11.3	Ability to restrict posting to a closed accounting period.	1		
E12.0	**Inquiries & Reporting**			
E12.1	Fixed Asset Master Information showing Asset number, Unit number, Serial number, Department, Categorization Codes, Company, Asset Description fields.	1		
E12.2	Asset Cost Summary showing Asset number, Unit number, Serial number, Department, Cost Amount, Accumulated Depreciation, Depreciation Expense, Net Book Value, Date Acquired, Asset Description fields.	1		
E12.3	Fixed Asset Continuity Schedule showing Asset ID, Asset Description, Beginning Asset Cost, Transfer In, Additions, Assets Sold or Retired, Assets Transfer Out, Ending Asset Cost, Beginning Accumulated Depreciation, Assets Transfer In, YTD Depreciation Expense, Asset Sold or Retired, Assets Transfer Out, Ending Accumulated Depreciation, Net Book Value.	1		
E12.4	Asset Additions showing Asset ID, Asset Description, Date Acquired, Asset Cost, Accumulated Depreciation, Depreciation Expense, Net Book Value.	1		
E12.5	Asset Disposals showing Asset ID, Asset Description, Disposal Date, Date Acquired, Asset Cost, Accumulated Depreciation, Net Book Value, Cash Proceeds, Gain or Loss on Disposal.	1		
E12.6	Asset by Location Department showing Asset ID, Asset Description, Serial Number, Unit Number, Date Acquired, Location/Department.	1		
E12.7	Depreciation Expense Information showing Asset ID, Asset Description, Asset Status, Ledger reference, Cost, Accumulated Depreciation, YTD Depreciation Expense, Current Period Depreciation Expense, Net Book Value, Start Depreciation Date, Depreciation Method, Asset Life.	1		
E12.8	Monthly Depreciation Calculation Report showing Asset ID, Asset Description, Acquisition Date, Depreciation Start Date, Depreciation End Date, Asset Life, Cost, Accumulated Depreciation Inception to Date, Accumulated Depreciation YTD, Depreciation Current, Depreciation Balance Adjustment.	1		
E13.0	**Audit Checks and System Integrity Reporting**			
E13.1	Ability to track and report on changes made to asset profiles.	1		
E13.2	Discrepancies or out-of-balance situations between the Fixed Asset ledger and General Ledger	1		
E13.3	Posted and Un-posted Fixed Asset to General Ledger transactions	1		

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Business Area: General Accounting

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
F1.0	**Company Profile**			
F1.1	Multiple companies capability with own unique Chart of Accounts.	1		
F1.2	Functional currency set up by company. Support for Canadian currency (CAD) is mandatory with all inquiries and financial reporting to be shown in CAD.	1		
F1.3	Company full legal name (description) of at least 35 characters in length.	1		
F1.4	Configurable fiscal date patterns by company. (Eg: Beginning fiscal date for company A is January 01, for company B is April 01)	1		
F1.5	More than 12 accounting periods. (YEC requires 13 periods whereby the 13th period is used for audit adjustments)	1		
F1.6	Retention of 7 years of historical data (expense and revenue). This information must be available for both system reports and inquiry functions.	1		
F2.0	**Business Units / Departments**			
F2.1	Multi-tiered organization structure with the capability of multiple business units for each tier.	1		
F2.2	Disable posting of transactions to a business units as required.	1		
F2.3	Grouping of business units into different categories for reporting and consolidation purposes.	1		
F2.4	Assignment of owners to business units.	1		
F3.0	**Chart of Accounts**			
F3.1	Multi-segment account codes (minimum of 3 segments and minimum of 8 characters per segment)	1		
F3.2	Disable/deactivate an account for the posting of transactions as required.	1		
F3.3	Prevent deletion of accounts with activity. (Eg: An expense account that is still referenced in an outstanding purchase order)	1		
F3.4	Automatic system roll-up of lower-level accounts to higher-level accounts for summary reporting.	1		
F3.5	Grouping of accounts into categories for reporting and consolidation purposes.	1		
F3.6	Ability to quickly set up accounts by copying accounts from one business unit to another.	1		
F4.0	**Ledgers**			
F4.1	Different ledgers capability. (Eg: Actual Ledger, Depreciations Ledger, Budget Ledger, Commitments Ledger, Job Cost Budget Ledger, Units Ledger, Forecast Ledger)	1		
F4.2	Definition of ledger yearend balance roll-over or carry forward rules.	1		
F4.3	Drill-down capability on all ledgers to source transactions.	1		
F5.0	**Journal Entry Processing**			
F5.1	Standard and recurring journal entries creation.	1		
F5.2	Reversal or voiding of journal entries with audit trail traceability.	1		

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Business Area: General Accounting

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
F5.3	Model or templates for frequently used transactions.	1		
F5.4	Copy journal entries from exsiting entries.	1		
F5.5	Deletion of unposted journal entries.	1		
F5.6	Review of journal entries prior to posting for identification and correction of errors.	1		
F5.7	Ability to create a percentage journal entry.	1		
F5.9	Payroll entries upload capability from ADP system.	1		
F5.10	Allocation journal entries creation.	1		
F5.11	Posting to current period and prior period (if not closed).	1		
F5.12	Closed period posting prevention.	1		
F5.13	Posting to future periods with the ability to define number of allowed future periods from current period.	1		
F5.14	Reference field to capture references to, for example, a fixed asset, a project, a work order.	1		
F5.15	Explanatory field(s) for the capture of additional notes and remarks.	1		
F5.16	Audit trail for manual and system generated journal entries showing transaction source, date and time of creation or revisions.	1		
F6.0	**Allocations**			
F6.1	Allocation of account balances to one or more other accounts or from one ledger to another.	1		
F6.2	Multiple allocation types capability. (Eg: Fixed, Pro-rata, Spread evenly or Arithmetic)	1		
F6.3	Indexed Allocations; redistribute amounts from one or more business units to one or more business units based on a index (rate).	1		
F6.4	Variable Numerator allocations; redistribute amounts from one or more business units to one or more business units with a common category. (Eg: Distribute an expense based on the number of people in a department)	1		
F6.5	Allocations using inception to date balances and allocate based on a user-defined categorization code. (Eg: AFUDC (Allowance for funds used during construction) interest to be charged to projects. Credit offset to revenue).	1		
F7.0	**Period & Annual Close**			
F7.1	Executiion of automatic journal entry to close all income and expense items to retained earnings account at year end.	1		
F7.2	Ability to run multiple preliminary period-end or annual-end closings.	1		
F7.3	Ability to run the annual close by company.	1		
F8.0	**Audit Checks and System Integrity Reporting**			
F8.1	Checks and balances to show that the General Ledger system is in balance with transactions and active sub-ledgers.	1		
F8.2	Checks and balances to show that companies are in balance with intercompany transactions.	1		

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Business Area: **General Accounting**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
F9.0	**Interface - 3rd Party Software**			
F9.1	Interface to the CIS system for the capture of electric utility sales and revenues.	1		
F9.2	Interface to ADP Payroll system for the capture of Payroll costs.	1		

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Business Area: **Inventory Management**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
G1.0	**Item Master**			
G1.1	Ability to set up stock and non-stock items including services in a centralized Item Master for use by all warehouses and business units for non-inventory purchases. There should be no threshold on how many items can be set up on the item master.	1		
G1.2	Unique alphanumeric item number identification of at least a 10-character code including descriptive text of at least 60 characters long.	1		
G1.3	Identification of the type of item; namely, 'stock', 'non-stock', 'new', 'salvaged', services.	1		
G1.4	Identification of item condition or status such as 'Active', 'Obsolete', 'Refurbished', 'Used', 'Discontinued'.			
G1.5	Ability to attach notes such as specifications, handling instructions, WHMIS alerts.	1		
G1.6	Support for potential use of Fortis naming convention of items.	3		
G1.7	Grouping of items into different categories and 2 additional levels of subcategories. For example, 'Poles' as a main category and within which subcategories 'Steel', 'Wood'.	1		
G2.0	**Units of Measure**			
G2.1	Configuration of various units of measure (UOM) for tracking, purchasing, shipping/issuing, volume and weight for an item. UOM's should be configurable or available for non-tangible items such as services where, for example, items could be purchased in units of hours.	1		
G2.2	Specification of standard and non-standard units of measure conversion factors by item. Examples: 1 gallon =3.79 litres, 32 eaches = 1 box.	1		
G3.0	**Item Cross-References**			
G.3.1	Cross-references to vendor part numbers by effectivity dates including references to alternates and supercedes.	1		
G4.0	**Warehousing**			
G4.1	Ability to set up multiple (overflow) warehouse locations for an item.	1		
G4.2	5-segment warehouse location identification format, AREA-AISLE-SECTION-SHELF-SLOT, with the following minimum requirements:	1		
G4.3	AREA – 4 characters	1		
G4.4	AISLE – 2 characters	1		
G4.5	SECTION – 2 characters	1		
G4.6	SHELF – 3 characters	1		
G4.7	SLOT – 4 characters	1		
G5.0	**Bills of Materials**			
G5.1	Configuration of Bills of Material (BOM) for specific tasks or jobs with the ability to specify quantities per BOM component.	1		

LEGEND

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Business Area: Inventory Management

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
G5.2	Submission of inventory request by BOM identification number for automatic generation of components for picking.	1		
G6.0	**Replenishment**			
G6.1	Specification of maximum and minimum stocking levels, reorder points, reorder quantities and safety stock levels by item.	1		
G6.2	Automatic generation of suggested order quantities, based on replenishment parameters, with the option of automatic generation of purchase orders.	1		
G7.0	**Suppliers**			
G7.1	Configuration of primary and secondary suppliers by item and/or item grouping including the specification of discontinued suppliers.	1		
G8.0	**Inventory Costing Options**			
G8.1	Same unit cost across all warehouses	1		
G8.2	Same unit cost within a warehouse	1		
G8.3	Unit cost by warehouse location	1		
G8.4	Different unit costs for new, refurbished/used, obsolete items	1		
G9.0	**Safety Stock**			
G9.1	Specification of safety stocking levels for emergency (maintenance) items and an expedient process to release safety stocks when required.	3		
G10.0	**Availability**			
G10.1	Visibility of inventory levels across all warehouses.	1		
G10.2	Ability to determine “true” inventory availability taking into account reservations and any safety stocking levels.	3		
G11.0	**Serial Number Tracking**			
G11.1	Capture of serial numbers for items such as Transformers requiring serial number traceability from receipts through to issues including installations.	1		
G12.0	**Inventory Issues**			
G12.1	Ability to initiate inventory requirements for work orders, jobs, project and other business units including the specification of required dates.	1		
G12.2	Pre-configured expense codes and automatic defaults of codes with the ability to override defaults as required.	1		
G12.3	Automatic generation of picking and shipping document when inventory requests are due.	1		
G13.0	**Inventory Transfers**			
G13.1	Ability to initiate inventory transfers by either the source or destination warehouse with the specification of required dates.	1		
G13.2	Automatic generation of picking and shipping documentation when transfers are due.	1		
G14.0	**Inventory Counts**			

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Business Area: **Inventory Management**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
G14.1	Frequency: Ability to configure cycle counts by items, by warehouse location and/or by item groups based on number-of-days frequency and/or by activity based on ABC classification.	1		
G14.2	Controls: Segregation of duties throughout the count process. System security and controls for different personnel to expedite the count generation, count entry, approvals and updates.	1		
G14.3	Count Sheets: Option to suppress the display of system onhand quantities on count sheets.	1		
G14.4	Count Sheets: Ability to generate write-in pages as required.	1		
G15.0	**ABC Classification**			
G15.1	ABC classification of items based on various parameters such as by activity and/or costs.	2		
G16.0	**Receiving**			
G16.1	Generation of a list of items to be received on a purchase order. This is required in the event that a picking/packing slip is absent.	1		
G16.2	Ability to inquire/report on all receipts for a purchase order or for the day.	1		
G16.3	Ability to receive warehouse-to-warehouse transfers at each warehouse.	1		
G16.4	Ability to enter receipts as fully received, partially received with the option to backorder or cancel residual outstanding quantity and completely backorder any outstanding quantity.	1		
G16.5	Traceability of receipts by unique receipt numbers.	1		
G16.6	Capture of serial numbers when items are received.	1		
G16.7	Advise of designated warehouse stocking location when an item is received and the ability to create overflow locations as required.	1		
G16.8	Configuration of receiving tolerances by units based on percentage and/or amounts with warning/error alerts.	1		
G16.9	Option to suppress display of and changes to costs at receiving.	1		
G16.10	Capture of supplier picking/packing slip numbers, container and shipping document information including any additional charges.	1		
G16.11	Process to return inventory with the ability to track returns with Return Authorization Numbers, notate reasons for returns and generate documentation to accompany return.	1		
G17.0	**Inquiries & Reporting**			
G17.1	Inquiry and reporting functions should, where applicable, display both quantities and costs.	1		
G17.2	Item Master Directory showing master list of items including description, item group/class, applicable units of measure and item status (for example, 'Obsolete', 'Discontinued', …)	1		
G17.3	Item Cross-References to Supplier numbers, alternates and supercedes.	1		
G17.4	ABC Classifications by item and/or item group at each warehouse and across all warehouses.	3		

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Business Area: **Inventory Management**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
G17.5	Stock Status for all items, for a group of item or for a specific item; at a specific warehouse and/or across all warehouses.	1		
G17.6	Overstocks by item at each warehouse and overall across all warehouses.	1		
G18.0	**Reconciliations**			
G18.1	Reconciliation facility is required, for example a report, to report any discrepancies between inventory values reported from Inventory and the General Ledger.	1		

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Business Area: **Maintenance**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
H1.0	**Equipment Profile**			
H1.1	Unique identification of equipment and components by a unit number and serial number.	1		
	Support for the profiling of each piece of equipment as follows:			
H1.2	1. Description of equipment	1		
H1.3	2. Site / Location / Unit / Line / Substation	1		
H1.4	3. Acquisition Date	1		
H1.5	4. Installation Date	1		
H1.6	5. In-Service Date	1		
H1.7	6. Disposal Date	1		
H1.8	7. Manufacturer profile including product and model number, model year, service and warranty agreements	1		
H1.9	8. Equipment Status; Available, Active, Inactive, Disposed	1		
H1.10	9. Parent unit reference for component units	1		
H1.11	10. Depreciation schedule	1		
H1.12	11. Salvage proceeds / disposal costs	1		
H2.0	**Component Relationships**			
H2.1	Configuration of parent/child component relationships with unlimited child components per level and unlimited number of levels. For example, parent substations with transformers and generators components and within transformers, protection meters, etc.	1		
H2.2	Tracking of parent history	1		
H3.0	**Location Tracking**			
H3.1	Ability to maintain and inquire on the location of each component and track start and end dates, status at each location a history of transfers.	1		
H4.0	**Maintenance History**			
H4.1	Tracking of service history of each piece of equipment including the capture of failures and causes, the number of downtimes, the duration of downtimes, maintenance dates, and the types of maintenance performed, for example, regular or emergency service.	1		
H5.0	**Meter Readings**			
H5.1	Maintenance of meter readings including capture of original meter readings and readings at meter changes.	1		
H6.0	**Preventive Maintenance Schedule**			
H6.1	Set up PM Schedules for different service types based on different intervals. For example, hours of operation, fuel usage, number of days interval from last maintenance and specific dates.	1		

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Business Area: **Maintenance**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
H1.0	**Equipment Profile**			
H6.2	Set up associations to link different types of maintenance to be performed at the same time.	1		
H6.3	Set up of maintenance loops for identical maintenance of multiple units of same equipment.	1		
H6.4	Notifications of upcoming maintenance requirements by pre-configured percentage due threshold limits.	1		
H6.5	Ability to attached model work orders and part lists to different types of maintenance.	1		
H6.6	Automatic generation of work orders when maintenance is due or coming due.	1		
H6.7	Ability to attach related documentation and notes to schedules.	1		
H6.8	Ability to print PM schedules as required.	1		
H7.0	**Parts Requirements**			
H7.1	Tracking of spare parts inventory at different locations with the ability to specify safety stocking levels for critical components.	1		
H7.2	Set up of parts list for different types of maintenance and association of parts list to work orders.	1		
H7.3	Automatic generation of parts list to be picked and issued from inventory when maintenance is coming due.	1		
H8.0	**Maintenance Costs**			
H8.1	Capture of total maintenance costs to date on a specific piece of equipment and at the parent level.	1		
H8.2	Capture of estimates and actuals by type of service/maintenance work.	1		
H8.3	Automatic capture of all actual costs incurred in the maintenance of a piece of equipment. Namely, internal labour costs, cost of materials issued from inventory, materials purchased, subcontract labour costs and equipment rental costs.	1		
H9.0	**Time Entry**			
H9.1	Set up of hourly labour rates by types of maintenance including overtime rates.	1		
H9.2	Capture/entry of labour hours by type of maintenance work performed on a work order and with reference to the applicable piece of equipment.	1		
H9.3	Automatic posting of labour hours to Financial and payroll systems.	1		
H10.0	**Work-Breakdown Structure**			
H10.1	Ability to set up parent/umbrella work orders with unlimited 'child' work orders.	1		
H10.2	Ability to capture and review estimated costs versus actual costs by individual work order and overall roll-up total costs to the parent work order.	1		

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Business Area: **Maintenance**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
H1.0	**Equipment Profile**			
H11.0	**Work Order Initiation**			
H11.1	Automatic system generation of work orders when PM schedules become due.	1		
H11.2	Ability to set up work orders as required for unplanned and emergency maintenance.	1		
H11.3	Ability to route and print work orders to specific printers.	1		
H11.4	Information required to be printed on work orders are as follows:			
H11.5	1. Work Order Number	1		
H11.6	2. Equipment information including service history	1		
H11.7	3. Description of maintenance and work steps	1		
H11.8	4. Estimated labour hours	1		
H11.9	5. Parts list or material requirements	1		
H11.10	6 Attachments of additional related documentation	1		
H11.11	7. Planned start and completion dates	1		
H12.0	**Work Order Approvals**			
H12.1	Electronic routing of approvals for unplanned work orders and optional approvals for planned work orders.	1		
H12.2	Electronic alerts to approvers on work orders awaiting their approval.	1		
H12.3	Ability to specify rejection reasons by approver.	1		
H12.4	Automatic notification to originators on whether their work orders have been approved or rejected.	1		
H13.0	**Work Order Status**			
H13.1	Ability to track the status of work orders from initiation to completion. Examples of statuses are: Initiation, Pending Approval, Approved, Awaiting Parts, Awaiting Labour Allocation, Parts Issued, In-Progress, Held, Completed.	1		
H14.0	**Work Order Costs**			
H14.1	Ability to track work order estimated versus actual costs broken down by labour, materials and travel.	1		
H15.0	**Work Order Close-Out**			
H15.1	Ability to capture and print (when required) the following close-out information on a work order:			
H15.2	1. Actual Start and Completion Dates	1		
H15.3	2. Description of actual work done	1		
H15.4	3. Deficiencies found	1		
H15.5	4. Actual labour hours expended	1		
H15.6	5. Actual material items used	1		

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Business Area: **Maintenance**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
H1.0	**Equipment Profile**			
H15.7	6. Return of unused parts to inventory or to supplier	3		
H15.8	7. In-Service Date/Time or expected In-Service Date/Time of equipment	1		
H15.9	8. Description of additional unplanned maintenance and repairs	1		
H15.10	9. Meter readings	1		
H15.11	10.Sign-offs	3		

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Business Area: **Payroll Interfaces**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
I1.0	**ADP Interface**			
I1.1	Electronic interface into the new proposed system from ADP Easy Labour (EZLabour). EZLabour is currently not implemented but the existence of an interface for future implementation would be beneficial.	3		
I1.2	Electronic interface into the new proposed system from Pay at Work.	1		
I1.3	Interface is expected to map to or reference existing accounts from the proposed system into ADP create final journal entries for posting into the proposed system.	1		
I1.4	Once the labour distribution is finalized in ADP Easy labour (EZLabour), this needs to interface to the proposed system also. This is a detailed time and labour distribution as opposed to the final journal entry for payment process.	3		
I1.5	Validation report for entries entered into the proposed system that reconciles with respective Easy Labour and Pay at Work.	1		
I2.0	**Easy Labour**			
I2.1	Standard labour cost needs to be mapped into proposed system.	1		

LEGEND

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Business Area: **Procurement**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
J1.0	**Contract Management**			
J1.1	**Contract Profile** The contract data required to be captured and printed are as follows:			
J1.2	1. Contract Number; preferably system generated.	1		
J1.3	2. Description of contract with the ability to include additional details as required,	1		
J1.4	3. Vendor information including vendor contact (name, phone, email).	1		
J1.5	4. YEC Contact/Designate.	1		
J1.6	5. Contract (Agreement) date plus contract start and end dates.	1		
J1.7	6. Specification and electronic attachment of required transmittals and submittals such as WCB and insurance coverages	1		
J1.8	7. Holdback terms.	1		
J1.9	8. Security deposit specifications.	1		
J1.10	9. Contract terms and conditions including any additional special comments.	1		
J1.11	10. Warranties.	1		
J1.12	11. Applicable expenses.	1		
J1.13	12. Account (Expense) codes.	1		
J1.14	13. contract status, for example, 'Initiated', 'Waiting Approval', 'In Progress', 'Completed', 'On Hold'.	1		
J1.15	Specification of types of transmittals and submittals. For example, WCB and Insurance coverages.	1		
J1.16	Specification of whether a transmittal or submittal is mandatory and issue alerts to Accounts Payable when mandatory submittals have not been received.	1		
J1.17	Capture effectivity dates on coverages and issue system alerts, based on a specified number of days prior to expiration, when coverages are about to expire.	1		
J2.0	**Holdbacks**			
J2.1	Specification of a percentage holdback for purchase order or contracts.	1		
J2.2	Automatic system calculation of holdbacks at invoice voucher match with the option to execute holdbacks inclusive or net of taxes.	1		
J2.3	Electronic routing of approvals for holdback releases.	1		
J3.0	**Commitments**			
J3.1	Automated tracking and reporting of commitments as follows:			
J3.2	1. budgets versus actuals	1		
J3.3	2. variances between commitments and actuals	1		
J3.4	3. budgets and commitments plus actuals.	1		
J4.0	**Requisitions**			
J4.1	Entry of purchase requisitions and routing of requisitions for approval.	1		

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Business Area: **Procurement**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
J4.2	Capture of expense codes when requisitions are created.	1		
J4.3	Optional printing of requisitions.	1		
J4.4	Optional attachments of related documents, for example, specifications, drawings, manual quotations.	1		
J4.5	References to system generated quotes and vendor responses.	1		
J5.0	**Visa Purchases**			
J5.1	Facility to receive an electronic file or spreadsheet downloaded from Visa and route applicable Visa purchases to respective employees for validations and any required managerial reviews.	1		
J5.2	Electronic capture of Visa purchases for analysis and audit reviews.	2		
J6.0	**Emergency Purchases**			
J6.1	Support for expedient system capture of emergency purchases ahead of invoice receipts.	2		
J7.0	**Serial Number Tracking**			
J7.1	Capture of serial numbers for items such as transformers requiring serial number traceability from receipts through to issues including installations.	1		
J8.0	**Purchase Orders**			
J8.1	Creation of purchase orders for goods and services with the option of system generated order numbers or manually assigned numbers for manual PO's.	1		
J8.2	Identification of different types of purchases orders for analysis. For example, services PO's and goods PO's.	1		
J8.3	Ability to print purchase orders as required or en masse whereby all purchase orders that are ready to be printed and transmitted to suppliers can be printed in a scheduled background mode without any manual intervention.	1		
J8.4	Ability to create purchase order in foreign currency with pre-configured currency conversion rates.	2		
J8.5	Specification of applicable taxes and exemptions where applicable.	1		
J8.6	Ability to distribute a purchase order item line by units, amount or percentage to various business unit account codes. For example, place an order of 100 units of widgets with a supplier and allocate 20 units to account1, 30 to account2, 50 to account3.	1		
J8.7	Creation and maintenance of purchase orders and types of purchase orders by responsibility.	1		
J9.0	**Purchase Order Presentation**			
J9.1	**Presentation** The presentation of Purchase Orders should enable the following information to be			
J9.2	1. YEC Purchase Order Number	1		
J9.3	2. YEC company logo, name and address	1		
J9.4	3. "Attention To" and instructions for invoice remittance	1		

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Business Area: **Procurement**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
J9.5	4. Supplier name, full address, phone and fax number	1		
J9.6	5. ShipTo address and optional 'Attention To' contact for delivery.	1		
J9.7	6. Reference to quotation/contract number and date where applicable	1		
J9.8	7. Shipping/Freight Handling Terms	1		
J9.9	8. Payment Terms	1		
J9.10	9. YEC Buyer/Contact (including phone number and email address)	1		
J9.11	10. Supplier Contact (including phone number and email address)	1		
J9.12	11. Shipping and delivery instructions	1		
J9.13	12. Special instructions to be specified as required	1		
J9.14	13. Additional charges, for example Taxes, Freight, Brokerage	1		
J9.15	14. Order Date, Requested/Required By Date, Promised Date	1		
J9.16	15. 'Order Taken By' name	1		
J9.17	16. Standard YEC language/text on terms and conditions	1		
J9.18	17. Order quantities and corresponding units of measures	1		
J9.19	18. YEC item numbers and description	1		
J9.20	19. Supplier item numbers or catalogue numbers, as required	1		
J9.21	20. Currency	1		
J9.22	21. Unit Price	1		
J9.23	22. Extended Price	1		
J9.24	23. Applicable taxes	1		
J9.25	24. Order total	1		
J9.26	25. Expense Code, as required	1		
J9.27	26. Signatures and corresponding dates	1		
J9.28	**Distribution** Ability to seamlessly automate purchase order transmissions via email or fax including potential support for EDI transmission.	2		
J10.0	**Approvals**			
J10.1	Approvals by budget amount and/or by purchase order amount.	1		
J10.2	Ability to set up different approvers for different purchase order threshold amounts. For example, amounts >= $10,000 is approved by J.Smith and >=$20,000 is approved by J.Doe.	1		
J10.3	Automatic routing of purchase orders for approval when budget amounts and/or purchase order amounts have exceeded pre-configured threshold limits.	1		
J10.4	Automatic alerts to approvers on purchase orders pending their approval.	1		
J10.5	Automatic notifications to originators on whether purchase orders have been approved or rejected.	1		
J10.6	Ability to enter reasons for rejected purchase orders.	1		

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Business Area: **Procurement**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
J10.7	Automatic escalation of purchase orders to the next level approver if the current approver has not responded by a specified time period.	1		
J10.8	Automatic re-routing of approved orders for approval when subsequent changes violate approval thresholds.	1		
J10.9	Various levels of signing authorities for purchasing agreements based on type of expense (whether O&M or Capital), the type of items purchased (whether inventory, non-inventory goods or services) and dollar limits.	1		
J10.10	Ability to delegate signing authority with effectivity dates.	1		
J11.0	**Quotations**			
J11.1	Entry and printing of items to be quoted.	2		
J11.2	Unique identification number to track each quote.	1		
J11.3	Entry and distribution of quotes to multiple suppliers.	1		
J11.4	Specification of required by dates.	1		
J11.5	Specification of special instructions, terms and conditions to suppliers.	1		
J11.6	Specification of price breaks by quantity.	1		
J11.7	Seamless transmission of quotes to suppliers via email and/or fax.	1		
J11.8	Capture of quote responses for comparison analysis.	1		
J11.9	Expedient release of 'best' quotes for automatic purchase order generation.	1		
J11.10	Traceability of quotes to purchase orders generated and vice-versa.	1		
J12.0	**Multi-Currency**			
J12.1	Accommodations for creating purchase orders and contracts in foreign currency.	1		
J12.2	Ability to maintain foreign currency exchange rates with effectivity dates.	1		
J12.3	Automatic defaults of exchange rates with the option to overwrite defaults for a specific order.	1		
J13.0	**Change Orders**			
J13.1	Tracking of changes to original service contracts including goods purchases.	1		
J14.0	**Goods Purchasing & Receiving**			
J14.1	Ability to purchase goods based on different pricing structures such as quantity breaks pricing, 'Cost Plus', quoted contract prices with effectivity dates and supplier catalogue prices.	1		
J14.2	Receive goods against a purchase order and backorder or cancel any residual outstanding quantities.	1		
J14.3	Ability to track receipts with a unique receipt identification number.	1		
J14.4	Capture serial numbers for units requiring serial number traceability. For example, transformers.	1		
J14.5	Capture supplier packing slips and Bills of Lading (BOL) reference numbers.	1		
J14.6	Ability to indicate condition of goods received and generate documents for the return of incorrectly shipped or damaged goods.	1		

LEGEND

Priority: **1**=Must Have **2**=Must Have for Future Implementation **3**=Nice to Have for Future Opportunity

Fit to Product Responses: ***Y*** *=Yes, within standard functionality* ***P*** *=Partially within standard functionality, achievable with customizations*
N *=No, not in product functionality* ***F*** *=Planned for future release.*

Business Area: **Procurement**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
J14.7	Electronic notification to buyer/originator of receipts and non-conformance items.	1		
J14.8	Capture of quality and delivery statistics for Supplier Performance Analysis.	1		
J14.9	Receiving of goods by job responsibility and/or originator.	1		
J15.0	**Services Purchasing & Receiving**			
J15.1	Ability to set up service purchase orders or contracts for lump-sum, time and materials, 'Cost Plus' and monthly leases.	1		
J15.2	Electronic routing of service invoices to respective managers for payment approvals.	1		
J16.0	**Supplier Price Catalogues**			
J16.1	Support for electronic capture of supplier price catalogues.	2		
J17.0	**Supplier Profile**			
J17.1	Ability to set up and maintain information on suppliers as follows:			
J17.2	1. Supplier Number - to uniquely identify each supplier.	1		
J17.3	2. Supplier Name, Address, Phone, Fax and Email Address.	1		
J17.4	3. Supplier (geographical) Locations.	1		
J17.5	4. Supplier Contacts including job title and contact information.	1		
J17.6	5. Payment Terms.	1		
J17.7	6. Types of services and products supplier including whether supplier is a primary/preferred source.	1		
J17.8	7. Supplier Status for example 'Inactive','Active'	1		
J17.9	Ability to limit Supplier Master maintenance to specific personnel.	1		
J18.0	**Supplier Performance - Goods**			
J18.1	Fill rates and availability statistics for goods purchases.	2		
J18.2	Statistics on the timeliness of delivery of shipments.	2		
J18.3	Quality of goods delivered statistics.	2		
J18.4	Accuracy of shipments and invoices statistics.	2		
J19.0	**Supplier Performance - Services**			
J19.1	Quality of Workmanship including materials and equipment provided.	1		
J19.2	Timeliness of completion for services.	1		
J19.3	Project Management with regards to co-ordination, quality control, scheduling and implementation.	1		
J19.4	Contract Management on all aspects of administration of a contract.	1		
J19.5	Health & Safety with regards to management and administration of all aspects of occupational health and safety provisions as stipulated in the contract, as per provincial/territorial legislature, as per YEC policies and COR Certification.	1		

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Business Area: **Procurement**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
J19.6	Automatic generation of Supplier Evaluation Questionnaire, at contract close, to project managers to capture feedback on supplier performance and the ability to customize questionnaires based on the different types of services performed.	1		
J20.0	**Inquiries and Reports**			
J20.1	**Supplier Master Directory** All information pertaining to a supplier including types of services and products offered, status ('Active', 'Inactive'), geographical locations whether a supplier is a primary/preferred supplier by product/services offering.	2		
J20.2	**Supplier Price Catalogues** Product and services offering including pricing and effectivity dates.	2		
J20.3	**Open Purchase Orders** Orders outstanding with suppliers including purchase order number, order date, required date, item number, description, order quantity, outstanding quantity, quantities received to date and last receipt date.	1		
J20.4	**Contracts** All information on a contract including history of holdbacks and releases, status of transmittals and submittals, invoices received and payments. Commitments versus actuals and commitments plus actuals versus budgets.	1		
J20.5	**Supplier Performance** Qualitative and quantitative statistics on the delivery of goods and services including accuracy of all supplier document such as invoices, packing/slips, contract progress reports.	1		

LEGEND

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Business Area: **Project Accounting**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
K1.0	**Project Initiation**			
K1.1	Ability to initiate a project with the capture of the following information:			
K1.2	1. Unique Project Identification Number	1		
K1.3	2. Project Title	1		
K1.4	3. Detailed Description, Objectives, Scope, discussion of alternatives/options where applicable	1		
K1.5	4. Project Initiator Name and Contact Information	1		
K1.6	5. Location of the project	1		
K1.7	6. Priority	1		
K1.8	7. Project Start and Completion Dates	1		
K1.9	8. Justification; Primary and Secondary	1		
K1.10	9. Initial Planned Costs	1		
K1.11	10. Timing of Cash Flow Projections	1		
K1.12	11. Qualification on the impacts on existing assets, if any	1		
K2.0	**Approvals**			
K2.1	Electronic routing of project for approvals based on one or more mandatory signing authorities and/or based on signing authorities by threshold limits.	1		
K2.2	Electronic notification/alert to approvers of projects awaiting their approval.	1		
K2.3	Ability to specify additional notes, queries and rejection reasons by approvers.	1		
K2.4	Notification to originators on whether a project has been approved or rejected.	1		
K3.0	**Project Work-Breakdown Structure**			
K3.1	Ability to set up a parent project with multiple levels of subprojects and within which multiple work orders per subproject.	1		
K3.2	Ability to capture and review estimated costs versus actual costs by work order, subprojects and overall totals at the parent project level.	1		
K4.0	**Costs Capture**			
K4.1	Ability to set up estimated costs and track actual costs for the following items:			
K4.2	1. Internal Labour (units and rates)	1		
K4.3	2. External Labour (units and rates or lump-sum agreements)	1		
K4.4	3. Material	1		
K4.5	4. Equipment (including rentals)	1		
K4.6	5. Travel (Accommodations, travel, meals, incidentals)	1		
K4.7	6. Salvages	1		
K4.8	7. Disposals	1		
K5.0	**Actuals**			

LEGEND

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Business Area: **Project Accounting**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
K5.1	Automatic capture of all actual costs from time/labour entry, material purchases, inventory issues, equipment rentals and contracts.	1		
K6.0	**Quotations**			
K6.1	Electronic entry and issuance of quotations to multiple suppliers and the entry of responses for analysis. Ability to generate purchase orders from 'best' quote.	1		
K7.0	**Work Order Initiation**			
K7.1	Ability to set up and issue work orders for projects including customer extensions. Profiling information			
K7.2	1. Work Order Number	1		
K7.3	2. Reference to project number	1		
K7.4	3. In Service Date / Initiation Date	1		
K7.5	4. Contact Name and contact information	1		
K7.6	5. Service to be provided	1		
K7.7	6. Company Identification	1		
K7.8	7. Service Area	1		
K7.9	8. Customer Identification/Reference (for customer extensions)	1		
K7.10	9. Description of Work	1		
K7.11	10. Costs Estimates (labour and materials) including labour units and rates	1		
K7.12	11. Material Requirements (quantity, specifications)	1		
K7.13	12. Attachments of additional documentation such as drawings and specifications.	1		
K8.0	**Work Order Approvals**			
K8.1	Electronic routing of work orders for approvals based on mandatory signatories and/or based on costs levels.	1		
K8.2	Electronic alerts to approvers on work orders awaiting their approval.	1		
K8.3	Ability to specify rejection reasons by approver.	1		
K8.4	Automatic notification to originators on whether their work orders have been approved or rejected.	1		
K9.0	**Work Order Costs**			
K9.1	Ability to track work order estimated versus actual costs broken down by labour, materials and travel.	1		
K10.0	**Work Order Close-Outs**			
K10.1	Ability to capture and print (when required) the following close-out information for a work order.	1		
K10.2	In-Service Date or expected In-Service Date.	1		
K10.3	Project Status – In Use (Yes/No)?	1		
K10.4	Asset Replacement Information (Historical In-Service Date, Replacement Cost)	1		

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Business Area: **Project Accounting**

	Requirement	Priority	Fit to Product	Fit/Gap Explanation (if applicable)
K10.5	Purchases of Land, Computer Equipment or Office Equipment	1		
K10.6	Site restoration costs and percentage to total project costs	1		
K10.7	Salvage costs or proceeds	1		
K10.8	Approval of actual transaction amounts	1		
K10.9	Expected additional charges after close-out	1		
K11.0	**Project & Work Order Statuses**			
K11.1	Electronic tracking of project status from initiation to completion. Provide identification of parent project, subproject and work order statuses at initiation, review, awaiting approval, commencement, in progress, completion and close-out.	1		

REFERENCE: **General**

TOPIC: **Forecasts**

PREAMBLE:

Yukon Electrical would like to better understand YEC's process for developing forecasts included in this application.

QUESTION:

a) Please provide details of YEC's process for developing the labour and other expenses forecasts included in this application. Include all important timelines, and all approvals required prior to finalizing the forecasts. Include the process for both O & M and Capital forecasts.

b) If different, please provide details of the process required for preparing internal budget forecasts.

ANSWER:

(a)

Yukon Energy budgets run on the fiscal year January 1 to December 31. The budgeting process for the following year usually starts in early to mid-summer with requests to managers.

Labour – The current staff complement, as well as any requests for new positions, is summarized into a corporate chart that is reviewed, amended (if necessary) and approved by senior management. This chart forms the basis for the budget. For each position finance staff assign a salary, benefits loading factor and expected performance and cost-of-living increment. Next, positions are analyzed for the expected split between capital and O&M. The capital portion is deducted for each position, leaving the O&M labour budget. This amount is adjusted for a vacancy allowance (estimate of FTE vacancies for the year), and the result is the final figure which goes in the budget package.

Other Expenses – Non-fuel O&M includes production, transmission, distribution, general O&M and administration. Front line managers with budget responsibilities in these areas assemble their requirements for the following year in early summer. These budgets are generally organized by function and location. These functional budgets are assembled and reviewed by senior management. Management reviews these numbers based on consistency with prior years and alignment with corporate objectives. The budget is adjusted if necessary and approved. Depreciation and amortization expense is forecast based on expected additions to fixed assets and deferred costs (planning, feasibility, regulatory, etc) during the year (these additions are the result of the capital planning process described below). These additions are accumulated with current balances in these accounts and depreciation and amortization are calculated based on approved rates by asset category. Fuel and purchased power are derived from sales forecasts. Return on rate base is an arithmetic determination based on forecast balances for the budget year.

Capital – As with the process above, a call is put out in early summer for capital project requests for the coming year. These projects are individually reviewed by members of the Project Review Committee (cross-sectional committee) for need, coordination with other initiatives and goals and proper budgets and classification with respect to capital versus O&M. This package is in turn reviewed by senior management in late summer and amalgamated with the rest of the business plan document.

The above pieces are assembled with the rest of the Business Plan package (i.e. depreciation, amortization, fuel expense, interest expense, etc) and management reviews one final time for overall return, logic and consistency with Corporate strategic objectives. The package is then forwarded to the Board of Directors for their approval at the December Board meeting.

(b)

It is not clear what is meant by “internal budgets”. The response to (a) above summarizes key budgeting processes in support of approved annual business plans.

REFERENCE: **Page 3-12, Lines 6 to 8**

TOPIC: **Administration Labour**

PREAMBLE:

"Administration labour increased between 2005 and 2007 due to both wage increases (negotiated and step increases) and increases in staff positions."

QUESTION:

a) Please provide a copy of the latest labour agreement negotiated between YEC and its in-scope workers regarding wage increases.

b) Does this agreement cover each of the Test Years? If not, please provide the basis for the requested increases for each of the Test Years.

c) Please provide the basis for the requested increases for employees not covered by a negotiated labour agreement.

d) Please provide a breakdown of the labour inflation for 2008 and 2009 included in forecasts as follows:
- employees covered by contract negotiations;
- employees not covered by contract; and
- increments/steps.

e) Please provide the 2005-2007 actuals as well as 2008-2009 forecasted increments/steps.

f) Please provide a business case for all employee additions since 2005 included in general administration. The business case should include information on:
- date when position added;
- job description;
- explanation of why position needed; and
- justification for position.

ANSWER:

(a)

Please see document provided as Attachment 1 to this response.

(b)

The agreement provided as Attachment 1 to YECL-YEC-1-37(a) covers both test years.

(c), **(d)** and **(e)**

Please see table provided below which includes wages and benefits for both union and out of scope employees in the administration function. YEC does not apply a different rate to union vs. non union employees and does not increase for step increments.

Labour Inflation for Union and Out of Scope Employees

	2005 Approved	2005 Actual	2006 Actual	2007 Actual	2008 GRA	2009 GRA
Marketing:						
Resource Planning	50	32	37	45	69	71
Business Development	59	28	41	47	0	0
Communications	0	73	76	88	100	103
Total Marketing	**109**	**133**	**155**	**181**	**169**	**174**
Customer Accounting	**275**	**233**	**221**	**260**	**239**	**246**
Other						
Environmental Mgt	30	5	25	41	0	0
General	1,393	1,658	1,622	1,920	1,851	1,907
Information Systems	162	184	278	296	344	353
Fish Hatchery	6	2	2	2	7	7
Fish Ladder	12	1	2	1	19	19
Safety	132	104	136	181	239	247
Training	185	129	144	142	199	205
Admin Board of Directors	32	29	28	38	45	46
Admin Union	0	12	2	6	0	0
Regulatory Affairs	0	0	28	7	88	91
Material Mgt		89	99	99	138	143
Contracting	77	109	103	111	148	153
Professional Development	0	2	2	2	13	14
Total Other	**2,030**	**2,325**	**2,471**	**2,847**	**3,091**	**3,185**
Total Adminstration	**2,414**	**2,691**	**2,846**	**3,288**	**3,498**	**3,605**
Year over year % increase			**5.77%**	**15.52%**	**6.40%**	**3.04%**
Economic increase January 1st each year			3%	3%	3.75%	3.5%
Number of new positions added			4	3	3.2	0
Number of new positions cancelled					(1.0)	
			4	3	2.2	0

The following is noted with regard to the above table:

1. **The following 4 new positions were added in 2006:** Apprentice Powerline Technician, SCC Operator, Plant Operator, Manager Operations; none of these positions have an impact on Administration.

2. **The following 3 new positions were added in 2007:** Vice-President, Operations and Engineering, Documentation Specialist and Manager, Environmental Assessment & Licensing; all of these positions have an impact on Administration Labour.

3. **The following 2.2 net positions were added in 2008:** Records Management Analyst, 2 Year Term Financial Administrator and Capital Planning and Project Coordinator the Office Administrator position was increased from 0.6 FTE to 0.8 FTE and the Civil Engineer position was cancelled; all positions would affect Administration Labour to some degree.

(f)

Please see LE-YEC-1-32.

TABLE OF CONTENTS

Article #	Article Heading	Page
1	Purpose	1
2	Interpretation and Definitions	1
3	Recognition	3
4	Application	5
5	Union Dues	5
6	Discrimination	5
7	Continuity of Service	6
8	Rights of Management	6
9	Notices	6
10	Headings	7
11	Grievance Procedure	7
12	Probation	11
13	Normal Hours of Work	11
13.01	Non-Shift Employees	11
13.02	Shift Employees – Plant Operators	13
13.03	Shift Employees – Systems Operators	14
13.04	Shift Change – Shift Worker	14
13.05	Overtime Banking	15
13.06	Leave Without Pay (LWOP)	15
13.07	Daylight Savings Time	16
13.08	Rest Breaks	16
13.09	Converting Annual Salary to Hourly Rate	16
13.10	Ticket Bonus	16
13.11	Travel Time	17
14	Salary Administration	17
15	Northern Allowances	18
16	Location Allowance	19
17	Callout	19
18	Shift Premium	20
19	Standby	20
20	Calculation of Premium Rates	21
21	Employee Travel	21
22	Job Evaluation	22
23	Description of Duties	24
24	Designated Paid Holidays	24

Article #	Article Heading	Page
25	Vacation Leave	25
26	Vacation Travel Allowance	27
27	Bereavement Leave	27
28	Court Leave	28
29	Maternity & Parental Leave	28
30	Special Leave	29
31	Recruitment Postings	30
32	Reduction of Staff	31
33	Termination of Service	32
34	Joint Consultation Committee (JCC)	33
35	Health and Safety	34
36	Bulletin Boards	35
37	Technological Change	35
38	Essential Services	36
39	Pension Plan	36
40	Group RRSP	37
41	Group Insurance Plan	37
42	Discipline	38
43	Term of Agreement	38
44	Collective Bargaining – Interest Arbitration	39
45	Wage Schedules	39
46	Apprentices	40
47	Injury on Duty Leave	40
48	Loss or Theft of Personal Property	40
Letter of Understanding #1	Northern Allowances	42
Letter of Understanding #2	Volunteer Activities	42
Letter of Understanding #3	Recognition of Supervisor Representation During Conflict Resolution Process for Two Bargaining Agency Employees	43
Letter of Understanding #4	Pension Plan Change	43
Letter of Understanding #5	Flex Time	44
Letter of Understanding #6	Acting Excluded Positions	44
Letter of Understanding #7	Plant Operators and Systems Control Centre Operators	45

ALPHABETICAL LISTING OF CONTENTS

Article #	Article Heading	Page
Letter of Understanding #6	Acting Excluded Positions	44
4	Application	5
46	Apprentices	40
27	Bereavement Leave	27
36	Bulletin Boards	35
20	Calculation of Premium Rates	21
17	Callout	19
44	Collective Bargaining – Interest Arbitration	39
7	Continuity of Service	6
13.09	Converting Annual Salary to Hourly Rate	16
28	Court Leave	28
13.07	Daylight Saving Time – Normal Hours of Work	16
23	Description of Duties	24
24	Designated Paid Holidays	24
42	Discipline	38
6	Discrimination	5
21	Employee Travel	21
38	Essential Services	36
Letter of Understanding #5	Flex Time	44
11	Grievance Procedure	7
41	Group Insurance Plan	37
40	Group RRSP	37
10	Headings	7
35	Health and Safety	34
47	Injury on Duty Leave	40
2	Interpretation and Definitions	1
22	Job Evaluation	21
34	Joint Consultation Committee (JCC)	33
13.06	Leave Without Pay (LWOP)	15
16	Location Allowance	19
48	Loss or Theft of Personal Property	40
29	Maternity & Parental Leave	28
13.01	Non-Shift Employees – Normal Hours of Work	11

13	Normal Hours of Work	11
15	Northern Allowances	18
Letter of Understanding #1	Northern Allowances	42
9	Notices	6
13.05	Overtime Banking	15
39	Pension Plan	36
Letter of Understanding #4	Pension Plan Change	43
Letter of Understanding #7	Plant Operators and Systems Control Centre Operators	45
12	Probation	11
1	Purpose	1
3	Recognition	3
Letter of Understanding #3	Recognition of Supervisor Representation During Conflict Resolution Process for Two Bargaining Agency Employees	43
31	Recruitment Postings	30
32	Reduction of Staff	31
13.08	Rest Breaks	16
8	Rights of Management	6
14	Salary Administration	17
13.02	Shift Employees – Plant Operators – Normal Hours of Work	13
13.03	Shift Employees – Systems Operators – Normal Hours of Work	14
13.04	Shift Change – Shift Worker – Normal Hours of Work	14
18	Shift Premium	20
30	Special Leave	29
19	Standby	20
37	Technological Change	35
43	Term of Agreement	38
33	Termination of Service	32
13.10	Ticket Bonus	16
13.11	Travel Time	17
5	Union Dues	5
25	Vacation Leave	25
26	Vacation Travel Allowance	27
Letter of Understanding #2	Volunteer Activities	42
45	Wage Schedules	39

Parties to the Agreement

AGREEMENT

THIS AGREEMENT made as of the first (1st) day of January A.D. 2008.

BETWEEN

THE YUKON ENERGY CORPORATION, body corporate with head office at the City of Whitehorse, in the Yukon Territory (hereinafter called "the Corporation").

OF THE FIRST PART,

AND

THE PUBLIC SERVICE ALLIANCE OF CANADA (YUKON EMPLOYEES' UNION Local Y024), a trade union within the meaning of the Canada Labour Code, of the said City of Whitehorse, in Yukon Territory (hereinafter called "the Union").

OF THE SECOND PART

Whereas the Corporation is a public utility engaged in the business of producing, purchasing, transmitting, distributing, delivering and selling electricity and of providing services in connection therewith and supplying electricity to communities and inhabitants in the Yukon and is directly accountable to the Yukon Utilities Board under the Public Utilities Act.

Article 1
Purpose

1.01 The purpose of this agreement is to maintain harmonious and mutually beneficial relationships between the Employer, the Employees and the Union, to set forth certain terms and conditions of employment relating to remuneration, hours of work, employee benefits and general working conditions affecting employees covered by the agreement and to ensure that all legislated measures are provided for the safety and occupational health of the employees.

Article 2
Interpretation and Definitions

"**Bargaining Unit**" means all employees employed by the Employer as described in Article 3.

"Calendar Year" means January 1 to December 31.

"Casual Worker" means a person who does not work more than three hundred and twenty (320) regular hours within any three (3) consecutive calendar months and all employees performing janitorial work in district offices and it is agreed shall not be included within the scope of this Collective Agreement.

"**Common-Law Spouse**" – A Common Law relationship exists when for a continuous period of at least one (1) year, an employee has lived with that person, publicly represented that person to be their spouse, and lives and intends to continue to live with that person as if the person were their spouse.

"**Day of Rest**" in relation to an employee means a day other than a recognized holiday on which that employee is not ordinarily required to perform the duties of their position for reasons other than by being on leave of absence.

"**Dependent Child**" means an unmarried natural, adopted, or step child who is entirely dependent on the employee for maintenance and support and who is:

(i) under 21 years of age

(ii) under 25 years of age and attending a college or university full-time, or

(iii) physically or mentally incapable of self-support and became incapable to that extent while entirely dependent on the employee for maintenance and support and while eligible under (i) or (ii) above

(iv) for further clarification, "entirely dependent" means the employee is the principal financial supporter

"**Employer**" means the Yukon Energy Corporation.

"Grievance" means a claim or complaint in writing involving the interpretation, application or alleged violation of this collective agreement, from an employee or group of employees of the Union, or either party and processed through the grievance procedure.

"**Permanent Employee**" means an employee who has been appointed by written notice to a permanently established full time position. Such appointment shall be conveyed to the employee and the Union in writing within seven (7) days of appointment.

"Permanent Part Time Employee" means an employee who has been appointed, by written notice, to a permanently established part time position. Such appointment shall be conveyed to the employee and the Union in writing within seven (7) days of appointment.

"**Probation Period**" means initial period of permanent or term employment during which the employer has an opportunity to assess the suitability of the employee.

"Seniority" means the length of an employee's accumulated service with the company and predecessor company (s) within the bargaining unit, calculated as the elapsed time from the date they were first employed, unless their seniority was broken in which event, calculation shall be from the date they returned to work following the last break in their seniority.

"Shift Employee" means an employee who is scheduled to work on a rotating or irregular basis.

"Spouse" means a person who is married to the employee, except that a person of the same or opposite sex who is living with the employee in a conjugal relationship for a continuous period of at least one (1) year**.**

"**Technological Change**" means the introduction by the Employer of equipment or material of a different nature than that previously utilized and a change in the Employer's operation directly related to the introduction of that equipment or material.

"**Temporary Employee**" means an employee hired for full time or part time work which is not of a permanent or continuing nature and further whose employment will be terminated on the completion of such work. A Temporary position shall not utilize a number of person hours in excess of sixty (60) per cent of the hours established for a permanent position. This category of employee shall not be utilized so as to displace any Permanent Employee or position or diminish the regular hours of work of any Permanent Employee. The Corporation undertakes to notify the Union in writing of the name of the employees hired in this category.

"**Term Employee**" means an employee who has been hired to a position established for a specified length of time for a specific project or for work which is not of a permanent or continuing nature, on either a full or part time basis, and further whose employment will be terminated on the completion of such work. This category of employee shall not be utilized so as to displace any permanent Employee or position or diminish the regular hours of work of any Permanent employee. The Corporation undertakes to notify the Union in writing of the name of the employees hired in this category.

Article 3
Recognition

3.01 a) The Corporation recognizes the Union as the exclusive bargaining agency for all employees as defined in the Canada Labour Relations Board Certificate as referred to in Article 4.00 or said certificate as it may be amended from time to time. The Corporation recognizes the right of an employee to be represented by a Union Representative.

b) Whereas by Certificate dated the December 11, 2001 and issued by the Canada Labour Relations Board (hereinafter called "The Board"), and made pursuant to the provisions of the Canada Labour Code, the Union has been certified as bargaining agent for the unit of employees of the Corporation which is mutually agreed as comprising: "All employees of Yukon Energy Corporation within the Yukon Territory including term employees, excluding President, Vice-President, Managers,

Engineers, Supervisors, Directors, Controllers, employees operating in a confidential capacity, and casual workers."

The above certificate is hereinafter referred to as "the Certificate".

3.02 a) The Employer acknowledges the right of the Union to appoint employees as representatives.

b) The Union may appoint up to three (3) representatives and three (3) alternate representatives, having regard to the Employer's structure.

c) The Union will provide the Employer with a list of its representatives and any revisions from time to time.

d) (i) All employees shall obtain their immediate out of scope supervisor's approval before leaving work to attend to Union business as per Article 3.02 (e). Such approved leave shall be at no loss of regular pay. All meetings to discuss other matters then those listed in 3.02 (e) will be arranged for outside of normal hours of work. All time granted accordingly, shall be reported as union leave on timesheets.

(ii) Employees will follow the procedures set out under Article 11.04 (a) to attempt to resolve disagreements resulting from this Collective Agreement.

e) Union business is defined as:
(i) Investigating complaints of an urgent nature;
(ii) Meeting with the employer to deal with a grievance;
(iii) Meeting with the employer at J.C.C.;
(iv) Attending such other meetings called by the employer; or
(v) Participating in a conflict resolution process, or Union business as agreed by the parties.

f) An employee shall not suffer a loss of regular pay as a result of:
(i) Being required by the employer to attend a meeting; or
(ii) Being called as a witness by the employer before third (3rd) parties.

g) Where it is agreed by the Corporation, all travel expenses incurred by the Union shall be paid by the employer.

h) (i) Where operational requirements permit, the Employer may grant leave without pay to a maximum of five (5) employees for the purpose of attending contract negotiation meetings with the Employer. All time granted accordingly, shall be reported as union leave on timesheets.

(ii) Subject to h(i) above, such employees will be granted leave without pay to attend subsequent negotiation meetings. All time granted accordingly, shall be reported as union leave on timesheets.

i) Where employees attend contract negotiations or attend Union conferences or seminars on leave without pay, they will remain on payroll and the Union will be invoiced accordingly.

j) Where it is operationally feasible, up to three (3) employees may be granted leave without pay to attend Union conferences or seminars.

Article 4
Application

4.01 This Agreement shall apply with respect to all of the Corporation's employees comprised within the bargaining unit prescribed by the Canada Labour Relations Board or the said certificate issued to the Public Service Alliance of Canada (Yukon Employees' Union) as it may be amended from time to time.

Article 5
Union Dues

5.01 All employees now members of the Union, and all employees eligible to become members of the Union, shall, as a condition of employment pay bi-weekly to the Union, monies equal to the dues as established from time to time in accordance with the Constitution and Bylaws of the Union. Such dues shall be deducted bi-weekly by the Corporation from the employee's pay and remitted to the Union at the end of the month following the deduction. The payment of dues does not require the employee to become a member.

5.02 The Corporation shall provide the Union with a printout, monthly, containing the following specifics:

1. List of the names of deductees
2. Employee Classification
3. Amount deducted from each employee

5.03 The Corporation will not authorize any other dues deduction except to the benefit of the Union, unless otherwise required by law.

Article 6
Discrimination

6.01 The Employer and the Union agree that there shall be no discrimination, interference, restriction, harassment or coercion exercised or practiced as set out by the Employment Standards Act of the Yukon Territory, the Canada Labour Code and the Yukon Human Rights Act.

Article 7
Continuity of Service

7.01 Subject to provisions in 38.00 (Essential Services) it is agreed that the service rendered by the Corporation, its management and employees directly or indirectly, to electric customers from time to time served by the Corporation, is essential to the welfare of these customers.

7.02 The Union agrees that it will not directly or indirectly sanction, authorize, or allow any stoppage of work or any action that restricts or limits service or production, and the employees agree that they will not be involved in such actions. The Corporation agrees that it will not cause any lockout of employees.

Article 8
Rights of Management

8.01 The Corporation retains the sole and exclusive control of all matters concerning the operation, management and administration of its business and the direction and control of the Corporation's workforce. The Corporation shall retain all the rights, responsibilities, functions and prerogatives of management, except as expressly modified or restricted by a specific provision of this agreement. The Corporation agrees to administer its rights in a manner that is non-discriminatory.

Article 9
Notices

9.01 Any notice required to be given by one party to the other hereunder shall be in writing and shall be sufficiently given, if presented by hand, or alternatively mailed to the party to whom such notice is to be given. Notice shall be directed to the parties as follows:

Corporation:
President/CEO & Director, Human Resources & Corporate Services
Yukon Energy Corporation
P.O. Box 5920
Whitehorse, Yukon Y1A 6S7

Union:
President
Public Service Alliance of Canada (Yukon Employees' Union, Local Y024)
100 – 2285 – 2nd Avenue
Whitehorse, Yukon Y1A 1C9

9.02 Each party may, from time to time, designate another representative to whom such notices may be served, and may change its address; in these instances written notice to that effect will be served to the other party.

Where such notice has been sent, it shall be deemed to have been received and the particular notice given, upon the expiration of five (5) days excluding Saturdays, Sundays and holidays next following the date of such mailing.

Article 10
Headings

10.01 The headings used throughout this Agreement are inserted for reference purposes only and are not to be considered or taken into account in construing the terms and conditions of this Agreement or of any portion herein, nor shall the same be deemed to qualify, modify or explain the effects of any such term, condition or provision.

10.02 Whenever the singular, masculine or feminine is used in this Agreement it shall be interpreted as if the plural, feminine or masculine has been used where the context or the parties so require.

Article 11
Grievance Procedure

11.01 a) The grievance procedure described in this Article will be used only to resolve disagreements involving the interpretation, application, administration or any alleged violation of the collective agreement.

b) The employee may be assisted and represented by a Union representative at any stage of this procedure.

c) A grievance shall not be invalid by reason only of the fact it is not in accordance with the Grievance Fact Sheet provided by the Employer.

d) For some issues it may be helpful to bring in a third party mediator to facilitate the discussions. The Corporation with agreement from the Union may refer the disagreement to mediation. The Union and the employer shall determine mutually acceptable terms for hiring a mediator, including time frames for conducting the mediation. Both parties must be willing to suspend the time limitations for processing grievances for the duration of the mediation. Mediation may be terminated by either party or the mediator at any time.

11.02 While this grievance procedure is in process, the employee involved will continue to faithfully perform the duties assigned.

11.03 No person who is employed in a managerial or confidential capacity shall seek by intimidation, by threat of dismissal or by any other kind of threat to cause an employee to abandon their grievance, as provided in the Collective Agreement.

11.04 Step 1 Discussion Stage

a) Before submitting a grievance, the employee involved in the disagreement shall seek to settle the difference in discussion with their immediate supervisor or if the disagreement relates to a recruitment posting, with the selecting supervisor.

b) The discussion should be held as soon as possible after the act which gave rise to the disagreement since any grievance must be submitted within certain time lines.

(i) In the case of a Recruitment Posting, a grievance must be submitted within seven (7) days of the employee receiving written reasons for not being selected.
(ii) In the case of a dismissal, a grievance must be submitted within ten (10) days of the dismissal.
(iii) In any other case, a grievance must be submitted within fifteen (15) days of the act giving rise to the grievance.

However, the parties agree that where the supervisor is not available or the discussion cannot be held, this requirement will not prevent any employee from submitting a grievance.

c) If the issue cannot be resolved at this stage, and the employee, group of employees or Union wishes to pursue the grievance, a first level "Grievance Fact Sheet" must be filed within the designated timelines; or

d) In the case of the discharge of an employee, unless the parties agree otherwise, the disagreement will automatically proceed to a Step 3 – Level 2 grievance.

e) An employee or group of employees must obtain the approval of the Union, and be represented by the Union, before a grievance can proceed to Step 2 – Level 1, or referred to Arbitration – Step 4 – Level 3.

11.05 Calculation of Time

Whenever a time limit is imposed in this article, the following rules apply:

a) Saturdays, Sundays and Statutory Holidays will not be included in calculating time.

b) If either party fails to process the grievance within the time limits established, that party will be deemed to have conceded the grievance in favour of the other party without prejudice to either party.

11.06 Step 2 - Level 1 Grievance

a) The employee is required to file a "Grievance Fact Sheet" to initiate the Level 1 grievance. The information contained in the "Circumstances and Nature of

Grievance" should contain enough information to enable the Director or designate to identify what is being alleged. A copy will be given to the employee's supervisor.

b) Where the grievance results from a Recruitment Posting, the grievance will be sent to the selecting supervisor and the Director/Manager within five (5) days of the employee being given written reason for not being selected for the position unless the time for filing of a grievance has been extended pursuant to Article 11.04 (b), where in the time for sending the grievance will be extended to 10 days.

c) In any other case, the grievance will be given to the employee's supervisor's Director/Manager within fifteen (15) days of the act causing the grievance, with a copy, for information purposes, to the employee's supervisor.

d) The Director/Manager will meet with the employee and supervisor to discuss the grievance. If the grievance arises from Article 31 (Recruitment Posting), the supervisor who made the decision shall attend.

e) Within fifteen (15) days of receiving the grievance, the Director/Manager or designate will either uphold or deny the grievance. The Director/Manager or designate's decision shall be in writing and given to the employee and the Union.

f) Failing settlement at this stage, the Union or the Employer may proceed to Step 3 – Level 2 grievance.

11.07 Step 3 – Level 2 Grievance

a) The Union may present the same grievance fact sheet to the President/CEO of the Corporation or designate that was filed for the Level 1 grievance within fifteen (15) days of receipt of the decision.

b) In the case of a grievance resulting from the dismissal of an employee, the employee is required to file a "Grievance Fact Sheet" to initiate the Level 2 grievance. The information contained in the "Circumstances and Nature of Grievance" should contain enough information to enable the President/CEO or designate to identify what is being alleged.

c) The President/CEO, or designate and affected manager/supervisor, where appropriate, will meet with the employee to discuss the grievance

d) Within fifteen (15) days of receipt of the Level 2 grievance, the President/CEO or designate will either uphold or deny the grievance. The President/CEO or designate's decision shall be in writing and given to the employee and the Union.

e) Failing settlement at this stage, the Corporation or the Union may refer the issue to Step 4 – Level 3 – Arbitration.

11.08 Policy Grievance

a) Either party to this Agreement may initiate a grievance regarding the interpretation, application, administration or any alleged violation of the policies that form part of this Collective Agreement as listed in Article 34.05.

b) The Union is required to file a "Grievance Fact Sheet" to initiate the Level 2 grievance. The information contained in the "Circumstances and Nature of Grievance" should contain enough information to enable the President/CEO or designate to identify what is being alleged.

c) A grievance under Article 11.08, once served on the other party, shall constitute a notice of request for a Level 2 hearing.

d) Failing settlement at this stage, the Corporation or the Union may refer the issue to Step 4 – Level 3 – Arbitration.

11.09 Step 4 – Level 3 Rights Arbitration

Either party to this agreement may immediately refer matters not resolved through the grievance procedure to a mutually agreed upon Arbitrator who shall have the power to determine whether any matter is arbitrable. The arbitrator shall settle and determine the said matters during the operation of this Collective Agreement.

a) By mutual agreement beforehand, the parties may opt for alternative methods such as mediation, in order to resolve a grievance. However, either party may request arbitration by letter to the other party within fifteen (15) days of receipt of the level 2 grievance decision. The letter shall state the matter sought to be arbitrated and the names of proposed arbitrators. The other party shall, within thirty (30) days of the receipt of such letter notify the first party in writing of the acceptance of one of the arbitrators named or propose others.

   The agreed upon arbitrator must be available to hear the grievance within six (6) months of receipt of notification to arbitrate or an alternative arbitrator shall be selected by both parties. The six (6) month timeframe may be extended if agreed to by both parties.

b) If the parties fail to agree on an Arbitrator within thirty (30) days of receipt of the second party's letter, either party may request the Minister of Labour to make an appointment or if both parties fail to agree on an alternative arbitrator as set out in 11.09 (a).

c) In addition to any powers contained in this agreement, the arbitrator has all the powers granted to arbitrators under Part 1 of the Canada Labour Code.

d) The arbitrator shall hear the grievance as soon as possible, and render a written decision within thirty (30) days. The decision, once forwarded to the parties is final

and binding on each part and any employee affected by it.

e) Each party shall pay one half of the fees and expenses of the arbitrator.

Article 12
Probation

12.01 All new hires shall be subject to a probationary period not to exceed six (6) months. During the probation period, employment may be terminated at the Corporation's discretion, for reason of general unsuitability of new hires. A review of each employee's performance will be discussed with them prior to the final thirty (30) days of the probation period.

The probation period for apprentices as specified in 12.01 above will be extended by the length of time that he/she is away from work attending school.

12.02 When a term or temporary employee is hired for a permanent position, and has been working in a related job, the probationary period will be reduced as follows:

a) If the person has been employed by the Corporation in a related job for more than three (3) months, the probationary period will be reduced by at least three (3) months, and may be reduced up to six (6) months, at the Corporation's discretion.

b) If the person has been employed by the Corporation in a related job for less than three (3) months, the probationary period will be reduced by the actual amount of time they have been employed in the related job.

Article 13
Normal Hours of Work

a) The hours of work stated in this Article shall not be construed as a guarantee of any minimum nor as a restriction on any maximum hours to be worked, but serves only as a basis for the calculation of overtime.

b) At all times it is the parties' mutual intent that the current practice of scheduling and/or backfilling shift employees so as to minimize costs will continue for the duration of this agreement.

13.01 Non-shift employees

a) For non-shift employees, a normal day's work shall be eight (8) hours between 06:00 and 20:00 hours as determined by the Corporation. A maximum lunch period of one (1) hour shall be observed taken approximately midway through each work day, unless otherwise agreed to by an employee and their immediate supervisor. The normal work week shall consist of forty (40) hours worked in any five (5) consecutive days Monday through Saturday inclusive, with the exception of a flexible work

arrangement under Letter of Understanding #5 in which case the normal work week can be Monday through Sunday by mutual agreement.

b) By mutual agreement between the employee and the supervisor, the hours of work per day for a specific job assignment may be extended to a maximum of ten (10) hours per day so as to average forty (40) hours per week over a pre-determined period of time and, consequently, overtime payment for the hours worked over eight (8) per day would not apply.

c) Certain work of a construction, maintenance or replacement nature on the Corporation's transmission, distribution and production facilities is required on a pre-planned basis, to be performed during other than normal hours of work for operational employees. In such cases the Corporation, on forty-eight (48) working hours' notice, may reschedule the normal hours of work of employees so affected as set out in Sub-Section 13.01 (a).

d) Authorized overtime for employees in this category shall be paid as follows: employees shall receive overtime pay at the hourly equivalent rate of two (2) times the employee's regular rate of pay for all authorized overtime worked in excess of eight (8) hours per day, ten (10) hours pursuant to Article 13.01 (b), and for all authorized overtime worked in excess of forty (40) hours per week and for all hours worked on Holidays as specified in 24.00 or on scheduled days of rest.

e) In the event that an employee works five (5) or more hours of overtime in the eight (8) hours immediately preceding their regularly scheduled work period, they shall only be required to report for work for either the first four (4) hours or the last four (4) hours of their next regularly scheduled work period with no loss of wages.

f) Employees working sixteen (16) or more consecutive hours in any twenty-four (24) hour period shall be allowed eight (8) consecutive hours of rest at no loss of wages before reporting for duty again.

g) Notwithstanding Article 13.01 (e) and (f), in emergency situations, the employee may be called back to work at the employee's regular rate of pay.

h) Employees will not normally be called upon to be away from home base on weekends except for work of an emergency nature, or by mutual agreement, or in economically viable situations (e.g. weather, transportation restrictions, etc.).

i) Except in the case of an emergency, the Corporation will endeavour to give a minimum of twenty (20) hours advance notice to employees prior to their being required to work away from home base for any period exceeding one (1) normal working day.

j) Except in the case of an emergency, or due to illness, bereavement or special leave, when the Corporation takes an employee off standby and that results in employees

being required to provide standby coverage, on days of rest, away from home base, in Faro, Mayo and Dawson City, the Corporation will give a minimum of five (5) calendar days advance notice. If such notice is not provided, the employee will be paid eight (8) hours of overtime for the first eight (8) hours of standby on the first day of rest. Standby pay and overtime pay for callouts during this period of time will not apply.

13.02 Shift Employees – Plant Operators

When because of operational requirements, hours of work are scheduled for employees on a rotating or irregular basis, they shall be scheduled so that employees:

a) Normal hours of work shall be a maximum of eight (8) hours per day between 0700 and 1800 hours. A maximum lunch period of one (1) hour shall be observed, unless otherwise agreed to by an employee and their immediate supervisor.

b) To ensure continuity of service to the Corporation's customers, employees in this category can be assigned to work a two (2) or three (3) shift rotating schedule.

c) The work schedule will be based on six hundred (600) hours in a fifteen (15) week rotating schedule.

d) Authorized overtime for employees in this category shall be paid at two (2) times the employee's regular rate of pay for:

   (i) All hours worked in excess of eight (8) hours per day when working normal hours or a three (3) shift rotating schedule
   (ii) All hours worked in excess of twelve (12) hours when working a two (2) shift rotating schedule
   (iii) All hours worked in excess of six hundred (600) hours in a period of fifteen (15) week rotating schedule
   (iv) All hours worked on Holidays as specified in Article 24.00 and on scheduled days of rest.

e) Employees shall be compensated for sickness and accident indemnity in accordance with the Corporate Sick Leave Policy in conjunction with the normal scheduled hours of work as posted on the shift schedule and approved Disability Plans (e.g. Short-term Disability, Long Term Disability, or WCB).

f) There will be an attempt not to schedule more than ten (10) shifts in a row.

g) When working a two (2) shift schedule, there will be an attempt to schedule a forty-eight (48) hour rest period between day and night shifts and to not schedule more than five (5) shifts in a row.

13.03 Shift Employees – Systems Operators

a) Systems Operators hours of work will be twelve (12) hours per shift based on six hundred (600) hours in a fifteen (15) week rotating schedule.

b) Systems Operators hours of work for maintenance shifts, shall be up to a maximum of eight (8) hours between 0700 and 1900 hours. A maximum lunch period of one (1) hour shall be observed, unless otherwise agreed to by an employee and their immediate supervisor.

c) Authorized overtime for employees in this category shall be paid at two (2) times the employee's regular rate of pay for:

(i) All hours worked in excess of twelve (12) hours per shift;
(ii) All hours worked in excess of eight (8) hours per shift on a scheduled maintenance shift;
(iii) All hours worked in excess of six hundred (600) hours in a period of fifteen (15) week rotating schedule;
(iv) All hours worked on Holidays as specified in Article 24.00 and on scheduled days of rest.

d) Employees shall be compensated for sickness and accident indemnity in accordance with the Corporate Sick Leave Policy in conjunction with the normal scheduled hours of work as posted on the shift schedule and approved Disability Plans (e.g. Short-term Disability, Long Term Disability, or WCB).

e) There will be an attempt to schedule a forty-eight (48) hour rest period between day and night shifts and to not schedule more than five (5) shifts in a row.

13.04 Shift Change – Shift Workers

a) All rotating shift schedules shall be posted to cover a minimum of ninety (90) calendar days. In January a master shift schedule for the year shall be prepared and all master shift schedules and subsequent revisions shall be circulated to the respective shift employees.

b) For Systems Operators a change from a maintenance shift to a regular day shift does not constitute a change of schedule.

c) If ten (10) or more days notice is given by the Corporation, the shift schedule may be changed without incurring any overtime.

d) If ten (10) days notice is not given by the Corporation, then the first two (2) shifts that have changed from days to afternoons/evenings or vice versa on the new schedule shall be paid at the applicable overtime rate and all subsequent shifts shall be paid at the regular rate of pay except as provided for in Article 13.04 (e).

e) If ten (10) days notice is not given by the Corporation, then for the thirty-five (35) calendar days following the posting of the revised schedule, the employee shall be paid at the applicable overtime rate for all hours worked on previously scheduled days of rest up to a maximum of five (5) shifts.

f) If an employee owes time to the Corporation resulting from shift scheduling and is called out to work on their day of rest, the time worked shall be paid at the applicable overtime rate and not deducted from the time owed.

g) If the employee owes time to the Corporation resulting from changes in the schedule, the employer is not entitled to recover the time in the next six hundred (600) hour fifteen (15) week shift cycle.

h) Provided sufficient advance notice is given and with the approval of the Corporation, employees may exchange shifts if there is no increased cost to the Corporation. Employees requesting shift changes must do so in writing.

13.05 Overtime Banking

In recognition that from time to time, an employee may require time off for personal reasons or unforeseen circumstances the following conditions may apply: Such leave shall not normally be taken in conjunction with annual vacation.

a) When an employee works overtime, they may direct that the amount payable for that overtime be banked rather than paid.

b) Nothing in this article guarantees an employee that a supervisor will approve any request to take time off.

c) In any year, an employee may bank overtime pay to a maximum of forty (40) hours at any one time. Systems Operators may bank overtime up to forty-eight (48) hours at any one time.

d) An employee may take time off and be paid out of their banked overtime by mutual agreement with their supervisor. An employee shall make a request at least six (6) working days prior to the first day they wish to take off. Requests should be made only when no overtime will result and that scheduled vacations will not be affected for them or other employees. The supervisor shall approve or reject the request as soon as possible, but at least three (3) working days prior to the first day the employee wishes to take off.

e) At the first pay period of the following year, employees will be paid any previous years amount which remains banked.

13.06 Leave Without Pay (LWOP)

Arrangements may be made to take time off without pay subject to the following:

a) the prior approval of the Department Director/Manager or designate;

b) the employee having used/scheduled all other leave (excluding leave without pay for union business);
c) A permanent employee with at least one (1) year of service, subject to providing the Corporation at least six (6) months written notice may apply for a leave of absence of up to one (1) year. Such request not to be unreasonably denied; and
d) An employee on any unpaid leave of absence may continue the Pension (where applicable) and other Benefit Plans, subject to carrier approval and at no additional cost to the employer, and providing they pay all the premiums and contributions themselves.

13.07 Daylight Savings Time

The following will apply when changing from Pacific Standard Time to Pacific Daylight Time and vice versa:

a) Systems Operators:

(i) Twelve (12) hours straight time shall be paid to the employees who work the full night shift, which commences on Saturday, when the springtime change occurs.
(ii) Twelve (12) hours straight time plus one (1) hour double time shall be paid to the employees who work the night shift, which commences on Saturday when the fall time change occurs.

b) All other employees:

(iii) Eight (8) hours straight time shall be paid to the employees who work the full shift, which commences between 2300 hours Saturday and 0100 hours Sunday, when the spring time change occurs.
(iv) Eight (8) hours straight time plus one (1) hour double time shall be paid to the employees who work the full shift, which commences between 2300 hours Saturday and 0100 hours Sunday, when the fall time change occurs.

13.08 Rest Breaks

The Corporation and Union acknowledge the benefits of 15 minute rest breaks approximately midway through each half day and will, whenever reasonable, provide such a break.

13.09 Converting Annual Salary to Hourly Rate

The hourly rate for full time employees is calculated by dividing the annual salary by 2,080 hours. (Calculation: 8 hours per day x 5 days per week x 52 weeks per year = 2,080).

13.10 Ticket Bonus

a) Each additional valid Journey ticket or approved course/certificate over and above that which is required for their job classification, to a maximum of two (2) tickets shall receive a fifty dollars ($50.00) per month Ticket Bonus. Tickets not relevant to

the job duties will not be eligible for the ticket bonus.

b) Ticket Bonuses as established in 13.10 (a) shall be reviewed yearly by the Corporation to determine the relevancy and application of the ticket in relation to the employees current job duties.

c) The following list of tickets may be applicable for the ticket bonus, however is not limited to this list.

Power Lineperson	Power Systems Electrician
Electrician	Welder
Heavy Duty Mechanic	Millwright
Instrumentation	Machinist
ICS Operator Course	

d) Effective January 1, 2002, the provisions in Article 13.10 shall not apply to new hires.

13.11 Travel Time

a) Authorized time required for travel outside regular working hours to/from the job site, shall be paid at two (2) times the employee's regular rate of pay.

b) Authorized time required for travel outside regular working hours between home base and training courses, workshops or seminars, at the employer's request, shall be paid for the first eight (8) hours at the regular rate of pay, and the applicable overtime rate thereafter.

Article 14
Salary Administration

14.01 New employees entering the service of the Corporation will be appropriately placed within the salary range at the discretion of the Corporation.

14.02 On the first of the month following successful completion of the probationary period, an employee will be advanced 3% in the wage range subject to satisfactory performance. Thereafter, 3% increments reflecting progression through the range will be semi-annually based on the employee's anniversary date, subject to satisfactory performance.

14.03 The Employer acknowledges the value and importance of timely performance evaluations, and further agrees to maintain a performance evaluation policy through the Joint Consultation Committee.

14.04 When a promotion occurs, the employee concerned shall be placed in that position within the new range which reflects an increase in wage which shall be no less than 3% in the range from which they were promoted.

14.05 If an employee is accepted under a posting for a lower level job or is transferred at their own request, they will be appropriately placed within the salary range for such job at the discretion of the Corporation.

14.06 An employee temporarily assigned, in writing, for a period of more than two (2) continuous working days to a position of higher classification shall, from the first day, be paid;

a) The minimum salary for the temporary position where that minimum is more than four percent (4%) above their present salary; or

b) Receive four percent (4%) where their salary or temporary assignment does not exceed the maximum of the range for the temporary position; or

c) Where the application of (b) above would provide for a temporary assignment which would exceed the maximum of the range for the temporary position, the employee would receive the maximum rate in the range for the temporary position.

14.07 In any event that an employee is retained in the temporary assignment for more than one (1) year, their wage shall be administered in the range of the new classification unless the parties agree otherwise.

Article 15
Northern Allowances

15.01 The Corporation's assistance to permanent and term full time employees to alleviate the higher cost of living in the Yukon will pay a flat rate northern allowance of six thousand three hundred dollars ($6,300.00) per annum, paid out equally on each pay date, plus five percent (5%) of base salary.

15.02 Permanent and term part time employees shall receive a prorated flat rate northern allowance on provisions in Article 15.01 on the basis of total regular hours to be worked in the year divided by the total regular full time hours, plus five percent (5%) of base salary.

15.03 Temporary employees who have been continuously employed for more than five (5) months, or are scheduled to be continuously employed for more than five (5) months shall be entitled to fifty percent (50%) of the flat rate northern allowance for the time worked. Such employees who work less than full time regular hours will be entitled to fifty percent (50%) of the six thousand three hundred dollars ($6,300.00) per annum prorated.

15.04 Northern allowances will not be earned for any month during which the employee does not earn ten (10) days pay in a calendar month due to short- term disability, long term disability, or periods of leave without pay. Northern allowances will be adjusted at the completion of the leave.

Article 16
Location Allowance

16.01 Location Allowance specified in this article shall be paid to employees on a pay period basis, and payroll administered in like manner to the Northern Allowance Article 15.00.

a) Effective January 1, 2007, permanent and term employees whose home base is in Dawson City, Mayo, or Faro shall receive a Location Allowance of two thousand one hundred dollars $2,100.00 per year over and above their standard Northern Allowance paid out equally on each pay.

b) In the event Aishihik is permanently staffed, the rate will be twelve hundred dollars $1,200.00 per year.

16.02 Permanent and term part time employees shall receive a prorated Location Allowance on provisions in Article 16.01(a & b) on the basis of total regular hours to be worked in the year divided by the total regular full time hours.

16.03 Temporary employees who have been continuously employed for more than five (5) months, or are scheduled to be continuously employed for more than five (5) months shall be entitled to fifty percent (50%) of the designated Location Allowance for the total time worked.

Article 17
Call Out

17.01 Employees will be paid at the overtime rate when called out to perform work outside their normal working hours.

17.02 a) If an employee is called out within two hours of the start of their regularly scheduled shift, they will be paid for the period from the time of the call-out to the start of their shift.

b) If an employee is called out any other time, they will be paid for the time actually worked, or for two (2) hours, whichever is greater. Time required to travel to/from the job site shall be considered time actually worked.

17.03 Employees called out are deemed to be on duty for the minimum period set out in Article 17.02, or until the work for which they have been called out is completed. Further calls received during this period will be considered a continuation of the initial call and not subject to call-out pay.

17.04 When an employee is authorized to continue working in excess of two (2) hours beyond the normal scheduled quitting time, the employee will be provided with a reasonable meal in the third hour and every four (4) hours thereafter, as arranged by the Corporation, or a dinner per diem as provided for in Article 21.02(a) at the employer's discretion paid

once for the work beyond the normal scheduled quitting time. If the employee does not leave the work site and the meal break does not exceed one-half (1/2) hour, and the wok continues after the meal break, the meal break will be considered as time worked at the applicable overtime rate. A practical application of the above arrangements may be made.

17.05 Notwithstanding the above, where the employee receives a call and can accomplish the work by telephone without returning to the workplace, the employee shall be compensated at the applicable overtime rate rounded up to the nearest fifteen (15) minute period.

Article 18
Shift Premium

18.01 An employee shall receive a shift premium for all hours worked, including overtime hours worked, on eight (8) hour shifts scheduled between 1600 hours and 2400 hours and between 2400 and 0800:

Effective January 1, 2008 - $1.45 per hour
Effective January 1, 2009 - $1.55 per hour
Effective January 1, 2010 - $1.65 per hour

18.02 An employee shall receive a shift premium for all hours worked, including overtime hours worked, on twelve (12) hour shifts scheduled between 1900 hours and 0700:

Effective January 1, 2008 - $1.65 per hour
Effective January 1, 2009 - $1.75 per hour
Effective January 1, 2010 - $1.85 per hour

18.03 Any job scheduled in advance for off-normal hours requires scheduling for at least three consecutive days to be considered as a scheduled shift.

Article 19
Standby

19.01 Where the employer requires the employee to be available on standby during off duty hours, the employee shall be entitled to be compensated at the rate of:

Effective January 1, 2008 - $3.53 per hour or portion thereof
Effective January 1, 2009 - $3.78 per hour or portion thereof
Effective January 1, 2010 - $4.03 per hour or portion thereof

19.02 The Corporation shall determine the number of employees required to standby in each circumstance and shall so designate these employees by schedule. Standby allowance will be paid only to employees officially designated for such duty. In designating

employees for standby, the Corporation will endeavor to arrange for the equitable distribution of standby duties.

19.03 a) Standby on a regular workday means availability on call outside of normal hours of work. On each scheduled day of rest and recognized holiday, standby means availability on call for the full twenty-four (24) hour period. An employee on standby may leave their home for personal reasons, provided they make arrangements to be reached and to be available for duty.

b) No standby premium shall be paid if an employee is unable to be reached or report for duty when required.

19.04 a) Effective January 1, 2005, employees shall not normally be required to standby more than three thousand seven hundred (3,700) hours in a calendar year where other qualified staff are available. Employees who have been on standby for more than three thousand seven hundred (3,700) hours in a calendar year shall be paid at one and a half times (1.5) times the normal standby hourly rate for standby worked in excess of these hours in a calendar year.

b) Effective January 1, 2006, employees shall not normally be required to standby more than three thousand seven hundred (3,700) hours in a calendar year where other qualified staff are available. Employees who have been on standby for more than three thousand seven hundred (3,700) hours in a calendar year shall be paid at two times (2) times the normal standby hourly rate for standby worked in excess of these hours in a calendar year.

Article 20
Calculation of Premium Rates

20.01 If two (2) or more premiums are applicable to the same hours worked, an employee shall receive only the highest premium rate applicable to such hours. For the same hours worked, an employee shall not receive a premium rate under more than one (1) provision of this Agreement unless otherwise specifically provided.

Article 21
Employee Travel

21.01 The Corporation will on production of receipts, pay for room or alternatively provide accommodation when working away from home.

21.02 a) An employee on travel status will receive the per diem for meals and incidentals equivalent to Federal Government rates for the Yukon which shall be adjusted annually on January 1st.

b) Employees working outside the geographical boundaries of the community that is their home base shall be on travel status, excluding the Takhini sub-station**.**

c) For employees on travel status to/from Aishihik, reimbursement shall be based on the "Aishihik" per diem as outlined in Appendix A of the Employee Travel Policy**.**

21.03 This will not apply to locally hired help employed for a specific job in the community in which they reside and who will be laid off prior to the crew moving to another location.

21.04 An employee who is required to work away from home shall be paid incidental expenses based on the per diem schedule for each night away from home.

Article 22
Job Evaluation

22.01 Job Evaluation System

a) The parties agree to implement the Job Evaluation Plan (Plan) pursuant to the Letter of Understanding # 4 effective July 1, 2005.

b) The parties agree the Job Evaluation Plan developed jointly and signed-off shall form part of the Collective Agreement.

c) The Employer agrees that any changes to the Plan factor or factor weightings shall be subject to agreement between the parties.

d) The Employer and the Union will establish a Joint Job Evaluation Committee (JJEC) for the evaluation of all bargaining unit positions.

(i) The JJEC will consist of at least four (4) members, comprised of equal representation from both Employer and the Union shall be responsible. The JJEC may call upon jointly agreed internal and/or external resources as required.

(ii) An employee shall suffer no loss of pay or benefits for serving on the JJEC.

22.02 Job Evaluation Review and Appeal

a) When new positions are established, the JJEC shall evaluate the jobs and shall notify the Union thereof within fifteen working (15) days of the evaluation being completed.

b) When significant differences, or changes, in job content effect the existing job evaluation to the extent that the Union or an employee request that the job be re-evaluated, the following procedure shall be followed:

(i) An employee or the Union shall initiate a written request to HR for a job to be re-evaluated within fifteen working (15) days of significant changes in job content arising.

(ii) An employee initiating a written request for re-evaluation must file a copy of the

request with the Union.

(iii) The JJEC shall complete the re-evaluation as soon as possible but not later than ninety (90) working days upon receipt of the written request for review.

(iv) HR shall notify the Union and the employee of the results of the re-evaluation within fifteen (15) working days of the completion of any evaluation.

(v) If the re-evaluation results in a higher pay level, it shall be retroactive to the date that HR received the written request for review.

(vi) If the re-evaluation results in a lower pay level, the employee shall retain their current rate of pay and any adjustments negotiated by the parties for as long as they remain in that position.

c) When significant differences or changes, in job content affect the existing job evaluation to the extent that the Employer requests that the job be re-evaluated, the following procedure shall be followed:

(i) The Employer shall initiate a request for re-evaluation within fifteen (15) working days of the significant changes in job content arising.

(ii) The Employer shall notify the Union of the initiation of the review.

(iii) The JJEC shall complete the re-evaluation as soon as possible but not later than ninety (90) working days upon receipt of the written request for review.

(iv) HR shall notify the Union and the employee of the results of the evaluation within fifteen (15) working days of the completion of any evaluation.

(v) If the re-evaluation results in a higher pay level, it shall be retroactive to the date the Employer initiated the request for re-evaluation.

(vi) If the re-evaluation results in a lower pay level, the employee shall retain their current rate of pay and any adjustments negotiated by the parties for as long as they remain in that position.

d) Where an employee and the Union are not satisfied with the JJEC's decision, and the Union agrees to represent the employee, the Union may refer JJEC's decision to arbitration by letter within fifteen (15) working days of receipt of the re-evaluation decision. The letter shall state the matter sought to be arbitrated and the names of proposed arbitrators. The Corporation shall, within thirty (30) days of the receipt of such letter notify the first party in writing of the acceptance of one of the arbitrators named or propose others. The Corporation also has the right to appeal under this process.

e) An independent Arbitrator trained in job evaluation, mutually agreed upon by both parties, will hear appeals of the JJEC's decisions within one hundred and twenty (120) working days or at the earliest mutually agreed upon date by both parties. A decision of the Arbitrator is final and binding. Each party shall pay one half (1/2) of the fees and expenses of the Arbitrator.

f) The Union may withdraw the appeal from the arbitration process at any time.

g) Unless the parties agree otherwise, the time lines in this article are mandatory.

Article 23
Description of Duties

23.01 Upon written request an employee will be provided a complete and current job description, including the position classification level and point factor ratings for their position.

23.02 Job descriptions will be established for each position by the supervisor and the Director. Job descriptions for bargaining unit employees will be issued to the incumbent and the Union.

23.03 When a job description is changed, the Corporation will, within fifteen (15) days of the change, give a copy of the revised job description to the Union and the incumbent.

23.04 The employee should review the job description annually for their position to ensure that the description is accurate and up to date. Where inaccuracies or discrepancies are identified, they will be discussed during the annual performance review. Where the supervisor in conjunction with the Director believe that there are significant changes to the job, they will notify the Human Resources Department within ninety (90) days. Where the Supervisor/Director believe that there are no significant changes to the job, they will notify the employee.

Article 24
Designated Paid Holidays

24.01 (a) All full time employees covered by this Collective Agreement shall receive eight (8) hours pay for designated paid holidays, except as provided by Article 24.02, as listed below:

New Year's Day	Labour Day
Heritage Day*****	Thanksgiving Day
Good Friday	Remembrance Day
Easter Sunday	Christmas Day
Victoria Day	Boxing Day
Canada Day	Discovery Day
National Aboriginal Day**	

*Whitehorse and Aishihik only
**Communities outside Whitehorse and Aishihik only

b) Pursuant to Article 24.01 (a), all part-time employees' designated paid holidays shall be prorated relative to regular scheduled hours.

24.02 Notwithstanding the above, should an additional statutory holiday be declared or proclaimed by the Canadian or Yukon Governments, it shall replace the day designated

for the celebration of the Heritage Day. Should a new, non-statutory holiday be established, the parties will meet to decide on a course of action to amend Article 24.01, holiday list.

24.03 a) To be eligible for and paid for any of the holidays listed above, an employee must have completed thirty (30) days of employment immediately preceding the holiday and they must have worked their scheduled work shift immediately before and immediately after such holiday. The only exclusion to this requirement will be where an employee is absent due to sickness or accident or by authority of the Corporation.

b) A temporary or term employee who does not meet the thirty (30) day requirement, but who has worked two hundred and forty (240) hours in the twelve (12) months immediately preceding the holiday and has worked their scheduled work shift immediately before and after the holiday, is eligible to be paid for the holiday.

24.04 Pursuant to Article 24.03, employees working on holidays listed in Article 24.01 will be paid two (2) times the regular rate for those hours that fall within the statutory holiday in addition to the regular pay for the holiday.

24.05 Should one of the recognized holidays for employees, other than shift employees, fall on a day of rest, the holiday shall be moved to the employee's first working day following his/her day of rest. Employees shall receive holiday pay only once for a given holiday.

24.06 Should one of the holidays listed in 24.01 fall on a regular day off of a shift employee, they shall be paid the employee's normal straight time hours, in addition to their regular pay, or be given equivalent time off.

Article 25
Leave

25.00 Except for Article 27 and Article 30 it is agreed that any paid day of leave is based on eight (8) hours.

Vacation Leave

25.01 a) All full time permanent and term employees who have completed twelve (12) months of continuous employment shall be entitled one hundred and sixty (160) hours per year.

b) A new permanent or term employee who has completed three (3) months of continuous employment may receive an advance of anticipated annual leave credits expected to be earned by the end of the calendar year.

c) All full time permanent employees who have completed eight (8) years of continuous employment shall be entitled two hundred (200) hours per year.

d) All full time permanent employees who have completed fifteen (15) years of continuous employment shall be entitled to two hundred and forty (240) hours per year.

e) All full time permanent employees who have completed twenty-two (22) years of continuous employment shall be entitled to two hundred and eighty (280) hours per year.

f) Subject to vacation scheduling under Article 25.03 employees may be permitted to take their earned vacation one (1) day at a time up to maximum of five (5) days in a calendar year, subject to receiving the prior approval of their immediate supervisor and providing such scheduling does not unduly interfere with efficiency or incur overtime.

25.02 Pursuant to Article 25.01, part-time employees annual leave credits shall be prorated on the basis of total regular hours to be worked in the year divided by the total regular full time hours.

25.03 a) Vacations may be taken at any time during the calendar year by mutual agreement between the employee and their supervisor provided that vacation scheduling is arranged to suit the work schedules of the Corporation.

b) In the year in which an employee qualifies for increased vacation entitlement pursuant to Article 25.01, such increased entitlement may be taken only after the employee's anniversary date of vacation entitlement.

25.04 In the event that a recognized holiday falls within the annual vacation period of an employee, such period shall be increased by eight (8) hours for each of the holidays so affected. Part time employees' vacation leave shall be prorated relative to regular scheduled hours.

25.05 a) Sick leave, short-term disability and long-term disability shall not be deemed to have broken the continuity of employment for annual leave purposes only for establishing the number of years of continuous employment when the employee resumes work.

b) Vacation leave will not be earned for any month during which the employee does not earn ten (10) days pay in a calendar month due to short-term disability and/or long-term disability**,** or periods of leave without pay**.** Annual vacation leave will be adjusted at the completion of the leave.

25.06 A full time employee may carryover sixty (60) hours of vacation accruals or for part-time employees the equivalent prorated hours. Accruals in excess of that amount will be paid out at the beginning of each calendar year.

25.07 Permanent, permanent part-time and term employees whose home base is more than one hundred (100) kilometers outside of Whitehorse and who proceed on annual vacation shall be allowed two (2) days of paid travel time annually.

25.08 In the event that the employment relationship is terminated and the employee has used more annual leave than they have earned then the Corporation can recover or withhold any amounts owing.

25.09 If an employee provides a written notice of their intention to retire in the next calendar year they may at their discretion carry-over up to one (1) year's entitlement of vacation leave to the next calendar year.

Article 26
Vacation Travel Allowance

26.01 Permanent and term employees are eligible for a vacation travel allowance for themselves and their families after the completion of twelve (12) months employment with the Corporation.

26.02 a) Effective January 1, 2004, the Corporation will pay the following travel allowance on the pay date following the employee's anniversary pursuant to an employee completing a statutory declaration form:

Employee	$1,300.00
Employee's spouse	$850.00
Each dependent child	$850.00

Income tax will not be withheld from this payment unless otherwise requested by the employee.

b) Unpaid vacation travel allowance will not be carried forward to the next year.

26.03 The employee will be responsible for retaining receipts for income tax purposes.

26.04 The Travel Allowance shall be prorated for permanent or term part-time employees on the basis of total regular hours to be worked in the year divided by the total regular full time hours.

Article 27
Bereavement Leave

27.01 a) The Corporation shall grant an employee bereavement leave with pay for a period of up to forty (40) hours for employees, other than Systems Operators, and sixty (60) hours for Systems Operators, where there is a death in the immediate family, for the purpose set out in Article 27.01 (b) (ii) below, or alternatively, the Corporation will grant bereavement leave where the death of a member of the immediate family is

imminent, provided such leave is in lieu of bereavement leave at a later date with respect to the same member of the immediate family. Upon written request an employee shall receive up forty (40) hours bereavement leave for immediate family without pay.

b) Bereavement leave granted under Article 27.01(a) may be taken by the employee at one of the following times:

(i) Immediately following the date of death; or
(ii) Within a period of thirteen (13) months from the date of death for the purpose of attending a religious or traditional ceremony or event related to the death.

c) The employee shall be entitled to utilize their bereavement leave as provided for in Article 27.01 (a) above over two (2) separate periods within the thirteen (13) month period.

d) Immediate family for the purpose of bereavement leave is defined as mother, father, sister, brother (or alternatively step-father, step-mother, or foster parent), spouse, son, daughter, step-child, grandparent (including spouse's), grandchild or ward of the employee, mother-in-law, father-in-law, sister-in-law, brother-in-law, son-in-law, daughter-in-law, and any relative permanently residing in the employee's household or with whom the employee permanently resides.

Article 28
Court Leave

28.01 An employee who is summoned for jury duty, or by subpoena to attend as a witness, shall be paid for time lost with a maximum of one day's regular pay for each day lost, less any amount paid by the courts.

Article 29
Maternity & Parental Leave

29.01 In the event of a birth or adoption of a child, permanent and permanent part time employees are entitled to unpaid parental leave to a maximum of thirty-seven (37) weeks. For the first eighty (80) hours of leave, the employee will receive their regular pay provided that they have been continuously employed by Yukon Energy for the past twelve (12) months. The remainder of the leave shall remain unpaid, except for any period during which the employee qualifies for sickness or disability payments.

29.02 An employee wishing to take parental leave may begin the leave upon four (4) weeks' written notice to the supervisor. This requirement is waived in the event a baby is born prematurely, and the employee could not reasonably provide four (4) weeks' notice.

29.03 An employee who wishes to resume employment after parental leave shall give the Corporation four weeks' written notice. The Corporation will then:

a) Reinstate the employee in the position occupied at the time parental leave began; or

b) Provide the employee with alternate work of a comparable nature, at not less than the same wage and other benefits that had accrued to the employee to the date on which parental leave began.

29.04 Where a pregnancy of an employee interferes with the performance of her duties, the Corporation may, by notice in writing to the employee, require her to begin parental leave. This Article may not be used if the employee is absent from work for medical reasons, certified by a physician.

a) When an employee adopts a child, the employee shall be entitled to take leave of absence without pay for a maximum of thirty-seven (37) weeks immediately following the adoption.

b) The employee will notify the Corporation of their intention to adopt and indicate that they intend to take parental leave under this Article.

c) When the adoption is finalized, the employee may begin parental leave after giving the Corporation as much notice as is possible under the circumstances.

29.05 A birth mother is entitled to a maximum of seventeen (17) weeks of unpaid maternity leave.

Article 30
Special Leave

30.01 a) Employees, other than Systems Operators, will be entitled to sixteen (16) hours special leave per year for the purpose of caring for a sick dependent child, parent or spouse. Systems Operators will be entitled to twenty-four (24) hours special leave per year for the purpose of caring for a sick dependent child, parent or spouse.

b) Effective January 1, 2009, employees, other than Systems Operators, will be entitled to twenty-four (24) hours special leave per year for the purpose of caring for a sick dependent child, parent, or spouse. Systems Operators will be entitled to thirty-six (36) hours special leave per year for the purpose of caring for a sick dependent child, parent, or spouse

30.02 Employees required to leave the community for purposes of taking a dependent child, parent, or spouse to a medical appointment may use the leave provided for in this Article.

Article 31
Recruitment Postings

31.01 a) The Corporation, it's management, employees, and Union are committed to the development of employees from within the bargaining unit.

b) When a permanent position, within the scope of the Collective Agreement, becomes vacant or a new position is created, a recruitment posting outlining details of the vacancy will be posted on Corporation bulletin boards for ten (10) working days. District offices will receive faxed copies of recruitment postings.

c) All Postings shall contain hiring criteria including educational and/or experience and related skill areas.

d) A copy of each posting will be directed to the Union.

e) All employees have the privilege of applying to posted positions. While first consideration will be given to applicants who are members of the bargaining unit, the Corporation reserves the right to fill vacancies from outside the bargaining unit.

f) Bargaining unit applicants will receive a personal written reply to their applications.

31.02 In considering such applicants, the factors which shall be considered are related ability, education, behaviour, performance, related skill areas, and seniority. When the overall assessment is equal for two (2) or more of the applicants, the applicant with the most seniority with the Corporation shall be selected for the position. An unsuccessful internal applicant shall be given a written reason for not being selected.

31.03 When making promotions and/or transfers, the factors listed in Article 31.02 shall apply.

31.04 The successful applicant will be advised of the appointment date to the new position in their letter of offer.

31.05 In instances where an employee who has been promoted to a higher classification and it is determined that they are unable to fulfill the job requirements or is unwilling to remain in that position, then within a three month trial period they may return to their former position.

31.06 No posting is required if a position has been re-assessed or re-evaluated to a higher classification, if the person who held the position before the re-assessment or re-evaluation remains in the position.

31.07 When an employee assumes a remote and difficult to fill position and has been assured a time certain rotation, the employee will be brought back to an equivalent level position in another location without posting.

31.08 An employee on an approved educational leave may be brought back to an equivalent level position within the bargaining unit without posting. The employee must remain a member in good standing with the Union while on leave.

31.09 In the case of Articles 31.06 and 31.07, the Corporation will inform the Union in advance of the application of these articles.

31.10 When an employee wishes to appeal a decision under Article 31.00, such appeals will be governed by the terms and procedures contained within Article 11.00 Grievance Procedure.

31.11 When an employee files a grievance under Article 31.10, the union representative and the grievor will be provided access to the grievor's pertinent documents.

Article 32
Reduction of Staff

32.01 This article does not restrict the Corporation's right to terminate an employee for disciplinary or performance reasons. The Corporation agrees that permanent employees will not be laid off or have their hours of work reduced as a direct result of the Corporation contracting out work.

a) Before there is a reduction in staff by way of layoff or termination(s) of permanent or permanent part-time employee(s), the Corporation will notify the Union and arrange a meeting to discuss the reduction in staff and the procedure to be used. The Corporation representatives at the meeting will include the President/CEO and the management of the Department in which the layoff or termination is to occur.

b) Employees directly affected by a reduction of staff will be given three (3) months written notice or pay in lieu thereof. Within fourteen (14) calendar days after receipt of notice those employees may elect at the time of layoff to:

(i) Accept the layoff and be placed on the recall list pursuant to Article 32.02; or

(ii) Accept severance pursuant to article 33.04 in which event the employment relationship will be terminated; or

(iii) Elect to displace another employee with lesser seniority at the same or lower classification provided they are immediately able to perform that job.

c) The Corporation will consider retraining or development as an alternative to reduction of staff, when a vacancy exists and the employee demonstrates the ability and aptitude to meet the new job requirements.

d) In the event of a reduction in staff the factors which shall be considered are; related ability, education, performance, and seniority related skill areas. These factors are

not listed in order of priority. When the overall assessment is equal for two (2) or more employees, the employees shall be laid-off in the reverse order of their seniority.

32.02 a) In the event of an increase in staff within one (1) year following reduction of staff, an employee on the recall list will be eligible for recall on a last out-first in basis, provided they are qualified for the position or could qualify within a familiarization period not to exceed one (1) month. To be eligible, the employee shall be on the recall list and advise the Corporation of any change in address. The Corporation will contact an eligible employee by registered mail and the employee must acknowledge receipt of the Corporation correspondence within seven (7) calendar days of the date of receipt of the Corporation correspondence and be prepared to report to work with the Corporation within twenty-one (21) calendar days of the date of receipt of the Corporation correspondence.

b) When re-called, the employee will be credited with their seniority and vacation entitlements under the collective agreement that had accrued to the employee up to the date of their layoff. The Corporation shall recall the employee as follows:

(i) to their former position occupied at the time of their termination if available; or

(ii) Subject to 32.02 (a) provide them with alternate work of a comparable nature at an appropriate wage commensurate with their experience and qualifications if available; or

(iii) Subject to 32.02 (a), any position with the employer and at the rate of pay for that position when recall under clause (i) and (ii) is not possible.

c) An employee who accepts a recall under clause (b) (iii) above shall remain on the recall list for the duration of the initial recall period for purposes of recall to a position covered by clauses (b) (i) and (b) (ii).

d) An employee who refuses a recall under clause (b) (iii) above shall not forfeit their remaining recall rights under clause (b) (i), or (b) (ii) above.

Article 33
Termination of Service

33.01 In the event of a Permanent Employee giving notice of termination to the Corporation, such termination shall require written notice of ten (10) working days.

33.02 In the event of the Corporation giving notice of termination to a permanent employee, such termination shall require notice of thirty (30) calendar days

33.03 An employee may be discharged for just cause without notice or pay in lieu thereof, subject to Article 11.00.

33.04 In the event of the Corporation terminating the employment of a permanent employee, other than for just cause, severance pay shall be paid to the employee in an amount equal to one (1) week's normal pay per year of seniority up to the maximum of twenty six (26) weeks since date of last hire based on their last month's wage rate.

Article 34
Joint Consultation Committee (JCC)

34.01 a) The parties acknowledge the mutual benefits to be derived from joint consultation and are prepared to continue meaningful consultation on matters of common interest.

b) The purpose of the JCC is to provide a forum to discuss policies and labour related matters.

c) The JCC shall be composed of an equal number of representatives of the parties to the Agreement. Such representatives are to include the President of the Union and the President/CEO of the Corporation.

d) No employee shall suffer loss of pay or benefits for serving on the JCC.

34.02 The JCC shall:

a) Meet as mutually agreed upon but not less than on a quarterly basis;

b) Discuss and attempt to arrive at mutually agreeable solutions to the problems or issues identified by either party;

c) The parties mutually agree that JCC shall not have the authority to alter, amend, change, modify or extend the terms and conditions of the Agreement and the details of specific grievances shall not be topics of joint consultation.

34.03 The JCC shall consider as appropriate matters for consultation, the following:

a) Harassment policy;
b) Job performance evaluation format;
c) Volunteer Leave Policy;
d) Health and Safety policy;
e) Employment Equity; and
f) Sick Leave Policy

The Employer agrees that in the matters identified above, new policies will not be introduced, and existing policies and guidelines will not be cancelled, or amended, in such a way to affect employees covered by this Agreement, until such time as the Union has been provided an opportunity to consider and consult on the proposals.

34.04 The JCC may:

a) Make final and binding decisions on those matters specifically agreed to in this Agreement or any other matters specifically referred to the Committee by mutual agreement of the parties. Both parties shall be bound by the decisions of the JCC. If the JCC chooses not to render a decision, the matter will be referred back to the parties.

b) Call upon additional persons for technical information or advice; and

c) Establish sub-committees, or ad-hoc committees as it deems necessary and set guidelines and operating procedures for such committees.

For the purposes of this Article, notices and correspondences shall be between the President of the Union and the President/CEO of the Yukon Energy Corporation with a copy to Human Resources and Yukon Employees Union.

34.05 The following policies at present or as amended through the process in 34.03 shall form part of the Collective Agreement:

a) Relocation policy;
b) Travel policy;
c) Clothing policy - Safety; and
d) Compassionate Care policy

34.06 Upon the request from the Union, the Corporation agrees to advise the Union at the beginning of each year, of the proposed Capital and Operational and Maintenance plans, and to review the status of these plans with the Union at the end of each year.

Article 35
Health & Safety

35.01 The Corporation and the Union recognize the vital importance of employee and Union involvement along with management in all aspects of health and safety programs affecting them. In particular; the participation on health and safety committees and in accident and incident investigations.

35.02 The parties shall continue to make all reasonable provisions for the occupational safety and health of employees. The employer will welcome suggestions on the subject from the Union and the parties will undertake to consult with the view to adopting and expeditiously implementing reasonable procedures and techniques designed and intended to reduce the risk of employment injury. Employees shall make every reasonable effort to reduce and obviate risk of employment injury.

35.03 Both parties agree to comply with the provisions and the requirements of the Yukon Occupational Health and Safety Act.

35.04 Employees are encouraged to refer safety matters to their immediate supervisor in an attempt to resolve any problems and where the safety matters cannot be resolved, both employees and supervisors are encouraged to refer safety issues to the Joint Health and Safety Committee.

Article 36
Bulletin Boards

36.01 The Employer shall provide the Union bulletin board space in a reasonable number of locations clearly identified for the use of the Union for posting notices pertaining to elections, appointments, meeting dates, news items, and social/recreational affairs.

36.02 Subject to current systems infrastructure, the Employer agrees the Union shall have access to e-mail for purposes of communicating information covered by Article 36.01 to Union members.

Article 37
Technological Change

37.01 When the Corporation is considering the introduction or implementation of a technological change which would result in changes in the employment status or working conditions of employees it shall provide the Union and every affected employee not less than one hundred (120) days written notice before the introduction or implementation of a technological change, with a written description of the change it intends to carry out, disclosing foreseeable adverse effects on employees. The Employer will seek ways and means of minimizing adverse effects on employees, which might result from such changes.

37.02 The parties agree that where technological change is likely to affect the terms and conditions or security of employment of a significant number of employees, this article will apply.

37.03 The written notice provided in Article 37.01 will provide the following information:

a) The nature and degree of change;

b) The anticipated date or dates the employer plans to effect the change;

c) The location or locations involved; and

d) The names of employees initially affected by the change.

37.04 Pursuant to Article 37.01 the Employer shall consult with the Union as soon as reasonably practicable concerning the effects of the technological change on employees. Such consultation will include but not necessarily be limited to the following:

a) The approximate number and location of employees likely to be affected by the change; and

b) The effect the change may be expected to have on working conditions or terms and conditions of employment on employees.

37.05 The parties agree to discuss alternatives such as training and/or layoff in instances of technological change.

Article 38
Essential Services

38.01 The parties agree that they provide an ESSENTIAL SERVICE and that Article 7 (Continuity of Service) has application in the event the parties fail to reach agreement for the renewal of this agreement. Further it is agreed that Article 44 (Collective Bargaining-Interest Arbitration) can be used to resolve the issues in dispute.

38.02 a) Should an employee covered by this agreement encounter a legal picket line by another trade union at locations other than the Employer's premises, employees covered by this agreement shall have the right to refuse to cross that legal picket line.

b) If an employee encounters such a picket line they will promptly report the matter to the Employer, the Employer will make every reasonable effort to ensure that the employee is deployed elsewhere so that the employee does not suffer a loss of pay or benefits.

38.03 Where a trade union not party to this collective agreement legally pickets at the Employer's premises then the parties agree that an ESSENTIAL SERVICES AGREEMENT shall be negotiated forthwith which will set out the levels of staffing that must be maintained while the legal picketing remains at the Employer's premises. Those employees not designated as essential will be deemed to be on leave without pay, however such an employee may access other leave, eg. vacation or bank time. While the parties are negotiating the levels of staffing, the normal complement of employees will be obliged to work.

Article 39
Pension Plan

39.01 The Yukon Energy Corporation's Employee Pension Plan shall form part of this collective agreement. It is understood and agreed that the Joint Pension Advisory Committee is not a negotiating committee and does not have authority to make any changes in pension involving any additional cost to either the employee or the Corporation.

39.02 No changes will be made to the current Pension Plan except through the recommendation of a majority of the Joint Pension Advisory Committee and the approval by the Board of Directors.

39.03 The Joint Pension Advisory Committee will be comprised of five (5) members. Two (2) representatives of the Union, one (1) out of scope employee representative, one (1) management representative, and one (1) representative of the Board of Directors, or their delegate.

39.04 The Joint Pension Advisory Committee will as a minimum review the following information annually:

a. Total employee contributions;
b. Total employer contributions;
c. Funded status of the plan; and
d. Reviewing the investment status of the plan.

Article 40
Group RRSP

40.01 a) All new permanent employees entering the Corporation shall automatically participate in the Group RRSP plan.

b) Participants in the Group RRSP plan contribute six percent (6%) of base salary. The Corporation matches the participant's contributions six percent (6%).

c) Employees may elect to make personal contributions in excess of the amounts stipulated above but they are not matched by the Employer.

d) A term employee upon commencement of their third (3rd) continuous year of employment may choose to be covered by the provisions of this Article.

Article 41
Group Insurance Plan

41.01 For the duration of this agreement the parties agree premium cost sharing for the group insurance benefit plans will remain unchanged and that levels of benefits will not be reduced unless by mutual agreement. For clarity, benefits in this regard are based on base salary plus northern allowances plus location allowances.

41.02 Basic Life, AD&D, Dependent's Life

a) For information purposes the Employer pays 100% of the premium cost for Basic Life Insurance, Accidental Death and Dismemberment, Dependent Life Insurance, Dental and Extended Health Insurance (including Pay Direct Drug (PDD) cards and Electronic Data Interchange (EDI)). Employees pay 100% of the cost of Short and

Long Term Disability Insurance, and Optional Life and Optional Dependant Life Insurance if they elect to participate in the latter two benefit plans.

b) Provided that the Employer fulfills its responsibility to pay its share of the premiums, and deduct the employee's share of their premiums, for the applicable benefit coverage, the Employer cannot be held responsible or liable for the rejection of any claim by the carrier(s).

Article 42
Discipline

42.01 The parties agree that the Corporation has the right to discipline and discharge for just cause. The purpose of discipline is corrective as opposed to punitive.

42.02 Where the Corporation intends to impose a written reprimand, suspension or discharge on an employee it will provide written reasons for the disciplinary action

42.03 The Corporation shall notify the Union that such discipline has occurred.

42.04 When an employee is required to attend a meeting for the purpose of discussing their conduct or actions that may result in disciplinary action or to render a disciplinary decision or notice of termination regarding that employee, the employee is entitled to have a representative of the union attend the meeting.

42.05 Any formal disciplinary notice placed on the employee's personnel file shall become null and void and not used in any future disciplinary decision after the employee attains a clear work record for twenty-four (24) months from the time of the last notice.

42.06 No member of the bargaining unit shall be forced to discipline another member of the bargaining unit.

Article 43
Term of Agreement

43.01 This agreement shall be binding and remain in effect from January 1, 2008 to December 31, 2010, and from year to year thereafter when notice has been given pursuant to Article 43.05.

43.02 Unless otherwise agreed by the parties, all provisions of the Agreement take effect January 1, 2008, or the date of ratification of both parties, or the date of the Arbitration decision pursuant to Article 44, whichever is later.

43.03 The provisions of this agreement shall remain in effect during negotiations for its renewal and until a new agreement becomes effective.

43.04 Except as provided within the collective agreement, where notice has been given under

Article 43.05, salaries and other conditions of employment will not be altered without consent by or on behalf of the employees affected during collective bargaining.

43.05 a) Within four (4) months preceding the expiry of this Agreement either party may by written notice require the other party to commence bargaining within twenty (20) days and that a full exchange of all proposals will take place in that time period.

b) If collective bargaining is not concluded within one (1) month preceding expiry, then unless mutually agreed by the parties to continue collective bargaining, the provisions of Article 44 will be triggered and arrangements will be made to convene an arbitration board with a view to having the arbitrated collective agreement prior to expiry.

c) Either party may apply to the Minister of Labour for the appointment of a Conciliation Officer pursuant to the Canada Labour Code.

Article 44
Collective Bargaining – Interest Arbitration

44.01 a) The Arbitration Board shall consist of a nominee of the Corporation and a nominee of the Union; such nominees shall elect within seven (7) days of the appointment of the second of them, a third person who shall be Chair. In the event the two nominees fail to agree upon a Chair, the appointment of a Chair shall be made forthwith by the Chief Justice of the Federal Court of Canada, Trial Division, upon request of either nominee. The nominees of the Corporation and the Union must be conveyed in writing to the other party within seven (7) days of the parties agreeing to go to arbitration pursuant to article 43.05.

b) The Board by its decision may alter, amend, change or delete the matters referred to it for settlement and determination;

c) The Arbitration Board shall issue an award in writing and the decision is final and binding upon the Corporation and the Union and upon an employee affected by it. The decision of a majority is the award of the Board.

d) Prior to the Arbitration Board convening, the parties agree to exchange a complete list of those items not yet resolved.

44.02 Each party shall bear the expenses of its respective nominee to the Board and the two parties shall bear equally the expenses of the Chair.

Article 45
Wage Schedules

45.01 The Wage Schedules respectively annexed hereto, are hereby incorporated into and made part of this Agreement and shall apply for as long as this Agreement remains in force and

effect. Further, any changes to the Collective Agreement or addendum as officially agreed to and signed by both parties shall be attached to and form part of this Collective Agreement.

Article 46
Apprentices

46.01 Apprentices will be compensated not less than the applicable level of the apprenticeship rate listed below for the applicable journey pay range or within the applicable journey pay range at the discretion of the Corporation.

46.02 Employees enrolled in recognized apprenticeship programs must successfully meet all apprenticeship requirements before being advanced.

46.03 Apprenticeship Rates

Training Term	**1-1**	**1-2**	**2-1**	**2-2**	**3-1**	**3-2**	**4-1**	**4-2**
% of Journey Rate	**60%**	**65%**	**70%**	**75%**	**80%**	**85%**	**90%**	**95%**

Notes: Training Term 1-1 = first year apprentice, first term; 1-2 first year apprentice, 2nd term, etc.

When the Corporation enrolls an employee in a recognized apprenticeship program, the employee shall be reclassified to the applicable journeyed job classification upon successful completion of the full program and receipt of the journey ticket.

Article 47
Injury on Duty Leave

47.01 To assist permanent employees on leave due to a work related injury, the employer will advance employees the wages WCB would normally provide during the WCB claims approval process. Employees will reimburse the Employer for any funds advanced. Employees shall earn vacation credits for the first thirty (30) calendar days of such leave**.**

Article 48
Loss or Theft of Personal Property

48.01 a) Upon submission of reasonable proof of loss or theft, the Corporation shall indemnify, pursuant to paragraph (b) below, with respect to loss or theft of personal property of an employee while on duty caused by the actions of a person, and provided such personal property is an article of use or wear of a type suitable for use while on duty.

b) The responsibility of the Corporation to indemnify an employee under paragraph (a) above shall be limited to reimbursing the employee:
   i. for the deductible costs, up to a maximum of $200.00, associated with his/her insurance coverage for loss or theft of the personal property; or,
   ii. if the employee does not have such insurance coverage, to a maximum of $200.00.

LETTER OF UNDERSTANDING #1

NORTHERN ALLOWANCES

The parties agree to re-open the collective agreement in the event the Corporation is transferred or devolved to another organization where succession rights under the Canada Labour Code do not apply. The re-opener will be confined to the integration of the Northern Allowances into the base salary. Other matters may be included in the re-opener by mutual agreement only. The parties to this collective agreement must ratify any changes as a result of this Memorandum of Agreement. This Memorandum of Agreement forms part of the collective agreement.

LETTER OF UNDERSTANDING #2

VOLUNTEER ACTIVITIES

The parties both recognize the value of employee's participation in volunteer activities of an essential nature to the community.

In recognition of the importance of such activities the employer agrees that employees who are Volunteer Fire Fighters, Ambulance Attendants, Search and Rescue, Auxiliary RCMP Officers (if responding to an emergency), and/or Victim Services Volunteers will be provided two (2) clear hours for each hour of voluntary activity, to a maximum of eight (8) clear hours, from the end of the volunteer activity until their reporting time without loss of salary.

The following examples are to provide clarity on the application of this Letter:

Activity Completed	Duration of Activity (Hours)	Clear Hours	Regular Start Time	Adjusted Start Time
3:00 a.m.	3 hours	6 hours	8:00 a.m.	9:00 a.m.
5:00 a.m.	4 hours	8 hours	8:00 a.m.	1:00 p.m.
7:00 a.m.	1 hour	2 hours	8:00 a.m.	9:00 a.m.

LETTER OF UNDERSTANDING #3

RECOGNITION OF SUPERVISOR REPRESENTATION DURING CONFLICT RESOLUTION PROCESS FOR TWO BARGAINING AGENCY EMPLOYEES

Yukon Energy Corporation (The "Corporation") recognizes the right of an employee to be represented by a Union Representative of the Public Service Alliance of Canada (The "The Union").

The parties recognize that from time to time, conflict resolution situations may arise between two members of the Union – a Supervisor and a subordinate employee. The parties also recognize that when a union member is assigned to perform management/supervisory functions over another union member, the Corporation will represent that member as if they are a management representative and that member shall be deemed to be outside the Objectives stated in the PSAC Constitution. Under such circumstances, the Supervisor shall be assisted and represented by Management at each stage of the conflict resolution process.

In addition, the Corporation shall bear the expenses of the Supervisor in the conflict resolution process.

The Employer shall have the same obligations and duties of fair and diligent representation as that of the Union and will be responsible for such representation or lack thereof.

LETTER OF UNDERSTANDING #4

PENSION PLAN CHANGES

1. Removing Contributions Cap

   You contribute 3.5% of your Earnings up to the Year's Maximum Pensionable Earnings (YMPE) and 5% of your Earnings that are in excess of the YMPE.

2. Pensionable Service

   For periods of disability to count as Pensionable Service, the member must make their contribution and the Corporation will make its contribution for the period of the leave.

   For periods of unpaid leave excluding disability leave to count as Pensionable Service, the member must make both their contributions and the Corporation's contributions for the period of leave.

LETTER OF UNDERSTANDING #5

FLEX TIME

Where a non-shift employee requests and where the Corporation in its discretion (such discretion to be exercised in a fair and reasonable manner) agrees to:

1. Vary the start and finish times of an employee; or

2. Change the hours of work per day, extended or compressed, to a maximum of twelve (12) hours per day so as to average forty (40) hours per week over a predetermined period of time. Authorized overtime rates apply after forty (40) hours of work per week averaged over the predetermined period of time.

It is understood that such change will not result in any additional costs to the employer (e.g., shift premiums, overtime premiums, etc.) or any reduction of service.

In addition, the change of start times will not constitute a change in the normal day's work as per Article 13.01(a); nor will it constitute rescheduled normal hours as per Article 13.01(c).

Should the Corporation discontinue or not allow the above changes then that decision is not grievable for the first nine (9) months after ratification. Either party upon thirty (30) days notice, following meaningful consultation between the parties, can terminate this Letter of Understanding.

LETTER OF UNDERSTANDING #6

ACTING EXCLUDED POSITIONS

The parties agree that employees covered by this Collective Agreement will not be assigned to act in an excluded position, outside the bargaining unit on a temporary basis without their agreement.

The parties agree that employees covered by this collective Agreement and are assigned, to act in an excluded position for a period of more than two (2) continuous working days, outside the bargaining unit on a temporary basis shall:

a) Continue to accumulate seniority;
b) Be paid the greater of:
    i. their minimum salary for the temporary position, or
    ii. their present salary plus five percent (5%).
c) All other provisions of the Collective Agreement apply (excluding Article 14.06)

LETTER OF UNDERSTANDING #7

PLANT OPERATORS AND SYSTEMS CONTROL CENTRE OPERATORS

Within three (3) months, the Corporation will endeavour to audit Plant Operator timesheets back to January 1, 2005 to ensure proper compensation of designated paid holidays.

In addition, the parties agree to commence within three (3) months of the signing of the collective agreement a review of the following issues:

1. Administration of the scheduling provisions of the collective agreement.
2. Floater positions for coverage or specific projects.
3. Whitehorse coverage on Saturdays and Sundays.
4. Maximum number of days scheduled in a row.
5. Consecutive days of rest.
6. Distribution of overtime.
7. Use of maintenance days in scheduling.

Any changes to the collective agreement resulting from the above review will be recommended to the Negotiating Committees.

The committee will consist of at least one local officer, one Plant Operator, one Systems Control Centre Operator and a representative of the Public Service Alliance of Canada. The employer may appoint up to four (4) representatives to sit on the committee. Time spent on the committee shall be at no loss of pay for bargaining unit members.

In addition to the issues outlined above, the proposals tabled by the union in November 2007 to deal with these issues (i.e., 13.06(f); 13.02(h); 13.03(f); 13.03(g)) shall be included in the committee's work.

In the event the committee fails to provide recommendations to their respective negotiating teams or the negotiating teams fail to reach agreement on any issue that requires the collective agreement to be amended, such issue shall be the subject o Arbitration as per article 44. The negotiating teams will convene within thirty (30) days of receiving the committee's recommendations.

IN WITNESS WHEREOF the Corporation has hereunto affixed its corporate seal, duly authenticated by the signature of its proper officers thereunto authorized, and the Union has caused these presents to be executed, all as of the day and year first above written.

FOR THE YUKON ENERGY CORPORATION LIMITED

_____
David Morrison

_____
Linda Greer

_____
Dave Wray

_____
Ed Mollard

FOR THE PUBLIC SERVICE ALLIANCE OF CANADA (YUKON EMPLOYEES' UNION Local Y024)

_____
Darrell Johnson

_____
Ken Sawyer

_____
Ed Peake

_____
Melaine Fillion

_____
Jim Brohman

_____
Jean Francois Des Lauriers

Wage Schedule
1-Jan-08
(+3.75%)

Level	Annual Min	Hourly Min	Annual Max	Hourly Max
1	23,276	11.19	27,385	13.17
2	26,910	12.94	31,660	15.22
3	30,971	14.89	36,438	17.52
4	35,889	17.25	42,222	20.30
5	41,447	19.93	48,760	23.44
6	47,858	23.01	56,304	27.07
7	55,553	26.71	65,356	31.42
8	64,530	31.02	75,917	36.50
9	70,877	34.08	83,385	40.09
10	74,542	35.84	87,697	42.16
11	78,776	37.87	92,678	44.56

Wage Schedule
1-Jan-09
(+3.5%)

Level	Annual Min	Hourly Min	Annual Max	Hourly Max
1	24,091	11.58	28,343	13.63
2	27,851	13.39	32,768	15.75
3	32,055	15.41	37,713	18.13
4	37,145	17.86	43,700	21.01
5	42,898	20.62	50,467	24.26
6	49,533	23.81	58,275	28.02
7	57,497	27.64	67,644	32.52
8	66,789	32.11	78,574	37.78
9	73,358	35.27	86,303	41.49
10	77,151	37.09	90,766	43.64
11	81,534	39.20	95,922	46.12

Wage Schedule
1-Jan-10
(+3.5%)

Level	Annual Min	Hourly Min	Annual Max	Hourly Max
1	24,934	11.99	29,335	14.10
2	28,826	13.86	33,915	16.31
3	33,177	15.95	39,033	18.77
4	38,445	18.48	45,229	21.74
5	44,399	21.35	52,233	25.11
6	51,266	24.65	60,314	29.00
7	59,510	28.61	70,011	33.66
8	69,127	33.23	81,324	39.10
9	75,925	36.50	89,324	42.94
10	79,852	38.39	93,943	45.16
11	84,387	40.57	99,279	47.73

REFERENCE: **Table 3.9**

TOPIC: **Administration**

PREAMBLE:

Yukon Electrical requires more detail to understand costs.

QUESTION:

a) For information systems for 2005-2009 provide:
   i. costs by system;
   ii. for each system provide breakdown of costs by service; and
   iii. for each service provide units provided and rates.

b) For general costs for 2005-2009, please provide details of each component over $50,000.

c) Recruitment costs:
   i. Please provide details of what comprises recruitment costs in each of 2005-2009; and

d) Board of Directors:
   i. Please provide details of costs including fees paid to Directors for attendance at meetings, retainers, etc; and
   ii. If a market study to determine whether Directors' fees are at market has been conducted, please provide; and
   iii. If a market study has not been undertaken what steps has YEC performed to ensure Directors' fees are not above market.

e) Out of scope labour:
   i. If a market study to determine whether out of scope salaries are at market has been conducted, please provide; and
   ii. If a market study has not been undertaken what steps has YEC performed to ensure out of scope salaries are not above market.

ANSWER:

(a)

There are no fees included in the information systems numbers included in Table 3.9 on page 3-10.

Costs incurred for information technology as set out in Table 3.9 are as follows:

$000s	2005 Actuals	2006 Actuals	2007 Actuals	2008 Forecasts	2009 Forecasts
Annual Software Maintenance	25	42	93	124	183
Consultants	94	108	137	100	112
Contractors		51	41		
Data Circuit	10	11	34	30	31
Legal	24				
Service/Maintenance	26	7	12	50	51
Small Hardware (<300)	4	25	8	20	21
Small items routinely under $15k	30	21	16	27	27
	215	267	343	353	427

YECL-YEC-1-33(a)(i) provides available information on licencing fees, which are a component of Annual Software Maintenance.

(b)

The Administration-General category is characterized by a large number of small charge items. Consequently, the $50,000 cutoff proposed in the question is insufficient to define a large number of the charges to this account. The table below provides all spending on items over $25,000 to better suit the nature of this category.

$000s	2005 Actuals	2006 Actuals	2007 Actuals	2008 Forecasts	2009 Forecasts
Consultants	123	179	69	144	147
Finance Software Lease	177	177	177	177	150
Legal	121	104	59	77	79
Stationary / Office Supplies	40	29	40	33	33
Telephone & Fax	50	47	40	45	46
FN Appenticeships	31	31	32	32	33
Corporate memberships	31	33	36	37	38
Small items routinely under $25k	297	205	144	200	208
Total	**870**	**805**	**597**	**745**	**734**

Other than 2007, which had lower than average use of consultants and legal services, the Administration-General expenses have been on a relatively stable decline since 2005.

(c)

Details of the recruitment costs in each of 2005-2009 are as follows:

$000s	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008 GRA**	**2009 GRA**
Consultants	76	14	34	60	62
Relocation	65		64	70	72
Interviewing Costs	30	5	83	35	36
	170	**19**	**181**	**165**	**169**

Consultants: This cost covers recruitment agencies. YEC uses five different recruiting firms, each of which may specialize in a type of recruiting, i.e. trades, engineers, or management. Some firms require a non-refundable down payment of up to $2,000, while others do not. Firms may charge anywhere from 16% to 22% of total compensation for a successful recruitment.

Relocation: This cost covers the following:

- House hunting trip for employee and spouse of not longer than five days which includes expenses for airfare, necessary transportation (i.e., taxis), accommodation, meals and incidentals at the Corporation's per diem rates.

- Expenses for moving household and personal effects from previous residence to new residence. This includes effects to a maximum of 4,500 kilograms, contents insurance and storage costs for a maximum of 60 days where an employee is not able to move into their new home right away.

- Reimbursement of travel expenses for employee and their dependents including cost of airfare or mileage, necessary transportation (i.e., taxis), accommodation, meals and incidentals at the Corporation's per diem rates.

- If an employee cannot move into their new home upon arrival, temporary accommodation up to a maximum of 21 days is provided, if a house-hunting trip was not utilized, and up to 14 days if a house-hunting trip was utilized.

- Real estate expenses which include real estate commission and legal fees for selling current home and for legal fees, required legal survey costs and appraisal fees for financial purposes in purchasing their new homes.

Interviewing Costs: This cost includes advertising and travel costs associated with bringing prospective candidates up to Whitehorse for interviewing.

(d)

(i)

Details on costs for the Board of Directors are provided below.

$000s	2005 Actuals	2006 Actuals	2007 Actuals	2008 Forecasts	2009 Forecasts
Consultants	64	11	53	25	26
Honoraria	71	65	85	93	95
Small items routinely under $10k	20	14	28	26	27
Total	**157**	**93**	**168**	**146**	**149**

(ii) and **(iii)**

No new studies have been completed since 2005. Please see report (Compensation of Boards of Directors 2003) provided as Attachment 1 provided to this response which was used by Yukon Energy in establishing Board of Director's fees for 2005.

(e)

(i) and **(ii)**

In 2006 Yukon Energy accessed Hay Group survey data for Canada to develop pay grids for out of scope positions. Hay Group made the following assumptions regarding the population of jobs at Yukon Energy, including where Yukon Energy would be attracting employees from, and where Yukon Energy might lose employees to:

- **National:** Hay Group used a national market since, at this level, Yukon Energy expects to attract individuals from outside the region.

- **Utilities Sector:** Hay Group used the Utilities sector database, since Yukon Energy looks for managers and professionals with some knowledge and experience in this area.

List of companies in the Utilities Sector		
Bluewater Power Distribution Corporation	BC Hydro and Power Authority	Bruce Power
Burlington Hydro Inc.	Duke Energy Gas Transmission	Emera Inc.
Enbridge Gas Distribution Inc	Enersource Hydro Mississauga	ENWIN Utilities Ltd.
EPCOR	Fortis Ontario Inc	Halifax Regional Water Commission
Horizon Utilities Corporation	Hydro One Brampton Inc	Hydro One Inc.
Hydro Ottawa Limited	Maritime Electric Company	Maxim Power Corp
NB Power Holding Corporation	Newfoundland and Labrador Hydro	Newfoundland Power Inc.
Northwest Territories Power Corporation	Nova Scotia Power Inc.	Oakville Hydro Corporation
Ontario Power Gneration Inc.	Oshawa PUC Networks Inc.	SaskEnergy Incorporated
SaskPower	Terasen Gas	Toronto Hydro Corporation
Trans Energy Corporation	Union Gas Ltd.	Whitby Hydro Energy Corporation
Yukon Energy Corporation		

- **Executive Level Versus All Jobs:** Hay Group used the executive market data for the jobs that form the core of the executive team.

- **Job Families**: Hay Group used all job families since there is a wide spectrum of jobs within the organization; this also ensured the data base was not narrowed down.

Hay Group used the median or P50 of the market plus 5% as the midpoint of the grade. This positioned Yukon Energy's base salary policy line roughly midway between P50 and P75, and serves to reflect the fact that Yukon Energy is smaller and in a more remote location than most of the companies in the sector where individuals will not have the support networks to call upon that may be found in larger organizations and more populated areas).

YEC is governed by PIPEDA which prevents YEC from releasing personal information and the Report requested in this IR which was described in detail in YEC's original report contained personal information. Further, the agreement with the Hay Group required information contained in the Report to be treated as confidential.

Section 7(3)(c) of PIPEDA states as follows;

> 7(3) For the purpose of clause 4.3 of Schedule 1, and despite the note that accompanies that clause, an organization may disclose personal information without the knowledge or consent of the individual only if the disclosure is....
>
> (c) Required to comply with a subpoena or warrant issued or an order made by a court, person or body with jurisdiction to compel the production of information, or to comply with rules of court relating to the production of records.

Further, the agreement with Hay Group permits YEC to release confidential information in similar circumstances

Accordingly, given the Board's direction YEC is no longer prevented from releasing the Report as requested.

A copy of the Hay Group Report (with the names of the individuals in the various positions at the time redacted) is provided as Attachment 2 to this response.

04-022

The Conference Board of Canada
Insights You Can Count On

Compensation of Boards of Directors 2003



Compensation of Boards of Directors
Increased Pay Reflects Greater Responsibilities

HUMAN RESOURCE MANAGEMENT

The Conference Board of Canada
Insights You Can Count On

Compensation of Boards of Directors 2003
by *Stacey Koumantaros*

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Preface

This, the 15th edition of the Compensation of Boards of Directors, summarizes the results of The Conference Board of Canada's biennial survey on the fees, retainers, and other compensation received by directors for board and committee service. Between December 2002 and January 2003, a questionnaire was sent to 674 predominately large and medium-sized organizations operating in a variety of regions and sectors. A total of 162 respondents chose to participate in this survey, giving a response rate of 24 per cent. We owe a special vote of thanks to the many executives, usually corporate secretaries, who completed the questionnaire and to the many organizations that continue to participate year after year. This report reflects their commitment to improving corporate governance standards in Canada.

Contents

Introduction 1

Chapter 1—Composition and Meetings of the Board 2
Inside and Outside Directors 2
Women Directors 2
Size of Board of Directors 3
Characteristics of Board Members 3
Frequency and Duration of Board Meetings 3
Electronic Communication 3

Chapter 2—Compensation for Regular Board Service 4
Potential Compensation Levels for Outside Directors: 2002 4
Compensation Increases for Outside Directors: 2000 to 2002 5
Method of Payment to Outside Directors 6
Compensation of Inside Directors 7

Chapter 3—Use of Stock 8
Stock as Compensation 8
Stock Ownership Programs 8

Chapter 4—Committee Service 10
Compensating Outside Directors for Committee Service 10
Compensating Inside Directors for Committee Service 10
Compensating Committee Chairpersons 11

Chapter 5—Board Chairpersons 13

Chapter 6—Assessment of Board Members 14

Appendix 1—A Comparison of the Public and Private Sectors 15

Appendix 2—Annual Compensation of Outside Directors for Regular Board Services 16

Appendix 3—Respondents' Profile 21

Introduction

This report updates the 2000 survey of compensation levels and practices of boards of directors. It provides benchmark data on compensation practices and summarizes various key factors in the board operations of a cross-section of the Canadian business community. The data were collected in December 2002 from 162 responding firms across 15 industry classifications (see Appendix 3 for Respondents' Profile).

HIGHLIGHTS

- The average annual potential compensation for outside directors increased by 29 per cent (from $18,939 to $24,428) over the last two years. A core group of 48 companies provided data in 2000 and 2002, from which these numbers are derived. The increased compensation reflects the greater responsibilities and accountability of board members.
- Compensation for members of boards of directors varies significantly depending upon the organization's size, sector, and industry. Overall, potential compensation ranges from a low of $580 per year for a medium-sized Crown corporation to a high of $122,946 for a large company in the manufacturing industry. The average amount of compensation in all responding organizations is $21,943.
- Median retainers and fees are $12,000 and $1,000, respectively. The general manufacturing industry reports the highest potential compensation, at $40,995, followed by communications and telecommunications at $31,135, and oil and gas at $28,371.
- Directors on the boards of the 10 largest private sector organizations categorized by assets receive an average of $60,856, compared with $31,315 for all large organizations in the survey.
- Compensation for board members of public sector corporations averages $8,108. This compares to $27,509 for private sector directors, and $14,836 for non-profit organizations.
- The use of stock as an element of outside director compensation continues to increase.[1] Ninety-one per cent (up from 85 per cent two years ago) of all publicly traded responding firms (n=77) promote stock ownership by means of compensation in the form of stock, equity ownership programs, or guidelines regarding stock ownership. Directors in the majority of publicly traded companies hold shares. In 97 per cent of these firms, at least one director holds shares. On average, 88 per cent of directors on these boards currently hold shares. The number of organizations reporting stock ownership guidelines has increased to 57 per cent of the responding organizations (44 per cent mandatory and 13 per cent non-mandatory), up from 36 per cent in 2000.

This report finds that the average amount of compensation in all responding organizations is $21,943.

- Organizations continue to focus on the effectiveness and assessment of the board and its members. Since 2000, there have been significant increases particularly in the prevalence of position descriptions, formal written limits to authority levels, and formal orientation programs, as well as in performance evaluations for the board as a whole and for individual board members.
- The average board has 12 directors (10 outside directors and 2 inside directors) and holds seven meetings per year, each lasting approximately five hours. In 79 per cent of responding organizations, directors are appointed for a specific term, the average being 2.1 years. The average tenure of board members is 6.4 years.
- The proportion of organizations with female directors continues to rise, up from 73 per cent in 2000 to 76 per cent in 2002. However, the percentage of women directors remains low, at 17 per cent. Only 9 per cent of board chairs are women.

1 Figures in this chapter refer to publicly traded companies. Privately held organizations that reported some share activity were excluded.

CHAPTER 1

Composition and Meetings of the Board

INSIDE AND OUTSIDE DIRECTORS

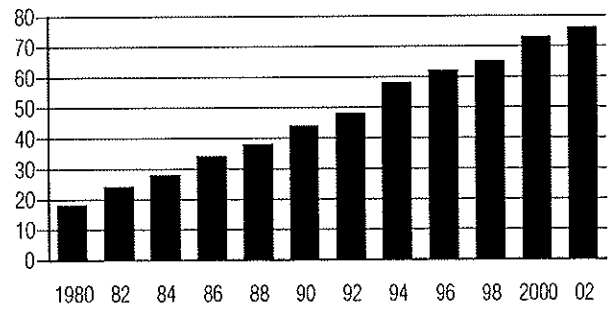
The vast majority of directors (87 per cent) are outside directors (see Table 1).[1] Of those directors, 64 per cent are fully independent. On average, boards are composed of 10 outside directors and 2 inside directors. The proportion of outside directors is greater on public sector boards (91 per cent) than on private sector boards, where 82 per cent of directors are outside directors. On non-profit boards, 89 per cent of directors are outside directors,[2] a percentage that lies between the private and public sector boards.

Table 1
Inside and Outside Directors, by Gender
(n=158)

	No.	%
Outside Directors		
Male	1,290	
Female	300	
Total outside directors	1,590	87
Inside Directors		
Male	228	
Female	17	
Total inside directors	245	13
Total number of directors	**1,835**	**100**

Source: The Conference Board of Canada.

Chart 1
Percentage of Firms with Women on Their Boards



Source: The Conference Board of Canada.

WOMEN DIRECTORS

Survey data indicate that of the 162 responding companies, 76 per cent have women directors on their boards, up from 73 per cent in 2000, and 65 per cent in 1998 (see Chart 1). Ninety-five per cent of public sector corporations have women directors, whereas 64 per cent of private sector companies have at least one female director. Large organizations are more likely than medium-sized or small firms to have women on their boards; however, the percentage gap between the company sizes has decreased significantly. The percentages are 88 per cent, 75 per cent, and 65 per cent for large, medium, and small firms, respectively, up from 86 per cent, 51 per cent, and 50 per cent in 2000. All not-for-profit respondents (n=17) reported having at least one woman director on their board.

Women outside directors continue to be more prevalent than their inside counterparts. Of the total number of inside directors, only 7 per cent are women. This contrasts with 19 per cent of outside directors. Women constitute only 9 per cent (up from 8 per cent in 2000) of board chairpersons and 17 per cent (up from 15.9 per cent in 2000) of the 1,835 directors included in this survey. The overall representation of women on boards continues to improve—it has more than tripled since 1990. However, other Conference Board research has found that this growth in representation may now have reached a plateau, following a strong increase in the mid-1990s.[3]

SIZE OF BOARD OF DIRECTORS

The total number of directors on a board ranges from 4 to 30. The average number of directors is 12. Differences in board size occur among industries. The largest boards are found in health and education, which have an average of 20 members, followed by financial services and trade (wholesale/retail), which each have an average of 14 members. The two industries—food, beverage, and tobacco; and transportation and utilities—each average 12 board members. The business/professional services industry reports the smallest boards, with an average of seven board members. Chart 2 provides additional details on the average number of directors on boards.

Chart 2
Mean Number of Directors on Boards, by Size of Firm



Note: Asset-size categories are (in $ millions): Small (under $150), Medium ($150–$2,000), Large (over $2,000).
Source: The Conference Board of Canada.

CHARACTERISTICS OF BOARD MEMBERS

In 79 per cent of responding organizations, directors are appointed for a specific term. The average is 2.1 years (see Table 2). Given that multiple terms are common, the average tenure of board members is 6.4 years. Twenty-six per cent of respondents report that their organizations have an official retirement age for directors, with the median age being 70.

Table 2
Characteristics of Board Members

	Years
Average term* (n=109)	2.1
Average tenure (n=129)	6.4
Average official retirement age** (n=41)	70.4

*79 per cent of respondents appoint directors for a specific term.
**26 per cent of respondents have an official retirement age.

Source: The Conference Board of Canada.

FREQUENCY AND DURATION OF BOARD MEETINGS

On average, boards of directors meet seven times per year; the overall number of meetings ranges from 3 to 52. Regular board meetings last from 20 minutes at the shortest end to 16 hours at the longest end. The average board meeting lasts five hours and has a 92 per cent attendance rate.

ELECTRONIC COMMUNICATION

The use of electronic communication methods, such as conference calls and closed circuit television, is prevalent. A full 65 per cent of respondents use these methods. Of these, 63 per cent pay directors for their participation at the same level they do for regular, face-to-face meetings. Twenty-eight per cent of respondents pay directors for their participation at a lower level than they do for regular, face-to-face meetings, while 9 per cent of respondents do not remunerate their directors for electronically held meetings.

1 An "outside director" is defined as a member of the board of directors who is not a current employee of the company. Former or retired employees and employees of a parent, controlling, or subsidiary company are considered to be outside directors. An "inside director" is defined as a full-time employee of the respondent firm, parent, controlling, or subsidiary company, who, in addition to assuming regular duties as an employee, sits on the board of directors. "Fully independent directors" are free from any material interest affecting their relationship with the company that dates back within the past five years. Please refer to the *Sarbanes-Oxley Act* or Securities Exchange Commission regulations for guidance. A more detailed description is also found noted in the *Canadian Directorship Practices: Composition, Role and Compensation of Boards of Directors* questionnaire on page 5.

2 Public sector board, as defined here, is the board of a Crown corporation or agency (public enterprise).

3 See the Conference Board study by David A.H. Brown, Debra L. Brown, and Vanessa Anastasopoulos, *Women on Boards: Not Just the Right Thing . . . But the "Bright" Thing*, (Ottawa: The Conference Board of Canada, 2002), pp. 4, 13–14. The study covers in detail the relationship between female representation on boards of directors and elements of board governance that contribute to improved organizational performance.

CHAPTER 2

Compensation for Regular Board Service

POTENTIAL COMPENSATION LEVELS FOR OUTSIDE DIRECTORS: 2002

Compensation for members of boards of directors varies significantly, depending upon the size, sector, and industry. This makes drawing comparisons quite challenging. The method of payment and number of meetings also affect the potential compensation of board members. Tables 3 and 4 illustrate the differences that these factors make on the compensation paid to outside directors among the 162 organizations participating in this year's survey. Appendix 1 offers an overall comparison of boards by sector, and Appendix 2 offers full details on a case-by-case basis.

Table 3
Compensation of Outside Directors for Regular Board Service, Overall Sample
(n=139)

	Mean ($)	Median ($)	Range ($)
Annual retainers	17,025	12,000	1,500–100,000
Per-meeting fees	1,005	1,000	20–2,334
Per diems	723	408	145–4,669
Other compensation*	9,043	6,000	1,000–25,000
Number of meetings per year	7	6	3–26
Potential compensation	21,943	17,000	580–122,946

*Other compensation (n=7) includes travel premiums and money to buy shares.
Source: The Conference Board of Canada.

Table 4
Potential Compensation of Outside Directors for Regular Board Service, by Asset Size, Sector, Ownership, and Industry

	Mean ($)	Median ($)	Range ($)
Small (n=40)	14,043	10,800	1,170–60,695
Medium (n=50)	19,077	15,000	580–77,000
Large (n=49)	31,315	25,000	1,820–122,946
Private sector companies (n=96)	27,509	22,250	1,820–122,946
Public sector corporations (n=34)	8,108	7,450	580–23,330
Non-for-profit corporations (n=9)	14,836	12,000	4,675–32,000
Publicly traded (n=75)	30,624	25,000	7,000–122,946
Privately held (n=64)	11,770	9,322	580–60,695
Food, beverage, and tobacco (n=3)	16,317	13,750	5,200–30,000
Chemical, pharmaceutical, and allied products (n=5)	21,652	18,000	3,000–56,759
Other general manufacturing (n=10)	40,995	23,500	7,000–122,946
Oil and gas (n=7)	28,371	35,000	8,000–45,500
Primary industries (n=9)	24,500	22,500	11,400–37,600
Transportation and utilities (n=21)	18,633	18,000	4,000–46,683
High technology (n=3)	21,267	14,000	12,800–37,000
Financial services, real estate, and holding (n=31)	20,985	13,000	1,500–77,000
Communications and telecommunications (n=9)	31,135	26,000	13,000–77,815
Business/professional services (n=10)	14,018	12,100	6,200–32,000
Construction and construction products (n=5)	27,380	27,500	18,000–36,000
Health and education (n=6)	2,735	2,200	580–5,250
Government/not for profit (n=9)	6,226	4,500	1,065–23,300
Trade (wholesale/retail) (n=7)	27,242	23,000	4,610–53,025
Other (n=4)	34,438	21,000	8,750–87,000

Note: Asset-size categories are (in $ millions): Small (under $150), Medium ($150–$2,000), Large (over $2,000).
Source: The Conference Board of Canada.

Overall, potential compensation ranges from a low of $580 per year for a medium-sized Crown corporation to a high of $122,946 for a large company in the manufacturing industry, with an average of $21,943 across all responding organizations. Median retainers and fees are $12,000 and $1,000, respectively. The highest compensation levels are found in the general manufacturing industry at $40,995, followed by communications and telecommunications at $31,135, and oil and gas at $28,371.

Tables 5 and 6 contain information on annual compensation to outside directors for regular board service for the 10 largest private sector organizations. Average compensation for directors in these organizations is significantly higher than that for large companies overall. Annual compensation for directors on the boards of the 10 largest organizations categorized by sales/service revenue averages $52,414. Directors on the boards of the 10 largest private sector organizations categorized by assets receive an average of $60,856, compared to $31,315 for all large organizations in the survey.[1]

Almost 60 per cent of respondents have adjusted the compensation of their board members since 2000. Participants report that they make adjustments approximately every 49 months. Compensation increases for directors of organizations responding to both the 2000 and 2002 surveys were attributed to multiple factors (see Chart 3). Approximately three-quarters increased the retainer amounts; 46 per cent increased per-meeting fees; 21 per cent increased the number of meetings; and 39 per cent increased per-diem fees.

COMPENSATION INCREASES FOR OUTSIDE DIRECTORS: 2000 TO 2002

A core sample comparison of 48 respondents participating in both the 2000 and 2002 surveys reveals strong increases in the compensation of outside directors for regular board service. Among these organizations, the overall average annual potential compensation to outside directors for regular board service increased by 29 per cent, from $18,939 to $24,428 between 2000 and 2002 (see Table 7).[2]

In sectors where there was more than one organization for the core sample comparison, the highest increase was in the government/not-for-profit sector at 56 per cent, followed by the food, beverage, and tobacco sector at 43.3 per cent (see Table 8). Higher-than-average increases in the retainers, including the introduction of a retainer for one government/non-profit organization, account for the increased average potential compensation in these two sectors.

Table 5
Annual Compensation of Outside Directors* for Regular Board Service, 10 Largest Private Sector Firms by Revenue

Company	No. of meetings	Annual retainer ($)	Per-meeting fee ($)	Potential compensation ($)
1	9	30,000	1,500	43,500
2	10	30,000	1,500	45,000
3	9	30,000	2,000	48,000
4	26	77,815	n.a.	77,815
5	6	77,815	2,334	122,946**
6	15	22,000	2,000	77,000**
7	7	35,000	1,500	45,500
8	4	25,000	1,250	30,000
9	10	30,000	1,250	42,500
10	8	75,000	1,500	87,000
Mean	*10*	*43,263*	*1,648*	*52,414*
Median	*9*	*30,000*	*1,500*	*46,750*

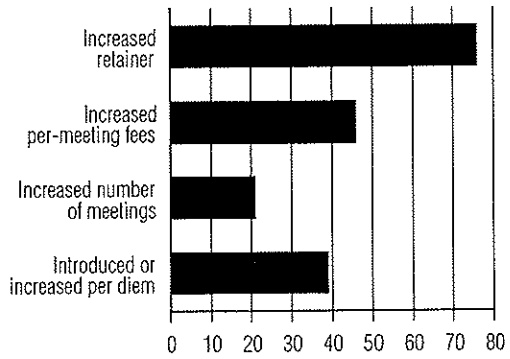
*Outside directors are non-employees of the company who sit on the board of directors. Former or retired employees are considered to be outside directors.
**These organizations also reported other compensation to their outside directors, such as money for travel and to buy shares.
Note: mean revenue of 10 largest private sector firms = $13,936 million; median revenue = $13,859 million.
n.a. = not applicable
Source: The Conference Board of Canada.

Table 6
Annual Compensation of Outside Directors for Regular Board Service, 10 Largest Private Sector Firms by Assets

Company	No. of meetings	Annual retainer ($)	Per-meeting fee & per diem ($)	Potential compensation ($)
1	9	30,000	1,500	43,500
2	10	30,000	1,500	45,000
3	8	100,000	n.a.	100,000
4	26	77,815	n.a.	77,815
5	9	20,000	1,200	30,800
6	8	75,000	1,500	87,000
7	6	15,000	1000	21,000
8	6	77,815	2,334	122,946*
9	7	35,000	1,500	45,500
10	7	35,000	n.a.	35,000
Mean	*10*	*49,563*	*1,505*	*60,856*
Median	*8*	*35,000*	*1,500*	*45,250*

*Organization also provides $4,669 per diem for travel.
Note: mean assets of 10 largest private sector firms = $46,158 million; median assets = $18,451 million.
n.a. = not applicable
Source: The Conference Board of Canada.

Chart 3
Explanation of Compensation Increase
(n=33; percentage of respondents to 2000 and 2002 surveys)



Note: includes multiple responses.
Source: The Conference Board of Canada.

There have been increases in annual compensation to outside directors in firms of all asset-size categories. Increases vary from a low of 23.1 per cent in medium-sized firms to a high of 43.2 per cent in small firms. Directors in large firms received an average increase of 30.5 per cent.

METHOD OF PAYMENT TO OUTSIDE DIRECTORS

The majority of companies (89 per cent) compensate their outside directors for regular board service. The most popular method of compensation is an annual retainer combined with a per-meeting fee and/or per diem (see Chart 4). The retainer represents 78 per cent

Table 7
Annual Compensation of Outside Directors for Regular Board Service, by Size
(48 respondents to 2000 and 2002 surveys)

	No. of firms	2000		2002		Change in mean over 2 years (%)
		Mean ($)	Median ($)	Mean ($)	Median ($)	
Small	9	6,957	5,075	9,964	7,400	43.2
Medium	15	19,354	13,400	23,822	17,000	23.1
Large	24	23,172	22,000	30,230	24,500	30.5
Overall	*48*	*18,939*	*15,750*	*24,428*	*15,750*	*29.0*

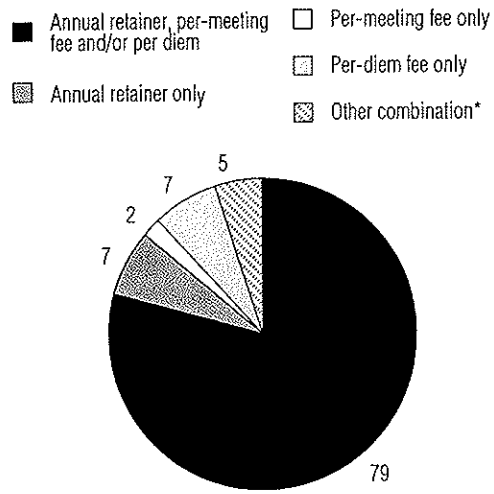
Note: Asset-size categories are (in $ millions): Small (under $150), Medium ($150–$2,000), Large (over $2,000).
Source: The Conference Board of Canada.

Table 8
Annual Compensation of Outside Directors for Regular Board Service, by Industry
(48 respondents to 2000 and 2002 surveys)

	No. of firms	2000		2002		Change in mean over 2 years (%)
		Mean ($)	Median ($)	Mean ($)	Median ($)	
Food, beverage, and tobacco	3	11,387	10,000	16,317	13,750	43.3
Chemical, pharmaceutical, and allied products	1	41,250	41,250	56,759	56,759	37.6
Other general manufacturing	1	76,500	76,500	122,946	122,946	60.7
Oil and gas	2	32,050	32,050	41,300	41,300	28.9
Primary industries	5	23,560	22,000	28,120	24,000	19.4
Transportation and utilities	8	13,663	10,000	18,554	14,725	35.8
Financial services, real estate, and holding	14	22,655	16,500	26,604	19,500	17.4
Communications and telecommunications	1	23,000	23,000	37,000	37,000	60.9
Business/professional services	1	8,500	8,500	16,375	16,375	92.6
Construction and construction products	2	23,240	23,240	27,000	27,000	16.2
Health and education	2	823	823	1,040	1,040	26.4
Government/not for profit	4	5,638	3,150	8,793	5,350	56.0
Trade (wholesale/retail)	3	9,862	6,512	12,723	10,560	29.0
Other	1	17,000	17,000	17,000	17,000	0
Overall	*48*	*18,939*	*15,750*	*24,428*	*15,750*	*29.0*

Source: The Conference Board of Canada.

Chart 4
Method of Payment to Outside Directors for Regular Board Service
(n=139; percentage of respondents)



*These organizations pay various combinations of retainers, meeting fees, or per diems, plus additional compensation such as travel and preparation time; money to buy shares, and out-of-province attendance premiums.
Source: The Conference Board of Canada.

of the average value of potential compensation. The remaining 22 per cent of the potential compensation mix, such as per-meeting fees and per diems, is based on attendance.

COMPENSATION OF INSIDE DIRECTORS

Only 9 per cent of responding organizations compensate inside directors for regular board service. The most common method of compensating inside directors is by an annual retainer.

The annual compensation to inside directors averages $25,936.

1 Organizations by revenue size (in $ millions): Small (under $150), Medium ($150–$1,000), Large (over $1,000). Organizations by asset size (in $ millions): Small (under $150), Medium ($150–$2,000), Large (over $2,000).

2 For the purpose of this study, "total annual potential compensation" or "annual compensation" is defined as compensation received in any form: a per-meeting fee and/or per diem, a retainer, or any combination of these. Attendance at all meetings is assumed. For example, when a firm pays an annual retainer and a per-meeting fee, the total annual compensation is calculated as the per-meeting fee times the number of meetings plus the annual retainer. This figure, as well as the other estimates of total annual potential compensation, has been calculated by The Conference Board of Canada.

CHAPTER 3

Use of Stock

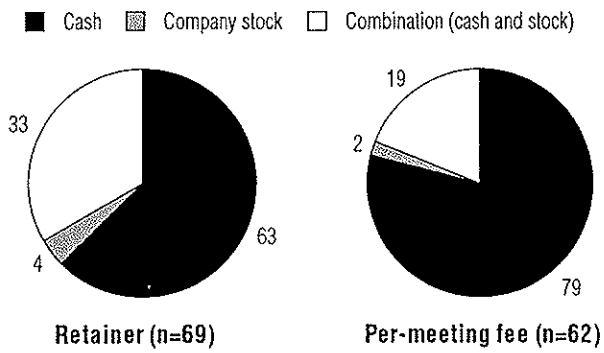
The interest in and promotion of stock as an element of outside director compensation continues to increase.[1] Ninety-one per cent (up from 85 per cent two years ago) of all publicly traded responding firms (n=77) promote stock ownership by means of compensation in the form of stock, equity ownership programs, or guidelines regarding stock ownership. Directors in the majority of publicly traded companies hold shares. In 97 per cent of responding firms with publicly traded shares, at least one director holds shares, while, on average, 88 per cent of directors on these boards currently hold shares (see Table 9). Seventy-two per cent reported that all directors on their boards were shareholders.

Table 9
Prevalence of Stock by Percentage
(n=76; percentage of publicly traded companies)

Where directors receive some or all of retainer/fee in stock	33
Where at least one director holds shares	97
Where all directors hold shares	72
Outside directors who hold shares	88

Source: The Conference Board of Canada.

Chart 5
Form of Compensation for Regular Board Service, by Method of Payment
(n=76; percentage of publicly traded companies)



Source: The Conference Board of Canada.

STOCK AS COMPENSATION

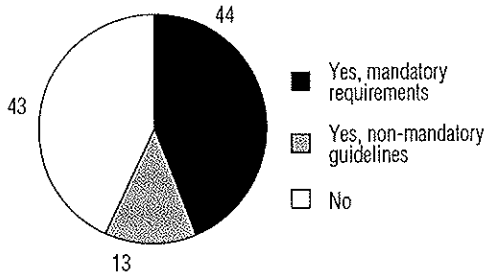
Organizations are using stock in combination with cash to a slightly lesser degree to compensate outside directors for regular board service. Overall, directors in 37 per cent of publicly traded organizations receive all or part of their retainers or fees in company stock, down from 46 per cent in 2000 and 39 per cent in 1998. The decreased use of stock as compensation may be partly due to the use of deferred share units by some organizations in conjunction with cash fees. Retainers are more likely to be paid entirely or in part in stock rather than by per-meeting fees and/or per diems (see Chart 5).

STOCK OWNERSHIP PROGRAMS

The number of organizations reporting either mandatory (44 per cent) or non-mandatory (13 per cent) stock ownership guidelines has increased to 57 per cent of the responding organizations, up from 36 per cent in 2000 (see Chart 6). The majority of these stock guidelines outline requirements regarding the minimum number or value of shares to be held, the length of time allowed to fulfill these requirements, and the length of time that shares must be held. Shares to be held range in number from 1 to 250,000 (the median is 4,000) or two to six times the annual retainer. Directors are typically given 1 to 10 years (the median is 2.5 years) to fulfill these requirements and must hold their shares for the duration of the directorship.

In addition to their retainers and fees, outside directors in almost two-thirds of publicly traded organizations are eligible for stock options either through an employee stock option plan (39 per cent) or through a separate plan for directors (24 per cent). Of those organizations whose outside directors are eligible to receive options through an employee or director plan, in 60 per cent of cases all outside directors received options during the past two years, while in 22 per cent of organizations some outside directors received options.

Chart 6
Share Ownership Guidelines for Outside Directors
(n=68; percentage of respondents)

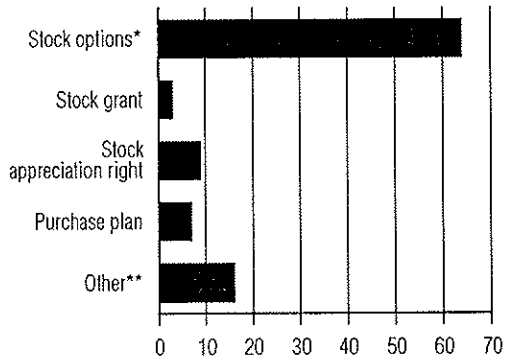


Source: The Conference Board of Canada.

To facilitate the ownership of stock by directors, organizations may offer formal assistance. This can take the form of the direction of retainers or fees towards purchasing stock (24 organizations); company matching of acquired shares (3 organizations); waiving of brokerage fees (5 organizations); a discount applied to purchase prices (3 organizations); and interest-free or low-rate loans (3 organizations). Thirty-seven per cent of publicly traded organizations do not assist directors to acquire stock.

Stock options remain by far the most popular type of stock ownership program. They are offered in 64 per cent of publicly traded firms (up from 60 per cent two years ago). Other forms of equity-based plans include stock grants, share appreciation rights, purchase plans, and other equity plans, including dividend reinvestment plans and deferred share units (see Chart 7).

Chart 7
Type of Stock Plan in Place
(n=76; percentage of publicly traded companies)



*Awarded through the employee stock plan (n=26) and/or through a separate plan for directors (n=16).
**Other equity plans include dividend reinvestment plan and deferred share units.
Source: The Conference Board of Canada.

1 Figures in this chapter refer to publicly traded companies. Privately held organizations that reported some share activity were excluded.

CHAPTER 4

Committee Service

The use of committees of boards of directors is widespread.[1] Ninety-eight per cent of respondents reported having at least one committee (see Table 10). The finance/audit committee is the most commonly reported standing committee of the board, followed by the governance committee (see Chart 8). Over one-third of these organizations indicate that some committees are tasked with multiple functions. For example, organizations frequently combine the nomination and governance and the human resources and compensation functions.

On average, a board has four committees in place. Outside director participation in committee activity is high, with 95 per cent of all outside directors serving on at least one committee. On average, a director sits on two committees.

Table 10
Profile of Committee Activity
(n=158)

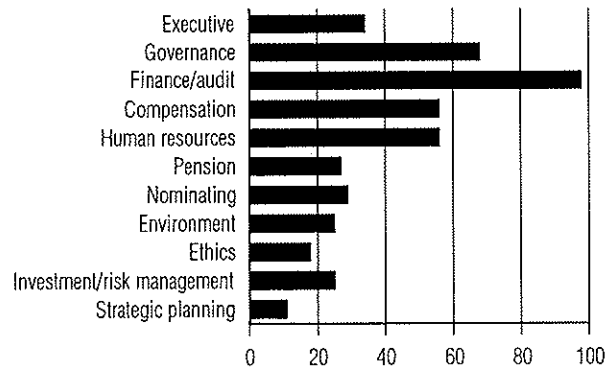
Firms with committees	98%
Number of committees	
1–2	15%
3–4	51%
5–6	23%
7+	10%
Average number of committees	4
Average number of directors on a committee	10
Average number of committees a director sits on	2

Source: The Conference Board of Canada.

COMPENSATING OUTSIDE DIRECTORS FOR COMMITTEE SERVICE

Most firms (82 per cent) compensate outside directors for committee service in addition to any compensation for regular board service. The most prevalent method of payment across all committees is a per-meeting fee of $1,000 or per-diem fee of $485. The most common retainer is $3,000.

Chart 8
Prevalence of Committees, by Type
(n=158; percentage of firms with committees)



Source: The Conference Board of Canada.

The average potential compensation for outside directors for committee service varies depending upon the committee on which they serve and the number of meetings per year. Members of the investment/risk management, finance/audit, and nominating committees receive the highest potential compensation. On average, this ranges from $7,045 for investment/risk management committee members to $3,795 for strategic planning committee members. Tables 11 and 12 highlight the compensation received by committee members depending on the type of committee on which they sit.

COMPENSATING INSIDE DIRECTORS FOR COMMITTEE SERVICE

The majority of inside directors who serve on committees are not compensated for committee service; only 9 per cent of firms with inside directors on committees provide such compensation. When inside directors are compensated, they are generally paid at the same rate as outside directors.

Table 11
Incidence of Outside Directors Who Are Paid for Committee Service and Method of Payment, by Committee

Committee	No. of organizations with this committee	No. of organizations with paid outside directors*	No. (and %) by method of payment							
			Retainer only		Per-meeting fee only		Per diem only		Combination	
Executive	53	29	3	(13)	10	(42)	6	(25)	5	(21)
Governance	108	86	4	(5)	44	(53)	14	(17)	21	(25)
Finance/audit	154	118	6	(5)	61	(54)	18	(16)	28	(25)
Compensation	89	68	5	(8)	34	(52)	8	(12)	19	(29)
Human resources	88	68	4	(6)	35	(53)	10	(15)	17	(26)
Pension	42	26	2	(8)	11	(42)	6	(23)	7	(27)
Nominating	45	29	1	(3)	18	(62)	2	(7)	8	(28)
Environment	40	32	1	(3)	17	(53)	2	(6)	12	(38)
Ethics	29	19	0	(0)	12	(67)	3	(17)	3	(17)
Investment/risk management	39	26	0	(0)	15	(63)	4	(17)	5	(21)
Strategic planning	18	10	0	(0)	7	(70)	2	(20)	1	(10)

*The total number of organizations reported on for method of payment differs from the number with paid outside directors due to incomplete data provided by respondents.
Source: The Conference Board of Canada.

Table 12
Annual Compensation of Outside Directors for Committee Service, by Committee

	Mean no. of annual committee meetings	Firms paying retainer		Firms paying per-meeting fee		Firms paying per-diem fee		Total potential compensation		
		No.	Median ($)	No.	Median ($)	No.	Median ($)	No.	Median ($)	Mean ($)
Executive	5	9	3,000	14	875	8	485	18	2,963	4,965
Governance	4	25	3,000	63	1,000	16	493	71	3,000	4,991
Finance/audit	5	34	3,000	86	1,000	22	430	101	4,000	5,632
Compensation	3	24	3,000	52	1,000	11	625	56	3,000	4,814
Human resources	4	21	3,000	51	1,000	12	493	58	3,825	5,375
Pension	4	9	3,000	17	1,200	7	485	21	3,750	4,996
Nominating	4	9	3,500	26	1,000	2	463	23	2,400	5,436
Environment	4	13	3,000	29	1,000	3	330	27	3,200	5,119
Ethics	4	3	3,000	15	1,200	3	300	15	2,400	4,781
Investment/risk management	7	5	5,000	20	1,000	5	300	21	4,000	7,045
Strategic planning	4	1	5,450	8	575	3	500	8	1,500	3,795

Source: The Conference Board of Canada.

COMPENSATING COMMITTEE CHAIRPERSONS

Seventy-nine per cent of all committees have a chairperson. The human resources, nominating, environment, and ethics committees are all chaired entirely by outside and/or fully independent directors. The percentage of fully independent directors chairing the board committees ranges from 35 per cent for the executive committees to 62 per cent for the nominating committees. In comparison, the percentage of inside director chairpersons is low. It is highest for the executive committees, at 15 per cent.

Additional compensation to committee chairpersons solely for these duties varies by type of committee (see Table 13). For example, 77 per cent of respondents paid a premium to the chairperson of the finance/audit committee, whereas 7 per cent paid a premium to the strategic planning committee chairperson.

The most common form of payment for committee chairs is an additional annual retainer, with the majority of organizations paying a standard retainer of $3,000. For organizations paying a per-meeting fee, the standard fee is $675, and for organizations paying a per-diem fee, the standard fee is $183.

Table 13
Annual Compensation of Committee Chairpersons, by Committee

	No. of firms with committee chairs	Firms paying premium to chairperson (%)	Retainer only		Per-meeting fee only		Per-diem fee only		Combination	
			No.	%	No.	%	No.	%	No.	%
Executive	41	13	8	73	0	—	1	10	2	18
Governance	90	66	52	81	6	9	2	3	4	6
Finance/audit	131	88	64	73	9	10	3	4	12	14
Compensation	69	49	36	79	4	8	3	7	6	12
Human resources	70	51	38	79	4	8	1	2	5	10
Pension	31	23	19	86	2	9	0	—	1	5
Nominating	33	14	12	86	0	—	0	—	2	14
Environment	29	26	20	80	3	12	0	—	2	8
Ethics	21	13	10	77	1	8	1	8	1	8
Investment/risk management	30	16	13	87	1	7	0	—	1	7
Strategic planning	12	7	7	100	0	—	0	—	0	—

	Firms paying retainer			Firms paying per-meeting fee			Firms paying per-diem fee		
	No.	Median	Mean	No.	Median	Mean	No.	Median	Mean
Executive	10	4,000	4,277	1	1,000	1,000	2	300	300
Governance	58	3,000	4,528	11	500	589	2	81	81
Finance/audit	77	3,000	4,760	20	675	676	4	183	190
Compensation	42	3,000	4,763	10	675	655	3	116	137
Human resources	44	3,000	4,786	9	500	617	1	116	116
Pension	20	3,000	4,396	3	375	475	0	—	—
Nominating	14	3,000	5,200	2	750	750	0	—	—
Environment	22	3,000	3,624	5	100	335	0	—	—
Ethics	11	5,000	5,426	2	1,250	1,250	1	250	250
Investment/risk management	14	5,000	5,532	2	688	688	0	—	—
Strategic planning	7	4,000	4,457	0	—	—	0	—	—

Source: The Conference Board of Canada.

1 "Committees" include only those consisting entirely of directors.

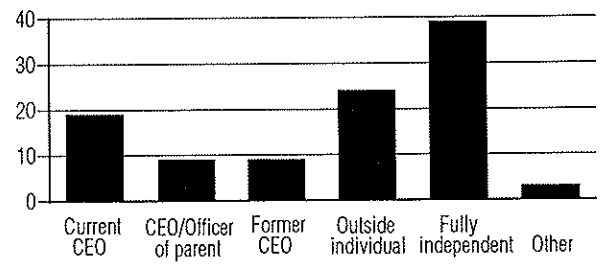
CHAPTER 5

Board Chairpersons

In keeping with governance guidelines, the prevalence of related chairs, particularly with respect to current chief executive officers (CEOs), has decreased since 2000. As illustrated in Chart 9, 24 per cent of board chairpersons are outside individuals, another 39 per cent are fully independent, 19 per cent are the current CEO (down from 31 per cent in 2000), 9 per cent are the former CEO, and 9 per cent are officers of the organization's parent company. Sixty-six per cent of board chairpersons serve on a part-time basis.

Almost two-thirds of the respondents (65 per cent) compensate chairpersons separately for board-chairing duties; however, this varies significantly depending on the category of chairperson as defined in the survey. While 82 per cent of organizations pay additional compensation to chairpersons who are outside or fully independent individuals, very few organizations provide additional compensation for a chairperson who is also the CEO. Seventy-seven per cent of former-CEO chairpersons are paid a premium. Part-time chairpersons are more likely to receive a premium for chairing than are full-time chairpersons. For those chairpersons of the 90 organizations that pay additional compensation for chairing the board, this amount ranges widely, from $1,000 to $560,268 (see Table 14).

Chart 9
Description of Chair
(n=151; percentage of respondents)



Source: The Conference Board of Canada.

Table 14
Compensation of Board Chairpersons
(n=140)

		Additional pay to chair		Amount ($)		
	No.	No.	%	Mean	Median	Range
Current CEO	29	2	7	*	*	*
CEO/officer of parent**	10	6	60	111,625	55,000	1,500–335,000
Former CEO	13	10	77	108,576	95,000	24,000–311,260
Outside individual	36	21	58	53,662	16,000	2,000–150,000
Fully independent	59	48	81	80,985	27,500	1,000–560,268
Other	4	3	75	*	*	*

*Too few responses to report (not all organizations that pay the chair reported an amount).
**One organization reported its additional pay to the chair in deferred share units ($1,000,000,000). This was excluded from the calculation.
Source: The Conference Board of Canada.

CHAPTER 6

Assessment of Board Members

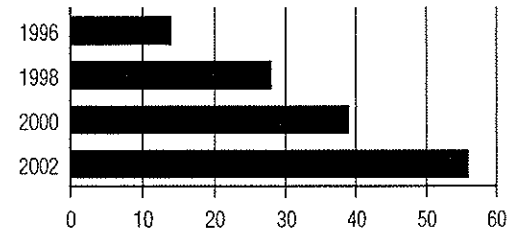
Organizations are focusing increasingly on the effectiveness and assessment of the board and its members. In particular, there have been significant increases since 2000 in the prevalence of position descriptions (see Chart 10), formal written limits to authority levels, and formal orientation programs, as well as performance evaluations for the board as a whole and for individual members (see Chart 11). The percentage of organizations conducting CEO performance evaluations remains high, at 91 per cent (see Table 15).

Table 15
Assessment and Evaluation of CEO and Board Members
(percentage of respondents)

	CEO	Board as a whole	Directors	Committee members
Position description/mandate statement in place	85	87	56	99
Formal written limits to authority levels	85	58	33	61
Formal orientation program in place	38	55	77	42
Formal education program in place	14	40	25	25
Performance evaluation conducted	91	92	49	73
Compensation affected by evaluation results	83	6	4	2
Reappointment affected by evaluation results	64	n.a.	33	36

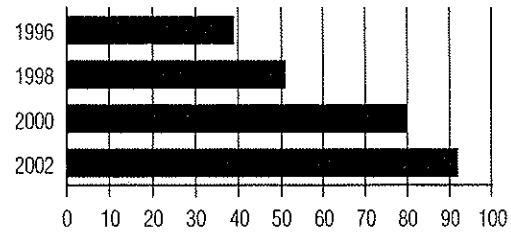
n.a. = not applicable
Source: The Conference Board of Canada.

Chart 10
Position Descriptions in Place for Directors
(percentage of respondents)



Source: The Conference Board of Canada.

Chart 11
Evaluation in Place of Board Performance
(percentage of respondents)



Source: The Conference Board of Canada.

APPENDIX 1

A Comparison of the Public and Private Sectors

Comparison of Private Sector Companies and Public Sector Corporations

	Private sector companies (n=101)	Not-for-profit companies (n=18)	Public sector corporations (n=43)
Mean board size	11	19	11
Number of meetings per year	6	7	8
Percentage of inside directors paid	12	6	7
Percentage of outside directors paid	97	53	85
Mean compensation paid to outside directors	$27,509	$14,836	$8,108
Percentage paying outside directors for committee service	88	56	78
Percentage with women directors	64	100	95

Comparison of Publicly Traded Corporations and Privately Held Companies

	Publicly traded (n=77)	Privately held (n=85)
Mean board size	11	13
Number of meetings per year	6	8
Percentage of inside directors paid	11	9
Percentage of outside directors paid	99	80
Mean compensation paid to outside directors	$30,624	$11,770
Percentage paying outside directors for committee service	89	74
Percentage with women directors	59	92

Source: The Conference Board of Canada.

APPENDIX 2

Annual Compensation of Outside Directors for Regular Board Services

Annual Compensation of Outside Directors for Regular Board Services, by Individual Company, 2000 and 2002

		2000					2002				
Industry & company	Size*	No. of meetings	Annual retainer ($)	Per-meeting fee ($)	Per-diem fee ($)	Potential compen-sation ($)	No. of meetings	Annual retainer ($)	Per-meeting fee ($)	Per-diem fee ($)	Potential compen-sation ($)
Food, beverage, and tobacco											
1	Small	12	—	—	180	2,160	12	2,500	225	—	5,200
2	Small	5	5,000	1,000	—	10,000	5	7,500	1,250	—	13,750
3	Large	4	18,000	1,000	—	22,000	4	25,000	1,250	—	30,000
Mean	*1,500*	*7*	*11,500*	*1,000*	*180*	*11,387*	*7*	*11,667*	*908*	—	*16,317*
Median	*102*	*5*	*11,500*	*1,000*	*180*	*10,000*	*5*	*7,500*	*1,250*	—	*13,750*
Chemical, pharmaceutical, and allied products											
1	Small	—	—	—	—	—	4	7,500	500	—	9,500
2	Small	—	—	—	—	—	8	10,000	1,000	—	18,000
3	Medium	1	—	—	—	—	4	3,000	—	—	3,000
4	Medium	—	—	—	—	—	6	15,000	1,000	—	21,000
5	Medium	5	33,750	—	1,500	41,250	7	35,017	1,553	1,553	56,759
Mean	*417*	*3*	*33,750*	—	*1,500*	*41,250*	*6*	*14,103*	*1,013*	*1,553*	*21,652*
Median	*446*	*3*	*33,750*	—	*1,500*	*41,250*	*6*	*10,000*	*1,000*	*1,553*	*18,000*
Other general manufacturing											
1	Small	—	—	—	—	—	4	5,000	500	—	7,000
2	Small	—	—	—	—	—	5	12,000	1,000	—	17,000
3	Small	—	—	—	—	—	7	15,000	1,000	—	22,000
4	Medium	—	—	—	—	—	4	10,000	1,000	—	14,000
5	Medium	—	—	—	—	—	5	10,000	1,000	—	15,000
6	Medium	—	—	—	—	—	6	22,500	1,000	1,000	34,500
7	Medium	—	—	—	—	—	4	47,500	1,250	—	52,500
8	Large	—	—	—	—	—	5	20,000	1,000	—	25,000
9	Large	—	—	—	—	—	8	100,000	—	—	100,000
10	Large	6	60,000	2,250	—	76,500	6	77,815	2,334	4,669	122,946
Mean	*4,398*	*6*	*60,000*	*2,250*	—	*76,500*	*5*	*31,982*	*1,120*	*2,835*	*40,995*
Median	*344*	*6*	*60,000*	*2,250*	—	*76,500*	*5*	*17,500*	*1,000*	*2,835*	*23,500*
Oil and gas											
1	Medium	—	—	—	—	—	4	4,000	1,000	—	8,000
2	Medium	—	—	—	—	—	4	11,000	1,000	—	15,000
3	Medium	—	—	—	—	—	5	15,000	500	—	17,500
4	Large	—	—	—	—	—	7	35,000	—	—	35,000
5	Large	5	28,100	1,800	—	37,100	5	28,100	1,800	—	37,100
6	Large	—	—	—	—	—	7	30,000	1,500	—	40,500
7	Large	7	20,000	1,000	—	27,000	7	35,000	1,500	—	45,500
Mean	*4,835*	*6*	*24,050*	*1,400*	—	*32,050*	*6*	*22,586*	*1,217*	—	*28,371*
Median	*5,325*	*6*	*24,050*	*1,400*	—	*32,050*	*5*	*28,100*	*1,250*	—	*35,000*

*Asset-size categories are (in $ millions): Small (under $150), Medium ($150–$2,000), Large (over $2,000).
Mean and median figures are in $ millions.

Industry & company	Size*	2000 No. of meetings	2000 Annual retainer ($)	2000 Per-meeting fee ($)	2000 Per-diem fee ($)	2000 Potential compensation ($)	2002 No. of meetings	2002 Annual retainer ($)	2002 Per-meeting fee ($)	2002 Per-diem fee ($)	2002 Potential compensation ($)
Primary industries											
1	Small	—	—	—	—	—	9	6,000	600	—	11,400
2	Small	—	—	—	—	—	6	10,000	750	—	14,500
3	Medium	—	—	—	—	—	5	10,000	1,000	1,000	20,000
4	Large	7	15,000	1,000	—	22,000	7	15,000	1,000	—	22,000
5	Large	5	10,000	1,500	—	17,500	5	15,000	1,500	—	22,500
6	Large	4	14,000	1,000	—	18,000	4	20,000	1,000	—	24,000
7	Large	—	—	—	—	—	6	25,000	1,500	—	34,000
8	Large	7	24,000	1,500	—	34,500	7	24,000	1,500	—	34,500
9	Large	9	15,000	1,200	—	25,800	8	18,000	1,200	—	37,600
Mean	*2,760*	*6*	*15,600*	*1,240*	—	*23,560*	*6*	*15,889*	*1,117*	*1,000*	*24,500*
Median	*2,900*	*7*	*15,000*	*1,200*	—	*22,000*	*6*	*15,000*	*1,000*	*1,000*	*22,500*
Transportation and utilities											
1	Small	—	—	—	—	—	8	7,000	400	—	10,200
2	Small	—	—	—	—	—	7	25,000	900	—	31,300
3	Small	—	—	—	—	—	52	—	—	—	—
4	Medium	6	2,500	250	—	4,000	6	2,500	250	—	4,000
5	Medium	—	—	—	—	—	5	4,700	310	310	7,800
6	Medium	—	—	—	—	—	10	8,000	400	—	12,000
7	Medium	—	—	—	—	—	5	8,000	600	—	12,000
8	Medium	—	—	—	—	—	4	11,000	800	—	14,200
9	Medium	—	—	—	—	—	5	10,000	1,000	—	15,000
10	Medium	—	—	—	—	—	5	15,000	—	750	18,750
11	Medium	—	—	—	—	—	4	17,000	1,100	—	21,400
12	Medium	—	—	—	—	—	10	15,000	1,000	—	25,000
13	Medium	6	8,000	900	—	13,400	20	8,000	900	—	26,000
14	Medium	—	—	—	—	—	6	—	—	—	—
15	Medium	—	—	—	—	—	4	—	—	—	—
16	Large	9	7,502	—	—	7,502	9	7,500	—	—	7,500
17	Large	8	6,000	500	—	10,000	6	6,500	550	—	9,800
18	Large	8	6,000	—	500	10,000	9	6,500	550	—	11,450
19	Large	8	3,000	—	300	5,400	4	15,000	—	750	18,000
20	Large	—	—	—	—	—	8	—	1,500	1,500	24,000
21	Large	6	17,500	1,250	—	27,000	6	17,500	1,250	—	25,000
22	Large	—	—	—	—	—	6	18,000	1,200	—	25,200
23	Large	—	—	—	—	—	6	20,000	1,000	—	26,000
24	Large	10	10,000	1,000	1,200	32,000	10	15,563	1,556	1,556	46,683
25	Large	10	—	—	—	—	10	—	—	—	—
Mean	*4,860*	*8*	*7,563*	*780*	*667*	*13,663*	*9*	*11,888*	*848*	*973*	*18,633*
Median	*1,000*	*8*	*6,751*	*900*	*500*	*10,000*	*6*	*10,500*	*900*	*750*	*18,000*
High technology											
1	Small	—	—	—	—	—	4	8,000	1,200	—	12,800
2	Medium	—	—	—	—	—	4	10,000	1,000	—	14,000
3	Medium	—	—	—	—	—	6	25,000	1,000	—	37,000
Mean	*445*	—	—	—	—	—	*5*	*14,333*	*1,067*	—	*21,267*
Median	*500*	—	—	—	—	—	*4*	*10,000*	*1,000*	—	*14,000*

*Asset-size categories are (in $ millions): Small (under $150), Medium ($150–$2,000), Large (over $2,000).
Mean and median figures are in $ millions.

Industry & company	Size*	2000 No. of meetings	2000 Annual retainer ($)	2000 Per-meeting fee ($)	2000 Per-diem fee ($)	2000 Potential compen-sation ($)	2002 No. of meetings	2002 Annual retainer ($)	2002 Per-meeting fee ($)	2002 Per-diem fee ($)	2002 Potential compen-sation ($)
Financial services, real estate, and holding											
1	Small	—	—	—	—	—	5	—	—	300	1,500
2	Small	—	—	—	—	—	6	5,400	—	375	7,650
3	Small	—	—	—	—	—	6	7,200	—	500	10,200
4	Small	5	8,600	750	—	12,350	5	9,200	750	—	12,950
5	Small	—	—	—	—	—	8	8,000	—	625	13,000
6	Small	—	—	—	—	—	4	54,471	1,556	—	60,695
7	Small	—	—	—	—	—	4	—	—	—	—
8	Small	—	—	—	—	—	4	—	—	—	—
9	Medium	10	3,000	—	250	5,500	9	3,000	250	—	5,250
10	Medium	—	—	—	—	—	10	6,200	20	—	6,400
11	Medium	8	4,500	—	375	7,500	8	4,500	—	375	7,313
12	Medium	—	—	—	—	—	4	7,500	—	—	7,500
13	Medium	—	—	—	—	—	13	5,200	175	250	10,725
14	Medium	4	15,000	1,000	—	19,000	4	15,000	1,000	—	19,000
15	Medium	4	16,000	—	—	16,000	4	16,000	—	4,000	32,000
16	Medium	—	—	—	—	—	10	30,000	1,250	—	42,500
17	Medium	8	30,000	2,000	—	47,000	9	30,000	2,000	—	48,000
18	Medium	10	47,000	2,000	—	67,000	15	22,000	2,000	—	77,000
19	Medium	—	—	—	—	—	5	—	—	—	—
20	Medium	—	—	—	—	—	5	—	—	—	—
21	Large	—	—	—	—	—	7	—	—	260	1,820
22	Large	—	—	—	—	—	5	—	650	—	3,250
23	Large	—	—	—	—	—	9	5,000	450	—	9,050
24	Large	7	4,500	375	—	7,125	7	6,200	—	485	9,595
25	Large	6	5,000	500	—	8,000	6	5,000	500	500	11,000
26	Large	10	2,500	—	300	5,500	10	6,200	—	485	11,050
27	Large	—	—	—	—	—	6	12,000	—	500	15,000
28	Large	—	—	—	—	—	4	11,500	1,000	—	15,500
29	Large	—	—	—	—	—	6	9,000	700	—	18,800
30	Large	4	13,000	1,000	—	17,000	4	16,000	1,000	—	20,000
31	Large	—	—	—	—	—	6	15,000	—	1,000	21,000
32	Large	8	15,000	1,000	—	23,000	9	20,000	1,200	—	30,800
33	Large	—	—	—	—	—	4	27,500	1,500	—	33,500
34	Large	10	30,000	1,500	—	45,000	9	30,000	1,500	—	43,500
35	Large	11	24,000	1,200	—	37,200	10	30,000	1,500	—	45,000
36	Large	—	—	—	—	—	12	—	—	—	—
37	Large	4	—	—	—	—	4	—	—	—	—
Mean	*13,156*	*7*	*15,579*	*944*	*308*	*22,655*	*7*	*14,895*	*1,000*	*743*	*20,985*
Median	*1,176*	*8*	*14,000*	*1,000*	*300*	*16,500*	*6*	*10,350*	*1,000*	*485*	*13,000*
Communications and telecommunications											
1	Small	—	—	—	—	—	4	20,000	1,500	—	26,000
2	Medium	—	—	—	—	—	8	8,000	625	—	13,000
3	Medium	—	—	—	—	—	5	12,000	1,000	—	17,000
4	Medium	—	—	—	—	—	7	18,000	1,000	—	25,000
5	Medium	—	—	—	—	—	5	25,000	1,500	—	32,500
6	Medium	—	—	—	—	—	7	25,000	1,500	—	35,500
7	Medium	—	—	—	—	—	10	—	—	—	—
8	Large	—	—	—	—	—	8	10,000	—	800	16,400
9	Large	8	15,000	1,000	—	23,000	8	25,000	1,500	—	37,000
10	Large	—	—	—	—	—	26	77,815	—	—	77,815
Mean	*4,038*	*8*	*15,000*	*1,000*	—	*23,000*	*9*	*24,535*	*1,232*	*800*	*31,135*
Median	*1,225*	*8*	*15,000*	*1,000*	—	*23,000*	*8*	*20,000*	*1,500*	*800*	*26,000*

*Asset-size categories are (in $ millions): Small (under $150), Medium ($150–$2,000), Large (over $2,000).
Mean and median figures are in $ millions.

Industry & company	Size*	2000 No. of meetings	2000 Annual retainer ($)	2000 Per-meeting fee ($)	2000 Per-diem fee ($)	2000 Potential compensation ($)	2002 No. of meetings	2002 Annual retainer ($)	2002 Per-meeting fee ($)	2002 Per-diem fee ($)	2002 Potential compensation ($)
Business/professional services											
1	Small	—	—	—	—	—	4	5,000	600	—	7,400
2	Small	—	—	—	—	—	6	2,500	1,000	—	8,500
3	Small	—	—	—	—	—	6	8,000	—	250	9,500
4	Small	—	—	—	—	—	4	10,000	800	—	13,200
5	Small	—	—	—	—	—	5	12,000	1,000	—	17,000
6	Small	—	—	—	—	—	4	15,000	1,000	—	19,000
7	Small	—	—	—	—	—	8	20,000	1,000	500	32,000
8	Small	—	—	—	—	—	10	—	—	—	—
9	Medium	—	—	—	—	—	4	4,700	—	375	6,200
10	Medium	—	—	—	—	—	4	10,000	—	250	11,000
11	Medium	10	6,000	—	250	8,500	5	10,750	750	375	16,375
12	Medium	—	—	—	—	—	4	—	—	—	—
Mean	*332*	*10*	*6,000*	—	*250*	*8,500*	*5*	*9,795*	*879*	*350*	*14,018*
Median	*82*	*10*	*6,000*	—	*250*	*8,500*	*5*	*10,000*	*1,000*	*375*	*12,100*
Construction and construction products											
1	Small	4	9,200	320	—	10,480	5	13,000	1,000	—	18,000
2	Small	—	—	—	—	—	6	25,000	1,250	—	32,500
3	Medium	4	30,000	1,500	—	36,000	4	30,000	1,500	—	36,000
4	Large	—	—	—	—	—	4	17,500	1,350	—	22,900
5	Large	—	—	—	—	—	5	20,000	1,500	—	27,500
Mean	*1,161*	*4*	*19,600*	*910*	—	*23,240*	*5*	*21,100*	*1,320*	—	*27,380*
Median	*140*	*4*	*19,600*	*910*	—	*23,240*	*5*	*20,000*	*1,350*	—	*27,500*
Health and education											
1	Small	—	—	—	—	—	8	—	—	275	2,200
2	Small	—	—	—	—	—	6	—	—	—	—
3	Small	—	—	—	—	—	4	—	—	—	—
4	Medium	7	—	—	—	145	4	—	—	145	580
5	Medium	10	—	—	150	1,500	10	—	—	150	1,500
6	Medium	—	—	—	—	—	11	—	—	200	2,200
7	Medium	—	—	—	—	—	7	—	—	750	5,250
8	Medium	—	—	—	—	—	5	—	—	—	—
9	Medium	—	—	—	—	—	10	—	—	—	—
10	Medium	—	—	—	—	—	9	—	—	—	—
11	Large	—	—	—	—	—	11	—	—	425	4,675
Mean	*740*	*9*	—	—	*150*	*823*	*8*	—	—	*324*	*2,734*
Median	*445*	*9*	—	—	*150*	*823*	*8*	—	—	*238*	*2,200*
Government/not for profit											
1	Small	3	—	—	250	750	3	—	—	390	1,170
2	Small	6	—	—	300	1,800	6	1,500	—	300	3,300
3	Small	—	—	—	—	—	8	2,500	—	250	4,500
4	Small	—	—	—	—	—	10	3,500	250	—	6,000
5	Small	—	—	—	—	—	11	3,400	—	260	6,260
6	Small	5	3,000	—	300	4,500	4	6,000	—	350	7,400
7	Small	12	14,000	125	—	15,500	12	21,500	150	—	23,300
8	Small	5	—	—	—	—	5	—	—	—	—
9	Small	—	—	—	—	—	4	—	—	—	—
10	Small	—	—	—	—	—	3	—	—	—	—
11	Medium	—	—	—	—	—	5	—	213	—	1,065
12	Medium	—	—	—	—	—	12	—	253	—	3,036
13	Medium	—	—	—	—	—	10	—	—	—	—
14	Medium	—	—	—	—	—	10	—	—	—	—
Mean	*184*	*6*	*8,500*	*125*	*283*	*5,638*	*7*	*6,400*	*217*	*310*	*6,226*
Median	*32*	*5*	*8,500*	*125*	*300*	*3,150*	*7*	*3,450*	*232*	*300*	*4,500*

*Asset-size categories are (in $ millions): Small (under $150), Medium ($150–$2,000), Large (over $2,000).
Mean and median figures are in $ millions.

Industry & company	Size*	2000 No. of meetings	2000 Annual retainer ($)	2000 Per-meeting fee ($)	2000 Per-diem fee ($)	2000 Potential compen-sation ($)	2002 No. of meetings	2002 Annual retainer ($)	2002 Per-meeting fee ($)	2002 Per-diem fee ($)	2002 Potential compen-sation ($)
Trade (wholesale/retail)											
1	Small	15	2,750	155	—	5,075	12	2,750	155	—	4,610
2	Small	—	—	—	—	—	11	7,500	—	—	7,500
3	Medium	10	3,552	—	296	6,512	8	7,920	—	330	10,560
4	Large	5	18,000	—	—	18,000	5	18,000	1,000	—	23,000
5	Large	—	—	—	—	—	8	30,000	1,500	—	42,000
6	Large	—	—	—	—	—	5	50,000	—	—	50,000
7	Large	—	—	—	—	—	9	25,000	1,725	—	53,025
Mean	*2,530*	*10*	*8,101*	*155*	*296*	*9,862*	*8*	*20,167*	*1,095*	*330*	*27,242*
Median	*3,000*	*10*	*3,552*	*155*	*296*	*6,512*	*8*	*18,000*	*1,250*	*330*	*23,000*
Other											
1	Small	—	—	—	—	—	5	5,000	750	—	8,750
2	Small	—	—	—	—	—		25,000	—	—	25,000
3	Medium	5	12,000	1,000	—	17,000	5	12,000	1,000	—	17,000
4	Large	—	—	—	—	—	8	75,000	1,500	—	87,000
Mean	*4,823*	*5*	*12,000*	*1,000*	*—*	*17,000*	*6*	*29,250*	*1,083*	*—*	*34,438*
Median	*437*	*5*	*12,000*	*1,000*	*—*	*17,000*	*5*	*18,500*	*1,000*	*—*	*21,000*
Total											
Mean	***5,042***	***7***	***14,766***	***1,051***	***439***	***18,939***	***7***	***17,025***	***1,005***	***723***	***21,943***
Median	***660***	***7***	***13,000***	***1,000***	***300***	***15,750***	***6***	***12,000***	***1,000***	***408***	***17,000***

*Asset-size categories are (in $ millions): Small (under $150), Medium ($150–$2,000), Large (over $2,000).
Mean and median figures are in $ millions.

APPENDIX 3

Respondents' Profile

Respondents' Profile
(n=162; percentage of respondents)

Industrial Classification		
Food, beverage, and tobacco		2
Chemical, pharmaceutical, and allied products		3
Other general manufacturing		6
Oil and gas		4
Primary industries		6
Transportation and utilities		15
High technology		2
Financial services, real estate, and holding		23
Communications and telecommunications		6
Business/professional services		7
Construction and construction products		3
Health and education		7
Government/not for profit		9
Trade (wholesale/retail)		4
Other		3
Ownership Description		
Widely held publicly traded corporation		31
Closely held (under 100 shareholders) corporation		3
Single-shareholder corporation		7
Significant shareholder (one major)		16
Crown corporation or agency (public enterprise)		26
Co-operative		4
Not for profit		12
Other		1
Size of Firms, by Assets, Revenues, and Number of Employees		
Assets *($ millions)*	Small (under $150)	30
	Medium ($150–$2,000)	38
	Large (over $2,000)	32
	Mean	*5,041*
	Median	*660*
Revenue *($ millions)*	Small (under $150)	34
	Medium ($150–$1,000)	32
	Large (over $1,000)	35
	Mean	*2,150*
	Median	*400*
Number of employees	Fewer than 500	26
	500–1,499	27
	1,500–4,999	28
	5,000 or more	19
Total number of employees		816,144

Source: The Conference Board of Canada.



Yukon Energy Corporation

Review of Job Evaluation and Pay Data For Selected Senior Jobs Final Report

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Proprietary:
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Table of Contents

INTRODUCTION....2

SUMMARY TABLE OF EVALUATIONS – REVISED STRUCTURE....3

NEW GRADE STRUCTURE....4

SUMMARY TABLE OF EVALUATIONS – WITH NO VP OPERATIONS AND ENGINEERING....7

SALARY MARKET DATA AND SALARY RANGES....8

SUMMARY AND NEXT STEPS....11

APPENDIX 1 - RATIONALES....12

APPENDIX 2 – LIST OF COMPANIES IN UTILITIES SECTOR SURVEY....20

Introduction

Yukon Energy has requested Hay Group to conduct a job evaluation and pay data review of selected positions, including the organization's senior leadership roles. There are 2 possible organization structures to consider: one with a new VP Operations and Engineering role added, and one with no change from current structure. This draft final report presents job evaluation results and market pay data for both structure options.

The revised organization structure would have a new role, VP Operations and Engineering, reporting to the CEO, with 3 Directors of Operations, Technical Services and HSE reporting into it. A new position will typically exert a downward pressure on the job sizing of the roles below it, since it represents an additional layer of management, and would take on some of the strategic and longer term aspects of the subordinate roles. These impacts will be considered in the job evaluation section.

YEC has a grade structure with 11 levels in place for jobs up to and including Leadhand position. There is a second grade structure with 5 levels for management and professional jobs. You have asked us to recommend a revised grade structure for the senior jobs which will overlap the lower grades and extend up to the senior levels in a seamless fashion.

Summary Table of Evaluations – Revised Structure

Using the revised organization structure with a VP Operations and Engineering, we have evaluated the 16 job descriptions you provided to us (including an Engineer-in-Training role for which there was no job description). We used the same Hay Guide Chart methodology as was used to evaluate the operational and administrative jobs in July 2005. We included Working Conditions as part of the job size. The jobs are mainly office-based, with occasional work required in the field, and in some cases scheduled work or travel outside regular working hours. We discussed the draft evaluations with you and made some changes to our original lines. The following table summarizes the results of the evaluations. Rationales for the evaluation lines are shown in Appendix 1.

No.	Name	Role Title	Know-How		Problem Solving		Account-ability		Total Hay Pts	Pr	Tot WC	Full Pts
1		President and CEO	G-III3	608	G4 (57)	350	G-3P	528	1486	A3	22	1508
2	Vacant	VP Operations and Engineering	FIII-3	460	F4 (50)	230	F-3P	350	1040	A3	24	1064
3		Chief Financial Officer	FII3	400	F4 (50)	200	F3C	230	830	A1	22	852
4		Director HR & Info Mgmt	FII3	400	E4 (43)	175	F-3C	200	775	A1	22	797
5		Director, Operations	F-II3	350	E4 (43)	152	E2+P	230	732	A3	24	756
6		Director, Technical Services	F-II3	350	E4 (43)	152	E2P	200	702	A2	24	726
7		Dir Resource Plng & Reg Affairs	F-II3	350	E4 (43)	152	E3C+	175	677	A1	22	699
8		Director, Health Safety & Env.	EII-3	264	E3+ (38)	100	E-3C	132	496	A2	24	520
9		Supervisor, Electrical Eng.	EII-3	264	E3+ (38)	100	D2P	132	496	A2	24	520
10		Supervisor, Mech. & Civil Eng.	EII-3	264	E3+ (38)	100	D2P	132	496	A2	24	520
12	Vacant	Manager, Operations	EII-3	264	E3+ (38)	100	D+2S	115	479	A1	24	503
11	Vacant	Supervisor, Financial & R.M.	EII-3	264	E3+ (38)	100	D+3C	115	479	A1	22	501
13		Controller	E-II-3	264	E3 (33)	87	D+3C	115	466	A2	22	488
14		Electrical Design Engineer	EI2	200	D+3 (33)	66	D2C	76	342	A1	24	366
15		Civil Engineer	EI2	200	D+3 (33)	66	D2C	76	342	A1	24	366
16		Supervisor, Communications	EI2	200	D+3 (33)	66	D-2+C	76	342	A1	22	364
17		Engineer in Training	D+I2	175	D3 (29)	50	C+2C	57	282	A1	24	306

New Grade Structure

Yukon Energy has established a grade structure for jobs up to and including Leadhand position. This covers 11 grades, and has Hay points associated with each grade. The structure looks as follows:

Level	Min Hay Points	Max Hay Points
1	83	97
2	98	115
3	116	136
4	137	160
5	161	188
6	189	221
7	222	260
8	261	305
9	306	358
10	359	420
11	421	493

This grade structure is based on single Hay steps, which is typical for jobs at this level. It increases as a geometric progression in 17% steps, and is the smallest grade width you would expect to find. For the jobs above this level, the single step grades could be continued, or we could move to a 2 step grade structure. The advantage of 2 steps per grade is that there are fewer, broader grades, making it easier to slot jobs into the structure, and giving more room to advance jobholders through the salary band without having to promote them to the next grade. It takes the emphasis off of the grading of jobs and puts it more onto managing performance as jobholders progress through a broader band.

For reasons of simplicity and consistency we would recommend that the existing single step grade structure be used as the basis for extending the levels to capture all jobs in the organization. This may require small changes to some of the boundaries in the current 11 grades, but not sufficient to change any existing job grades. An additional 5 grades will be needed to cover jobs up to and including Director/VP level. If the CEO role is included, an additional 7 levels are needed. The revised grade structure would look as follows:

Level	Min Hay Pts	Max Hay Pts
1	83	97
2	98	115
3	116	136
4	137	160
5	161	188
6	189	221
7	222	260
8	261	305
9	306	358
10	359	412
11	413	472
12	473	557
13	558	657
14	658	779
15	780	929
16	930	1084
17	1085	1275
18	1276	1512

Existing grades 10 and 11 have been shortened at the top end from 420 to 412 and from 493 to 472 respectively. This should not be a problem for the negotiated settlement since it means that individual jobs can progress more

rapidly to the next level than previously. In practice, this should not happen often since there will be few jobs evaluated between these 2 thin slices.

We would recommend that the CEO role not be included in the structure as it is a one-off role that will not have any other jobs in the same grade. This would leave 16 grades to cover the whole organization from top to bottom.

No.	Name	Role Title	Full Pts	New Grade
1		President and CEO	1508	18
2	Vacant	VP Operations and Engineering	1064	16
3		Chief Financial Officer	852	15
4		Director HR & Info Mgmt	797	15
5		Director, Operations	756	14
6		Director, Technical Services	726	14
7		Dir Resource Plng & Reg Affairs	699	14
8		Director, Health Safety & Env.	520	12
9		Supervisor, Electrical Eng.	520	12
10		Supervisor, Mech. & Civil Eng.	520	12
12	Vacant	Manager, Operations	503	12
11	Vacant	Supervisor, Financial & R.M.	501	12
13		Controller	488	12
14		Electrical Design Engineer	366	10
15		Civil Engineer	366	10
16		Supervisor, Communications	364	10
17		Engineer in Training	306	9

Summary Table of Evaluations – with no VP Operations and Engineering

We have also evaluated the current organization structure without a VP Operations and Engineering. With one less layer of management, the direct reports (jobs 2, 3 and 7) will increase in size by one Hay step. The revised evaluation lines will look as follows:

	Revised Evaluations Assuming no VP Operations and Engineering		Hay Points								Working Conditions		
No.	Name	Role Title	Know-How		Problem Solving		Account-ability		Total Hay Pts	Pr	Tot WC	Full Pts	New Grade
1		President and CEO	G-III3	608	G4 (57)	350	G-3P	528	1486	A3	22	1508	18
2		Director, Operations	FII3	400	F4 (50)	200	F-2+P	304	904	A3	24	928	15
3		Director, Technical Services	FII3	400	F4 (50)	200	F-2P	264	864	A2	24	888	15
4		Chief Financial Officer	FII3	400	F4 (50)	200	F3C	230	830	A1	22	852	15
5		Director HR & Info Mgmt	FII3	400	E4 (43)	175	F-3C	200	775	A1	22	797	15
6		Dir Resource Plng & Reg Affairs	F-II3	350	E4 (43)	152	E3C+	175	677	A1	22	699	14
7		Director, Health Safety & Env.	EII3	304	E3+ (38)	115	E3C	152	571	A2	24	595	13
8		Supervisor, Electrical Eng.	EII-3	264	E3+ (38)	100	D2P	132	496	A2	24	520	12
9		Supervisor, Mech. & Civil Eng.	EII-3	264	E3+ (38)	100	D2P	132	496	A2	24	520	12
10	Vacant	Manager, Operations	EII-3	264	E3+ (38)	100	D+2S	115	479	A1	24	503	12
11	Vacant	Supervisor, Financial & R.M.	EII-3	264	E3+ (38)	100	D+3C	115	479	A1	22	501	12
12		Controller	E-II-3	264	E3 (33)	87	D+3C	115	466	A2	22	488	12
13		Electrical Design Engineer	EI2	200	D+3 (33)	66	D2C	76	342	A1	24	366	10
14		Civil Engineer	EI2	200	D+3 (33)	66	D2C	76	342	A1	24	366	10
15		Supervisor, Communications	EI2	200	D+3 (33)	66	D-2+C	76	342	A1	22	364	10
16		Engineer in Training	D+I2	175	D3 (29)	50	C+2C	57	282	A1	24	306	9

Salary Market Data and Salary Ranges

Using the Hay evaluation points (including Working Conditions), we are able to access the Hay Group survey data for Canada. The database can be cut in a number of ways, including by industrial sector, by geography, by job class (executive vs professional and middle management), and by job family. It is best to take as broad a cut of the database as possible to increase the validity of the data points and to give more consistent results from year to year. We have made a number of assumptions about the population of jobs at YEC – where you will be attracting employees from, and where you might lose them to, as follows:

- **National:** we have used a national market since, at this level, you will be attracting individuals from outside the region
- **Utilities Sector:** we have used the Utilities sector database, since you are looking for managers and professionals with some knowledge and experience in this area
- **Executive Level vs All Jobs:** we have used the executive market data for grades 15 and above since these jobs will form the core of the executive team, and this is the lowest level in the database for executive jobs
- **Job Families:** we have used all job families since there is a wide spectrum of jobs in the organization, and so as not to narrow down the database.

The survey base date is May 1 2006. A list of companies in the Utilities Sector is given in Appendix 2.

The following table shows the market median (P50) and upper (P75) and lower (P25) quartiles for the proposed grade structure. These ranges do not represent salary ranges, they simply show where the market position is. We will need to make a policy decision about where to position YEC against the market (e.g. P50 or P75), and use that as the midpoint of the salary range. We can then decide how broad to make the salary ranges, and they are typically broader than the spread between P25 and P75.

	Utilities Sector Canada May 1 2006		
Grade	P25	P50	P75
9	$58,300	$63,900	$76,400
10	$63,100	$69,500	$79,100
11	$68,800	$76,100	$84,200
12	$75,500	$83,300	$91,500
13	$82,100	$89,200	$97,600
14	$89,900	$96,600	$106,100
15	$101,400	$113,700	$123,800
16	$110,600	$123,700	$139,300
17	$134,000	$143,400	$161,900
18	$160,100	$174,100	$190,900

We have used the median or P50 of the market plus 5% as the midpoint of the grade. This positions the YEC base salary policy line roughly midway between P50 and P75. This will reflect the fact that YEC is smaller and in a more remote location than most of the companies in the sector, where individuals will not have the support networks to call upon that may be found in larger organizations and more populated areas. Next, we should look at how wide the salary ranges should be. Typically, for a single step grade structure, as we have here, the range is plus or minus 20% around the midpoint, for a total spread of 40%. We note that the current salary ranges you provided to us, based on 2006 Band Min and Max, have only a 15% total spread, less than half the usual breadth. Also, there is very little or no overlap between the maximum salary of one grade and the minimum salary of the next, as we would normally expect to see.

Current Salary Ranges for YEC		
Salary Band	2006 Band Minimum	2006 Band Maximum
1	$63,903	$73,488
2	$74,231	$85,365
3	$85,558	$98,393
4	$98,221	$112,954

5	$111,881	$128,663

Using the new grades and P50 + 5% survey position as midpoint, we calculate the following salary ranges. We have included both organization structures, with and without VP Operations and Engineering. The salary ranges are broader than the current YEC ranges, and there is more overlap between levels.

YEC					Proposed Base Salary Ranges		
No.	Name	Role Title	Full Pts	New Grade	Minimum 80%	Midpoint 100%	Maximum 120%
1		President and CEO	1508	18	$146,240	$182,800	$219,360
2	Vacant	VP Operations and Engineering	1064	16	$103,920	$129,900	$155,880
3		Chief Financial Officer	852	15	$95,520	$119,400	$143,280
4		Director HR & Info Mgmt	797	15	$95,520	$119,400	$143,280
5		Director, Operations	756	14	$81,120	$101,400	$121,680
6		Director, Technical Services	726	14	$81,120	$101,400	$121,680
7		Dir Resource Plng & Reg Affairs	699	14	$81,120	$101,400	$121,680
8		Director, Health Safety & Env.	520	12	$70,000	$87,500	$105,000
9		Supervisor, Electrical Eng.	520	12	$70,000	$87,500	$105,000
10		Supervisor, Mech. & Civil Eng.	520	12	$70,000	$87,500	$105,000
12	Vacant	Manager, Operations	503	12	$70,000	$87,500	$105,000
11	Vacant	Supervisor, Financial & R.M.	501	12	$70,000	$87,500	$105,000
13		Controller	488	12	$70,000	$87,500	$105,000
14		Electrical Design Engineer	366	10	$58,400	$73,000	$87,600
15		Civil Engineer	366	10	$58,400	$73,000	$87,600
16		Supervisor, Communications	364	10	$58,400	$73,000	$87,600
17		Engineer in Training	306	9	$53,680	$67,100	$80,520
	with no VP Ops & Engineering:						
5		Director, Operations	928	15	$95,520	$119,400	$143,280
6		Director, Technical Services	888	15	$95,520	$119,400	$143,280
8		Director, Health Safety & Env.	595	13	$74,960	$93,700	$112,440

Executive Survey	
All Jobs Survey	

Summary and Next Steps

We have made a number of assumptions about the market sector in which YEC is competing – National Utilities Sector at Executive and All Jobs levels – and the market positioning of your grade midpoints – at P50 plus 5%. The resulting salary ranges are broader than your current ranges, with greater overlap between levels. The proposed ranges generally start at a lower level. The new salary midpoint is roughly equal to the current salary minimum, and the new salary maximum is slightly higher than the existing salary maximum. You should compare actual salary practice against the market and the proposed salary ranges to see how individual salaries slot into the picture.

We have not discussed any incentive plan that YEC may offer to employees. The market data presented is for base salary, and there will also be a total cash market which includes bonus or incentive payments. This needs to be taken into account when determining how competitive YEC will be.

Another assumption we have made is about the grade structure for management and professional level. We have extended the single step structure from below, which is one option. A second option would be to look at a broader grade width, say 2 steps. This would give fewer grades at the top end, probably half as many, and would put more jobs into a single grade. The advantage of this approach is that the emphasis is taken off of the narrow bands, where you have to be promoted to the next grade to get a substantial pay increase. Instead, the emphasis is more on managing performance and progressing individuals through a broader salary range. The downside is that it puts more onus on managers to manage performance.

Once you have had a chance to review this report, we can discuss it in more detail.

Appendix 1 - Rationales

1. ***President & CEO*** Yukon Energy provides power to a diverse customer base spread across a large geographical area. The organization is focused on electrical power generation and has a range of functions including operations, technical services, and other support functions. It is driven primarily by its operations department with a focus on delivery of power to its consumers. The position of President & CEO reports into the Chair of the Yukon Development Corporation which in turn reports into the Department of Energy, Mines and Resources. This position has a long time horizon, leading the organization's strategic planning for the future. Plans are approved by the Board of Yukon Development Corporation. The incumbent requires a degree in engineering, economics or business administration or a related field and will possess substantial management and leadership experience in the industry gained through 10 or more years of experience. The position is prime accountable for the operating budget of $27m. We have compared this role to similar senior roles in the power and utilities sector, and to CEO roles in industrial and service companies.

Position	Know-How	Problem-Solving	Accountability	Total
President & CEO	G-III3 608	G4 (57) 350	G-3P 528	1486 A3

2. ***Vice-President, Operations & Engineering*** With Yukon Energy's primary focus on the delivery of power to its consumers, the operations department is the driving force within the organization. This will be a new role if approved by the Board which co-ordinates the work of Operations, Engineering and Health, Safety & Environment departments, as well as advises on the organization's strategy and future planning from a technical point of view. With the majority of the organization's structure reporting into it, the Vice-President, Operations & Engineering is seen as the second largest position in the organization. The incumbent requires a university degree or college diploma in engineering, business administration, commerce or other discipline related to an electrical utility with several years of experience in a leadership role in an electrical utility. The role has prime accountability for the operating budget.

Position	Know-How	Problem-Solving	Accountability	Total
Vice-President, Operations & Engineering	FIII-3 460	F4 (50) 230	F-3P 350	1040 A3

3. ***Chief Financial Officer*** As the head of the Finance department, the Chief Financial Officer is responsible for managing the financial, treasury, risk management, procurement, and regulatory affairs of the organization. This position is a member of the leadership team and reports to the President & CEO. The role is the prime contact with banks and lending institutions to arrange financial requirements of the Corporation. The incumbent requires an accounting designation (CA, CMA, CGA), MBA or relevant postgraduate degree and a minimum of 8 years related financial experience.

Position	Know-How	Problem-Solving	Accountability	Total
Chief Financial Officer	FII3 400	F4 (50) 200	F3C 230	830 A1

4. ***Director, Human Resources & Information Management*** This position is responsible for strategic direction and leadership of human resource, information technology and records management. Providing key support to the organization at large, this position is responsible for a diverse group of functions that are typically not grouped under one department. As a member of the leadership team, this position contributes to the organizational strategic direction speaking on behalf of HR and IT. The incumbent requires a BA in Human Resource Management or equivalent and seven to ten years' generalist experience, with five years HR leadership experience. In addition, knowledge of Computer Science or Information Technology with related experience is required.

Position	Know-How	Problem-Solving	Accountability	Total
Director, Human Resources & Information Management	FII3 400	E4 (43) 175	F-3C 200	775 A1

5. ***Director, Operations*** Reporting to the Vice President, Operations and Engineering in the future, this position is head of the Operations department, the largest department within the organization by headcount. It is concerned with ensuring the safe, reliable and efficient operation of power generation, transmission and

distribution facilities. The position sits on the Leadership Team and recommends changes and improvements to the organization's systems and facilities. It covers 4 technical disciplines, and resolves all problems which occur in its own area. It is seen as same sized role as Director, Technical Services. The incumbent requires a relevant engineering degree (in Canada), eligible for registration in Yukon, or equivalent education and experience and at least 10 years of related experience in progressively more responsible management positions, preferably in hydro and/or diesel power generation, transmission and distribution.

Position	Know-How	Problem-Solving	Accountability	Total
Director, Operations	F-II3 350	E4 (43) 152	E2+P 230	732 A3

6. ***Director, Technical Services*** As the head of the Technical Services department, the Director is responsible for managing engineering programs, policies, procedures and capital budgeting. It works with and develops guidelines, standards and plans, operating and capital budgets for the engineering department. This position has 12 direct reports and works with the Leadership Team, and will report into the Vice President, Operations and Engineering in future. The incumbent requires a relevant engineering degree (in Canada), eligible for registration in Yukon, with a minimum of 8 years experience in the electrical utility or related industry, including proven experience at the executive level or equivalent education and experience. It is prime on the department budget. It is seen as being similar in size to Director Operations, but with A2 profile.

Position	Know-How	Problem-Solving	Accountability	Total
Director, Technical Services	F-II3 350	E4 (43) 152	E2P 200	702 A2

7. ***Director, Resource Planning & Regulatory Affairs*** This position's key role involves the identification and progression of business development opportunities. Therefore it must be very familiar with local and regional governments as well as managing a wide range of external business relationships. In addition to business development, this role is responsible for developing and updating the resource plan and managing the annual capital and operation's budgets for the department. It is a member of the leadership team and

reports to the President & CEO. This position has no direct reports but receives guidance and information from others to carry out planning and analysis. The incumbent requires academic credentials which include a combination of a degree in business, engineering, finance or accounting with 6 to 8 years direct business development and management experience identifying, cultivating, assessing and implementing creative, innovative business opportunities, preferably in the energy industry.

Position	Know-How	Problem-Solving	Accountability	Total
Director, Resource Planning & Regulatory Affairs	F-II3 350	E4 (43) 152	E3C+ 175	677 A1

8. ***Director, Health, Safety and Environment*** A member of the Leadership Team and reporting in the future to the Vice-President, Operations & Engineering, this position is responsible for planning and directing the organization's occupational health, safety and environmental programs. It does not have any direct reports, but works cooperatively across the various departments throughout the organization. The incumbent is an expert on issues relating to health, safety and environment, and requires a related post secondary education degree or diploma or certification as a Canadian Registered Safety Professional (CRSP) with experience in organizing and managing health safety and environmental programs.

Position	Know-How	Problem-Solving	Accountability	Total
Director, Health, Safety and Environment	EII-3 264	E3+ (38) 100	E-3C 132	496 A2

9. ***Supervisor, Electrical Engineering*** This role reports to the Director of Technical Services and has a team of 6 professionals and technicians. It is responsible for detailed analysis, plans, studies, and other documentation in support of planning and design for expansion, modification, operation and maintenance of generation, transmission and distribution assets. The incumbent needs to be a registered Professional Electrical Engineer (in Canada), eligible for registration in Yukon with several years experience in utility or related industry.

Position	Know-How	Problem-Solving	Accountability	Total
Supervisor, Electrical Engineering	EII-3 264	E3+ (38) 100	D2P 132	496 A2

10. ***Supervisor, Mechanical/Civil Engineering*** This role reports to the Director of Technical Services and has a team of 3. It is responsible for researching, designing and developing projects for the construction or repair of facilities, earth structures, powerhouses and dams. Similar to the Supervisor, Electrical Engineering, this role is fundamentally concerned with the design and preparation of project plans. The incumbent needs to be a registered Professional Mechanical or Civil Engineer (in Canada), eligible for registration in Yukon with experience relating to engineering design and project management.

Position	Know-How	Problem-Solving	Accountability	Total
Supervisor, Civil/Mech Engineering	EII-3 264	E3+ (38) 100	D2P 132	496 A2

11. ***Manager, Operations*** This role reports directly to the Director Operations, and has 1 direct report. This is a hands-on position which oversees and provides operational and planning support to the Director Operations for generation, substation, transmission and distribution assets. It is the problem-solving role for the operations group, and allows the Director to be more strategic. Although this position does not have a reporting relationship with the 4 Leadhands in the Operations group, it has a strong influence in helping them achieve their accountabilities; hence it is shown as a shared accountability. The incumbent requires a related technology diploma or to be a Registered Professional Electrical Engineer (in Canada), or have equivalent education and 10 years of related experience in progressively more responsible management positions.

Position	Know-How	Problem-Solving	Accountability	Total
Manager, Operations	EII-3 264	E3+ (38) 100	D+2S 115	479 A1

12. ***Supervisor, Financial and Risk Management*** A member of the risk management committee, this role evaluates and forecasts the operating and maintenance budgets. In addition, it is responsible for the cost-effective and efficient management of the organization's customer service and risk management activities. It has a small team of 2 direct reports and is directly responsible to the Chief Financial Officer. In particular, this role has the freedom to research and recommend new policies and strategies with respect to financial and risk management issues. The incumbent must have a professional accounting designation (e.g. CA, CGA, CMA) with several years of experience in accounting, auditing, budgeting, risk management, financial planning and/or analysis.

Position	Know-How	Problem-Solving	Accountability	Total
Supervisor, Financial and Risk Management	EII-3 264	E3+ (38) 100	D+3C 115	479 A1

13. ***Controller*** This position organizes, directs, controls and evaluates the operation of the accounting department. It is responsible for the preparation of management and annual financial statements to comply with GAAP and regulatory requirements. This position has a team of 4 direct reports, and it reports to the Chief Financial Officer. The incumbent needs to hold a professional accounting designation (e.g. CA, CGA, CMA) with several years of experience in accounting, auditing, budgeting, financial planning and/or analysis.

Position	Know-How	Problem-Solving	Accountability	Total
Controller	E-II-3 264	E3 (33) 87	D+3C 115	466 A2

14. ***Electrical Design Engineer*** This position plans, organizes and directs all or part of electric utility projects. It manages projects throughout the entire lifecycle. It is under the direct supervision of the Supervisor, Electrical Engineering. The incumbent requires a degree in electrical engineering (in Canada) and must be eligible for registration as a Professional Engineer or Engineer in Training in the Yukon.

Position	Know-How	Problem-Solving	Accountability	Total
Electrical Design Engineer	EI2 200	D+3 (33) 66	D2C 76	342 A1

15. ***Civil Engineer*** This position develops, designs and manages projects for the construction or repair of facilities, earth structures, powerhouses and dams. It is under the direct supervision of the Supervisor, Mechanical/Civil Engineering. The incumbent requires a degree in civil engineering (in Canada) with water resource specialization and must be eligible for registration as a Professional Engineer or Engineer in Training in the Yukon.

Position	Know-How	Problem-Solving	Accountability	Total
Civil Engineer	EI2 200	D+3 (33) 66	D2C 76	342 A1

16. ***Supervisor, Communications*** This position is responsible for the delivery of the organization's communications plan, drawn from the corporate strategic plan, which is aimed specifically at enhancing the corporate image and reputation. Guidance is readily available from the CEO and other senior managers. It is concerned with all aspects of public relations-related issues, including administration of sponsorship and donations, making recommendations around the organization's website, and assisting in media relation activities. Fundamentally, this position is not concerned with the "what" of the message, since this comes from the relevant technical director, but rather "how" it is communicated. The incumbent typically requires a business degree in Communications or Public Relations with a minimum of 5 years of marketing, corporate communication or public relations experience.

Position	Know-How	Problem-Solving	Accountability	Total
Supervisor, Communications	EI2 200	D+3 (33) 66	D-2+C 76	342 A1

17. ***Engineer in Training*** This is an entry level position for a graduate engineer who is eligible for registration as an Engineer-in-Training. The jobholder will work under readily available supervision on assigned projects which are well-defined components of larger activities.

Position	Know-How	Problem-Solving	Accountability	Total
Engineer in Training	D+I2 175	D3 (29) 50	C+2C 57	282 A1

Summary of Working Conditions

Working Conditions cover 4 areas that may be encountered by the jobholder while carrying out the role:

- Physical Effort
- Physical Environment
- Sensory Attention
- Mental Stress

For each of the four factors, it is important to consider the 3 variables of intensity, duration and frequency.

The jobs above are mainly office-based, with occasional work required in the field, and in some cases scheduled work or travel outside regular working hours. Physical effort is minimal, so all jobs were given a 3. Physical environment will be mainly office conditions, but with occasional visits of varying frequency and duration to the field, where some harsh conditions will be encountered. This factor was set between medium (3) and high (5) Minimal. All jobs were given Moderate sensory attention (8), due to use of video display terminals, technical troubleshooting, reading of technical drawings and designs. Mental stress was set at Moderate (8), due to work schedules involving time spent outside regular working hours, and travel.

At these job sizes, particularly managerial level and above, the working conditions are going to have a smaller impact on overall job size than at the lower job levels. The working conditions are shown in the summary table of job sizes.

Appendix 2 – List of Companies in Utilities Sector Survey

Bluewater Power Distribution Corporation	British Columbia Hydro and Power Authority	Bruce Power
Burlington Hydro Inc.	Duke Energy Gas Transmission	Emera Inc.
Enbridge Gas Distribution Inc.	Enersource Hydro Mississauga	ENWIN Utilities Ltd.
EPCOR	Fortis Ontario Inc.	Halifax Regional Water Commission
Horizon Utilities Corporation	Hydro One Brampton Inc.	Hydro One Inc.
Hydro Ottawa Limited	Maritime Electric Company	Maxim Power Corp.
NB Power Holding Corporation	Newfoundland and Labrador Hydro	Newfoundland Power Inc.
Northwest Territories Power Corporation	Nova Scotia Power Inc.	Oakville Hydro Corporation
Ontario Power Generation Inc.	Oshawa PUC Networks Inc.	SaskEnergy Incorporated
SaskPower	Terasen Gas	Toronto Hydro Corporation
TransAlta Corporation	Union Gas Ltd.	Whitby Hydro Energy Corporation
Yukon Energy Corporation		

REFERENCE: **Table 3.3**

TOPIC: **Non-Fuel Operating, Maintenance, and Administrative Expenses**

QUESTION:

a) For each of Production, Transmission, Distribution, and General O&M, and Administration, please provide costs by activity for 2005-2009 by the following components:
   i labour
   ii fringe
   iii contractor services
   iv other

b) For costs included in contractor services, please provide:
   i details and costs of each of the services being provided; and
   ii a business case justifying use of contractor.

ANSWER:

(a) and **(b)**

Please see YECL-YEC-1-40(g) and UCG-YEC-1-38(a) in regards to labour and fringe expenses. Also see UCG-YEC-1-40 in regards to production expenses, UCG-YEC-1-41 for transmission expenses, UCG-YEC-1-42 for distribution expenses, and CW-YEC-1-22 for General O&M. For specific contractor and consultant expenses in each category, see the table below:

Consultant and Contractor Expenses

$000s	2005 Actuals	2006 Actuals	2007 Actuals	2008 Forecasts	2009 Forecasts
Production	270	127	169	141	129
Transmission	241	183	331	326	448
Distribution	77	95	12	58	91
General	113	43	35	54	56
Administration	631	622	664	666	830
Total	1331	1071	1211	1245	1553

It is not possible to provide detail on each response to the question due to the immense level of detail required to review and summarize each use of a contractor within the noted categories.

Contractors are not hired specifically on a “business case” basis. Functional managers hire external contractors under two scenarios a) when they have insufficient internal resources to achieve desired goals and b) where a particular expertise is required that does not exist with internal resources. This includes a huge variety of tasks, covering everything from snow clearing to survey services to divers.

REFERENCE: **Page 3-6 and Table 3.3 & 3.4**

TOPIC: **Labour**

PREAMBLE:

Yukon Electrical wishes to understand the components of labour dollars.

QUESTION:

a) Provide, by department detailed in Table 3.4, costs associated with:
   i Northern allowance;
   ii Travel related benefits provided to employees;
   iii Variable pay programs other bonus related programs provided to employees;
   iv Fringe benefits; and
   v Other - provide details of other labour related costs included in the forecasts.

b) Please indicate where the items in (a) above are included in YEC's forecasted revenue requirement.

c) If there are variable pay programs or other bonus programs, please provide a redacted copy of the contract between employee and YEC.

d) If there is no formal contract signed by the employee, please provide the policy for when payment is made under these programs.

e) Please confirm that there are no earnings related incentive programs included in revenue requirement.

(f) If not confirmed, please explain.

(g) Provide details, description and quantification of the components of fringe benefits/fringe benefit rate (e.g. CPP, EI, Pension, etc).

ANSWER:

(a)

i. Northern Allowance is made up of $6,300 per year flat rate per annum and 5% of base salary per annum.

ii. Permanent and term employees are eligible for a vacation travel allowance for themselves and their families after the completion of twelve months of employment with the Corporation. They are eligible to the following benefit for vacation travel allowance:

Employee	$1,300
Employee's spouse	$ 850
Each dependent child	$ 850

iii. Yukon Energy does not have variable pay programs or other bonus related programs provided to employees except as noted below in (c) and (d).

iv. Fringe benefits are included in labour costs.

v. The other labour related costs in the forecasts are as follows: employee benefits, leave entitlements, shift differentials, standby, and overtime. All of these cost items are included in the labour cost.

(b)

All costs identified in (a) are included in labour in Tab 3 of the General Rate Application and as such are included in YEC's forecast revenue requirement.

(c) and **(d)**

At the time the labour amounts were prepared for the Revenue Requirement there were no contracts with variable pay programs or other bonus programs. Since that time one contract was entered into which includes a bonus provision. However, no change will be made to the labour amounts to reflect any bonus that might be paid.

(e)

Confirmed.

Forecast labour expense reported in the application as part of revenue requirement does not include any provision or amounts for earnings related incentive programs.

(f)

Not applicable.

(g)

For 2008 and 2009 GRA Fringe and Burden for Full time and Term is 54.78% and for Casuals is 14.71%. Further, details, description and quantification for the components of fringe benefits/ fringe benefit rate are as follows:

- **Northern Fringe & Burden** - This fringe covers the cost of the Northern Allowances that employees are entitled to as per the union agreement and the terms and conditions for out of scope employees. This is applied to Full Time Permanent Employees and Term Employees (EI reduced employees) and Casual Employees (regular EI employees). This benefit is based on regular wages earned.

- **Benefits Fringe & Burden** - This fringe covers the cost of CPP, EI, WCB, Health & Dental Benefits, Life and Accident Death & Dismemberment Insurance, Vacation Pay for causal/part time employees. This is applied to Full Time Permanent Employees and Term Employees (EI reduced employees) and Casual Employees (regular EI employees). This benefit is calculated on regular wages earned.

- **Vacation Travel Allowance Fringe & Burden** - This fringe covers the cost of the Vacation Travel Allowance that is paid to full time permanent and term employees. This fringe is applied to regular wages earned for Full Time Permanent Employees and Term Employees.

- **Pension/RRSP Fringe & Burden** - This fringe covers the cost of the Pension and RRSP as per the union contract and the out of scope terms and conditions and only applies to full time permanent employees This fringe is applied to regular wares to Full Time Permanent employees.

- **Leave Fringe & Burden** - This fringe covers the cost of leave employees are entitled to according to the union contract and the out of scope terms and conditions. This fringe is only applied to regular wages earned for Full Time permanent employees.

- **Stat Fringe & Burden** - This fringe covers the cost of statutory holiday leave taken by full time employees throughout the year. This fringe is only applied to regular wages earned for Full Time Permanents and Term employees

REFERENCE: **Page 3-7 and Table 3.4**

TOPIC: **Employee Complement**

PREAMBLE:

Table 3.4
Employee Complement History

	Actual 2005	Actual 2006	Actual 2007	GRA 2008	GRA 2009
President	1.60	1.50	2.50	2.50	2.50
Communications	1.00	1.00	1.00	1.00	1.00
Human Resources & Info. Mgmt.	6.06	6.01	6.00	7.00	7.00
Business Development	1.08	1.00	1.00	1.00	1.00
Finance, Cust. Acctg. & Purchasing	11.05	11.49	11.63	12.81	12.81
Operations	34.82	39.43	38.60	40.20	40.10
Engineering Services	13.21	13.58	14.00	12.67	12.00
Health, Safety & Environment	1.00	1.00	3.00	3.33	3.33
Total	69.82	75.01	77.73	80.51	79.74

QUESTION:

a) For 2005-2009, please provide the vacancy rate by department as well as the overall corporate vacancy rate.

b) For 2008 and 2009, please provide the vacancy rate assumptions used in developing the forecast complement. Also provide the overall corporate vacancy rate forecast.

c) Please expand Table 3.4 to identify the employee complement separately charged to O&M and to Capital.

ANSWER:

(a) and **(b)**

Actual corporate vacancy rates for the period of 2005-2007 are as follows:

Vacancy Rates - Actuals

	Percentage	# of Employees	FTE
2005	2.95%	70.97	2.09
2006	5.70%	75.72	4.32
2007	7.21%	78.44	5.65
2008	4.73%	81.22	3.84
Average	5.14%	76.59	3.94

For 2008 and 2009, the vacancy rate assumptions used were 5% which equals approximately 4 FTEs. YEC reviewed the historical vacancy rates from 2005 to 2007; staff turnover and time it took to fill newly created positions and determined that the corporation was experiencing approximately a 5% or 4 FTE's vacancy. A 5% reduction was applied to the loaded cost of each employee.

Yukon Energy does not track individual department vacancy rates. The degree of position transfers between departments would make it difficult or impossible to provide this information in many cases.

(c)

Please see UCG-YEC-1-35(a).

REFERENCE: **Section 3**

TOPIC: **Labour**

PREAMBLE:

Yukon Electrical is interested in understanding the labour costs of YEC.

QUESTION:

a) Please provide a complete organizational chart(s) for all employees of YEC.

b) How many employees did YEC have when they took over the management of the government power system assets in 1997? What have been the fundamental changes to the business of YEC that have created the need for the significant number of new positions since that time?

c) Please provide YEC's total labour costs, including both capital and O & M, and the overall average labour cost per employee

d) What are YEC's total costs, per customer and per pole, for both Transmission and Distribution expenses?

e) On line 20 and 21 page 3-9 YEC refers to "less time being spent on maintenance of the fleet…." Please identify the savings expected to be achieved in each test year. Where are the savings reflected in the application?

f) In table 3.8 page 3-9 please provide a breakdown of all company owned properties. Please provide the details of the costs associated with each of the properties that are included in the test period revenue requirement.

g) Please define and itemize special projects included in table 3.8.

h) In regard to transportation costs in table 3.8, are these YEC's entire transportation costs or are there additional transportation costs allocated to

projects? If there are transportation costs allocated to projects please provide these costs.

ANSWER:

(a)

Please see Attachment 1 provided to LE-YEC-1-32(a).

(b)

Yukon Energy had 3.4 FTE employees (1997) when it took over direct management of its assets. Staffing levels and changes over time are reviewed in LE-YEC-1-32 in this proceeding, and UCG-YEC-I-46 from the 2005 proceeding.

There has not been a "fundamental" change in YEC's business since assuming direct management. Increases in staffing are justified as needed to deal with issues such as aging infrastructure (e.g. most of YEC's hydro assets were constructed in the 50's and 60's), additions of new assets (e.g. >350 km of new transmission added in last five years), availability of external contractors, planning for increased demand and changes in regulations (OH&S, YESAB).

(c)

Please see UCG-YEC-1-35.

(d)

Total labour cost figures used in this analysis are from tables 3.6 (Transmission) and 3.7 (Distribution). Pole count and customer count data is as-of December 2008.

Labour cost per pole and per customer for Transmission and Distribution

	Proposed $ (000's)		Cost per Pole ($/pole)			Cost per Customer ($/customer)		
	2008	2009	# poles	2008	2009	# Customers	2008	2009
Transmission	466	482	4,941	94	98	1,875	249	257
Distribution	505	521	3,201	158	163	1,875	269	278

(e)

The cited quote relates to labour costs for General O&M. These savings are reflected in Table 3.8, which notes test year labour cost forecasts for General O&M at levels below those experienced in 2005 to 2007 actuals.

(f)

Yukon Energy does not track costs by property. YEC tracks company-owned houses and company owned buildings by community. Details on the costs associated with company owned buildings are as provided below.

Maintenance of Company Owned Buildings

Maintenance of Co-Owned Houses	Cost Description	2008 ($000)	2009 ($000)
Faro	Gasoline/Heating Fuel	2	2
	Materials(Small Tools)	2	24
	Parts and services	3	3
Faro-Sub-Total		7	29
Dawson	Gasoline/Heating Fuel	43	44
	Janitorial		1
	Materials(Small Tools)	1	1
	Outside Service	5	5
	Parts and services	17	17
	Snow Removal	2	2
	Utilities	9	10
Dawson Sub-Total		78	79
Mayo	Contractors	8	9
	Gasoline/Heating Fuel	9	9
	Outside Service	2	2
	Road & Ground Maintenance	5	5
Mayo Sub-Total		24	25
Aishihik	Materials(Small Tools)	1	6
	Parts and services	3	3
Aishihik Sub-Total		4	9
Maintenance of Co-Owned Houses Sub-Total		**112**	**141**
Maintenance of Co-Owned Buildings	**Cost Description**	**2008 ($000)**	**2009 ($000)**
Faro	Materials(Small Tools)	1	1
	Snow Removal	2	2
Faro Sub-Total		3	3
Dawson	Contractors	11	17
	Janitorial	2	2
	Materials(Small Tools)	1	1
	Parts and services	5	5
	Road & Ground Maintenance	2	2
	Snow Removal	4	4
Dawson Sub-Total		24	30
Mayo	Gasoline/Heating Fuel	8	8
	Materials(Small Tools)	1	
	Parts and services	6	6
	Snow Removal	19	20
Mayo Sub-Total		34	35
Aishihik	Gasoline/Heating Fuel	2	2
	Parts and services	1	1
	Snow Removal	8	8
Aishihik Sub-Total		10	10
Whitehorse	Contractors	23	18
	Gasoline/Heating Fuel	8	8
	Janitorial	28	29
	Materials(Small Tools)	9	27
	Parts and services	17	18
	Road & Ground Maintenanc	11	
	Snow Removal	23	23
	Utilities	11	12
	Office Rent / Yard Rent	28	29
Whitehorse Sub-Total		159	164
Maintenance of Co-Owned Buildings Sub-Total		**231**	**243**
Grand Total		**342**	**384**

(g)

The only two items in Table 3.8 that are not SCADA or Communications are $20,000 for replacement of a damaged transformer at Stewart Crossing in 2005, and $9,000 for software for modelling the Corporation's electrical system load flows.

(h)

Table 3.8 reports those vehicle costs charged to operations. The table below reports the vehicle costs charged to capital projects.

Vehicle Costs Charged to Capital Projects ($)

Actual	Actual	Actual	Actual
2005	2006	2007	2008
72,338	79,244	89,829	107,083

REFERENCE: **Page 3-10 of the Application**

TOPIC: **Administration Costs**

PREAMBLE:

Yukon Electrical wishes to understand Administration costs of YEC.

QUESTION:

a) Please provide a list of the training and conferences that have been attended by staff from 2005-2009. Please provide the location of the training, conferences and business related travel and the costs associated with each. Also, please provide any documented benefits that have been implemented as a result of the training/conference attendance.

ANSWER:

(a)

Please see Attachment 1 to this response. Out of Territory training was not available in Yukon. Documentation regarding benefits is not available.

2005 Training Costs

Department	# of Employees	Training Description	Cost	Location
				OT - Out of Territory
Engineering Services				
Supervisor, Mechanical Engineering	1	Installation Code for Oil-Burning Equip	285.00	Yukon
Civil Engineer	1	YESAAS Course	200.00	Yukon
Electrical Engineer	3	PLC Part II	450.00	Yukon
Electrical Engineer	1	Power Transformer Forum	1,519.60	OT
Electrical Engineer	1	High Voltage Substation Design	3,178.86	OT
Electrical Engineer	1	PLC Advanced Training	4,718.35	OT
Draftsperson	1	Staking and Easement Acquisition	4,331.96	OT
Draftsperson	1	Electrical course	514.02	Yukon
Electrican Capital Projects	1	Grounding in Power Systems	2,018.62	OT
Distribution Technologist	1	Fund Electrical Distribution	3,252.31	OT
Electrical Engineer	2	PLC Part I - 2004 costs	300.00	Yukon
Land Technician	1	Conflict Management	350.00	Yukon
Land Technician	1	Communicating in Conflict	250.00	Yukon
Coordinator, Property & Projects	1	Installation Code for Oil-Burning Equip	200.00	Yukon
Resource Mgt Eng	1	YESAAS Course	200.00	Yukon
Resource Mgt Eng	1	Visible Emissions Certification	400.00	Yukon
Technical Services	13	Monthly working lunches	747.85	Yukon
		Sub-Total Technical Services	**22,916.57**	
Operations				
Director	1	Employment and Human Rights Laws for Managers	2,461.00	OT
Manager	1	Electrical Safety in The Workplace	1,632.12	OT
Manager	1	CEA Health & Safety Course	1,060.84	OT
Manager	1	Lancaster House	390.00	Yukon
Leadhand, SCC	1	Purchasing course	1,576.21	OT
Leadhand, Electrical	1	Electrical Testing	649.00	Yukon
Leadhand, Electrical	1	Leading High Performance Teams	2,380.40	OT
Leadhand, Electrical	1	Coaching & Mentoring	995.00	OT
Mtce Electrician	1	PSE Apprenticeship	3,023.66	OT
Mtce Electrician	1	Electrical Maintenance Forum	1,649.37	OT
Mtce Electrician	1	Technical course	3,099.21	OT
Leadhand, T & D	1	T & D conference	3,391.82	OT
Line Tech - Mayo	1	GPS Training	100.00	Yukon
Plant Operator/Tradesperson	1	Apprenticeship	165.30	Yukon
		Sub-Total Operations	**22,573.93**	
Finance				
Controller	1	Writing	424.10	Yukon
Controller	2	CICA Handbook Update	4,091.78	OT
Controller	1	Financial Statement Presentations	325.00	Yukon
Supervisor, Financial & Risk Mgt.	1	Electric Systems for non-engineers	3,651.46	OT
Supervisor, Financial & Risk Mgt.	1	Dealing with Irate Customers	269.00	Yukon
Revenue & Financial Analyst	1	Electric Systems for non-engineers	3,954.93	OT
Financial Administrator	2	Payroll update	2,291.46	OT
PT Office Administrator-Dawson	1	Supervisor I	1,000.00	Yukon
Buyer	1	Purchasing course	1,927.66	OT
Buyer	1	Public Sector Contracting	550.00	Yukon
Buyer	3	Secrets of Successful Bidding	900.00	Yukon
Buyer	1	Principals of Buying	575.00	Yukon
Assistant Buyer	1	Public Sector Contracting	550.00	Yukon
Assistant Buyer	1	Microsoft Word-correspond. course	175.00	Yukon
Corporate Services	3	Pre-Qualifying Vendor Workshop	3,659.27	Yukon
Contract Law	29	Contract Law	10,779.93	Yukon
JDE Training-Purchasing & Warehouse	7	JDE-purchasing & inventory modules	10,531.24	Yukon
		Sub-Total Finance	**45,655.83**	
Resource Dev't				
Director	1	Finance fundamentals	2,480.41	OT
		Sub-Total Resource Dev't	**2,480.41**	
Corporate Services				
Director	2	Finding, Hiring and Develop Skilled Staff	6,726.90	OT
Director	1	PowerPoint correspondence course	170.09	Yukon
Director	1	1 Athabasca correspondence course	591.59	Yukon
Administrative/HR Assistant	1	1 Athabasca correspondence course	633.00	Yukon
Administrative/HR Assistant	1	Stepping Up To Leadership	750.00	Yukon
Administrative/HR Assistant	1	1 Athabasca correspondence course	591.59	Yukon
Administrative Assistant	1	Admin course-Minute Taking	269.00	Yukon
Administrative Assistant	1	Outrageous Confidence	550.00	Yukon
Database Administ.	1	Financial Fundamentals	1,533.48	OT
Database Administ.	2	Polar Group 2003 Server Software	4,000.00	Yukon
Network Administ.	1	Exchange server	2,256.74	OT
IT Technical Support	1	Web Programming	2,845.53	OT
RRSP	20	Annual RRSP workshop	2,792.00	Yukon
Project Management	20	Project Management	23,297.96	Yukon
Powerful Presentations	10	Power Presentations	14,208.36	Yukon
Safety	10	TDG software	1,814.00	Yukon
Safety	40	Job safety planning	11,674.01	Yukon
Safety	12	St Johns First Aid	1,821.68	Yukon
Safety	1	2004 Safety training costs	599.70	Yukon
**Various Training Costs			2,096.22	Yukon
		Sub-Total Corporate Svcs	**79,221.85**	
President				
Supervisor, Communication		Electric Systems/Distrib for non-eng.	4,102.72	
		Sub-Total President & CEO	**4,102.72**	
		Grand Total	**176,951.31**	

2006 Training Costs

Department	# of Employees	Training Description	Cost	Location
				OT - Out of Territory
Engineering Services				
Director, Tech Services	3	WHMS & TDG	300.00	Yukon
Supervisor, Mechanical/Civil Engineering	1	Hydrology Workshop	2,410.29	OT
Supervisor, Electrical Engineering	1	Hydro Generator Maintenance	2,623.98	OT
Supervisor, Electrical Engineering	1	Arc Flash & Protection / Electrical Safety Training	1,847.41	OT
Electrical Engineer	1	Relay	5,449.57	OT
Distribution Technologist	1	Staking Technician Certification Program	4,962.35	OT
Civil Engineer	1	Envir. Mgt System	3,779.02	OT
Electrical Engineer	1	GE Course from 2005	60.95	Yukon
Land Technician		Achieving Your Highest Potential	445.00	Yukon
Land Technician		Engineering Plan Development	1,671.59	OT
YESA/PLC	7	Local Short Courses	1,205.50	Yukon
Technical Services	13	Monthly working lunches	1,429.09	Yukon
		Sub-Total Technical Services	**25,884.75**	
Operations				
Director	1	Transformer Diagnostics - not taken, credit with Air Canada	3,313.99	OT
Mtce Electrician	1	PSE Apprenticeship	3,341.87	OT
Mtce Electrician	1	Circuit Breaker & Switchgear Testing & Maintenance & Application Forum	1,645.49	OT
Mtce Electrician	3	Breaker Test Set Training	1,640.54	Yukon
Leadhand, Electrical	1	Arc Flash Protection & Electrical Safety Training	2,012.91	OT
Power Line Tech	1	PLT Apprenticeship	1,770.91	OT
SCC Operator	2	System Protection	6,881.11	OT
Warehouse Admin.	1	Forklift Certification	1,665.90	OT
Mtce Mechanic	1	Supervisory Level I	750.00	Yukon
Mtce Mechanic	1	Diesel Conference	2,474.99	Yukon
Mtce Mechanic	1	Practices-Maintenance & Operations	3,086.95	OT
Power Line Tech	1	Microsoft Office	125.00	Yukon
Mtce Electrician	1	Canadian Electrical Code Essentials	805.50	Yukon
Mtce Electrician	2	National Building Code Part 3	800.00	Yukon
Mtce Electrician	1	Coaching & Mentoring	1,990.00	OT
Coordinator, Property & Security	1	NRC Finance	200.00	Yukon
		Sub-Total Operations	**32,505.16**	
Finance				
CFO	2	Risk & Insurance Management Conference	4,979.46	OT
CFO	1	2006 International Risk Management Conference	3,735.40	OT
Supervisor, Financial & Risk Mgt.		CICA Handbook Accounting Refresher	1,764.64	OT
Financial Administrator	1	Payroll course	831.04	Yukon
Financial Administrator	2	Year End - Payroll Course	620.00	Yukon
Financial Administrator	1	Access	135.00	Yukon
Financial Systems Administrator	1	Advanced Excel - Vancouver	1,843.54	OT
Financial Systems Administrator	1	Conflict Resolution	329.90	Yukon
Buyer	1	Specification Writing	209.17	Yukon
Buyer	2	Laws of Agency & Employment & Competitive Bidding	1,175.00	IT
Buyer	2	Contract Administration	5,491.33	OT
		Sub-Total Finance	**21,114.48**	
Resource Planning & Regulatory Affairs				
Director		Cost of Service	5,563.78	OT
Director		Strategic Management	1,846.96	Yukon
Director		Analytical Tools	1,846.96	Yukon
		Sub-Total Resource Dev't	**9,257.70**	
HR & Information Mangement				
Director	1	Recruitment & Selection-corresp.	145.00	Yukon
Director	4	Records Mgmt Essentials	3,400.00	Yukon
Director	1	Succession Planning / Recruitment	5,510.71	OT
Director	1	Labour Relations	2,173.34	OT
HR/Records Mgmt Advisor	1	ARMA Conference	3,106.27	OT
HR/Records Mgmt Advisor	1	Workforce	2,885.96	OT
Administrative Assistant	1	Human Resource Mgmt	274.43	Yukon
Network Administ.	1	Conflict Management	350.00	Yukon
	11	Advanced Excel	1,846.78	Yukon
Supervisory	15	Leadership Challenge	6,030.96	Yukon
	15	Appropriate Workplace Conduct	813.05	Yukon
Safety	12	1st Aid	1,163.49	Yukon
Safety	19	Fall Arrest Training	6,401.60	Yukon
	10	HMI Training	15,162.82	Yukon
Safety	20	ATV & Snowmobile operations	1,092.88	Yukon
Cancelled Course Costs			687.68	Yukon
Cost recovered from City of Whitehorse for Powerful Presentations			(4,950.18)	
		Sub-Total HR & Information Management	**46,094.79**	
President				
Director, Health Safety & Environment	1	H & S Conference	1,356.74	OT
Director, Health Safety & Environment	1	Arc Flash & Protection/Electrical Safety Training	1,862.34	OT
Supervisor, Communication	1	Adobe	125.00	Yukon
Supervisor, Communication	1	Developing Satisfaction Surveys	499.00	Yukon
		Sub-Total President & CEO	**3,843.08**	
		Grand Total	**138,699.96**	

2007 Training Costs

Department	# of Employees	Training Description	Cost	Location
				OT - Out of Territory
HR & Information Management				
Database Administrator	1	Developing MS SAP.NET Web Applications	1,923	OT
Database Administrator	1	Dreamweaver	200	Yukon
HR Advisor	1	Records Management	5,938	OT
Documentation Specialist	1	CSA Workplace Electrical Safety Conference 2007	5,420	OT
		CSA Lockout - Control of Hazardous Energy	0	OT
Director HR & Information Mgmt	1	Labour Relations	1,135	OT
		Sub-Total HR & Information Management	**14,615**	
Engineering Services				
Director, Engineering Services	1	Essential Management Skills	3,639	OT
Electrical Engineer	1	Dist & Tx Line Design, NWPPA courses	3,580	OT
Electrical Engineer	1	Load Sharing & Speed Controls	3,837	OT
Draftsperson	1	Microstation V8 2D Level II	1,187	OT
Supervisor, Mech & Civil Engineering	1	Permafrost Construction, Uof A	4,030	OT
Coordinator Capital Projects	1	MS Project Comprehensive Intro	4,415	OT
Director, Engineering Services	2	Dam Safety & Inspection	420	Yukon
Electrical Engineer	2	Time Management	840	Yukon
Various	7	The Art Form of Specification Writing	490	Yukon
		Sub-Total Engineering Services	**22,438**	
Finance				
Controller	1	Leadership training (succession plan)	2,259	OT
Controller	1	IFRS - A Comparison to Canadian GAAP	1,220	OT
Supervisor, Financial & Risk Management	1	Accounting Refresher	1,194	OT
Financial Administrator	1	Dealing with Anger	350	Yukon
Buyer	1	PMAC courses	150	Yukon
Buyer	1	PMAC courses	110	Yukon
Buyer	1	Risk Management	1,853	OT
Procurement & Contract Administrator	1	A Beginner's Guide to P-Cards	118	Yukon
Procurement & Contract Administrator	1	Principals of Buying	500	Yukon
Procurement & Contract Administrator	1	Drafting Procurement Contracts	400	Yukon
Procurement & Contract Administrator	1	Law of Contracts	400	Yukon
Procurement & Contract Administrator	1	Drafting Contracts I	700	Yukon
Procurement & Contract Administrator	1	Laws of RFP's & RFQ's	1,386	OT
Procurement & Contract Administrator	1	Contract Admin for Services	104	Yukon
Procurement & Contract Administrator	1	Wellness Workshop	50	Yukon
		Canadian Payroll Association	99	Yukon
	1	2006 Training Costs	104	Yukon
	2		6,460	OT
		Sub-Total Finance	**17,455**	
President				
Manager, Environmental Assessment	1	Managing Environmental Impacts of Linear Corridors & Infrastructure	2,455	OT
		Sub-Total President	**2,455**	
Operations				
Leadhand SCC	2	Omega Lift Inc. - Equipment Orientation	1,230	OT
Leadhand, Electrical Maintenance	1	Coaching/Mentoring & Leading High Perfmance teams	1,661	OT
Maintenance Electrician	1	Level 2 Thermography Training	3,824	OT
Maintenance Electrician	1	Appretiship Training - PSE	9	Yukon
Various	4	AVTS Training	2,085	Yukon
Various	3	Class 3 to Class 1 License Upgrade	3,592	Yukon
PLT	1	Apprenticeship - PLT	5,386	OT
Director, Operations	1	Doble - Life of a Transformer	1,863	OT
Director, Operations	1	Duty to Accommodate	3,307	OT
Manager, Operations	1	Coaching & Mentoring & Guidelines for a New Manager	3,691	OT
		Sub-Total Operations	**26,649**	
Health & Safety				
Various Employees	15	First Aid	1,452	Yukon
Various Employees	12	Fall Arrest (completion of remaing employees from last year)	7,302	Yukon
Various Employees	35	Arch Flash Awareness	15,064	Yukon
Various Employees	18	Equipotenial Bonding & Grounding	7,200	Yukon
		2006 Costs	138	Yukon
		Sub-Total Health & Safety	**31,156**	
Corporate Training				
Various Employees	20	Retirement Planning & Financial Education	17,000	Yukon
Various Employees	20	Puchasing Best Practices	8,201	Yukon
Various Employees	42	SharePoint training	1,162	Yukon
Various Employees		Training Materials	1,161	Yukon
		Sub-Total Corporate	**27,524**	
		Grand-Total	**142,292**	

2008 Training Budget

Department	Training Description	# of Employees	Estimated Training Costs	Training Location
Operations				OT - Out of Territory
2 PLT's	Metering Course	2	3,900.00	OT
Leadhand, T&D	Transmission Equipotential Training	1	1,500.00	OT
Leadhand, Electrical Maintenance	Essential Management Skills	1	3,895.00	OT
Maintenance Electrician	Hands on Relay school (Basic)	1	2,485.00	OT
Leadhand, SCC	Scada User Group Meeting	1	3,395.00	OT
Maintenance Mechanic	Governor School Training	1	3,850.00	OT
Maintenance Mechanic	Governor School Training	1	3,850.00	OT
Maintenance Mechanic	Supervisor Level II	1	800.00	OT
Plant Operator	Generating Station-IPP Operators	1	2,750.00	OT
Plant Operator	Generating Station-IPP Operators	1	2,750.00	OT
Manager, Operations	Communication Skills for Managers	1	3,850.00	OT
Apprentice PLT	Powerline Technician - 3rd level	1	100.00	OT
Apprentice PLT	Powerline Technician - 1st level	1	4,000.00	OT
Apprentice PLT	Powerline Technician - 1st level	1	4,000.00	OT
Apprentice Heavy Duty Equipment Technician	Heavy Duty Equipment Technician (Off Road) 1st Level	1	4,000.00	OT
Apprentice PLT	Powerline Technician - 3rd level	1	1,000.00	OT
Apprentice, PSE	Power System Electrician-3rd level	1	4,000.00	OT
Director, Operations	Improving Asset Reliability through Operations Management	1	2,450.00	OT
	Sub-Total Operations		**52,575.00**	
Engineering Services				
Supervisor, Electrical Engineering	Leadership Skills	1	3,000.00	OT
Supervisor, Mechanical/Civil Engineering	Resource & Cost Estimating or	1	3,950.00	OT
Draftsperson	File Management/Info System	1	500.00	Yukon
Draftsperson	File Management/Info System	1	500.00	Yukon
Supervisor, Electrical Engineering	Leadership Skills	1	3,500.00	OT
Electrical Engineer	Effective Communication/Delegation	1	1,200.00	Yukon
Distribution Technician	Interpersonal Communications	1	1,200.00	Yukon
EE Department	PSS-SinCal for Engineers	7	10,250.00	Yukon
Engineering Services	Local Short Courses	10	2,500.00	Yukon
	Sub-Total Engineering Services		**26,600.00**	
HR & Information Management				
Network Administrator	Project Management-Tools & Techniques	1	950.00	Yukon
Database Administrator	Introduction to XML and Microsoft.Net Platform	1	2,950.00	OT
Network/Systems Administrator	Project Mgt for Information Systems	1	750.00	Yukon
HR Advisor	Human Resources	1	2,900.00	OT
Records Mgt Analyst	Records Management	1	2,900.00	OT
Director. HR & Information Management	Labour Relations	1	2,900.00	OT
	Sub-Total HR & Information Management		**13,350.00**	
President				
Vacant-VP Ops & ENG	Leadership or Technical	1	3,150.00	OT
Corporate Secretary	Administrative Professional Course	1	3,600.00	OT
Manager, Environment Assessment & Licensing	ISO 14001 Essentials	1	2,395.00	OT
Supervisor, Communications	How to prepare and care for museum displays	1	2,420.00	OT
Supervisor, Communications	Corel Paint Shop program - training	1	200.00	Yukon
	Sub-Total President		**11,765.00**	
Business Development				
Director, Resource Planning & Regulatory Affairs	Utility performance standards	1	2,685.00	OT
Director, Resource Planning & Regulatory Affairs	Value Analysis Seminar	1	315.00	Yukon
	Sub-Total Business Development		**3,000.00**	
Finance				
Controller	Accounting Update	1	1,628.45	OT
Controller	2007 Expenses	1	146.55	
Controller	IFRS	1	600.00	Yukon
Financial Administrator	Fundamentals of JDE	1	750.00	Yukon
Financial Administrator	Payroll Certification	1	250.00	Yukon
Financial Administrator	Taxable Benefits Seminar	1	350.00	Yukon
Financial Administrator	Fundamentals of JDE	1	750.00	Yukon
Financial Administrator	Fundamentals of JDE	1	750.00	Yukon
Financial Administrator	Pay at Work	1	200.00	Yukon
Financial Administrator	Taxable Benefits Seminar	1	350.00	Yukon
AP Clerk	Accoutning 101 & 102	1	650.00	Yukon
Sr. Office Administrator	Train the trainer course for the new CIS system (estimated time is April 2008) See Note 1	1	2,340.00	OT
Sr. Office Administrator	Training on the CIS system at the YECL office	1	3,525.00	Yukon
Office Administrator	Training on the CIS system at the YECL office	1	3,525.00	Yukon
Office Administrator	Excel training at college	1	250.00	Yukon
Supervisor, Financial & Risk Management	Fundamentals of JDE	1	750.00	Yukon
Supervisor, Financial & Risk Management	IFRS training	1	3,725.00	OT
Supervisor, Financial & Risk Management	IFRS training	1	600.00	Yukon
CFO	Cost of Service/Rate Design Training	1	1,980.00	OT
CFO	IFRS training	1	600.00	Yukon
Revenue & Financial Anaylst	Cost of Service/Rate Design Training	1	1,680.00	OT
Buyer	PMAC courses (Approved 1 course only)	1	375.00	Yukon
	Sub-Total Finance		**25,775.00**	
Health & Safety				
Manager, Health & Safety	Overview of Electrical Operations	1	1,600.00	OT
Various	Wellness Program		5,000.00	Yukon
5 employees	Air Brake Endoresement	5	500.00	Yukon
31 employees	Arc Flash Awareness Video	31	200.00	Yukon
17 employees	Audiograms	14	425.00	Yukon
6 employees	Confined Space Entry, Work & Rescue	6	540.00	Yukon
12 employees	Principles of H&S Mgt	12	1,080.00	Yukon
12 employees	Leadership for Safety Excellence	12	2,160.00	Yukon
3 employees	Auditor Training	3	540.00	Yukon
5 employees	Crane Oper (7,300 kg -13,600 kg)	5	2,500.00	Yukon
5 employees	Crane Operator (> 13,600 kg)	5	2,500.00	Yukon
6 employees	Fall Arrest – Working At Heights	6	540.00	Yukon
6 employees	JH&SC trng for new Reps	6	540.00	Yukon
24 employees	Snowmachine Operations	24	0.00	Yukon
10 employees	Standard First Aid	10	1,400.00	Yukon
60 employees	Substance Abuse Workshop	60	5,400.00	Yukon
34 employees	WHMIS	34	340.00	Yukon
	Sub-Total Health & Safety		**25,265.00**	
Corporate				
All Employees	Retirement Planning & Financial Education	40	10,700	Yukon
All Employees	Approprite Workplace Conduct	75	2,000	Yukon
5 employees	SharePoint-Train the Trainer	5	18,000	Yukon
6 employees	DRP - costs in each department	6		Yukon
Various	Contingency Fund-10% of Budget		11,820	Yukon
	Sub-Total Corporate		**42,520**	
	Total 2008 Budget		**$200,850**	

2009 Training Budget

Department	Training Description	# of Employees	Cost	Training Location
Resource Planning				OT- Out of Territory
Director, Resource Planning & Regulatory Affairs	Supply options alternatives (Geothermal, wind, solar or DSM)	1	3,500	OT
	Sub-Total Recourse Planning		**3,500**	
Finance				
CFO	CICA CFO Leadership Program	1	8,000	OT
Financial Adminstrator	CPA - Payroll Year End (last taken 2007)	1	500	Yukon
Financial Adminstrator	Advanced Excel	1	500	Yukon
Financial Adminstrator	CPA - Job Specific	1	500	Yukon
AP Clerk	Pay at work on-line training course	1	500	Yukon
Controller	Update on GAAP/IFRS	1	2,750	OT
Supervisor, Financial & Risk Management	IFRS - the next steps (anticipate a 2 day course)	1	1,900	OT
Sr. Office Administrator	Excel	1	130	Yukon
Office Adminstrator	Excel	1	130	Yukon
Revenue & Financial Analyst	Project Management	1	1,000	Yukon
Buyer or Cont Adm	Procurement	1	2,775	OT
	Sub-Total Finance		**18,685**	
HR & Information Management				
HR Advisor	Conflict Mgmt or a Supervision Course	1	500	Yukon
Director, HR & IM	HR Conference/Workshop	1	2,550	OT
Maintenance Electrician	Cisco Technician Entry	1	2,500	OT
Network/Systems Administrator	Cisco Networkers	1	3,600	OT
	Sub-Total HR & Information Management		**9,150**	
Environment				
Manager, Environment Assessment & Licensing	PMP (Project Management Professional) Certification Preparation	1	1,000	Yukon
Various	Spill Response	Various	5,000	Yukon
	Sub-Total Environment		**6,000**	
President				
Corporate Secretary	Administration /Corporate Governance	1	2,950	OT
Supervisor, Communications	Blogging - web seminar	1	300	Yukon
VP, Ops & Engineering	Leadership/Technical	1	3,500	OT
VP, Ops & Engineering	Contract Law - on-line	1	500	Yukon
	Sub-Total President		**7,250**	
Health & Safety				
Manager, H&S	Overview of Electrical Operations	1	2,200	OT
Supervisory & Managerial Staff (25)	Substance Abuse Workshop	25	3,085	Yukon
All who drive co. vehicles	Defensive Driving (*Partnering with YTG to save $$)	70	1,000	Yukon
24 employees	ATV Operations	24	5,340	Yukon
15 employees	Confined Space / Self Rescue	15	1,520	Yukon
20 employees	Standard First Aid	20	5,000	Yukon
10 employees	Crane Operator	10	5,000	Yukon
5 employees	JHSC Rep / Member Training	5	725	Yukon
All	Subscribe to online WHMIS/TDG	70	2,000	Yukon
35 employees	Medical Monitoring (audiograms, D/L medicals, etc.)	35	2,000	Yukon
	Sub-Total Health & Safety		**27,870**	
Operations				
Leadhand, Electrical Maintenance	PLC Maintenance for GE Fanuc	1	4,200	OT
Maintenance Electrician	SEL 351 R Recloser control	1	3,920	OT
Maintenance Electrician	Hands on Relay school (Basic)	1	2,485	OT
SCC Operator	SOS International - Power Starters	3	4,200	Yukon
PLT	Equipotential Grounding	2	5,900	Yukon
PLT	Training from EITI assessment?	2	6,000	OT
Maintenance Mechanic	American Governor School	1	4,245	OT
Maintenance Mechanic	Fluid Life	1	3,175	OT
Maintenance Mechanic	Class 1 Drivers License	1	2,000	Yukon
Maintenance Mechanic	Compresser Training	1	3,300	OT
Coordinator, Property & Security	Crime Prevention Through Environmental Design	1	800	Yukon
Director, Operatations	Management Training	1	2,550	OT
Manager, Operations	Management Training	1	2,550	OT
	Sub-Total Operations		**45,325**	
Engineering Services				
Supervisor, Mechanical/Civil Engineering	Resource & Cost Estimating	1	4,800	OT
Supervisor, Electrical Engineering	Leadership/Technical	1	2,550	OT
Ron Gee	CDA Dam Safety Workshop	1	2,300	OT
Draftsperson	Microstation 3D Level 1	2	4,800	OT
Director, Engineering Services	IRIS HydroGen Course or	1	3,700	OT
Electrical Engineer	Effective Communication/Delegation	1	1,200	Yukon
Electrical Engineer	Presentation Skills	1	800	Yukon
Distribution Technician	Interpersonal Communications	1	1,200	Yukon
6 Employees	MS Project Training	6	20,000	Yukon
T.S Local Training	Local Short Courses	10	2,500	Yukon
	Sub-Total Engineering Services		**43,850**	
Corporate				
Various Employees	RRSP Seminar		3,000	Yukon
Various Employees	Misc In-House short courses		1,370	Yukon
Various Employees	Office 2007 rollout		20,000	Yukon
	10% Contingency		25,000	Yukon
	Sub-Total Corporate		**49,370**	
	2009 Budget		**211,000**	

Apprenticeships

Apprentice PLT	Powerline Technician - 3rd level	2	7,000	OT
Apprentice Heavy Duty Equipment Technician	Industrial Mechanic - 1st level	1	3,500	OT
Apprentice Heavy Duty Equipment Technician	Industrial Mechanic - 2nd level	1	3,500	OT
Leadhand, Electrical Maintenance	Power System Electrician - 3rd Level	1	3,500	OT
Maintenance Electrican	Power System Electrician - 4th Level	1	3,500	OT
			21,000	

REFERENCE: **Page 3-12 line 10 through 27**

TOPIC: **General Administration**

PREAMBLE:

Yukon Electrical would like to better understand employee turn over

QUESTION:

a) In the positions described from line 10 to 27 on pages 3-12 please indicate the turnover in each position since 2005 and the reasons for the turnover.

b) Please indicate, when each position was filled, and if the individual was hired locally or recruited from outside the Yukon. If the latter, please identify the moving costs associated with attracting such employees.

ANSWER:

(a) and **(b)**

Please see the table provided below.

Position Name	Hire Date	Hired From	Moving Costs ($000)	Termination Date	Reason
Documentation Specialist	23-Apr-07	Whitehorse	N/A	9-Jun-08	Relocated out of territory
Manager, Environmental Assessment & Licencing	5-Oct-07	Whitehorse	N/A	N/A	
Records Management Analyst	4-Feb-08	Whitehorse	N/A	N/A	
2 Year Term Financial Administrator	15-Jul-08	Whitehorse	N/A	N/A	
Office Administrator - increase to .8 py	1-Mar-99	Dawson City	N/A	N/A	
Manager, Operations	21-Jul-07	Outside of Territory	$35	N/A	
Vice President Operations & Engineering	10-Mar-08	Outside of Territory	$53	N/A	
Coorindator Capital Projects	4-Feb-08	Whitehorse	N/A	N/A	
Maintenance Mechanic	6-Jun-06	Whitehorse	N/A	N/A	
Apprentice Powerline Technician	7-May-07	Whitehorse	N/A	N/A	
Apprentice Powerline Technician	1-Jan-07	Mayo	N/A	N/A	
Apprentice Powerline Technician	4-Jun-07	Whitehorse	N/A	13-Jul-07	Returned to previous employer
Engineering-In-Training	16-Oct-06	Whitehorse	N/A	19-Sep-08	Extended personal leave

REFERENCE: **Page 3-10 Table 3.9**

TOPIC: **General**

PREAMBLE:

Yukon Electrical would like to better understand the costs imbedded in General

QUESTION:

a) Please describe in detail the type of activities that take place in this account and the cost associated with each activity

b) Please detail the job classes that would charge time into this account. Indicate if the job class or position is in or out of scope.

ANSWER:

(a)

This is a general administration account that is used for corporate wide costs that do not belong to a unique function. These are costs required to administer the organization. Details of non-labour amounts are provided in YECL-YEC-1-38(b).

(b)

Please see Table provided below.

Position Name	Regular Time Percent Charged to General Admin.	**Union/Out of Scope or Confidential Exclusion**
President & CEO	63.00%	Out of Scope
Vice-President, Operations & Engineering	86.00%	Out of Scope
Coordinator, Property & Security	10.00%	Union
Leadhand, Transmission & Distribution	8.31%	Union
Powerline Technician	0.82%	Union
Powerline Technician	0.82%	Union
Senior Powerline Technician	3.86%	Union
Apprentice Powerline Technician	10.32%	Union
Senior Powerline Technician	9.72%	Union
Powerline Technician	8.00%	Union
Powerline Technician	15.00%	Union
Powerline Technician	1.00%	Union
Apprentice Powerline Technician	8.00%	Union
Maintenance Mechanic	5.00%	Union
Plant Operator II	5.00%	Union
Plant Operator I	5.00%	Union
Plant Operator I	2.00%	Union
Plant Operator I	5.00%	Union
Maintenance Electrician	1.00%	Union
Maintenance Electrician	1.00%	Union
Maintenance Electrician	1.00%	Union
Maintenance Electrician	1.00%	Union
Maintenance Electrician	1.00%	Union
Director, Health, Safety & Environment	10.00%	Out of Scope
Director, Technical Services	15.00%	Out of Scope
Coordinator, Capital Projects	5.00%	Union
Land Technician	5.00%	Union
Supervisor, Mechanical & Civil Engineering	25.00%	Out of Scope
Civil Engineer	15.00%	Out of Scope
Term Civil Engineer	10.00%	Out of Scope
Coordinator, Mechanical Projects	15.00%	Union
Draftsperson	20.00%	Union
Term Draftsperson	15.00%	Union
Supervisor, Electrical Engineering	20.00%	Out of Scope
Electrical Engineer	12.00%	Out of Scope
Electrical Engineer	12.00%	Out of Scope
Electrical Engineer	12.00%	Out of Scope
Distribution Technologist	3.00%	Union
Engineer in Training	12.00%	Out of Scope
Corporate Secretary	25.00%	Confidential Exclusion
Director, Human Resources & Information Management	60.00%	Out of Scope
HR & Records Management Advisor	96.00%	Confidential Exclusion
Administrative Assistant/Receptionist	97.00%	Confidential Exclusion
Relief Administrative Assistant	50.00%	Confidential Exclusion
Documentation Specialist	100.00%	Union
Records Management Analyst	100.00%	Confidential Exclusion
Chief Financial Officer	86.00%	Out of Scope
Revenue & Financial Analyst	50.00%	Union
Controller	70.00%	Out of Scope
Financial Systems Administrator	77.00%	Union
Financial Administrator	68.00%	Union
Accounts Payable Clerk	73.00%	Union
Financial Administrator	77.00%	Union
Term Financial Administrator	77.00%	Union
Supervisor, Financial & Risk Management	59.50%	Out of Scope
Senior Office Administrator	5.00%	Union
Manager, Environmental Assessment & Licensing	86.00%	Out of Scope

REFERENCE:

TOPIC: **General**

PREAMBLE:

Yukon Electrical is interested in understanding the steps YEC has taken to ensure productivity and efficiency of its organization.

QUESTION:

a) Please provide a listing of the initiatives demonstrating cost savings that YEC has under taken toward increasing productivity and where such productivity gains can be found in the application.

ANSWER:

(a)

The major increased improvement in the Application, resulting in savings to ratepayers, is timely completion of CSTP/MS and connection of Minto and Pelly Crossing to displace diesel generation with surplus hydro generation.

Yukon Energy strives for maximum use of resources in all areas of operations, as our application demonstrates. For example, additions to labour are only approved after thorough review by appropriate levels of management; see LE-YEC-1-32.

Internal labour resources for an ongoing required long-term activity are generally more affordable than external resources, so where a long-term need is identified, Yukon Energy will staff that position vs. using more expensive external consultants or contractors. One specific example of this concept is the creation of a records management position – this internal position is considerably less expensive than a consultant, and, as well, creation of a proper records management system allows other employees to be more productive in terms of the ease of access to records.

Yukon Energy feels that the pattern of costs shown in the application demonstrates a commitment to providing for the needs of our customers while ensuring costs do not

increase disproportionately. Other initiatives like our Employee Wellness program, helps to keep employees operating at maximum effectiveness.

REFERENCE: **Page 3-11 lines 18~24 of application**

TOPIC: **Safety**

PREAMBLE:

Safety expenses have had significant fluctuations since 2005, increases of 42% in 2006, increases of 145% in 2007, decreases of 127% based on 2008 proposed and a forecast of a 174.5% increase for 2009. As per table 3.9 page 3-10 Yukon Electrical wishes to understand the variances in this activity

QUESTION:

a) Please provide variance explanations year over year from 2005 to 2009 for the safety account.

b) Please provide the detailed components and benefits associated with the additional $100,000 requested in 2009 for process documentation.

c) Please provide a copy of the most recent audit conducted by a third party or external source which verifies that YEC's safety program meets all legislative, regulatory and industry standards for an electrical utility. Please include all recommendations of the audit.

ANSWER:

(a)

Variance explanations ($000), year over year from 2005 to 2009 for Safety expenditures are provided below:

2006:
Spending in 2006 increased by approximately $16,000 over 2005. This increase is largely attributable to increased costs for purchasing Safety Aids ($6,000) and Contractor costs ($9,000).

2007:
Spending in 2007 increased by approximately $79,000 over 2006. This increase is largely attributable to one time increased costs related to legal expenses ($62,000) and for purchasing safety aids ($10,000).

2008:
Spending in 2008 decreased by approximately $73,000 compared to 2007. This decrease is largely attributable to reduced legal costs ($64,000) and reduced costs related to purchasing small tools ($15,000). These decreases were offset to a small degree by small increases in other cost categories.

2009:
Spending in 2009 is forecast to increase by approximately $103,000 compared to 2008. This increase is largely attributable to increased contractor costs ($102,000). This relates to the need to document YEC's safety procedures as described on Page 3-11.

(b)

The process documentation will address the following components and requirements:

- Section 3(1)(b) of the Occupational Health and Safety Act requires employers to document, so far as reasonably practicable, that work techniques and procedures are adopted and used that will prevent or reduce the risk of occupational illness and injury.

- Section 7 (d) of the Occupational Health and Safety Act requires, for prescribed workers, written instructions as to the measures and procedures to be taken for the worker.

- The Yukon Worker's Compensation Health and Safety Board also requires that safe work procedures be followed.

In order to address these requirements, and to ensure the health and safety of its workers, YEC creates and documents Safe Job Procedures (SJP) for the most applicable activities and undertaken by its employees. SJPs document the steps involved in completing a specific task in a manner that minimizes the potential for an

employee being exposed to a health or safety hazard. SJPs help to ensure quality control and are used to train workers in new or infrequently done tasks.

SJPs are reviewed frequently and require updating from time to time. SJPs are also required for new tasks. The added $100,000 in safety spending in 2009 will ensure that SJPs are updated for the applicable tasks done by the Corporation.

The benefits of the updated SJPs include allowing the Corporation to maintain its high standards for workplace health and safety and meeting or exceeding the requirements of the Yukon Occupational Health and Safety Act and the Yukon Worker's Compensation Health and Safety Board.

(c)

A key initiative in Yukon Energy's safety program over the last few years has been achieving registration under the Yukon's Certificate of Recognition (COR) program. In that context, the last audit conducted on YEC's health and safety management system occurred in 2008. The purpose of this review was to provide management with an assessment of the safety management system, with a view towards developing a plan for continuous improvement of this system, as well as preparing the organization for registration under the Yukon COR program. To qualify for registration, an external audit is required to be passed; conducting this internal review provided management with an opportunity to assess the system as is currently stands and focus improvements on key areas prior to engaging the external audit.

This audit was conducted by Yukon Energy's corporate health and safety manager, who carries certification as a Canadian Registered Safety Professional. In addition, this individual previously was employed by the Northern Safety Network, with overall responsibility for managing the COR program in Yukon on behalf of the Yukon Workers' Compensation Health & Safety Board (YWCHSB). The audit methodology used is nationally recognized and approved by the YWCHSB and Northern Safety Network Yukon as appropriate for this jurisdiction.

Attached is a narrative description of the auditor's findings, as well as the audit summary worksheet that describes the findings. Generally, the scoring was favorable for the Corporation, with the exception of the areas relating to Safe Work Practices and Safe

Job Procedures. The Corporation has committed budget dollars in the 2009 safety budget to improve these areas prior to the COR registration audit process.

December 19, 2008

To File:

Re: Certificate of Recognition Baseline Audit, YEC

The attached summarizes a Baseline Audit for Yukon Energy. The obvious commitment to a solid safe and healthy workplace was evident by the level of assistance provided by all staff.

It is anticipated that this organization will become an industry leader in Health and Safety. This executive summary will describe my findings while conducting the Audit and provide the reader with an 'element by element' snapshot of the organization's health and safety systems. For this audit, I have used the audit instrument approved by the Canadian Federation of Construction Safety Associations, the YWCHSB and the Northern Safety Network Yukon.

3 Worksites visited
9 Management/Supervisor interviews
7 Worker interviews
0 Contractors were interviewed

Element 1
The Corporate Health & Policy Statement and the 1-page 'Commitment to Health & Safety' documents are posted throughout all YEC's sites and available to all employees through the intranet. Managers, Supervisors and Workers are aware of their responsibilities and accountabilities in respect of health and safety. Good job on this element.

Element 2
Hazard Assessment and Control – Hazard Assessments are available for all critical tasks and most are prioritized according to risk. It does appear however, that Hazard Assessments are not being undertaken on each project. The recommendation is that Hazard Assessments be completed on each project and involve/include the affected workers.

Element 3
The *most applicable/critical* safe work practices (SWP's) are either missing or out of date. The organization did not receive the required 50% score to pass this element of the audit. The safe work practices are guidelines or general "DO's & DON'Ts" on how to carry out specific tasks. SWP's are designed to inform the worker about the known hazards that are present and provide direction on how to safeguard against the hazard. During the audit, it was noted that there is a consultant and a 'Subject-Matter-Expert' (a YEC retiree) developing Safe Work Practices. The recommendation here is that the SWP development continues for all critical tasks and be completed prior to the COR audit planned for mid-2009.

Element 4
As in Element 3 above, safe job procedures (SJPs) were in the process of being developed during the audit. Those that were found appeared to be complete and were easy to understand but review dates were passed.

Again, the *most critical/applicable* SJPs were not found during this audit. The recommendation here is that the SJP development continue and be completed prior to the COR audit in mid-2009.

Element 5
Company rules were written, and available for all employees to read (on the intranet) and interviews supported that workers receive the rules and Code of Conduct training as part of their safety orientation on or about day one of employment. Good job on this element.

Element 6
The PPE use at YEC has become second nature to the workforce. Very good job in this element. The Policy on PPE seems to deliver an effective message. The supervisors include PPE use as an evaluation item in performance reviews. Specialized PPE is available, including the SCBA apparatus as the Aishihik facility. Hearing protection is also available and is used when required. Minutes from previous years' JHSC meetings confirm the Committee has assisted by developing standard selection criteria for certain PPE items such as hard hats and flame resistant clothing.

Element 7
The maintenance records for diesel generators, substation equipment and other mechanical or electrical components are clear, concise and meticulously kept. PM schedules for all equipment and rolling stock including forklifts are up to date and adhered to. The audit did not uncover a system to remove defective tools from service. The recommendation is to ensure there is a system to remove defective or broken tools from service and the workers are trained accordingly. Overall though, a good job on this element of the audit.

Element 8
Training and Communications. Documentation confirmed that the health and safety orientation for employees and contractors is clear and mandatory. All employees receive a full orientation to the H&S program and non-administrative employees complete a WHMIS training session as well. (If required, a TDG training session is also carried out.) Employees and Contractors receive an Orientation Guide Booklet. The inclusion of Bear Awareness and Helicopter Safety is a useful and pertinent part of the YEC orientation. Some employees would like to see the Contractors receive a wallet-sized card confirming "Safety Orientation Completed". I agree, this would be a good addition to the orientation program.

Many of the staff have completed the PHSM and LSE courses offered by the NSNY. *(Principles of Health & Safety Management and Leadership for Safety Excellence)* It was also apparent that the training plans for 2009 include a Crane Operator certification program, Arc flash and ATV training. By using the qualified trainers at NSNY, Orbis Engineering and the Department of Environment we will be assured of consistent curriculum that is kept up to date. Weekly and monthly safety meetings are done and this was verified through review of minutes from Whitehorse and the communities.

Element 9
Inspections. While standardized forms are in place and used, the documentation confirmed that site inspections are not being carried out as frequently as stated in the company policy. There was also no evidence of senior management participating in inspections. Most inspections are carried out by the Manager, Health and Safety, Supervisors and the JHSC members and representatives. Work areas are inspected, including communities. The senior managers review and sign off the inspection sheets with the H&S Manager. The recommendation here is to encourage managers' participation in the site inspections on at least a quarterly basis.

Element 10
Investigations are carried out for vehicle, property, third party, near miss, first aid and medical incidents. Verified by reviewing incident reports. Most supervisors have been trained to investigate incidents, but not all. Fortunately the incident frequency at YEC has been low in 2008 leaving limited opportunity for worker participation this year. In every case the Manager, Health & Safety and members of the JHSC and senior management participate in incident investigations. In some cases members of the Risk Management committee also participate. Investigation training has been provided by a group out of Alberta called "Utility Risk Management." Recommendations and results from the Incident Reports are reviewed on a monthly basis by the JHSC and the President. Recommend that all supervisors and/or lead hands complete Incident Investigation Training in 2009.

Element 11
Emergency Preparedness, First Aid Services, Fire Fighting and Emergency Communications. YEC has done an excellent job on this section of the audit. The emergency response protocol is current and appears to take into account all hazards regarding hydro generation, transmission and distribution. Observed site evacuation plans in all offices and common areas in Whitehorse that were up to date. First aid kits are compliant with the Yukon's Minimum First Aid Regulations and confirmed that in addition to 22 standard first aiders in the organization, there are now 3 Advanced First Aid persons based in Whitehorse. The Procedures for Emergency Evacuation are posted on the intranet and the employees interviewed knew where to find them. The ER Notification Matrix is also current and available to all. It was also noted that this is included in the Orientation package for all employees and contractors. Employees know how to use the satellite phone systems (Iridium) and the SPOT TPS transponder systems that all employees use in company trucks.

Element 12
Statistics and records are available and confirm that monthly and annual summaries are kept. Through YEC's affiliation with the Canadian Electricity Association the annual *KPI's* show progress and confirm YEC is a leader in the utility industry when it comes to frequency and severity figures. Through a H&S newsletter the workforce is kept informed on the company's H&S records and know how YEC compares to other utilities.

Element 13
Legislation. Incident reporting is done and conforms to Yukon's OHS Act. In all cases YEC is meeting the requirements of the YWCHSB's Occupational Health and Safety Regulations – although as mentioned in my review of Elements 3 and 4, more *written* safe job procedures are required to ensure compliance with the regulations and earn YEC the minimum 50% passing mark on audited elements 3 and 4. Interviews confirmed that employees understand their legislated responsibilities and know how to report incidents, near misses, vehicular and 3rd party incidents.

Medical monitoring is done and confirmed through review of annual audiometric test results for YEC employees employed in noise-exposure occupations.

Element 14
As required, YEC has a well established and committed JHSC. The committee meets on the 3rd Thursday of every month. In 2008 the Committee was never without a quorum. Reps are elected by their peers and all work sections and communities are represented. The Committee members have completed the training required by the Yukons OH&S Act. The Committee has representation of both labour and management and the Manager, H&S acts as a neutral advisor to the Committee. Minutes of meetings and Action Checklists are posted on the intranet and all workers read them after each meeting. (Verified by interview.) JHSC's recommendations made to the President are documented. At every JHSC meeting Incident Reports are

reviewed. The YEC JHSC's commitment to a safe and healthy workplace is proven by their interest and involvement in the company H&S program.

In Summary

Overall the health and safety program is well structured, well documented and easy to follow. This audit resulted in a very high score of 86%, although due to the low scores in Elements 3 and 4, Yukon Energy did not 'pass' the NSNY audit. If this were an audit for COR, the organization may qualify for a *Limited Scope Audit*.

At this time, it is my recommendation that *before* contracting another external auditor to complete the COR audit, we will use this *baseline audit* as a starting point to develop an Action Plan and ensure the missing SJP's and SWP's are in place.

Melanie Pettefer,
Canadian Registered Safety Professional 00-1730
Certified Auditor #05-11-1828

NSNY *Audit Document:* **Audit Summary Sheet**

Company YUKON ENERGY Name of Auditor M. PETTEFER Date of Audit JUNE 24/08

Element #	Element Name	Possible Score	Actual Score	Minimum Standard	Auditor Comments
1	(Corporate) Safety Policy	17	17	9	Good job on this element
2	Hazard Assessment	40	31	20	Prioritize/Rate hazards
3	Safe Work Practices–Implementation	7	3	4	Most applicable/critical SWP's missing
4	Job Procedures–Implementation	8	2	4	" " " SJP's missing
5	Company Rules	6	6	3	Good work/communication
6	Personal Protective Equipment	10	10	5	Good job on PPE use
7	Preventative Maintenance	6	4	3	Beef up defective tool removal rule
8	Training and Communication	40	40	20	Excellent!
9	Inspections	24	19	12	Training req'd here
10	Investigations	27	23	14	More training req'd
11	Emergency Preparedness	24	24	12	ERP & DRP are up to date
12	Statistics and Records	6	6	5	This is YEC's 1st audit.
13	Legislation	9	9	5	Due diligence! Good job.
	TOTAL (where element 14 is N/A)	**228**	194		
14	JH&SC and Safety Representatives	15	15	8	Well done
	TOTAL (with element 14)	**243**	209		

Minimum Standard = 80% overall score and 50% each element

Actual Score / Possible Score x 100 = 86 %

Standard Achieved: **YES** ____ **NO** X

Reviewed: _____
Senior Organization/Company Officer

Auditor Signature: M Pettefer

Goal for Next Audit: 86 % Percentage

The goal for the next audit must be set by the organization/company representative

REFERENCE: **Page 3 - 11, lines 18 through 23**

TOPIC: **Safety/Training**

PREAMBLE:

Footnote 6, suggests procedures be in place and workers be trained to perform jobs safely. Table 3.9 Training

QUESTION:

a) Please provide the types of training identified and number of employees requiring the training along with the associated costs of each training activity.

b) Please provide details as to what facility employees will receive trade related training at, specific to each job class identified.

c) Please provide the average cost per employee for the required training.

ANSWER:

(a), **(b)** and **(c)**

For 2009, the types of training, number of employees requiring training and associated costs of each training activity are anticipated as follows:

- **The Crane Safety Regulations:** The Occupational Health and Safety Regulations (OHS), Part 5, require YEC to ensure all operators of mobile cranes are assessed and are competent to operate. This training will be offered to all employees who operate mobile cranes. This is a new regulation (2006) and the requirement to ensure competency for crane operators must be met before July 1, 2009. The cost of training is $500 per person, plus GST. There are 23 employees that require this training. The trainer and assessors are from BC and are approved by the Yukon Worker's Compensation Health and Safety Board (YWCHSB).

- **Training for Confined Space Entry and Self Rescue:** This training is required in order to comply with OHS Regulations, Part 2. Local trainers will deliver this material. Fifteen employees will receive this training at an estimated cost of $1520.

- **Substance Abuse Awareness:** This training is provided for supervisors and lead hands. Estimated cost is $3,085. There are 25 employees receiving this training.

- **Certification of Recognition (COR) Training:** This training will continue at an estimated cost of $100 per employee. Twenty employees require this training.

- **Hazard Assessment & Control Training:** The training is provided to employees to ensure that they learn the correct use of hazard assessment and control methods. The estimated cost of this training is $75 per employee. This training will be provided to 30 employees (at a half day course offered by the NSNY/YWCHSB).

- **Arc Flash Awareness:** This training will be one day duration and is being offered by Orbis Engineering. This will be offered to all employees in trades as well as non-technical managers and supervisors. The estimated cost of this training is $11,000.

Most training will be carried out at the Whitehorse facility; however, employees in communities outside Whitehorse will also be participating. Schedule accommodation is being provided to allow for travel to Whitehorse.

See also YECL-YEC-1-43 for actual and budgeted spending on individual training courses in 2005 to 2009.

REFERENCE: **YEC state that an additional 100K is required in 2009 to document YEC's safety procedures with specific reference to the legal requirements of the Yukon Occupational Health and Safety Act Sections 3(1)(b), 3(1)(c) and 7(d)**

TOPIC: **Safety/Legal Requirements**

PREAMBLE:

Yukon Electrical would like to better understand to what safety standard YEC is operating under.

QUESTION:

a) Since the Occupational and Safety Act has been in effect since December of 1992, what documented procedural tools as YEC used to date, and are currently using, to meet the legal requirements of the Act?

b) To what industry standard are the newly documented safety procedures written?

c) Are these increased costs for safety / training at YEC related to Certificate of Recognition (COR) certification requirements. If so what are the specific costs of COR certification that are included in this current GRA application?

d) Please confirm if YEC is COR certified. If COR certification is not in place, please confirm when YEC anticipates COR certification will be completed.

e) What process does YEC currently use to ensure employees who work in safety sensitive positions are adequately trained and qualified?

f) Is the safety training for YEC employees available locally? Specifically where and by whom is the training provided.

g) Please provide the number of medical aid and lost time incidents experienced by YEC for each of the years 1997 to present. Please include the number of days lost per year.

ANSWER:

(a)

Yukon Energy has been using and continues to use written procedures. Yukon Energy is addressing the requirements in the Yukon's OHS Regulations, to provide written and verbal instructions to complete tasks. Factors being considered are frequency or infrequency of tasks as well as risk and hazard assessments.

(b)

Newly documented Safe Job Procedures (SJPs) conform with Yukon Worker's Compensation Health and Safety Board (YWCHSB) Occupational Health and Safety regulations, the Alberta Electrical Utility Code, CSA and utility industry best practices.

(c)

Yes, some costs are related to the Certificate of Recognition (COR) certification requirements. Specific and anticipated costs include training for employees and contracting an external auditor (estimated $7,000-10,000). See also response to YECL-YEC-1-48(a).

(d)

YEC is not currently COR certified, but anticipates such certification in the third quarter of 2009.

(e)

All workers are trained in the safe operation of equipment and processes. Workers are required to demonstrate competency including familiarity with operating instructions, procedures and safe work practices.

Lead Hands, Supervisors and Managers are also aware of their duties in respect of health and safety as set out in Yukon's OHS Act.

YEC ensures employees are adequately trained and qualified in the following ways:

- As trades and journeypersons employees each have their own specific knowledge, training and experience.

- Employee safety demonstrations review the provisions of the OH&S Act, providing employees with knowledge of and familiarity with these provisions.

- Through employee safety orientations, employees are made aware, and have knowledge of, any potential or actual danger to health or safety in the workplace.

Job-specific and new employees' training is verified through the review of training records, and orientations. Refresher training is scheduled and is documented.

Training is conducted by qualified persons.

(f)

Some safety training is available locally. Some contracted trainers include Orbis Engineering, Northern Safety Network, and Fulford Harbour (for crane operator competency assessments).

(g)

For the number of medical aid and lost time incidents experienced by YEC for each of the years 2005 (the date of YEC's last Revenue Requirement Application) to present, as well as the number of days lost, please see the table below.

Year	Medical Aids	LTA's	Days Lost
2008	**4**	**0**	**0**
2007	**2**	**0**	**0**
2006	**5**	**3**	**30**
2005	**5**	**1**	**5**

REFERENCE: **Introduction Page 2-12**

TOPIC: **Diesel Generation**

PREAMBLE:

Yukon Electrical wishes to better understand the way in which diesel will be consumed in the test period.

QUESTION:

a) Please provide the monthly load duration curves for 2008 and 2009.

b) Please overlay hydro supply levels on the above curves.

c) Please provide the same curves with and without Secondary Sales.

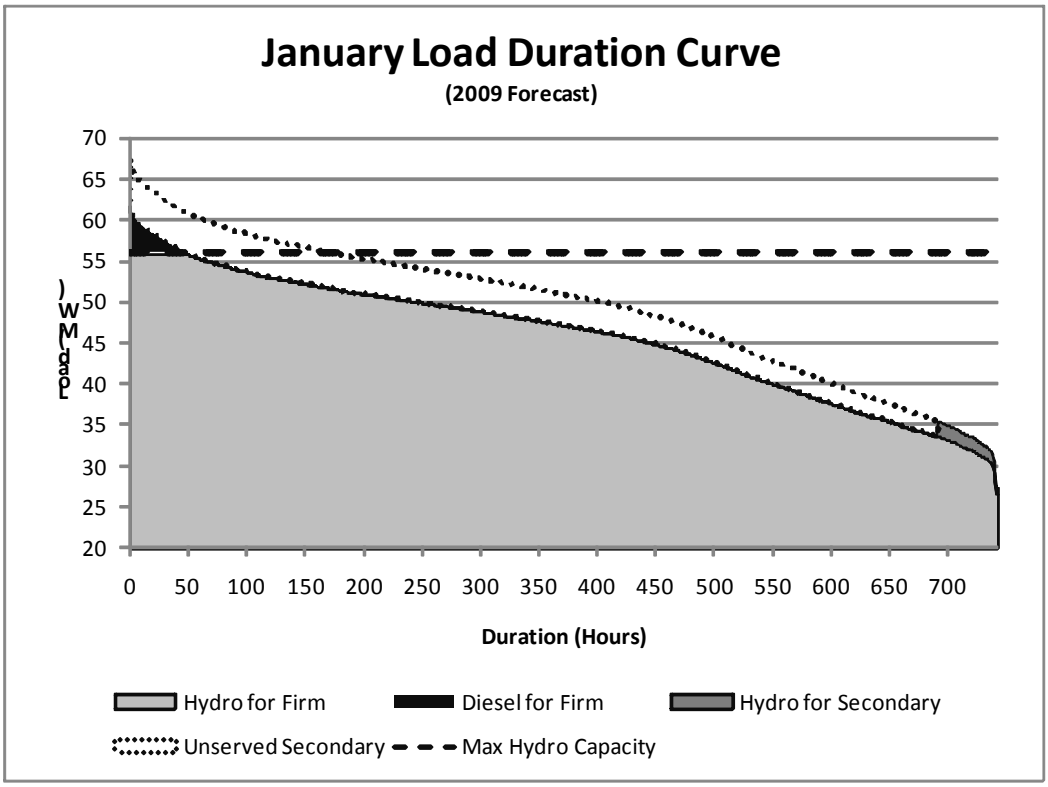
d) Please provide a diesel unit availability chart for each unit.

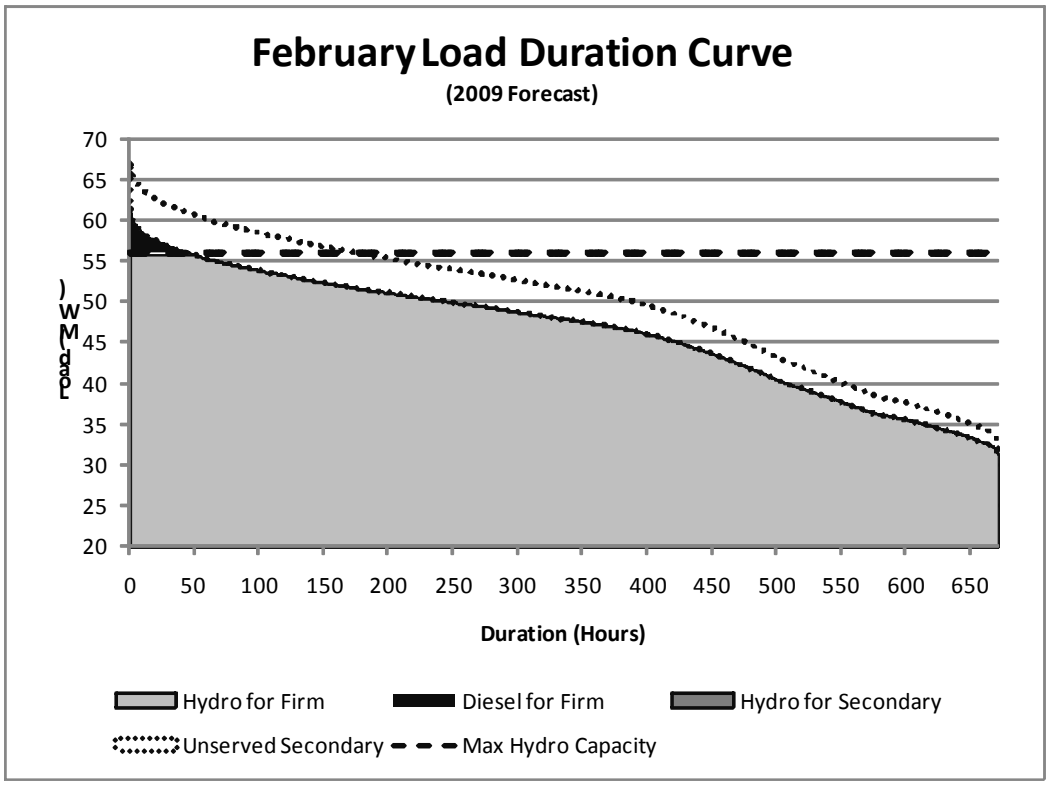
e) In the 20 year Resource plan page 9 it mentions that the Mirrlees rebuilds will ADD capacity to the WAF grid. Were these units removed from rate base and from the WAF grid? Please provide the technical feasibility study done on the Mirrlees referred to in the 20 year Resource Plan on page 9.

ANSWER:

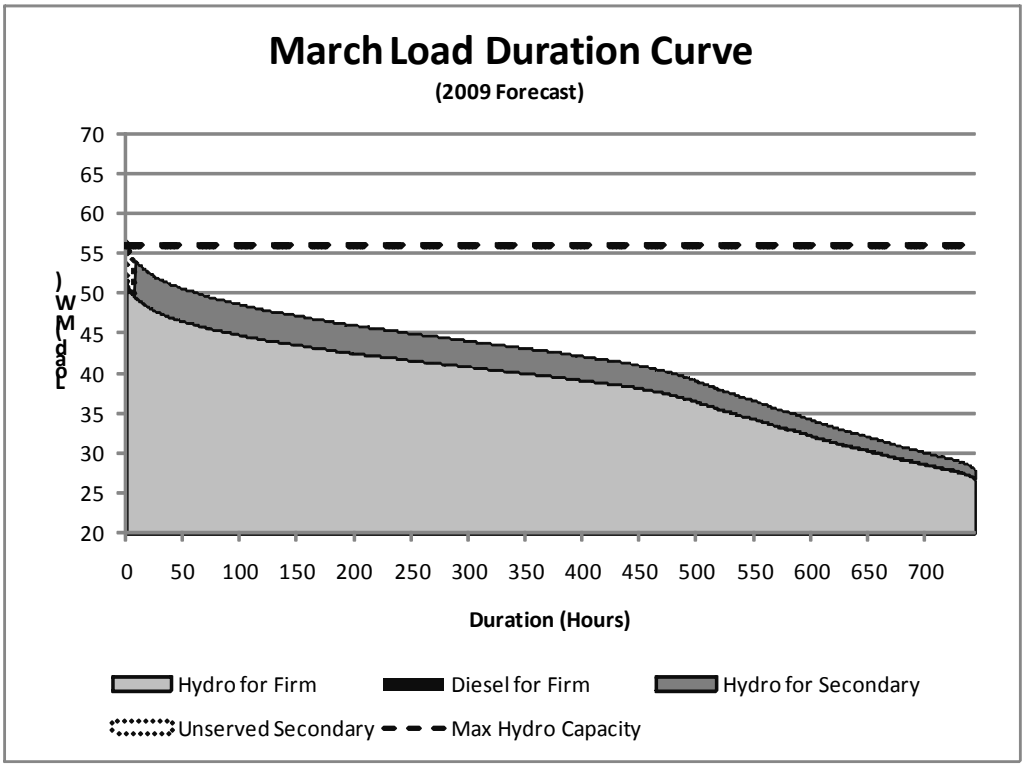
(a), **(b)** and **(c)**

Please see the charts below for 2009, based on the detailed analysis provided in YECL-YEC-1-23(b). No similar analysis was conducted for forecast 2008, but the general load shape is expected to be largely similar.


January Load Duration Curve
(2009 Forecast)
70
65
60
55
50
45
40
35
30
25
20
0
50
100
150
200
250
300
350
400
450
500
550
600
650
700
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Unserved Secondary
Max Hydro Capacity


February Load Duration Curve
(2009 Forecast)
70
65
60
55
50
45
40
35
30
25
20
0
50
100
150
200
250
300
350
400
450
500
550
600
650
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Unserved Secondary
Max Hydro Capacity

1


March Load Duration Curve
(2009 Forecast)
70
65
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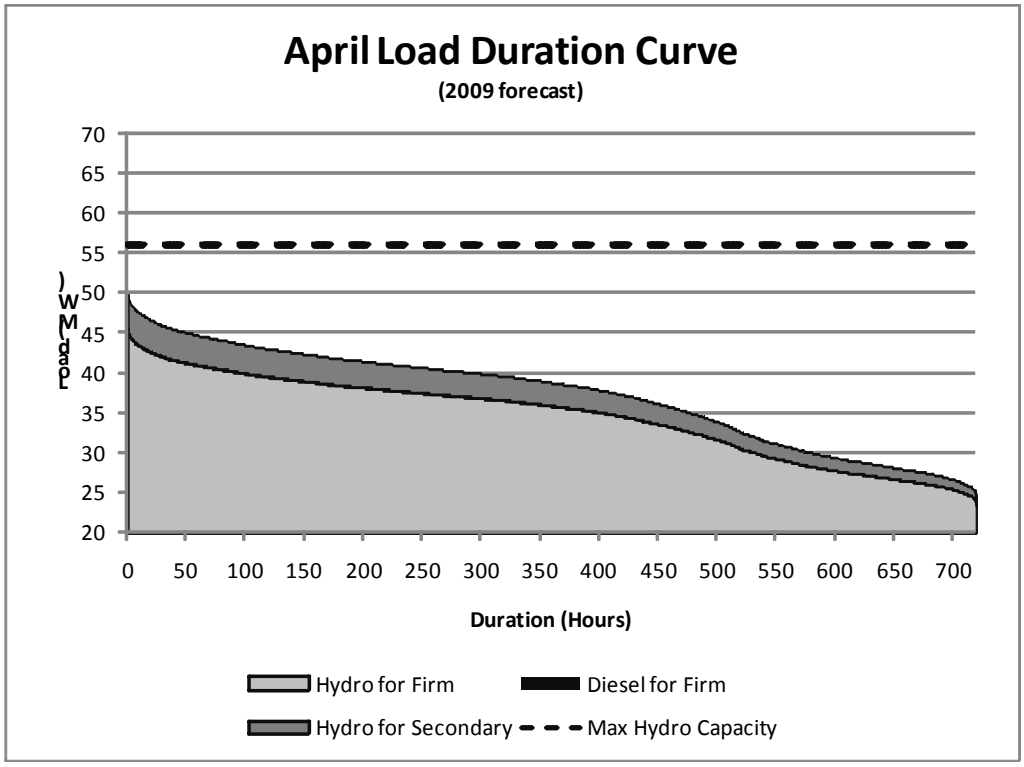
0 50 100 150 200 250 300 350 400 450 500 550 600 650 700
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Unserved Secondary
Max Hydro Capacity


April Load Duration Curve
(2009 forecast)
70
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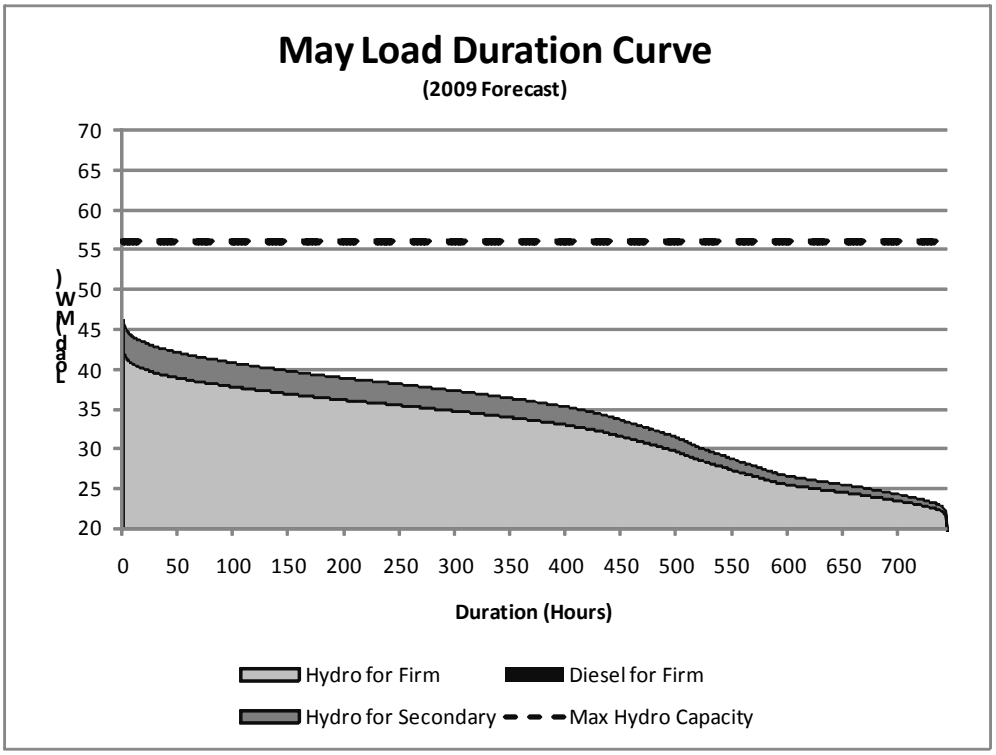
0 50 100 150 200 250 300 350 400 450 500 550 600 650 700
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Max Hydro Capacity

1


May Load Duration Curve
(2009 Forecast)
70
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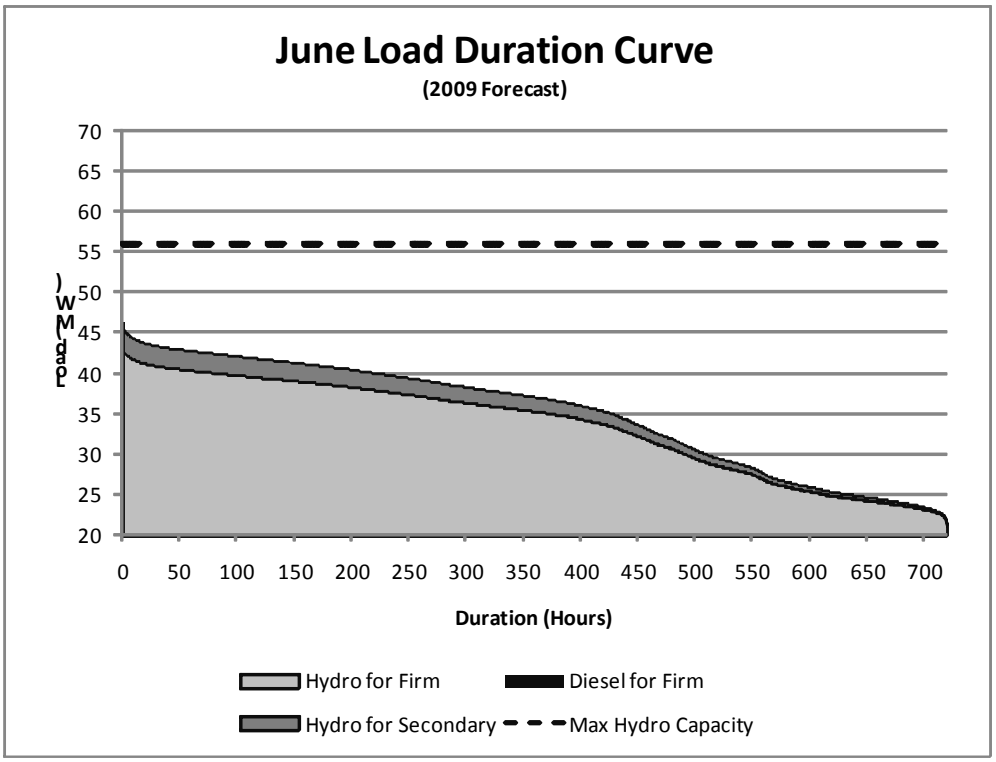
0 50 100 150 200 250 300 350 400 450 500 550 600 650 700
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Max Hydro Capacity


June Load Duration Curve
(2009 Forecast)
70
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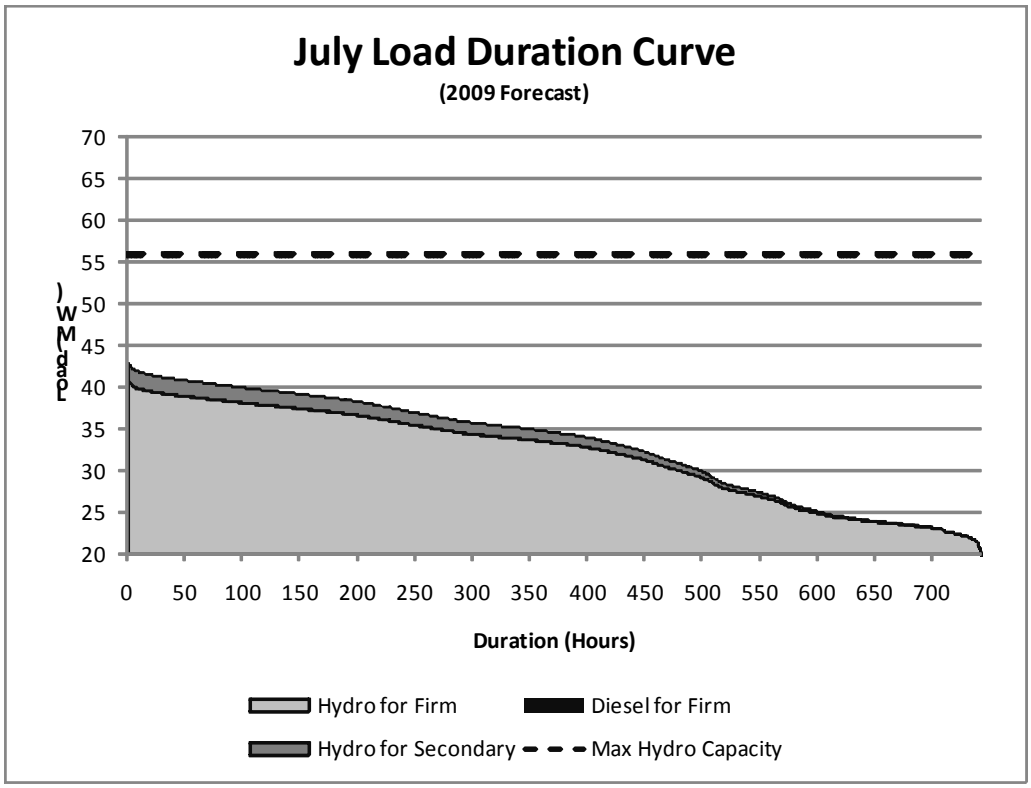
0 50 100 150 200 250 300 350 400 450 500 550 600 650 700
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Max Hydro Capacity

1


July Load Duration Curve
(2009 Forecast)
70
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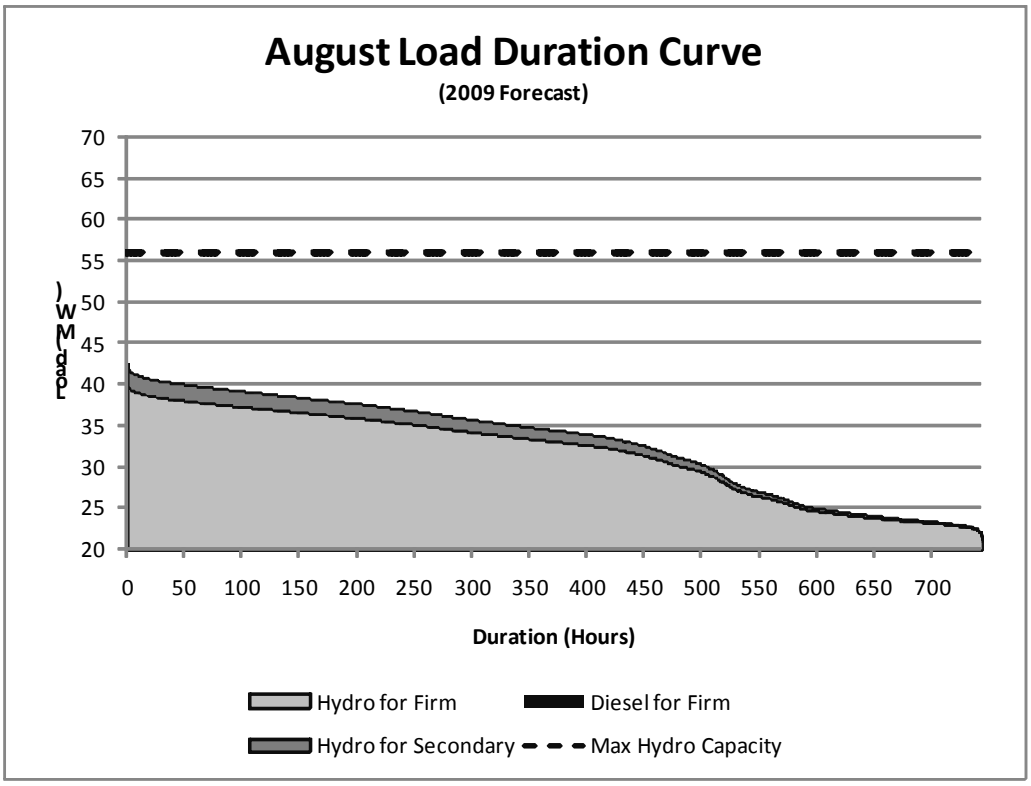
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Max Hydro Capacity


August Load Duration Curve
(2009 Forecast)
70
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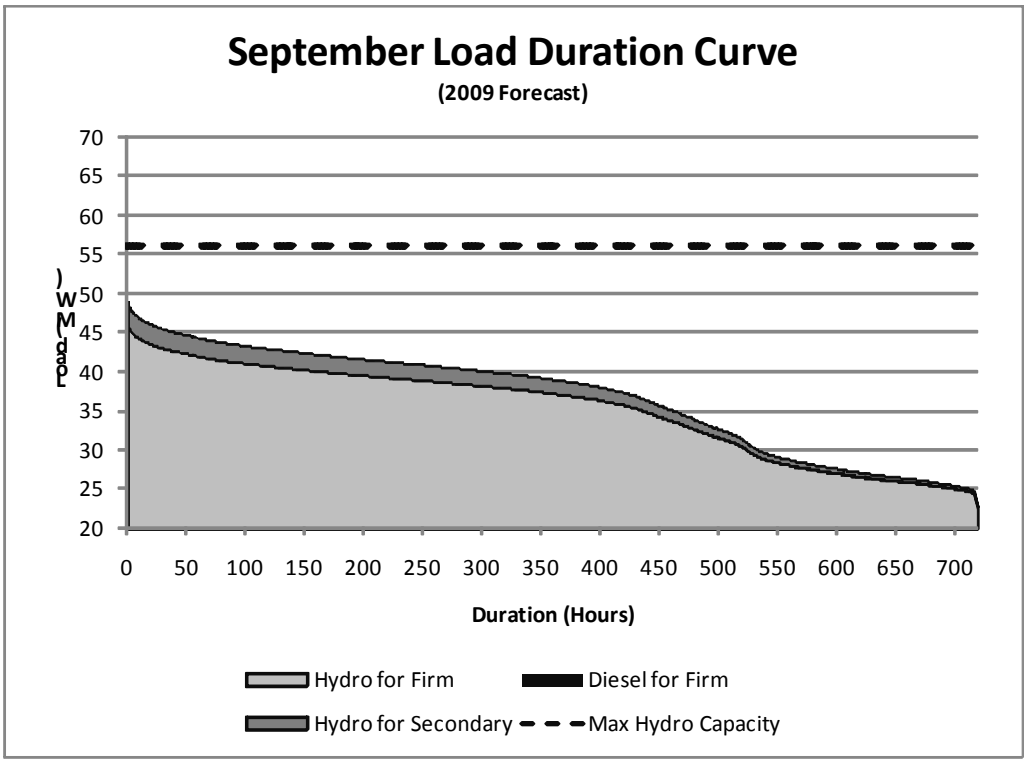
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Max Hydro Capacity

1


September Load Duration Curve
(2009 Forecast)
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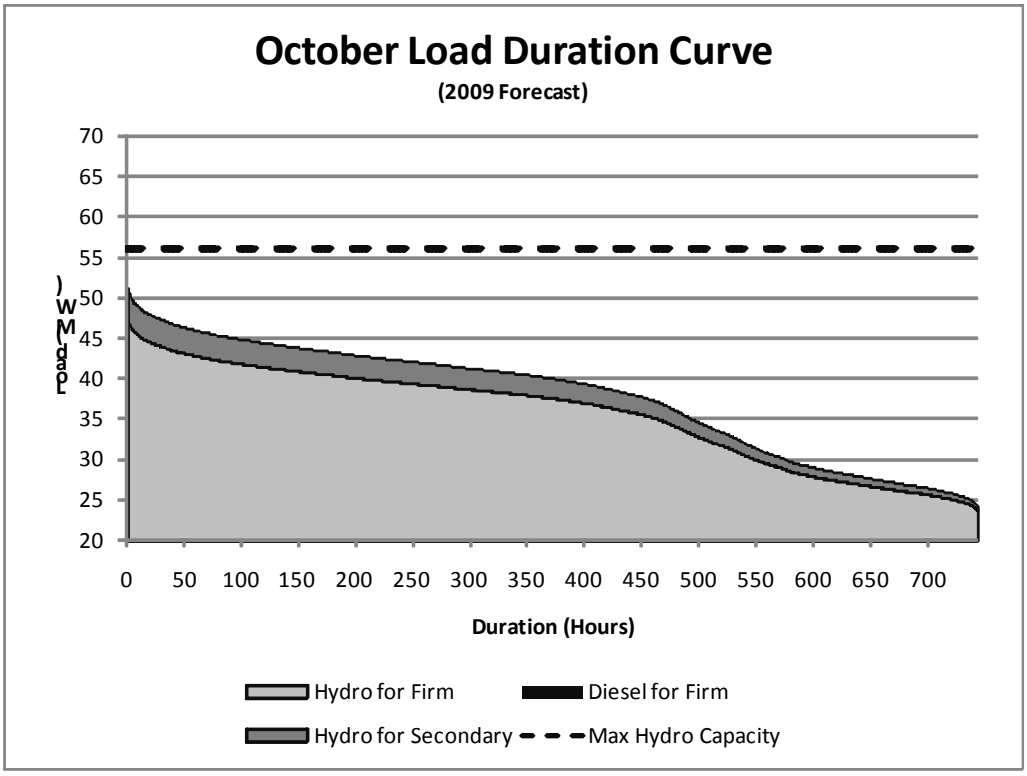
0 50 100 150 200 250 300 350 400 450 500 550 600 650 700
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Max Hydro Capacity


October Load Duration Curve
(2009 Forecast)
70
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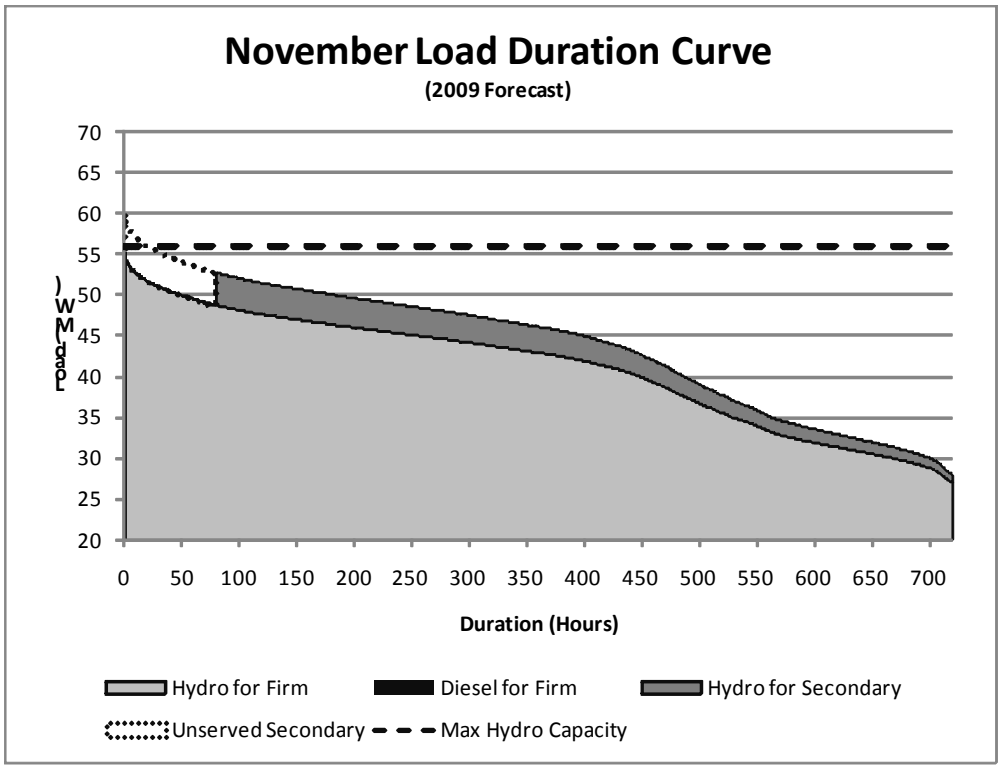
0 50 100 150 200 250 300 350 400 450 500 550 600 650 700
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Max Hydro Capacity

1


November Load Duration Curve
(2009 Forecast)
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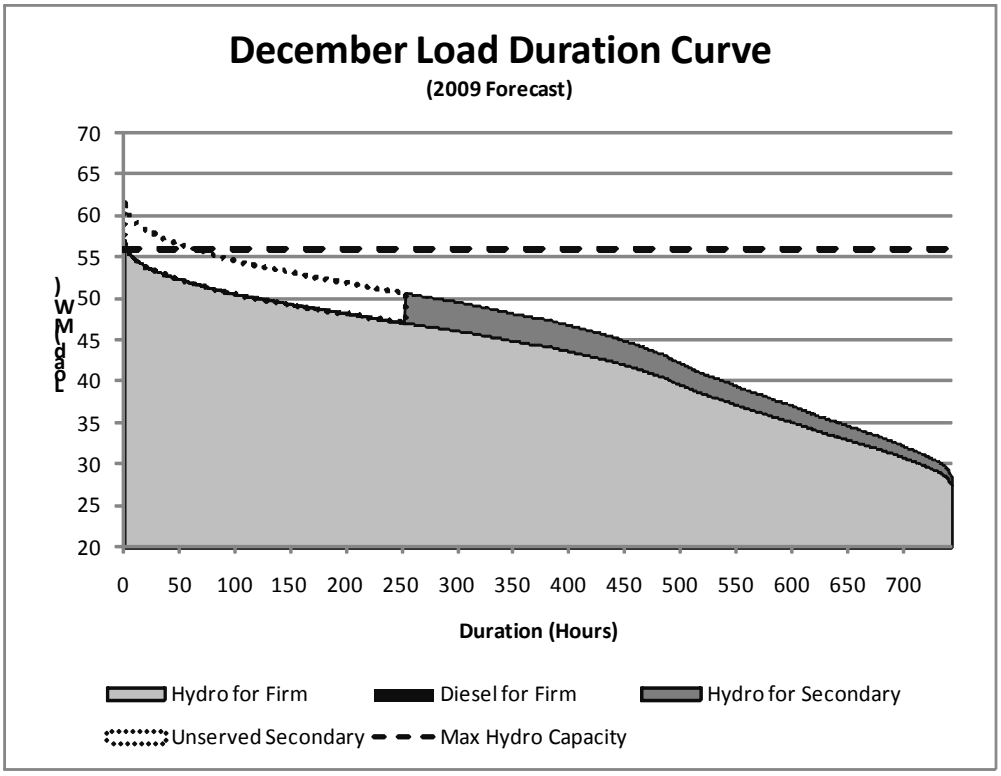
0 50 100 150 200 250 300 350 400 450 500 550 600 650 700
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Unserved Secondary
Max Hydro Capacity


December Load Duration Curve
(2009 Forecast)
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0 50 100 150 200 250 300 350 400 450 500 550 600 650 700
Duration (Hours)
Hydro for Firm
Diesel for Firm
Hydro for Secondary
Unserved Secondary
Max Hydro Capacity

(d)

YEC does not have a forecast availability charge for the test years. On a prospective basis, Yukon Energy's system is planned on the basis of an assumed 10% Forced Outage Rate for diesel units.

(e)

The units were not removed from rate base or from the WAF grid before or since the Resource Plan proceeding, but were forecast to be retired. As noted at page 4-2 of the 20-Year Resource Plan, plans for the retirement of the three Whitehorse Mirrlees Units (WD1, WD2 and WD3) had been in place for some time (as far back as the 1992 Resource Plan hearing). While the planned retirement had been delayed over the years, by the time of the Resource Plan hearing in 2006 further delay related to the retirement of the units was not possible without material investment in major tear-down overhaul work. As a result of life extension plans, compared to the scenario with these units retired, the refurbished units have become a source of supply.

The confirmation of Mirrlees technical feasibility was provided at the 2006 Resource Plan hearing in extensive detail. It was not a "study". The reference to feasibility provided on that page refers to a series of investigations undertaken to confirm technical feasibility.

REFERENCE: **Page 3-4, Table 3.2, Page 3-5, lines 1-11**

TOPIC: **Fuel Costs**

QUESTION:

a) Please provide complete details of fuel expense by plant. Include details of sales, station service, litres of fuel used, average costs and fuel expense.

b) Please provide the heat rate at each stand by plant YEC operates and confirm how these heat rates are calculated.

c) Please provide the details on any initiative that YEC has taken to improve heat rates (lines 3 & 4 Page 3-5 speak of improved efficiency).

ANSWER:

(a)

Please see UCG-YEC-1-30 (a) and (e).

(b)

Please see page 3-5 of Tab 3 of the Application.

(c)

Please see response to LE-YEC-1-50.

REFERENCE: **Page 7-5 & Page 9-18**

ISSUE: **Property, Plant & Equipment**

PREAMBLE:

Yukon Electrical wishes to understand differences between the application versus what is in the audited financial statements.

QUESTION:

a) Please reconcile the cost of PP&E values stated on page 7-5 line 5 with the audited financial statements on page 9-18 for the year 2007.

ANSWER:

(a)

Please see Note 2 to Schedule 8 on page 7-12 of the Application.

REFERENCE: **Page 3-8 Lines 2 through 8**

TOPIC: **Brushing**

PREAMBLE:

Yukon Electrical is interested in understanding the fluctuations from year to year in the brushing program at YEC, 105% increase from 2006 to 2007 actuals and 47% increase from 2008 to 2009 proposed expenditures.

QUESTION:

a) Please explain in detail what is meant by a "Stage increase in brushing activity, which is a periodic and cyclical requirement in the Yukon".

b) Please provide the details of YEC's transmission and distribution brushing programs, including copies of policies and practices regarding same.

ANSWER:

(a) and **(b)**

Yukon Energy does not have written policies on brushing and line assessments. Please see YUB-YEC-1-37 (d) and (e) for description of YEC's pole replacement and brushing program.

REFERENCE: **Page 5-15 & 5-16 Lines 26 to 31 & 1 to 17 respectively**

TOPIC: **Fleet**

PREAMBLE:

Yukon Electrical would like to better understand YEC's fleet requirements and inventory.

QUESTION:

a) Please provide a comprehensive listing of all fleet and transportation equipment currently owned by YEC, please include all terrain vehicles and trailers.

b) Please provide a listing of all fleet equipment leased or rented by YEC.

c) Please provide copies of the tendering documents YEC use when purchasing fleet equipment.

d) Please provide the standards and design YEC has developed for the purchase of new service trucks with service bodies.

e) Please provide the business case for the purchase of the bucket truck in 2008 as well as the detailed specification of the truck to be purchased.

f) Please provide the business case for the purchase of the "Off Road Maintenance Vehicle" to be purchased in 2009 as well as the detailed specification of the unit to be purchased. Please provide the details on the annual lease costs for the current Nodwell supplied by Arctic Power.

ANSWER:

(a)

Please see Attachment 1 to this response.

(b)

YEC has no fleet rental or lease agreements at this time.

(c)

Please see Attachment 2 to this response.

(d)

The specification provided in response to (c) above represents Yukon Energy's standard for an electrician's service body. There are different specifications depending on the needs of the end user (e.g. electrician, mechanic, lineman, pool, etc). Each year Yukon Energy reviews the vehicles up for replacement and assesses whether the specification needs to be modified due to the changing needs of the user, available units on the market, and/or capital and operating costs.

(e)

This unit replaces a bucket truck destroyed in a roll-over accident in 2002. Since that time, crews have met this need with existing line equipment (i.e. digger truck). The higher travel between communities has increased maintenance costs on this unit; as well, it is a physically larger unit, and not well suited to accessing distribution lines within Yukon Energy served communities. Unit specifications are as follows:

2008 GMC TopKick C5500
Duramax 6.6 Diesel 330 hp
Automatic
Versalift VST 240I
Outriggers
Jib & Winch

(f)

The unit specification is provided as Attachment 3 to this response. For 2008 and 2009, the Arctic Power lease cost is $8,000/month, plus operating costs.

Please see payback analysis provided as Attachment 1 to UCG-YEC-1-84.

YUKON ENERGY CORPORATION VEHICLE/MOBILE EQUIPMENT LIST AS OF JAN 2009

UNIT #	FUEL #	PIN	YEAR	MAKE	MODEL	TYPE	SERIAL #	LOCATION
30	12460	300	1997	CHEV	CHEYENE R/C P/U	1/2 TON 2X4	1GCEC14R4VZ233796	WHITEHORSE
31	11594	310	1997	CHEV	CHEYENE R/C P/U	1/2 TON 2X4	1GCEC14R5VZ236271	WHITEHORSE
32	11595	320	1997	CHEV	CHEYENE R/C P/U	3/4 TON 2X4 CANOPY	1GCGC24RXVE268316	WHITEHORSE
33	11596	330	1998	CHEV	CHEYENE R/C P/U	1/2 TON 4X4	1GCEK14RXWZ136008	WHITEHORSE
36	11599	360	1998	CHEV	CHEYENE EXTENDED CAB	3/4 TON 4X4 S/B	1GBHK34ROWE251057	WHITEHORSE
38	11601	380	1998	DODGE	RAM P/U	1/2 TON 2X4	1B7HC16YXWS712476	WHITEHORSE
39	15351	390	1998	DODGE	RAM P/U EXTENDED CAB	1/2 TON 4X4 CANOPY	3B7HF12Z7WG211400	DAWSON
49	12494	490	1999	FORD	1999 FORD	F800	3FEXF801XXMA03653	DAWSON
51	14470	210	1998	DODGE	RAM 3500 CHASSIS	1 TON S/B EXT. CAB	1B7MC3365WJ232820	WHITEHORSE
52		520	1998	CHEV	CHEYENE CHASSIS	3/4 TON 4X4 S/B	1GCGK29R4WE239651	DAWSON
55	11583	200	1999	DODGE	RAM 2500 CHASSIS	3/4 TON 4X4 S/B EXT CAB	1B7KF23Z3XJ609133	MAYO
57	13178	570	2001	DODGE	RAM 1500 P/U	1/2 TON 4X4 EXT CAB	1B7HF13Z01J221708	WHITEHORSE
58	13179	580	2001	DODGE	RAM 1500 P/U	1/2 TON 4X4 EXT CAB	1B7HF13Z21J221709	WHITEHORSE
59	14506	260	2002	CHEV	SILVERADO 1500	1/2 TON 4X4 S/B EXT CAB	2GCEK19T421181050	WHITEHORSE
60	11585	220	2002	CHEV	SILVERADO 2500	3/4 TON 4X4 S/B EXT CAB	1GCGK29U62Z152972	WHITEHORSE
62	14331	270	2002	CHEV	SILVERADO 1500	1/2 TON 4X4 S/B EXT CAB	2GCEK19T821182590	WHITEHORSE
63	11613	630	2003	FORD	F350	1 TON 4X4 S/B EXT CAB	1FTSX31LX3ED40391	WHITEHORSE
64	11597	340	2003	DODGE	RAM 3500 CHASSIS	1 TON 4X4 EXT CAB	3D7LU38C93G825106	WHITEHORSE
65	15736	650	2004	GMC	SAFARI VAN	ALL WHEEL DRIVE	1GTDL19X54B508117	WHITEHORSE
66	11591	660	2004	CHEV	TRAILBLAZER	4X4 SUV	1GNDT13SX42434908	WHITEHORSE
67	16366	670	2006	FORD	F350	1 TON 4X4 S/B EXT CAB	1FDSX35Y56EA46953	WHITEHORSE
68	16367	680	2006	FORD	F350	1 TON 4X4 S/B EXT CAB	1FDSX35Y16EA46951	DAWSON
69	16368	690	2006	FORD	F350	1 TON 4X4 S/B EXT CAB	1FDSX35Y36EA46952	WHITEHORSE
70	16369	700	2006	FORD	F350	1 TON 4X4 S/B EXT CAB	1FDSX35Y76EA46954	WHITEHORSE
71	16333	710	2005	DODGE	RAM P/U QUAD CAB	1/2 TON 4X4	1D7HU18D35J540048	WHITEHORSE
72	16325	720	2005	DODGE	RAM P/U QUAD CAB	1/2 TON 4X4	1D7HU18D55J540049	WHITEHORSE
73	11588	730	2005	CHEV	MALIBU	4 DOOR SEDAN	1G1ZT528X5F325783	WHITEHORSE
74	16482	740	2006	FORD	F350	1 TON 4X4 S/B EXT CAB	1FDSX35Y26EB58089	MAYO
75			2007	KENWORTH	T800	CONVENT TRACTOR	1NKDLU0X17R900021	WHITEHORSE
76			2007	CHEV	SILVERADO 3500	1 TON 4X4 S/B EXT CAB	1GBJK39U57E141508	WHITEHORSE
77			2007	CHEV	SILVERADO 3500	1 TON 4X4 S/B EXT CAB	1GBJK39U37E140955	WHITEHORSE
78			2007	FORD	F350	1 TON 4X4 S/B EXT CAB	1FDSX35Y47EB20767	WHITEHORSE
79			2007	FORD	F350	1 TON 4X4 S/B EXT CAB	1FDSX35Y67EB20768	WHITEHORSE
80		800	2007	FORD	F350	1 TON 4X4 S/B EXT CAB	1FDSX35Y87EB20769	FARO
81	20578	810	2008	GMC	SIERRA 150	1/2 TON 4X4 EXT CAB	1GTEK19J28E134900	WHITEHORSE
82	20579	820	2008	CHEV	TRAILBLAZER	4X4 SUV	1GNDT13S882140414	WHITEHORSE
83	20580	830	2008	GMC	SIERRA 250	3/4 TON 4X4 EXT CAB	1GTHK29K98E141404	WHITEHORSE
84	20581	840	2008	DODGE	RAM 3500 CHASSIS	1 TON 4X4 S/B EXT CAB	3D6WH48DX8G135182	WHITEHORSE
85	20582	850	2008	FORD	F350	1 TON 4X4 S/B EXT CAB	1FDSX35508EC57986	WHITEHORSE
86		860	2008	DODGE	RAM P/U QUAD CAB	3/4 TON 4X4 EXT CAB	3D7KS28D38G238542	MAYO
87		870	2008	FORD	F150	1/2 TON 4X4 EXT CAB	1FTVX14518KF06966	WHITEHORSE
88		880	2008	GMC	TOPKICK	C5500	1GDE5C1998F400794	WHITEHORSE
89			2008	CHEV	SILVERADO 1500	1/2 TON 4X4 EXT CAB	1GCEK19C78Z300063	WHITEHORSE

UNIT #		YEAR	MAKE	MODEL	TYPE	SERIAL #	LOCATION
Nodwell		1980		TF-240	LEASED FROM ARCTIC POWER	24005578D002	WHITEHORSE
1A		1992	CUSTOM	TRAILER/SPILL RES	UTILITY	YK01508	WHITEHORSE
2A		1991	CUSTOM	TRAILER/DECK	UTILITY	YK00404	WHITEHORSE
5A		1987	CUSTOM	TRAILER	WATER	YK00684	FARO
7A		1980	RD RUNNER	TRAILER	BOAT	15688	MAYO
10A	4 WHEELER	2000	POLARIS	MAGNUM 500	4 WHEELER	4XACD50AXYA336159	DAWSON
11A		1981	FRUEHAUF	TRAILER	LOW BED (YM1)	2H8P04520BR029701	WHITEHORSE
14A		1999	ALTA. TRAILERS	TRAILER	LINE MAINT.	2T9DFYHD4X1057852	WHITEHORSE
15A		1999	HOMEMADE	TRAILER	UTILITY (SOLAR TRAILER)	102173	WHITEHORSE
16A		1999	CZ ENGINEERING	TRAILER	POLE	4CZPA2717X109F003	DAWSON
17A			JOHN DEERE	JD350 BL	BULLDOZER	180315	MAYO
19A		1999	ALUM/TEK IND.	TRAILER	MOBILE GENERATOR (YM2)	YK05257	WHITEHORSE
20A	SNOWMOBILE	2000	POLARIS	S00SD5BS	SNOWMOBILE	4XASD5BS2YC022883	FARO
21A	4 WHEELER	2000	POLARIS	AOOCD5OAB	4 WHEELER	4XACD5OA3YA317095	FARO
23A		1999	N/A	TRAILER	4 WHEELER TUB TRAILER	N/A	FARO
24A		2000	LOWE	1457 14' BOAT	BOAT	N/A	MAYO
25A	SNOWMOBILE	2001	POLARIS	550 Sport Touring	SNOWMOBILE	4XASD5BS31C147011	MAYO
26A	SNOWMOBILE	2001	POLARIS	500 Sport Touring Classic	SNOWMOBILE	4XAST4BS41C142574	DAWSON
27A	SNOWMOBILE	1994	ARCTIC CAT	CHEETAH	SNOWMOBILE	941115	WHITEHORSE
28A		1996	XINHUI CIMC	CONTAINER	STORAGE TRAILER	1AA-X050GC40	WHITEHORSE
29A		2001	MISTY RIVER	SCOUT 1600	15' BOAT	QGN46697B101	WHITEHORSE
30A		2001	EZLOADER	1250 LB.	BOAT TRAILER	71A115149	WHITEHORSE
31A		1992	WELLS CARGO	CARGO TRAILER	SUBSTATION TECH	1WC200G28N4011020	WHITEHORSE
33A		2002	CZ ENGINEERING	TRAILER	POLE	4CZPA27182110K013	WHITEHORSE
34A		1993	HYSTER	H60XL	FORKLIFT	D117B4531P	WHITEHORSE
35A		2002	TRAILTECH	TRAILER	SNOWMOBILE	2CU3F7A1422012200	WHITEHORSE
36A	4 WHEELER	2002	POLARIS	MAGNUM 500 RMK	4 WHEELER	4XACD50A12C604253	MAYO
37A	SNOWMOBILE	2003	ARCTIC CAT	MOUNTAIN CAT 600	SNOWMOBILE	4UF03SNW13T156351	WHITEHORSE
40A		2005	TRAILTECH	TRAILER	SNOWMOBILE	2CU3F7A1652018634	WHITEHORSE
42A		2006	TRAILTECH	TRAILER	SNOWMOBILE	2CU3F7A1362019175	WHITEHORSE
43A		2006	MAGNUM	TRAILER	MOBILE GENERATOR (YM3)	5AJGS16136B001493	WHITEHORSE
44A	6X6 ATV	2007	POLARIS	RANGER 6X6	6X6 ATV	4XARF68A27DO47627	WHITEHORSE
45A		2007	TRAILTECH	TRAILER/DECK	FLATDECK	2CU33ALA672023354	WHITEHORSE
46A		2008	DOUBLE A	TRAILER/DECK	FLATDECK	2DASC316X8T008597	WHITEHORSE
47A		2006	MAGNUM	TRAILER	MOBILE GENERATOR (YM4)	5AJGS11197B010532	WHITEHORSE
48A		2007	OMEGA LIFT	2414-10	FORKLIFT	OM603TWS	WHITEHORSE
49A		2008	DOUBLE A	TRAILER	SNOWMOBILE	2DAMC31418T008477	WHITEHORSE
50A	6X6 ATV	2008	POLARIS	RANGER 6X6	6X6 ATV	4XARFG8A384725237	WHITEHORSE
51A	6X6 ATV	2008	POLARIS	RANGER 6X6	6x6 ATV	4XARF68A184724037	WHITEHORSE
52A		2008	DOUBLE A	TRAILER/DECK	FLATDECK	2DAMC31418T009435	WHITEHORSE
53A	Boat/Motor	2006	ZODIAC	MK3 BOAT	XDCB296NB606	20 HP MOTOR	BMAJ1402938
54A	SNOWMOBILE	2009	SKI - DO	SKANDIC	SNOWMOBILE	YH2SFW9V99R000620	WHITEHORSE

YUKON ENERGY CORPORATION

Minimum Vehicle Specifications

Unit # 85 Spec.# YEC 2007-85

This unit is a minimum 1 ton chassis, non dual rear wheels, 4x4 extended cab complete with a minimum of three doors, with service body supplied and installed as per attached specs.

POWER TRAIN:
Engine – 8 cylinder 5.7 minimum (gas)
Transmission - Heavy duty manual, 5-speed overdrive
Shield – Transfer case
Differential – Limited Slip
Front Axle - Manufacturer's standard hubs

CHASSIS & SUSPENSION:
Shocks – Heavy duty front and rear
Stabilizer – Front
Heavy duty Transfer case
Brakes - Heavy duty power
Steering – Power
Hooks - Tow 2 front & 2 rear - SAE Rated

WHEELS & TIRES:
Vehicles having 16” tires are to be equipped with
Bridgestone 235 / 85R16 E/10P VSX
Vehicles having 17” tires are to be equipped with
BFG All Terrain T/A 285/70R17 D/8P
Vehicles having 18” tires are to be equipped with
275/65R18 Dean / Cooper sxt 10 ply
Spare- As above with rim

ELECTRICAL:
Block Heater
Dual Batteries- Heavy duty max. CCA Battery Blanket
Heavy Duty Alternator - max. amps
Radio - AM/FM / CD player
Air Conditioning
12-Volt Auxiliary Power Outlet
Wipers – Intermittent
Roof Clearance Lights
Through the roof spot light – mounted 8” from front. Sparton
Cat. #475-20 R011018 (Nor Truck Calgary (403) 250-5355

COOLING & HEATING:
-50°C Antifreeze
Heavy Duty Cooling System - engine & transmission

INTERIOR:
Color – Blue / Gray (Dark Colors)

1

Seats – Full foam padded cloth, bench, folding back, 40/20/40 split-bench, center arm rest/storage
Arm Rest – Left & right
Visor – Left & right
Heater - High output cold climate package
Mirrors - Inside center
Lamp – Dome roof mounted
Headliner – Full

EXTERIOR:

Color – Manufacturer's standard white
Mirrors – Left & right (7"x 9")

OPTIONS:

Heater – Block
Oil Pan Heater
Cruise Control
Bumper – Standard
Bumper – Rear standard step
Fuel Tank – Auxiliary/maximum capacity
2" receiver hitch with 7 pin Pollack trailer plug.

GENERAL BODY & EQUIPMENT

EDMONTON, CALGARY, SASKATOON, GRANDE PRAIRIE

APPROVED FOR PRODUCTION
Oct. 28. '05 CM

CUSTOMER: WHITEHORSE MOTORS/YUKON ENERGY
SALES/CONTACT: S. CASSELS

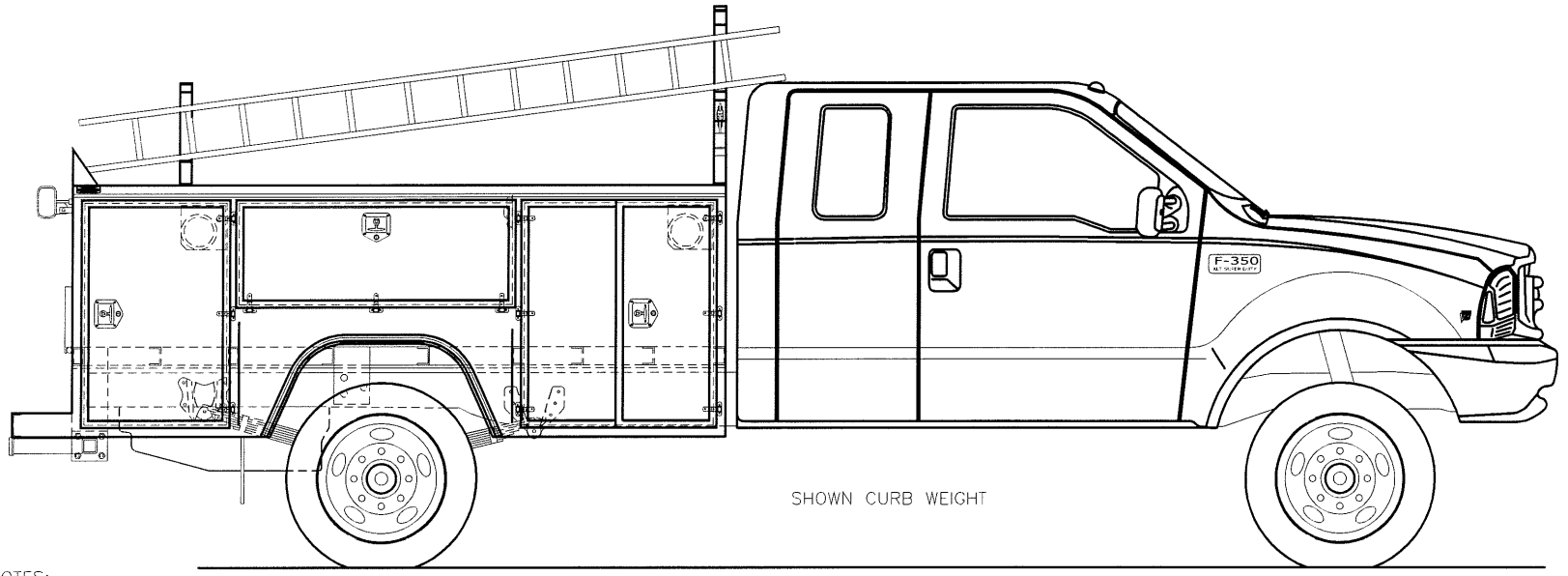
BODY DESCRIPTION: 110" SERVICE BODY
c/w LIFTMOORE L-21-7 CRANE
WORK ORDER # 31159
UNIT #

BODY MATERIAL: ALUMINUM
ASSEMBLED IN: EDMONTON

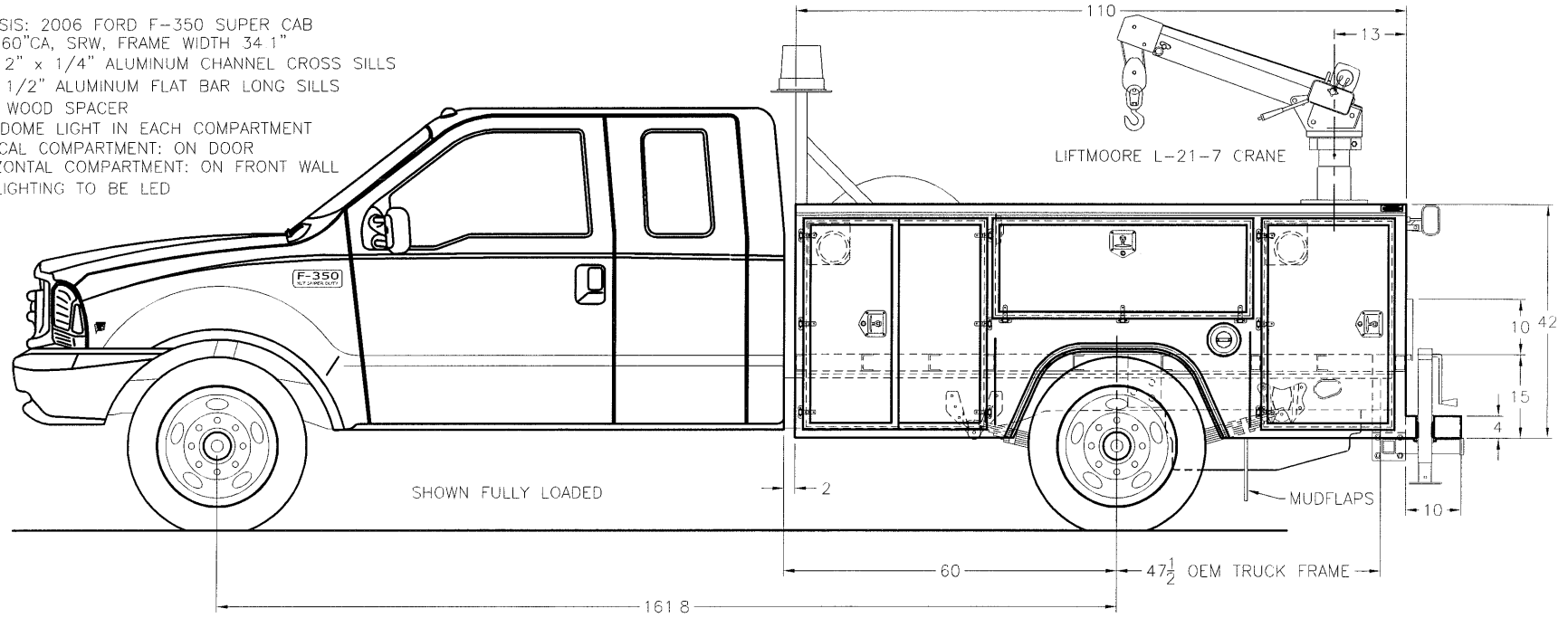
CHASSIS: 2006 FORD F-350 SUPER CAB, 4x4, 60"CA, SRW

PAGE	DESCRIPTION	DATE DRAWN	REV.	DATE ISSUED
1	BODY/CHASSIS VIEW	JUNE 7, 2005	2	OCT. 27, 2005
2	ROAD SIDE ELEVATION	JUNE 7, 2005	2	OCT. 27, 2005
3	CURB SIDE ELEVATION	JUNE 7, 2005	2	OCT. 27, 2005
4	REAR VIEW	JUNE 7, 2005	1	OCT. 27, 2005
5	PLAN VIEW	JUNE 7, 2005	2	OCT. 27, 2005
6	FLOOR DETAIL	JUNE 7, 2005	1	JUNE 27, 2005
7	FLOOR LAYOUT	JUNE 7, 2005	1	OCT. 27, 2005
8	FRONT RACK DETAIL	JUNE 7, 2005	0	JUNE 27, 2005
9-1~3	LADDER RACK DETAIL	JUNE 7, 2005	0	JUNE 27, 2005

DRAWN BY: P. GAO	CHECKED BY: C.MAILLET	APPROVED BY:	FILE: 2662TS00
DATE: JUNE 7, 2005	DATE: OCT.28, 2005	DATE:	



NOTES:
1. CHASSIS: 2006 FORD F-350 SUPER CAB 4x4, 60"CA, SRW, FRAME WIDTH 34.1"
2. 3" x 2" x 1/4" ALUMINUM CHANNEL CROSS SILLS
3. 3" x 1/2" ALUMINUM FLAT BAR LONG SILLS
4. 3/4" WOOD SPACER
5. ONE DOME LIGHT IN EACH COMPARTMENT
   VERTICAL COMPARTMENT: ON DOOR
   HORIZONTAL COMPARTMENT: ON FRONT WALL
6. ALL LIGHTING TO BE LED



REV	DATE	BY	DESCRIPTION
2	OCT 27, 2005	C M	ADD HITCH RECEIVER
1	06/27 2005	T H	INCREASE LENGTH TO 110"

GENERAL BODY & EQUIPMENT

Customer: WHITEHORSE MOTORS/YUKON ENERGY

Date:	Scale:	Dr. By:	Ck. By:	Page#:	ACAD File:
JUNE 7, 2005	1/32	P. GAO	T. HOUNSOME	1 OF 1	2662TS00-1

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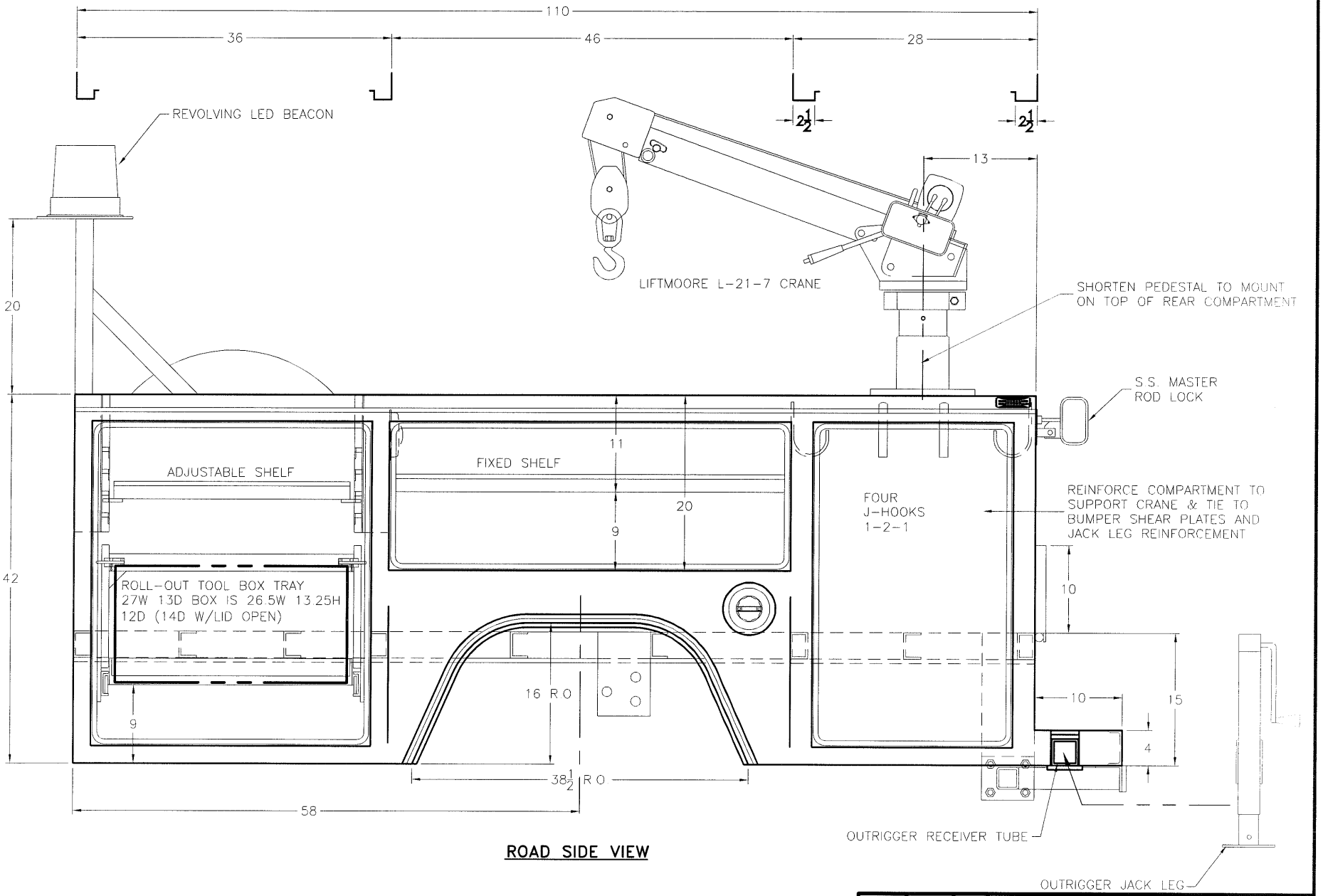

ROAD SIDE VIEW

REV	DATE	BY	DESCRIPTION
2	OCT 27, 2005	C.M	ADD HITCH RECEIVER
1	06/27 2005	T.H	INCREASE LENGTH TO 110"

GENERAL BODY & EQUIPMENT

Customer: WHITEHORSE MOTORS/YUKON ENERGY

Date:	Scale:	Dr. By:	Ck By:	Page#:	ACAD File:
JUNE 7, 2005	1/16	P. GAO	T. HOUNSOME	1 OF 1	2662TS00-2

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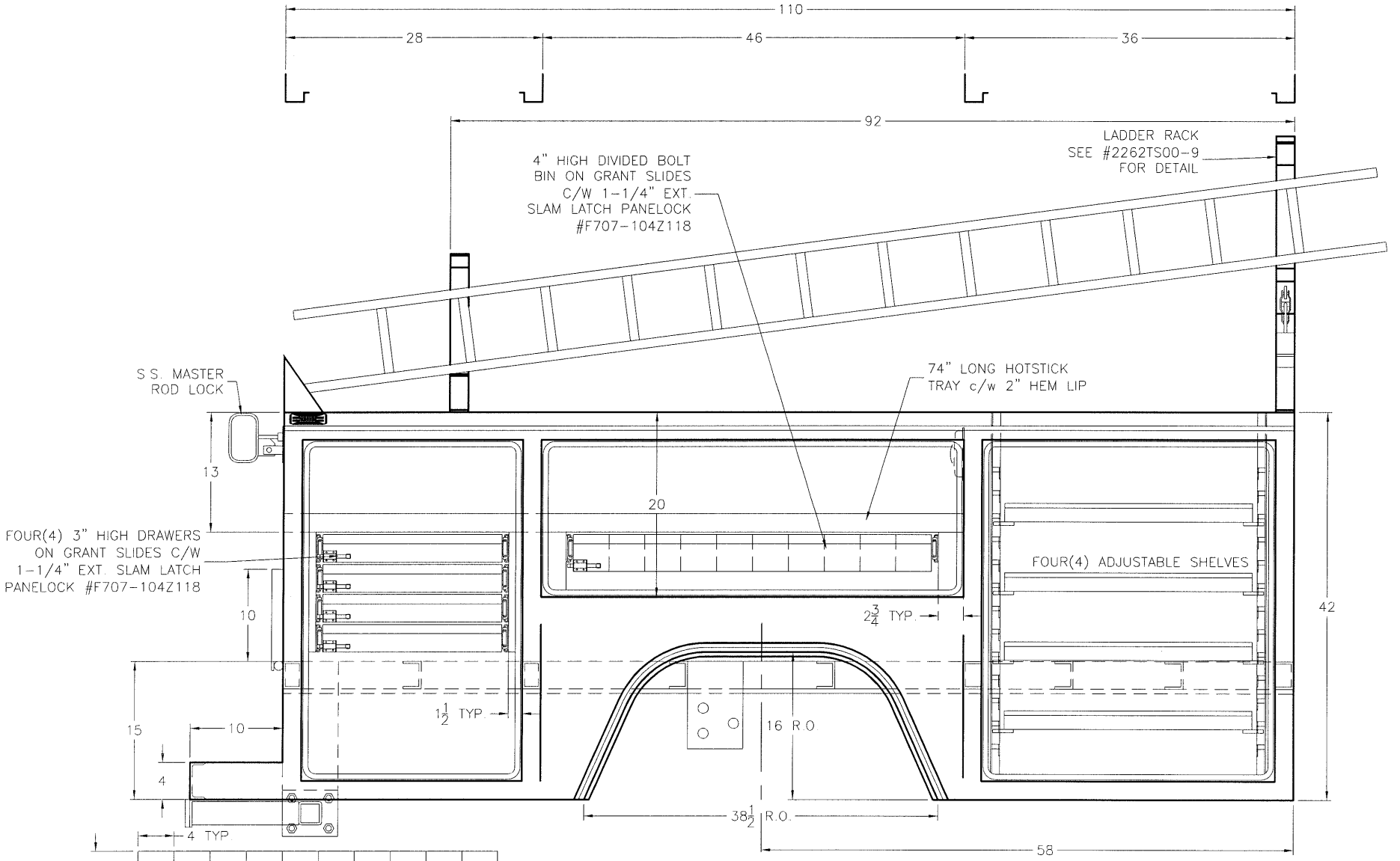

CURB SIDE VIEW

DIVIDED BOLT BIN DETAIL

REV	DATE	BY	DESCRIPTION
2	OCT 27, 2005	C.M	ADD HITCH RECEIVER
1	06/27 2005	T.H.	INCREASE LENGTH TO 110"

GENERAL BODY & EQUIPMENT

Customer: WHITEHORSE MOTORS/YUKON ENERGY

Date:	Scale:	Dr. By:	Ck By:	Page#:	ACAD File:
JUNE 7, 2005	1/16	P. GAO	T. HOUNSOME	1 OF 1	2662TS00-3

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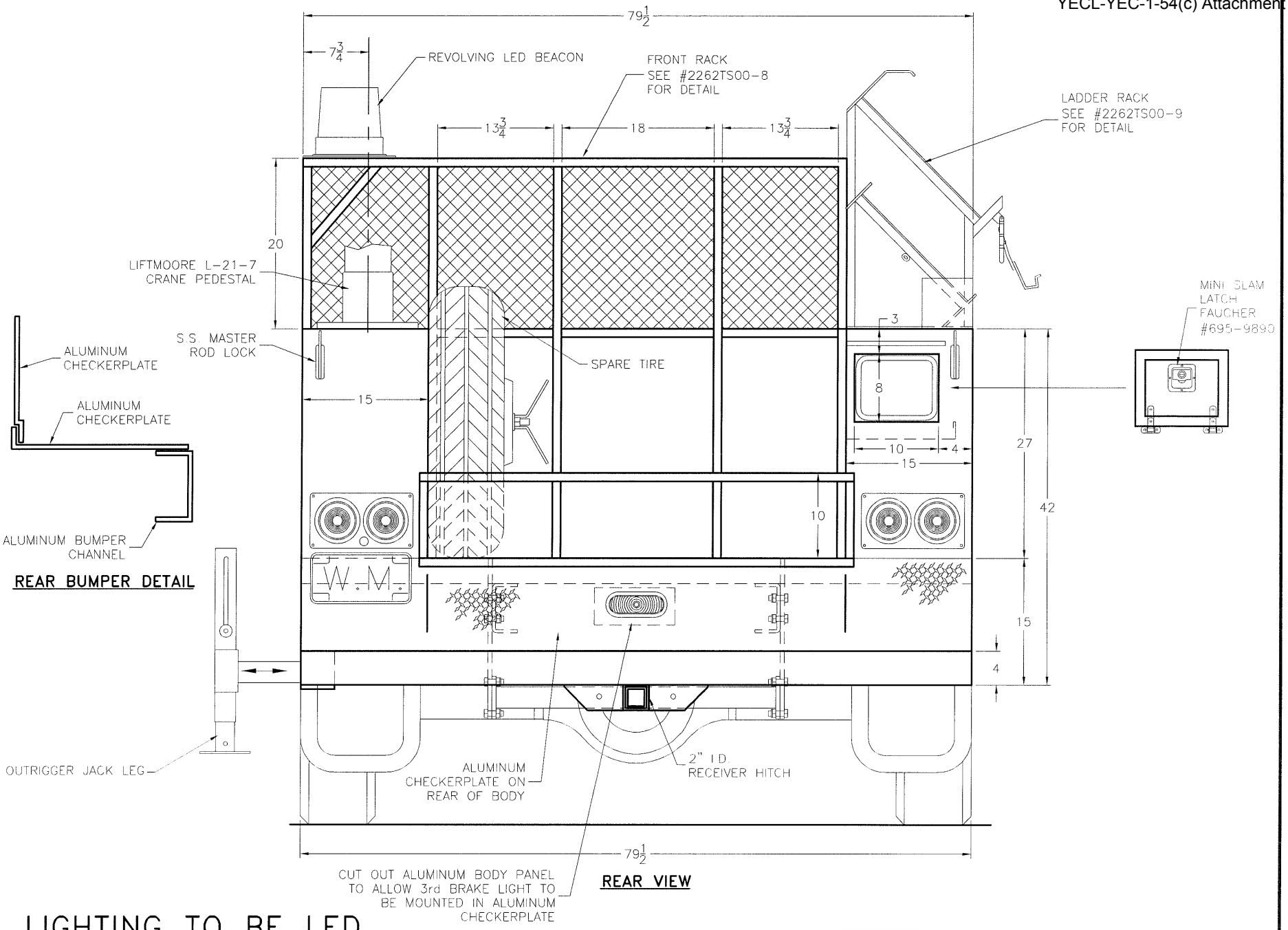

ALL LIGHTING TO BE LED

REV	DATE	BY	DESCRIPTION
1	OCT 27, 2005	C M	ADD HITCH RECEIVER

GENERAL BODY & EQUIPMENT

Customer: WHITEHORSE MOTORS/YUKON ENERGY

Date:	Scale:	Dr By:	Ck By:	Page#:	ACAD File:
JUNE 7, 2005	1/16	P. GAO	T. HOUNSOME	1 OF 1	2662TS00-4

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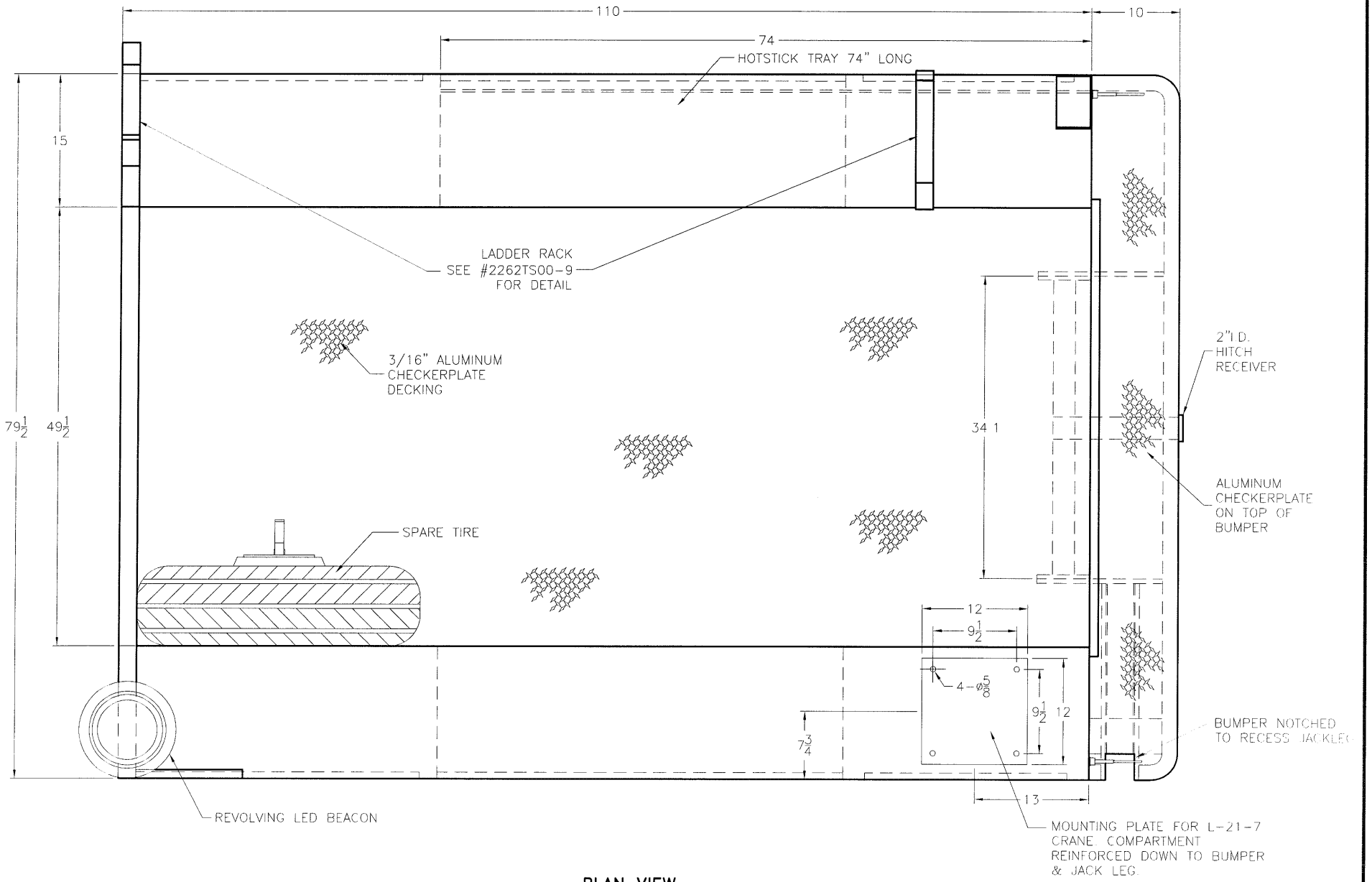

PLAN VIEW

REV	DATE	BY	DESCRIPTION
2	OCT 27, 2005	C.M.	ADD RECEIVER HITCH
1	06/27 2005	T.H.	INCREASE LENGTH TO 110"

GENERAL BODY & EQUIPMENT

Customer: WHITEHORSE MOTORS/YUKON ENERGY

Date: JUNE 7, 2005 | Scale: 1/16 | Dr. By: P. GAO | Ck By: T. HOUNSOME | Page#: 1 OF 1 | ACAD File: 2662TS00-5

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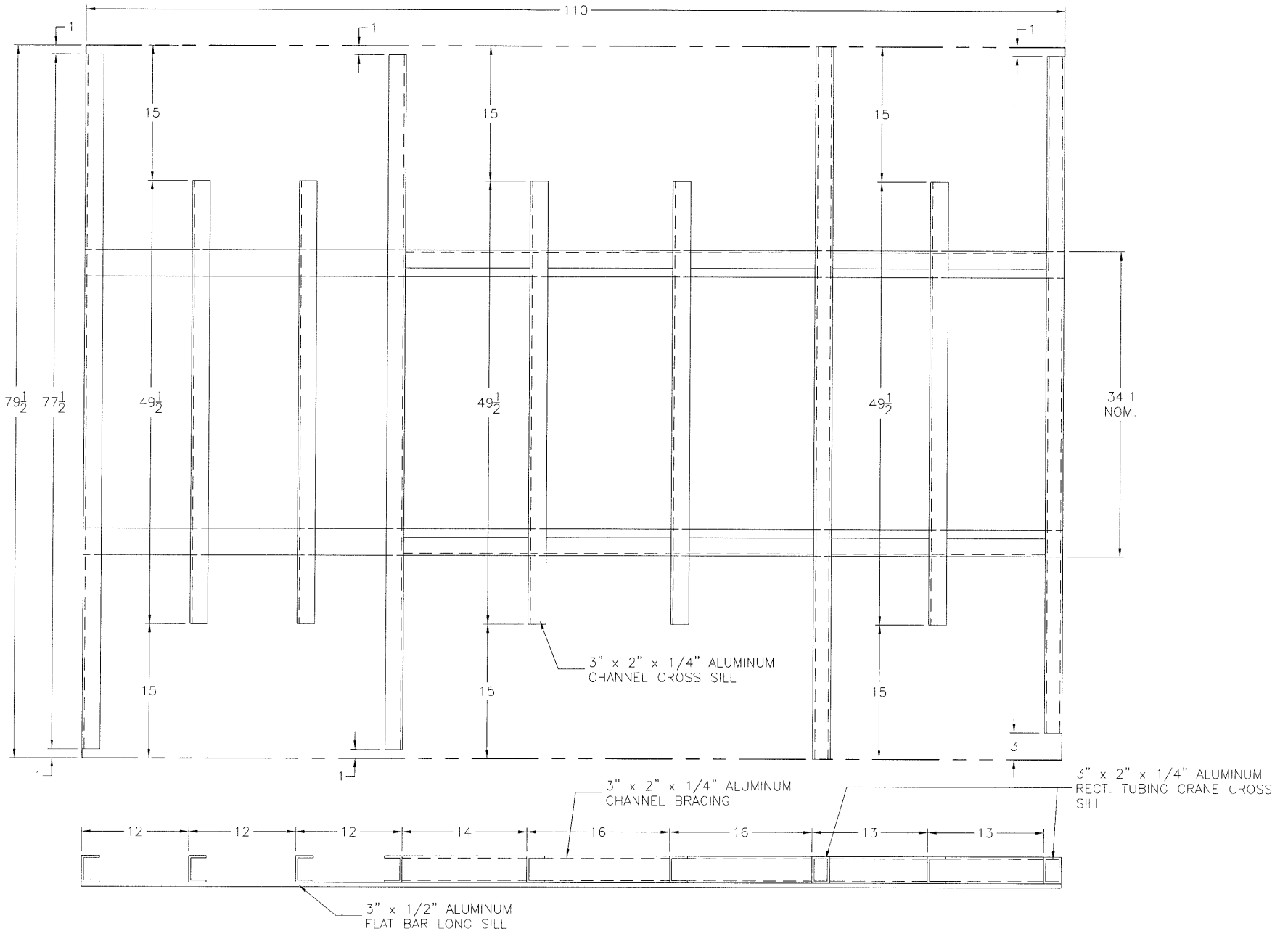

REV	DATE	BY	DESCRIPTION
1	06/27 2005	T.H	INCREASE LENGTH TO 110"

GENERAL BODY & EQUIPMENT

Customer: WHITEHORSE MOTORS/YUKON ENERGY

Date:	Scale:	Dr By:	Ck. By:	Page#:	ACAD File:
JUNE 7, 2005	1/16	P. GAO	T. HOUNSOME	1 OF 1	2662TS00-6

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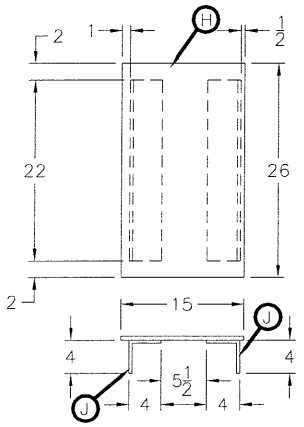

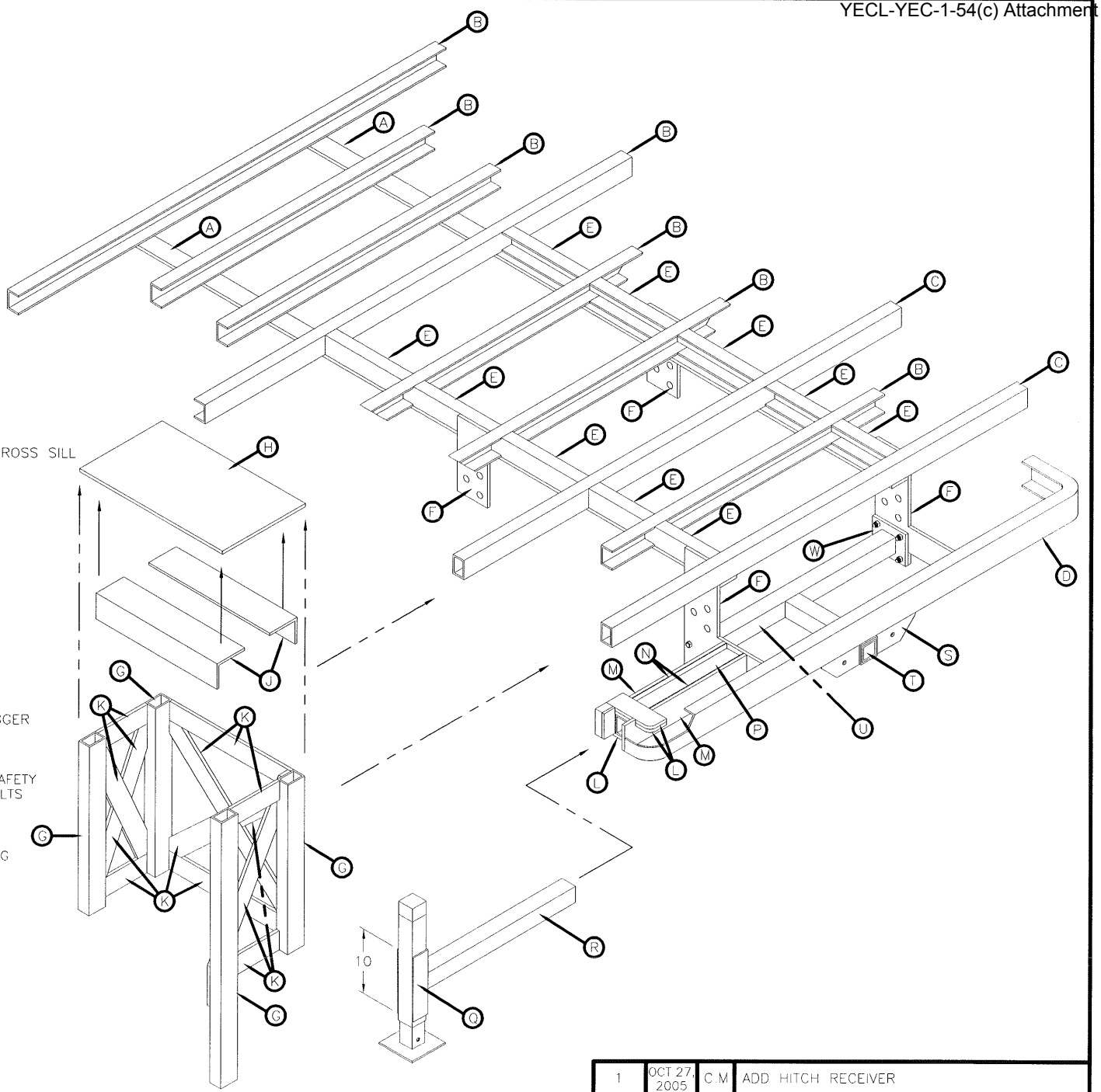

- A 3" x 1/4" ALUMINUM FLAT BAR LONG SILL
- B 3" x 2" x 1/4" ALUMINUM CHANNEL CROSS SILL
- C 3" x 2" x 1/4" RECT. ALUMINUM TUBING CRANE CROSS SILL
- D 4" X 2" X 1/4" ALUMINUM BUMPER CHANNEL
- E 3" x 2" x 1/4" ALUMINUM CHANNEL BRACING
- F 6" x 1/2" ALUMINUM SHEAR PLATE
- G 3" x 2" x 1/4" RECT. ALUMINUM TUBING
- H 1/2" ALUMINUM CRANE MOUNT BASE PLATE
- J 4" x 4" x 3/8" ALUMINUM FORMED ANGLE
- K 3" x 1/4" ALUMINUM FLAT BAR BRACING
- L 3" x 1/2" ALUMINUM FLAT BAR
- M 1/2" x 4" ALUMINUM FLAT BAR
- N 1/8" ALUMINUM SHIM
- P 2-1/2" I.D. ALUMINUM OUTRIGGER RECEIVER TUBE
- Q 3/16" FORMED STEEL CHANNEL WELDED TO OUTRIGGER
- R 2-1/2" X 2-1/2" X 1/4" SQUARE STEEL TUBING
- S 3" x 2-1/2" x 1/4" STEEL ANGLE FOR MOUNTING SAFETY CHAIN HOOKS BOLTED TO ANGLE USING 1/2" DIA. BOLTS
- T 2" I.D. SQUARE STEEL TUBING HITCH RECEIVER
- U 2-1/2" x 2-1/2" O.D. x 1/4" SQUARE STEEL TUBING
- W 6" x 5" x 1/2" STEEL HITCH MOUNTING PLATE

REV	DATE	BY	DESCRIPTION
1	OCT 27, 2005	C.M.	ADD HITCH RECEIVER

GENERAL BODY & EQUIPMENT

Customer: WHITEHORSE MOTORS/YUKON ENERGY

Date:	Scale:	Dr By:	Ck By:	Page#:	ACAD File:
JUNE 7, 2005	1/24	P. GAO	T. HOUNSOME	1 OF 1	2662TS00-7

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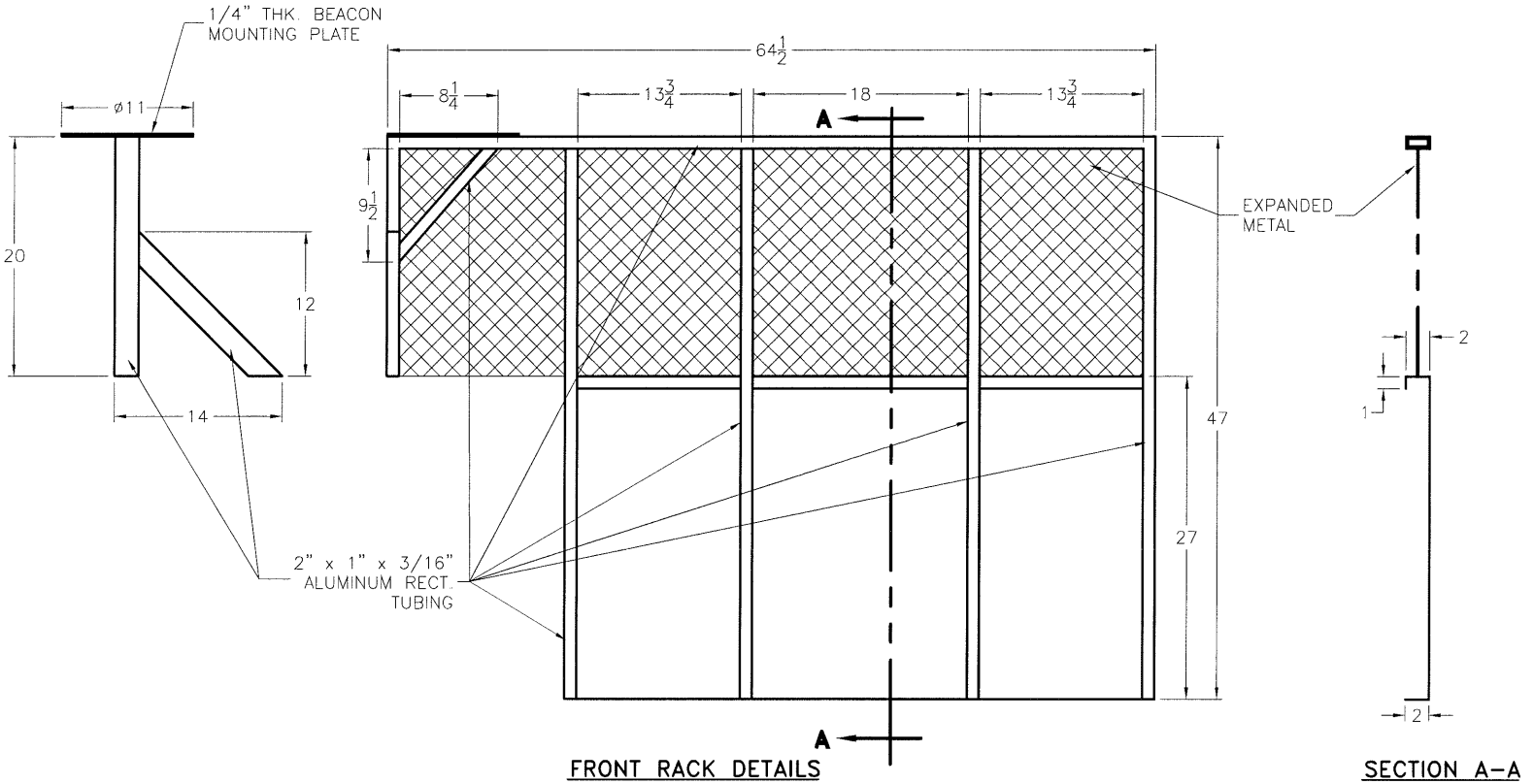

FRONT RACK DETAILS

SECTION A–A

GENERAL BODY & EQUIPMENT	Customer: WHITEHORSE MOTORS/YUKON ENERGY	REV	DATE	BY	DESCRIPTION
	Date: JUNE 7, 2005	Scale: 1/16	Dr. By: P. GAO	Ck. By: T. HOUNSOME	Page#: 1 OF 1	ACAD File: 2662TS00-8

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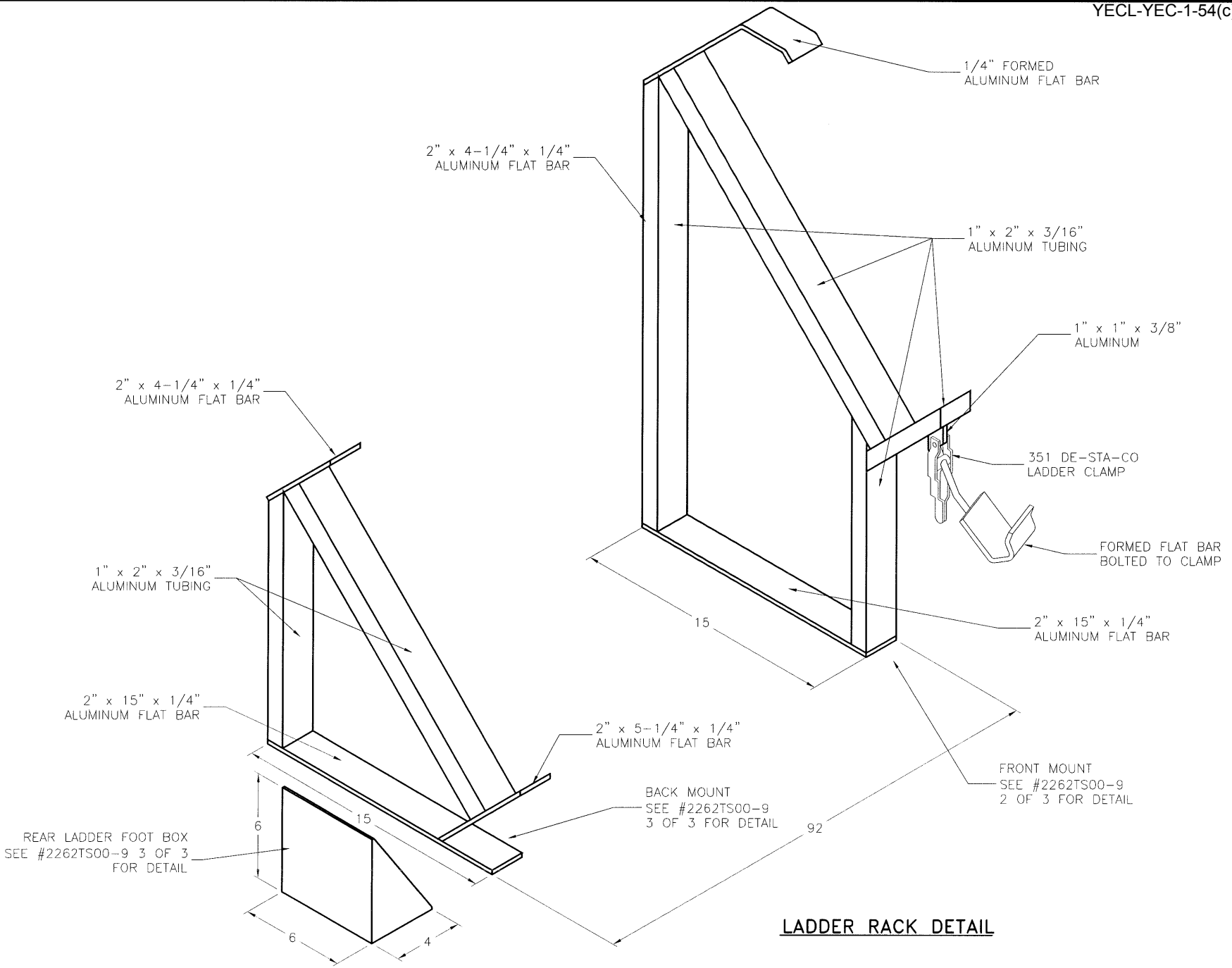

LADDER RACK DETAIL

GENERAL BODY & EQUIPMENT

Customer: WHITEHORSE MOTORS/YUKON ENERGY	REV	DATE	BY	DESCRIPTION
Date: JUNE 7, 2005	Scale: 1/8	Dr By: P. GAO	Ck By: T. HOUNSOME	Page#: 1 OF 3	ACAD File: 2662TS00-9

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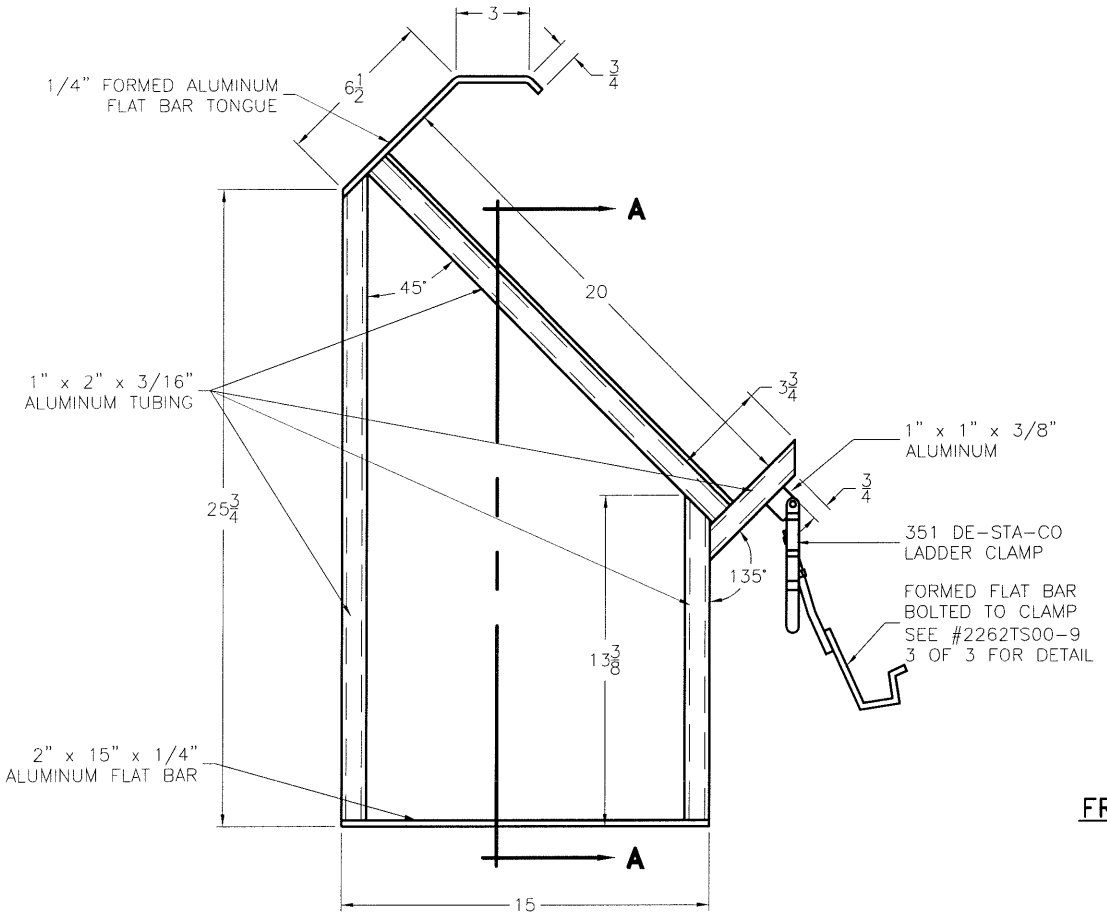
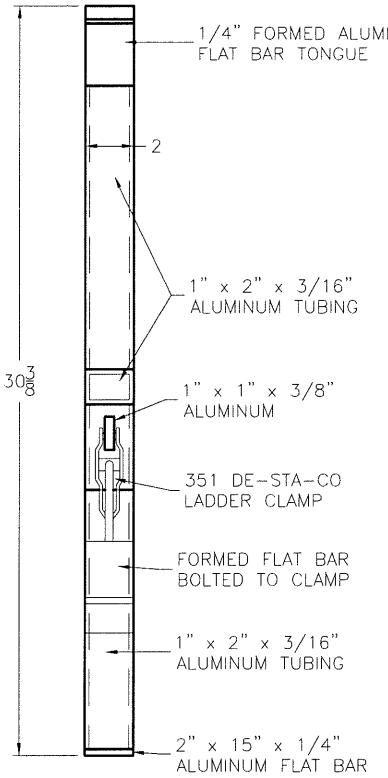
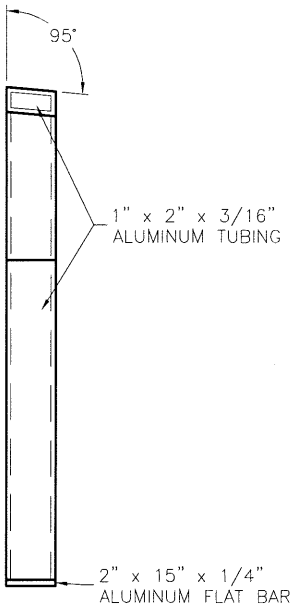


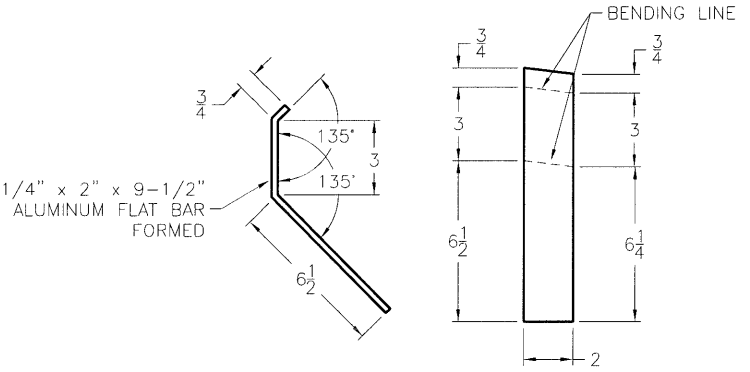
FRONT MOUNT – REAR VIEW



FRONT MOUNT – SIDE VIEW



SECTION A–A



FLAT BAR TONGUE

GENERAL BODY & EQUIPMENT	Customer: WHITEHORSE MOTORS/YUKON ENERGY	REV	DATE	BY	DESCRIPTION
	Date: JUNE 7, 2005	Scale: 1/8	Dr By: P. GAO	Ck. By: T. HOUNSOME	Page#: 2 OF 3	ACAD File: 2662TS00-9

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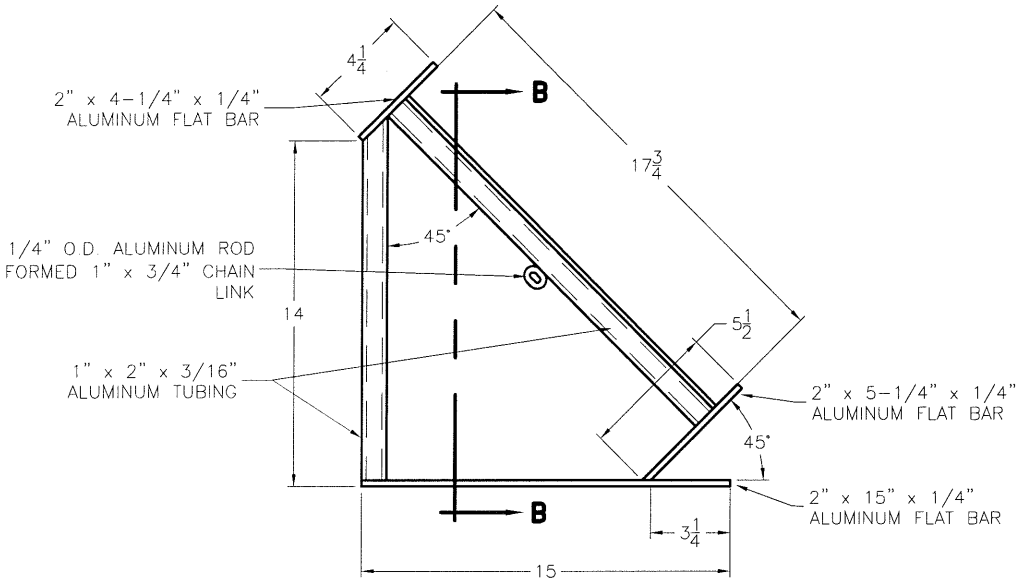
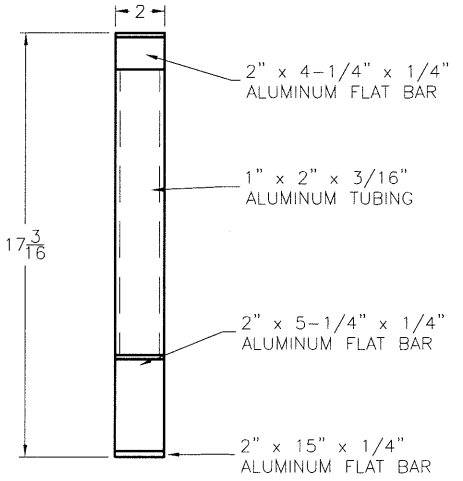
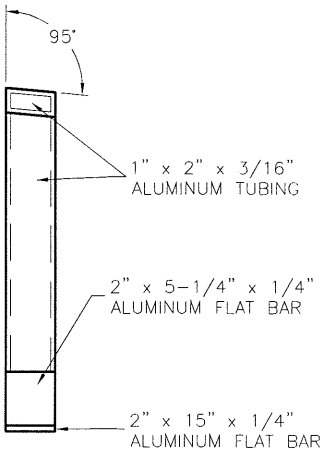


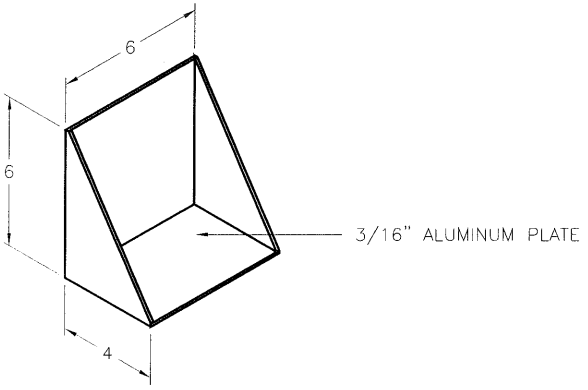
REAR MOUNT – REAR VIEW



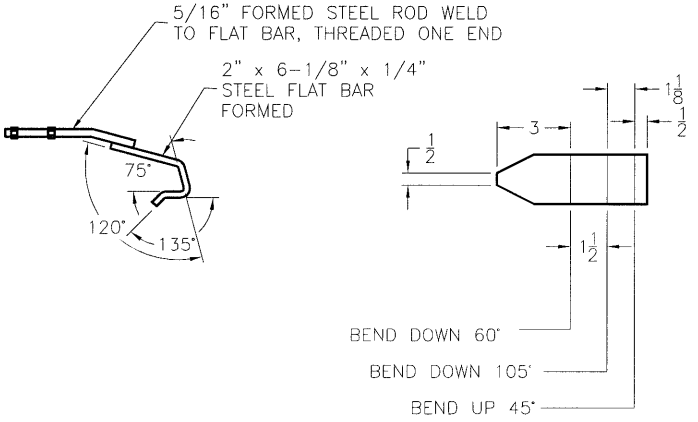
REAR MOUNT – SIDE VIEW



SECTION B–B



REAR LADDER FOOT BOX



CLAMP DETAIL

GENERAL BODY & EQUIPMENT	Customer: WHITEHORSE MOTORS/YUKON ENERGY	REV	DATE	BY	DESCRIPTION
	Date: JUNE 7, 2005	Scale: 1/8	Dr By: P. GAO	Ck By: T. HOUNSOME	Page#: 3 OF 3	ACAD File: 2662TS00-9

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TRACK INDUSTRIES LTD.

5529 3RD Street S.E.
Calgary, Alberta
T3E 1H4

Tel: 403-255-5323
Fax: 403-255-7494
Toll free: 1-888-255-5323

Wednesday, April 23,2008

CUSTOMER; Yukon Energy Corporation.

MODEL; HT-300XL

DATE; Wednesday, April 23,2008

STANDARD SPECIFICATIONS

DRIVE TRAIN

Engine:	Cummins Diesel EPA electronic engine QSC-280HP 2200 RPM Donaldson Air cleaner with precleaner and indicator Donaldson exhaust Electric throttle foot / toggle set Oil 0140 Rottela Shell Horton fan clutch Grid air heater (no ether start aid required) Espar hydronic 4 engine preheater with 7 day timer
Pump drive:	Durst 3 hole 1.23-1 ratio with 14 inch over centre clutch
Pump:	Sundstrand 90L series
Drive motors:	Rexroth 107CC variable output
Track drives:	O&K 55 series 66-1 ratio – speed 5.5 mph / 8 kms
Brakes:	Service: Hydrostatic Parking: Internal disc brakes on O&K wheel ends Hydraulic drive cooler electric with hydraulic drive fan

STEERING SYSTEM

Steering wheel

RUNNING GEAR

Tracks:	40 inch (838mm) Muskeg (D-Dent)
Track belt:	PN-240 6 ply Goodyear, 240 PSI per layer
Grouser bar:	1/2 in x 3 in (12.7mm x 76.2mm) spring steel with bolt on re-enforcing bars every bar
Traction Cleats	Re-enforcing bar with ice pick every five grouser bars
Sprocket drive:	Steel, with replaceable urethane sprockets
Sprocket idler:	Steel, with replaceable urethane sprockets
Suspension:	Heavy duty walking beams c/w urethane bushings
Hubs:	10 stud oil bath with metal face seals
Wheels:	6.50 x 20 - 10 stud heavy duty, extra re-enforcing
Tires:	8.25 x 20 Solid rubber

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T3E 1H4

Tel: 403-255-5323
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CAB

TI 2 man c/w engine dog house
Acoustic lined and insulated I interior sound level max 85 dba
All welded construction
Dog house with hinged sides for access to engine compartment
Sliding door windows
Fixed rear window, defrost on rear window (heated)
ROPS certified SAE J1040 or CSA B352
3 sets of keys for doors and storage compartments, keyed alike.

Accessories:

Windshield wiper (2), 2 speed with washer
Escape hatch (2), above operator and co-driver 26" x 21"
Bucket style suspension seats (2) shock ride
Sunvisor (2) seat belts (2)
Dome light (2)
Westcoast Mirrors (2) brush protected

ELECTRICAL SYSTEM (All non functional switches removed)

System:	12 volt
Alternator:	Delco Remy 160 amp
Batteries:	2 Extra heavy duty high capacity
Headlights:	Sealed beam (2) forward on grill guard or under cab windshield visor halogen
Spot Lights	Two cab roof mounted Night Ray model 475-20
Instrument panel:	Full instrumentation: charge pressure (silicone filled) , fuel gauge, hydraulic temperature, two power point accessory outlet.
Engine monitor system:	High temperature ,low oil shutdown ,low coolant.
Hydrostatic gauges:	Roda Deaco overspeed positive air shut off electric Temperature gauge and charge pressure (silicone filled pressure gauge only)
Windshield wipers:	Two speed
Miscellaneous:	Engine block heater Deck light (2) on rear cab halogen Backup alarm (1) inside rear frame Engine preheater with 7 day timer All wire connections to be soldered and heat shrink no blade connections (screw lug only) Electrical diagnostic plug dash mount in cab Remote start studs with covers at front frame Duel electric horns Inclinometer forward aft and side function

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Calgary, Alberta
T3E 1H4

Tel: 403-255-5323
Fax: 403-255-7494
Toll free: 1-888-255-5323

HEATING & COOLING SYSTEM

System:	110degrees F (38 C) ambient operating radiator assembly Chargeair cooling and radiator purge chamber
Arctic pack:	Cab heater 40,000 Btu's c/w (2) defroster fans, rear heated windows electric
Hoses:	Engine and radiator, Arctic (blue) cold weather
Antifreeze:	Ethylene Glycol to -50 degrees C, extended life coolant pre diluted to 50 I 50 mixture. Factory filled decal at radiator fill area.
Fan:	Electric clutch with manual override as indicated in engine specs.
Cooling system heater:	115 volt 1000 watt, heater cord routed to the back of cab

HYDRAULIC

Reservoir:	190-245 litre capacity (full at time of delivery) spec to carrier required capacity
Oil:	Shell synthetic customer spec with blue dye
Heater:	In tank Arctic Fox engine coolant operated * 120 volt 300 watt, heater cord routed to back of cab
Hoses:	High pressure hydraulic hoses, round shaft hangers for all hoses
Tool outlet	Two hydraulic tool outlet each side behind cab or rear deck
Filler cap:	Locking hydraulic oil fill cap

FRAME

Welded frame of high strength steel corten I double frame
Full belly pans, sealed, removable
Frame sealed for limited oil leakage from Hydrostatic system
All high pressure hydraulic hoses contained within frame tub
Front and rear tow and tie down rings, 2 front 2 rear with 2 trailer safety chain eyes
Pintle hook Buyers BP200 swivel mounted at rear frame

WINCH

30,000lbs front mounted Hydraulic operated c/w customer spec cable and tail chain.
Electrically actuated with proportional control.

BRUSH GUARD

Full brush guard to protect cab front and mirrors with front bumper to accommodate winch cable roller guide and two track mounting roller guides.

TANKS

Fuel:	350 litre aluminum, in frame Locking fuel cap

TOOLS

Track mounting tool
Wheel wrench c\w handle

TRACK INDUSTRIES LTD.

5529 3RD Street S.E.
Calgary, Alberta
T3E 1H4

Tel: 403-255-5323
Fax: 403-255-7494
Toll free: 1-888-255-5323

PAINT

Cab, white to match crane boom
Hydraulic tank, brushguard, filter box, battery box, tank rack. White as above
Deck, Chassis, wheels and lower frame, Black Urethane
All paint applied in accordance to standard #TS0010.

MANUALS

Three complete sets of Track Industries manuals, parts and service
(supplied in vehicle at time of delivery)
3 – Service engine and hydraulics manuals
3 – Service for carrier manuals
3 – Complete parts manuals for carrier only
Photo copies of wiring diagrams and hydraulic schematic with manuals.

Fuel, oil and antifreeze levels full at time of delivery.

Engine oil 0140 Rottela Shell
Hydraulic oil customer spec with blue dye
Antifreeze 50 I 50 mix Texaco
Windshield washer fluid
75W80 semi synthetic gear oil, torque hubs and pump drive shell customer spec

Delivery 12 months from receipt of purchase order

20% deposit required upon receipt of purchase order

YUKON UTILITIES BOARD
(YUB)

REFERENCE: **Application, page 2-1**

ISSUE/SUB-ISSUE: **Retail Customers**

YEC directly serves about 1900 customers at the distribution (retail) level (about 11% of all electrical retail customers in Yukon), most of whom live in and around Dawson City, Mayo and Faro.

QUESTION:

a) Should the remaining 89% of retail customers or their representative be consulted on rate design issues?

ANSWER:

(a)

In Yukon, as a result of OIC 1995/90 (and predecessor OICs going back to the time before YEC's first rate application), all retail ratepayers of YEC and YECL have an equal and direct interest in the revenue requirements of each utility and in related retail rate design issues. The Board is required to establish equalized rates for each retail rate class that do not vary as between YEC and YECL, reflecting the combined revenue requirement of the two utilities and a common rate design for customers of both utilities.

It is unclear what type of consultation the question envisages. If the question refers to Board processes, today, as in the past, all ratepayers have the ability to take part in the process established by the Board to deal with YEC's Application. More specifically in this Application a large percentage of ratepayers are directly or indirectly represented by intervenors who are actively taking part in the Board's process.

REFERENCE: **Application, page 2-5**

ISSUE/SUB-ISSUE: **Sales to Minto Mine**

Forecast industrial sales as provided in July 2008 by Minto Explorations Ltd. for the last three months of 2008 are 6,845 MW.h and forecast industrial sales for 2009 are 29,023 MW.h.

QUESTION:

a) What date did sales to Minto begin? What are the 2008 actual energy sales to Minto?

b) Please reconcile the 2009 forecast industrial sales to Minto versus the assumed load of 32.5 GW.h in the PPA application. What loads in the original assumptions did not materialize?

ANSWER:

(a)

Commencement of Delivery as defined in the PPA occurred on November 22, 2008. The mine was first energized on November 15, 2008. Between November 15, 2008 and November 22, 2008, crews worked on equipment settings and completed commissioning activities.

Actual energy sales to Minto in 2008 were 3,200,484 kWhs (see PWP/HML-YEC-1-16(a)).

(b)

Based on information provided by Minto, Yukon Energy is unable to provide any more detail than has been provided at Tab 2 of the Application (pages 2-5 and 2-6).

REFERENCE: **Section 2.2.2.2 Update on Other Mines**

ISSUE/SUB-ISSUE: **Carmacks Copper Mine**

The projected in-service date at this time is 2011, with an expected annual requirement averaging approximately 4 GW.h per month (48 GW.h per year) and a mine life of at least six years.

QUESTION:

a) If the projected in-service date is 2011, when would construction need to begin?

b) Would 2010 inventory and other working capital items be affected by this project?

c) If this mine goes ahead, does this accelerate the need for the second phase of the CSTP?

d) Are costs with respect to the Carmacks Copper PPA included in the forecast of regulatory costs during the test years?

ANSWER:

(a)

Yukon Energy does not have environmental regulatory approvals required to construct transmission to the site of the Carmacks Copper project. While any line may require up to 1 year for construction, environmental studies and reviews may necessitate up to one additional year (depending on the voltage and level of YESAB review).

(b)

Yukon Energy does not typically use inventory for the purposes of major capital projects. As a result, there would be no expected impact on inventory levels or other capital items for 2010.

(c)

If the Carmacks Copper mine proceeds in the near-term, it underlines the need for the second stage of the CSTP.

However, the Carmacks Copper project is only one potential basis for accelerating the second phase of CSTP. At the present time, it is also expected that near-term government infrastructure funding combined with connection of the Alexco mine in 2010 may serve as the impetus for proceeding quickly with this project.

(d)

No. Any costs for such PPA negotiation are part of the Western Copper grid connection (deferred planning and study costs). No costs are presently forecast for regulatory review for a Carmacks Copper PPA.

REFERENCE: **Tab 3 Revenue Requirement**

ISSUE/SUB-ISSUE: **Consultants**

QUESTION:

a) Please provide a table showing the amount YEC has spent and forecast to spend on consultants for the years 2005 to 2009 inclusive. Within the table provide a breakdown for each year based on the categories of Capital, O&M, Admin and General, and Regulatory, listing the individual or organization that provided the service. Provide reference to specific schedules containing these costs.

b) For those individuals or organizations listed in part A, for those instances where the costs exceed $50,000 in a given year, provide the terms of reference of the consulting engagement, the related project, and what results were achieved.

ANSWER:

(a)

Please see tables provided as Attachment 1 to this response for spending and forecast for consultants. For clarity, figures reported for 2005-2008 inclusive are actuals; figures for 2009 are forecast and reflect the estimated spending by area. Yukon Energy does not forecast spending by individual consultant. As well, spending on consultants for capital is not possible as budgeting is done at the project level. Where project budgets by function are prepared, they are in manual records and therefore not readily amalgamated.

The costs summarized cross reference to the GRA tables as follows:

Administration	Table 3.9
Production	Table 3.5
Transmission	Table 3.6
General	Table 3.8

(b)

Please see tables provided as Attachment 2 to this response; explanations are provided for all vendors with payments in a given year and category that exceed $100,000, as directed by Board Order 2009-4.

YUB-YEC-1-4 (a) - Consultant Costs

Year	Activity Type	Vendor	Total ($000)
2005	Administration	Intergroup Consultants Ltd.	46
		Norfolk Group, The	3
		Wood & Associates	1
		Western Industrial Relations Ltd	4
		Deloitte & Touche LLP	18
		M.P. Computing Ltd.	17
		Peter T. Boland & Assoc. Inc	8
		R & D Environmental Management	112
		L.P. Kurach & Associates	31
		Gannett Fleming, Inc.	3
		Leading Edge Projects Inc	2
		Derek Crowe Photography	1
		Impact Management Consulting Group	16
		Mackin Gibson Consulting Group	46
		Hay Group Limited	5
		Brown Governance Inc.	6
		Pashniak, David	1
		Coe & Company International Inc	45
		Pulse - 8 Safety Consultants	8
		Cenera	14
		Subtotal	385
	Capital	Acres International	31
		Arctic Power & Communication Systems	19
		Davis LLP	77
		EBA Engineering Consultants Ltd	32
		Intergroup Consultants Ltd.	541
		Klohn-Crippen Consultants Ltd.	2
		Larry Duguay & Associates Consulting	6
		Government of Yukon	246
		North/South Consultants Inc.	62
		Wood, Kathleen	16
		Yukon Electrical Co. Ltd.	15
		Yukon Engineering Services Inc	140
		Microage	3
		Champagne Aishihik First Nation	2
		Wood & Associates	5
		Yukon Conservation Society	4
		Utilitech Consulting Inc.	8
		Dorward Engineering Services Ltd.	4
		Pinard, JP	1

Year	Activity Type	Vendor	Total ($000)
		Planetworks Consulting	6
		Utilities Consumers Group	1
		Klohn Crippen	110
		A B Sturton Consultants Inc	17
		Adec Systems Inc	1
		BC Hydro	4
		M.P. Computing Ltd.	7
		Northwest Hydraulic Consultant	30
		Kobayashi & Zedda Architects Ltd	1
		Orbis Engineering Field Service	8
		R & D Environmental Management	2
		D.S. Matheson	1
		John S. Cooke /dba /Yukon Teleco	4
		Access Mining Consultants Ltd.	24
		Quest Engineering Group	21
		Amec Earth & Environmental Ltd.	8
		FSC Architects & Engineers	4
		Leading Edge Projects Inc	18
		GE Canada	9
		Mackin Gibson Consulting Group	19
		Matherson, David	4
		University of Saskatchewan	18
		Brown Governance Inc.	3
		Percival, Peter	1
		Bob Baxter, Steve Duncan & Gordon Clark	7
		McMahon, Patrick	7
		Allwest Reporting Ltd	2
		Hatch Acres Incorporated	12
		Spin Drift	4
		Subtotal	1568
	General	Martin Contracting	4
		GP Technologies Ltd.	7
		Subtotal	11
	Production	Acres International	14
		EBA Engineering Consultants Ltd	3
		Yukon Engineering Services Inc	3
		BC Hydro	2
		Underhill Geomatics Ltd.	5
		Access Mining Consultants Ltd.	4
		Canadian Projects Limited	6
		Subtotal	37
	Transmission	Impact Management Consulting	1
2005 Total		**Grand Total**	**2002**

Year	Activity Type	Vendor	Total ($000)
2006	Administration	EBA Engineering Consultants Ltd	5
		Intergroup Consultants Ltd.	28
		Aon Consulting Inc.	21
		Aasman Design Inc.	4
		Western Industrial Relations Ltd	6
		M.P. Computing Ltd.	35
		Archbould Photography	1
		Utility Risk Management Ltd.	4
		Polar Group ICT Inc.	6
		R & D Environmental Management	148
		Vancouver Computer Drafting Services	15
		Derek Crowe Photography	3
		Mackin Gibson Consulting Group	93
		Hay Group Limited	14
		Hatch Acres Incorporated	27
		Coe & Company International Inc	2
		eCorall Solutions Inc.	5
		Pulse - 8 Safety Consultants	13
		Cenera	31
		MacKay LLP	5
		Vincent L. Ready	5
		Health Benefits Consulting Inc	1
		Peter R. Richardson & Associates	50
		PDM Consultants Inc.	4
		MGCG Ltd.	26
		Borealis Productions	8
		Subtotal	558
	Capital	Acres International	1
		Davis LLP	121
		EBA Engineering Consultants Ltd	26
		Intergroup Consultants Ltd.	1110
		North/South Consultants Inc.	33
		Yukon Engineering Services Inc	47
		Gartner Lee Limited	45
		Champagne Aishihik First Nation	19
		Wood & Associates	6
		Powertech Labs Inc.	2
		Klohn Crippen	3
		Deloitte & Touche LLP	1
		BC Hydro	15

Year	Activity Type	Vendor	Total ($000)
		Underhill Geomatics Ltd.	17
		Northwest Hydraulic Consultant	7
		Kobayashi & Zedda Architects Ltd	15
		Orbis Engineering Field Service	24
		R & D Environmental Management	5
		Access Mining Consultants Ltd.	118
		Quest Engineering Group	3
		Amec Earth & Environmental Ltd.	4
		FSC Architects & Engineers	14
		Vancouver Computer Drafting Services	69
		Canadian Projects Limited	1
		Leading Edge Projects Inc	35
		Hatch Acres Incorporated	35
		NWT Power Corporation	45
		Reliable Electric & Communication	3
		MGCG Ltd.	124
		KGS Group	15
		PowerComp Associates Ltd.	20
		Subtotal	1983
	Production	Acres International	5
		EBA Engineering Consultants Ltd	4
		Yukon Engineering Services Inc	3
		Hatch Acres Incorporated	10
		CJ Consulting	4
		Subtotal	25
2006 Total		**Grand Total**	**2566**

Year	Activity Type	Vendor	Total ($000)
2007	Administration	Intergroup Consultants Ltd.	38
		Larry Duguay & Associates Consulting	1
		Aon Consulting Inc.	52
		Western Industrial Relations Ltd	13
		M.P. Computing Ltd.	4
		Archbould Photography	4
		R & D Environmental Management	96
		L.P. Kurach & Associates	22
		Vancouver Computer Drafting Services	46
		Yukon Council on Disability	1
		Leading Edge Projects Inc	1
		Derek Crowe Photography	3
		Phelps, Willard	8
		Hay Group Limited	8
		eCorall Solutions Inc.	9
		Pulse - 8 Safety Consultants	1
		PDM Consultants Inc.	12
		MGCG Ltd.	130
		Kim J. Lang	9
		Environmental Dynamics Inc.	1
		Jack Sekhon & Associates Inc.	27
		Harwood Information Associates	14
		Capital Helicopters (1995) Inc	1
		H. Allen Hope, Q.C.	2
		Subtotal	502
	Capital	Davis LLP	151
		EBA Engineering Consultants Ltd	42
		Intergroup Consultants Ltd.	804
		Larry Duguay & Aassociates Consulting	29
		North/South Consultants Inc.	17
		Yukon Engineering Services Inc	13
		Yukon Electrical Co. Ltd.	13
		Gartner Lee Limited	9
		BC Hydro International Limited	10
		Wood & Associates	1
		Utilitech Consulting Inc.	8
		Yukon Conservation Society	4
		Utilities Consumers Group	54
		Klohn Crippen	90
		Greer, Sheila C	2

Year	Activity Type	Vendor	Total ($000)
		Archbould Photography	2
		Underhill Geomatics Ltd.	5
		Northwest Hydraulic Consultant	39
		Kobayashi & Zedda Architects Ltd	6
		Orbis Engineering Field Service	2
		EHV Line Consultants Inc.	47
		R & D Environmental Management	3
		Access Mining Consultants Ltd.	1
		Quest Engineering Group	6
		Amec Earth & Environmental Ltd.	1
		Government of Yukon	260
		Canadian Projects Limited	4
		Leading Edge Projects Inc	7
		ConeTec Investigations Ltd.	19
		ZE Power Engineering	65
		Percival, Peter	3
		Challenger Geomatics Ltd.	48
		MGCG Ltd.	193
		KGS Group	334
		Kim J. Lang	9
		Environmental Dynamics Inc.	86
		Wardrop Engineering Inc.	318
		Threlkeld Consulting Ltd.	161
		Laberge Environmental Services	15
		Wilson Hydrotechnical Services	35
		Vanbibber, Pat	10
		Gittins, Rich	9
		Subtotal	2930
	Production	EBA Engineering Consultants Ltd	1
		Yukon Engineering Services Inc	3
		Utilitech Consulting Inc.	1
		Underhill Geomatics Ltd.	12
		Northwest Hydraulic Consultant	5
		Michael A. Watson	4
		White Mountain Environmental Consulting	4
		Phoenix Engineering	16
		Subtotal	46
	Transmission	Orbis Engineering Field Service	6
2007 Total		**Grand Total**	**3485**

Year	Activity Type	Vendor	Total ($000)
2008	Administration	Davis LLP	11
		Intergroup Consultants Ltd.	78
		Aon Consulting Inc.	22
		Aon Reed Stenhouse Inc.	6
		Aasman Design Inc.	6
		M.P. Computing Ltd.	2
		Archbould Photography	2
		R & D Environmental Management	53
		Quest Engineering Group	4
		Marsh Lake Tents & Events	2
		Wordsworth & Associates	19
		L.P. Kurach & Associates	24
		Vancouver Computer Drafting Services	14
		Leading Edge Projects Inc	2
		Hay Group Limited	22
		eCorall Solutions Inc.	20
		PDM Consultants Inc.	18
		MGCG Ltd.	20
		Kim J. Lang	34
		Harwood Information Associates	5
		Networkologist	68
		Kasawski, Theron W	1
		Vandelay Systems	2
		UMA Engineering Ltd.	10
		Pereira, John	6
		Performance Improvement for Industry Inc	17
		Penta Can	26
		McCarthy Tetrault LLP	5
		Richard Zral Enterprises	2
		International Quest Engineering	9
		Infomentat Inc.	5
		GD Hill	1
		Quality Training Consultants Ltd	10
			526
	Capital	Davis LLP	103
		EBA Engineering Consultants Ltd	112
		Intergroup Consultants Ltd.	544
		North/South Consultants Inc.	13
		Gartner Lee Limited	14
		Northern Climate Engineering Ltd	17

Year	Activity Type	Vendor	Total ($000)
		Klohn Crippen	104
		N. A. Jacobsen P.Eng.	3
		Government of Yukon	20
		BC Hydro	14
		M.P. Computing Ltd.	5
		Archbould Photography	2
		Underhill Geomatics Ltd.	12
		Northwest Hydraulic Consultant	62
		Arctic Alpine Seeds Ltd.	4
		Orbis Engineering Field Service	28
		R & D Environmental Management	4
		D.S. Matheson	19
		Canadian Projects Limited	4
		Leading Edge Projects Inc	1
		Derek Crowe Photography	2
		Martin Contracting	1
		Challenger Geomatics	18
		eCorall Solutions Inc.	61
		Challenger Geomatics Ltd.	3
		CJ Consulting	10
		KGS Group	388
		Environmental Dynamics Inc.	334
		Wardrop Engineering Inc.	1421
		Threlkeld Consulting Ltd.	302
		Harwood Information Associates	2
		Wilson Hydrotechnical Services	17
		Matrix Research Ltd.	22
		Networkologist	54
		Hatch Ltd.	3
		Bill McKenzie	8
		D.A. Harris & Associates Ltd.	3
		UMA Engineering Ltd.	29
		Technolise	14
		Ghomsehi, Dr. Mory	6
		Earth Tech Canada Inc.	19
		Sadlier-Brown Consulting Ltd.	8
		Iris Power LP	10
		Surespan Construction Ltd.	12
		Infomentat Inc.	1
		Bluewater Biosciences	16
		EBA Engineering Consultants Ltd	2
		BC Hydro	7
		Subtotal	3857
	Production	Underhill Geomatics Ltd.	7
		Vandelay Systems	1
		Hatch Ltd.	2
		Meerholz Canada	8
		Performance Improvement for Industry Inc	3
		Subtotal	21

Year	Activity Type	Vendor	Total ($000)
2008 Total		**Grand Total**	**4404**

Year	Activity Type	Vendor	Total ($000)
2009	Administration		558
	Production		28
	General		4
2009 Total	**Grand Total**		**590**

Year	Activity Type	Vendor	Total ($000)	Project Description
2005	Administration	R & D Environmental Management	**112**	Manage all aspects of the Yukon Energy fish hatchery (including freshwater program on behalf of YG)
2005	Capital	Government of Yukon	**246**	Payment to YG represents costs of Yukon Utilities Board to administer the Yukon Energy 2005 Revenue Requirement and Related Matters process. (costs recorded as deferred rate case costs)
		Intergroup Consultants Ltd.	297	Regulatory advisory services provided in support of preparation and defense of 2005 Revenue Requirement and Related Revenues application (costs recorded as deferred rate case costs)
			193	Planning consulting costs associated with the preparation of the 20 Year Resource Plan. (recorded as other deferred planning costs)
			41	Oversight and planning consulting services provided as part of planning for CSTP Stage I. (recorded as part of capital cost of the project)
			11	Miscellaneous consulting services provided to YDC - Costs were 100% recovered from YDC.
			541	
		Yukon Engineering Services Inc	93	Aishihik Lake Boat Launch consulting services
			9	Advisory services - Aishihk erosion/berm studies
			2	Engineering advisory services - WRGS Rip Rap
			35	Preliminary survey work - CSTP Stage I
			140	
		Klohn Crippen	39	WH4 Intake - seismic assessment
			71	Dam Safety Reviews
			110	

Year	Activity Type	Vendor	Total ($000)	Project Description
2006	Administration	R & D Environmental Management	**148**	Manage all aspects of the Yukon Energy fish hatchery (including freshwater program on behalf of YG)
2006	Capital	Intergroup Consultants Ltd.	278	Planning consulting costs associated with the preparation and defense of the 20 Year Resource Plan. (recorded as other deferred planning costs)
			805	Oversight and planning consulting services provided as part of planning for CSTP Stage I including preparation of YESAB submission, First Nation consultation and negotiation of LOI and PPA with Minto Explorations Incorporated. (recorded as part of capital cost of the project)
			27	Miscellaneous consulting services provided to YDC - Costs were 100% recovered from YDC.
			1110	
		Access Mining Consultants Ltd.	**118**	CSTP Planning - GIS, environmental screening, heritage, mapping, YESAB issues)
		MGCG Ltd.	95	Computer consulting - server replacements
			30	Business process analysis - customer information system
			124	
		Davis LLP	16	Resource Plan Peer Review
			105	Mayo Dawson Claims process - legal support; costs incurred were written off to the Shareholder's account
			121	

Year	Activity Type	Vendor	Total ($000)	Project Description
2007	Administration	MGCG Ltd.	**130**	IT advisory services including active directory, policy development, communications needs assessment, preventative maintenance and tape backup design.
2007	Capital	Intergroup Consultants Ltd.	95	Planning consulting costs associated with follow up on YUB recommendations on the 20 Year Resource Plan. (recorded as other deferred planning costs)
			649	Consulting services re: CSTP Stage I (project oversight and planning, First Nation consultation, YESAB application research and preparation and participation in YUB Part 3 Process)
			30	Consulting advisory services re: hydro generation pre-feasibility planning
			15	Assistance in negotiations of Power Purchase Agreement with Minto Explorations Ltd.
			1	Planning consultation - Western Copper transmission project.
			15	Consulting services provided to YDC - Costs were 100% recovered from YDC.
			804	
		Davis LLP	69	Legal services - Mayo-Dawson Claims process; costs incurred were written off to the Shareholder's account
			16	CSTP Oversight
			65	Minto Explorations Ltd PPA - due diligence
			151	
		MGCG Ltd.	24	IT advisory services re: communications network enhancements
			25	IT advisory services re: webserver technology
			50	Customer information system assessment project - resulted in recommendation to Board of Directors on CIS solution
			46	IT advisory services re: VMWare Implementation
			38	IT advisory services re: sharepoint webserver implementation
			11	IT advisory services re: Financial Information Systems current state analysis
			193	
		KGS Group	55	Enginnering consultations - Yukon River Downstream Icing
			278	Resource planning - Hydro generations and pre-feasibility
			334	
		Government of Yukon	152	Payment to YG represents costs of Yukon Utilities Board to administer the Yukon Energy 20 year Resource Plan. (costs recorded as deferred planning costs)
			108	Payment to YG represents costs of Yukon Utilities Board to administer the regulatory processes related to CSTP Stage I (i.e. Part 3)
			260	
		Wardrop Engineering Inc.	48	Engineering design - CSTP Stage I
			270	Project Management costs - CSTP I
			318	
		Threlkeld Consulting Ltd.	161	Owner's representative/technical adviser - CSTP Stage I

Year	Activity Type	Vendor	Total ($000)	Project Description
2008	Capital	Intergroup Consultants Ltd.	18	Consulting advisory services re: hydro generation pre-feasibility planning
			194	Regulatory advisory services provided in support of preparation and defense of 2008/2009 General Rate Application (costs recorded as deferred rate case costs)
			22	Consulting services - CSTP Stage I - oversight and First Nation consultations
			2	Minto Explorations Ltd Power Purchase Agreement - follow up interpretations
			221	Mayo B Hydro Development project management and environmental assessment
			83	Oversight on resource plan project investigation for example Marsh Lake, Atlin, Gladstone, and other large hydro
			3	Consulting services provided to YDC - Costs were 100% recovered from YDC.
			544	
		Davis LLP	**103**	Legal services - diesel plant air emissions permits
		EBA Engineering Consultants Ltd	16	Mayo hydro facility liquifaction study
			19	Gladstone diversion project - environmental baseline field work
			77	Geothermal assessment
			112	
		Klohn Crippen	10	Mayo hydro facility liquifaction study
			94	AH3 hydro project - preliminary engineering
			104	
		KGS Group	17	Engineering modelling - Southern lakes Hydrology
			46	Yukon River Downstream Icing
			97	Resource development - hydro generation and pre-feasibility
			19	Aishihik Hydro - downstream icing study
			23	Wareham (Mayo) intake rock face assessment
			187	Preliminary engineering - Mayo B
			388	
		Environmental Dynamics Inc.	59	Aishihik fish monitoring
			8	CSTP stage I - mapping activities
			268	Mayo B environmental assessment
			334	
		Wardrop Engineering Inc.	506	Engineering design - CSTP Stage I
			915	Project Management costs - CSTP I
			1421	
		Threlkeld Consulting Ltd.	**302**	Owner's representative/technical adviser - CSTP Stage I

REFERENCE: **Application, Page 3-2**

ISSUE/SUB-ISSUE: **Stage 1 CSTP**

Completion of Stage One CSTP, which contributes to these increased revenue requirements, is the key factor leading to an overall 2009 rate reduction.

QUESTION:

a) On what date did Minto become a customer of YEC?

b) When did the actual connection of the Minto mine to the grid occur?

c) When did Pelly Crossing connect to the grid?

ANSWER:

(a)

Commencement of Delivery as defined in the PPA occurred on November 22, 2008.

(b)

The mine was first energized on November 15, 2008. Between November 15, 2008 and November 22, 2008, crews worked on equipment settings and completed commissioning activities.

(c)

The community of Pelly Crossing was energized from the transmission line on November 19, 2008.

REFERENCE: **Insurance and Reserve for Injury and Damages (IRID)**

QUESTION:

a) Please provide a continuity table of IRID showing the appropriations going in and the charges against for the years 2005 to 2009 inclusive.

b) Please provide a detailed breakdown of the actual charges against IRID for the years 2005-2008 inclusive and the forecast charges for 2009.

ANSWER:

(a) and **(b)**

Please see table below which provides a continuity schedule for the Reserve for Injuries and Damages (RFID) for the years 2005 to 2008 inclusive. With respect to 2009, the GRA has been prepared on the assumption that charges would equal the 2009 appropriation, at $150,000.

Please see also response to YECL-YEC-1-29.

Continuity Schedule – YEC Reserve for Injuries and Damages

	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)
Opening Balance	**797**	**-33**	**500**	**463**
Additions				
Computer Stolen	4			
Third Party Vehicle Damage - Mayo	1			
Service Truck Fire Loss	1			
Dawson Hse H20 Damage	6			
Marsh Lake Dam Repair	2			
YUB Board Order 2005-12 transfer from Reg Liability	-743			
Takhini Substn Break-In		15		
Kulan Break In		32		
L171 Lightning Arr Failure		11		
L171 Insulator Failure		35		
Whitehorse Hydrant Leak		36		
Unit 63 Vehicle Theft		2		
WH1 Hub and Blade Repair		302		
Aishihik Cable Repair		200		
L174 Broken Pole			39	
Marsh Lake Water Damage			17	
Kulan Warehouse Water Damage			7	
L172 Insulator Failure				40
Rock Creek Crossing				11
Polaris Ranger & Trailer Replacement				9
Repair Outage Damage				25
Streetlight damage				1
Total	**-730**	**633**	**63**	**86**
Annual Provision	**-100**	**-100**	**-100**	**-50**
Closing Balance	**-33**	**500**	**463**	**500**

REFERENCE: **Application, Page 3-16**

ISSUE/SUB-ISSUE: **Regulatory Liabilities**

QUESTION:

a) Does the balance in Regulated Liabilities accrue interest? If not, why not?

ANSWER:

(a)

No, the balance in Regulated Liabilities does not accrue interest. Regulatory Liabilities represent amounts held by the utility on behalf of ratepayers, and act as an offset to ratebase and as such do not accrue any interest (but rather serve effectively as a form of no-cost capital).

REFERENCE: **Application, Page 3-17**

ISSUE/SUB-ISSUE: **FRSR and Depreciation**

QUESTION:

a) Please provide a continuity schedule of the balance in FRSR from 2005 to 2009 inclusive.

b) Since Order 2005-12, has YEC made any changes to its depreciation assumptions or undertaken any further studies on depreciation?

ANSWER:

(a)

Please see response to CW-YEC-1-25(a).

(b)

YEC has not made any changes to its depreciation assumptions or undertaken any further studies on depreciation since Order 2005-12.

REFERENCE: **Application, Page 3-17**

ISSUE/SUB-ISSUE: **Contributions**

QUESTION:

a) Please provide continuity schedules of contributions and amortization of contributions for the years 2005 to 2009 inclusive. Within the schedule provide a breakdown based on the following categories:

YTG Contributions
YDC Contributions
Minto Exploration Contributions Other Contributions

b) Please provide a table on the CSTP project showing capital costs, contributions by the parties listed above and any amortization of the capital costs and contributions for the period 2006 to 2009 inclusive.

ANSWER:

(a)

The continuity schedule of contributions and amortization of contributions is set out in Tab 7, Schedule 1, rows 22-26.

All contributions received from 2005 to 2007 were "Other Contributions" with the exception of:

- $4.450 million in 2007, which was from Yukon Government ($0.450 million) and YDC ($4 million).

Forecast 2008 contributions in the GRA are all "Other Contributions" with the exception of:

- $10.000 million from YTG for CSTP
- $3.000 million from YTG for CSTP
- $7.200 million from Minto for the CSTP main line

- $9.989 million from Minto for the Minto spur
- $1.500 million from YTG for Aishihik 3rd turbine, and
- $0.030 million from YTG for fish hatchery upgrades.

Forecast 2009 contributions in the GRA are all "Other Contributions" with the exception of:

- $3.500 million from YTG for the Aishihik 3rd turbine.

(b)

For spending on CSTP by year, please see Table 5.2. For contributions to CSTP by year, please see YUB-YEC-1-9(a). No amortization of capital costs or contributions occurred in 2007 or prior as the project was in 'work in progress'. For 2008 and 2009 CSTP in service values, please see the table below:

CSTP capital cost and contributions

$000s	2008	2009
Capital Cost		
Opening Balance	0	38174
Additions from WIP	38383	0
Depreciation	-209	-840
Closing Balance	38174	37334
Contribution		
Opening Balance	0	34449
Additions from WIP	34629	0
Depreciation	-180	-722
Closing Balance	34449	33727

REFERENCE: **Application, Page 3-17**

ISSUE/SUB-ISSUE: **Planning and Study Costs**

The largest component of this increase since 2005 ($0.547 million) relates to planning and study costs, which is primarily studies of the existing system and options for expanding the quantity of renewable generation, as well as studies related to the safety and reliability of the system, the Minto Mine PPA negotiations, and other small projects, offset by the termination of amortization since 2005 on old study amounts as they become fully amortized.

QUESTION:

a) What is the result of the studies on renewable generation?

b) Why are the Minto PPA negotiations accounted for in this manner?

c) Why are safety and reliability studies amortized and not directly expensed?

ANSWER:

(a)

Studies on renewable generation have concluded that there are near-term as well as long-term opportunities for Yukon Energy to expand the available complement of renewable generation, as well as transmission interconnections that facilitate optimum use of renewable generation in order to meet anticipated load increases.

The main focus of recent studies has been to identify and assess near term options (i.e., in-service as soon as 2010 and up to 2015) to serve potential new load that may be connected during this time.

At a high level, the conclusions indicate that the unit costs of enhancement to existing hydro generation (as well as timing requirements to develop) are below the costs (and development timing) that would need to be incurred for developing new “greenfield” hydro sites. Options studies for enhancements to existing generation identified Mayo B as the largest single addition to the system in terms of energy (in the range of 30-40

GW.h) and licencing timeframe. Smaller generation enhancements, such as a small scale Atlin winter storage project, the Marsh Lake Fall-Winter storage project, or a Gladstone diversion, were also identified as near term options that can be developed at an attractive cost, but earliest feasible in-service dates present specific risks that depend on the timeframes necessary to plan and licence the projects. More information on these options is provided at Tab 5, page 5-20.

Other enhancements to existing facilities, such as re-runnering existing hydro units, are still being reviewed.

(b)

The Minto PPA negotiations are accounted for in this manner in order to amortize the costs of putting in place the PPA over the period of benefits derived from the agreement.

(c)

Finance Accounting Practice FX-005, filed as an Attachment to YUB-YEC-1-59.1 (filed during the Requirement Revenues and Related Matters hearing) provides (at page 13) guidelines for the amortization of study costs. The costs are amortized in part as they are only periodic requirements (such as the study that resulted in Yukon Energy adopting a new capacity planning criteria) or the benefits of the studies extend over a number of years.

REFERENCE: **Application, Page 3-19**

ISSUE/SUB-ISSUE: **Cost of Debt, Unsecured Advances from YDC**

QUESTION:

a) Please provide the terms of the YDC loans and notes as listed in Schedule 13 of Tab 7.

ANSWER:

(a)

Please see Note 13 to the 2007 Financial Statements included in the Application at Tab 9, as well as the response to CW-YEC-1-26(a).

REFERENCE: **Application, Page 3-19**

ISSUE/SUB-ISSUE: **Cost of Debt, Minto Mine Obligation re: Diesels**

QUESTION:

a) In Order 2007-5, what comments did the Board make regarding the purchase of the Minto diesels?

b) Has YEC provided a business case on the purchase of the Minto diesels? If not, Please provide the business case showing where this option fits according to YEC's 20 Year Resource Plan and what options in the Resource Plan are recommended to be deferred because of this option.

c) Has the Board approved the incorporation of the Minto diesels into rate base?

d) Could YEC obtain an unsecured advance from YDC to finance the Minto diesels?

ANSWER:

(a)

In Appendix A to Board Order 2007-5 the Board noted as follows (at page 19-20):

> The Board is of the view that section 10.2 of the PPA provides adequate protection for YEC and Yukon ratepayers as to the condition of the units. The Board accepts that the price for the units as determined in the PPA and as further noted in UCG-YEC-2-14 and YUB-YEC-1-8 is reasonable. The Board also accepts the terms as to the mobility of the units. However, the Board is not convinced the units are needed. Other than a parenthetic notation late in the Resource Plan process, YEC has not demonstrated a need for the units nor provided an adequate business case supporting this option. Given the new capacity criteria employed by YEC, YEC has not furnished evidence that these units are needed based on those criteria, nor where this capacity addition stacks with the other projects identified within the Resource Plan.

> Further, the new funding available for the third turbine at Aishihik from the Government of Yukon also brings into question the need for the units and whether they would be a least cost option. The Board agrees with YECL that no evidence has been offered to support the statement that line loss reductions will offset other incremental costs. The Board also agrees with Mr. Percival and UCG's argument that if YEC did not agree to finance the customer contribution from Minto, the use of the units as security would not be necessary. In the event that YEC had to use the units as security for collection from Minto, it is questionable that the units would be in the condition stated in section 10.2 as under those circumstances the units are more likely to be in a distressed condition. Based on the foregoing, the Board does not accept the purchase of the Diesel Units as part of the PPA.
>
> YEC is free to purchase the units; however, at this time the Board cannot provide any assurance to YEC that the units would be approved as an addition to rate base. However, it is open to YEC to develop an appropriate business case supporting the need for the Diesel Units and include it for consideration in its next GRA.

The Board provided as follows with regard to Directive 15:

> The Board does not accept the purchase of the Diesel Units as part of the PPA. YEC is free to purchase the units; however, at this time the Board cannot provide any assurance to YEC that the units would be approved as an addition to rate base. However, it is open to YEC to develop an appropriate business case supporting the need for the Diesel Units and include it for consideration in its next GRA.

(b)

Yukon Energy provides its case in support of the Minto Diesels in Tab 5 of the Application in Section 5.2.1.2, at pages 5-7 to 5-11.

In its Order the Board expressed concern that issues of price (i.e., the least cost option) and need had been insufficiently addressed during the Resource Plan process and the

PPA hearing – these issues are specifically addressed in the above-referenced pages of the Application.

As noted on pages 5-8 and 5-9 of the Application, the cost of the Minto diesels (estimated in the Application at $0.498 million/MW including work required to winterize the units) remains competitive with the estimated costs of the Mirrlees Life Extension Project ($0.457 million/MW as noted in supplementary filing Exhibit 16 of the Resource Plan proceeding). Further, it is noted that acquiring the units provides some flexibility with regard to long term planning. Once all PPA commitments have been met regarding the units YEC may elect to sell the units or move them from the mine site to an alternate location.

As noted at page 5-9 of the Application, the Faro Mirrlees re-commissioning project is nearing completion. The Whitehorse Mirrlees Refurbishment (3 units totally 14 MW) is budgeted and anticipated to occur as follows:

- In 2008: Unit #3, providing an additional 5 MW of capacity at a cost of $1.1 million, plus an additional $0.535 million generator rewind for 2010.

- In 2010: Unit #2, providing an additional 5 MW of capacity at a cost of $1.250 million, plus $0.435 million for the generator.

- In 2012: Unit #1, providing an additional 4 MW of capacity at a cost of $1.050 million, with no required generator rewind.

Upgrades to common systems were undertaken in 2007 (at a cost of $0.468 million) and 2008 (at a cost of $0.450 million), and are also anticipated to take place in 2010-12 (at an anticipated cost of $1.465 million).

As noted at page 5-9 of the Application, the purchase of the Minto diesels has not changed the planned refurbishment of Unit #3 and Unit #2 or any further planned upgrades to common systems. However, as noted, the timing for refurbishment of Unit #1 is flexible and the option exists to mothball the unit for pending optimum capacity for the unit to be brought back into service.

At page 5-11, three other benefits are noted from acquiring the Minto diesel units:

- Units are located near key major loads at the end of a long transmission line (reductions in line losses when diesel units needed to serve these loads).
- The units can be run without any emissions impacts in Whitehorse.
- Cost effective contingency protection in the near term.

(c)

In Order 2007-5, the Board did not approve the purchase of the Minto diesels noting (at page 20), “at this time the Board cannot provide any assurance to YEC that the units would be approved as an addition to rate base” and providing that “it is open to YEC to develop an appropriate business case supporting the need for the Diesel Units and include it for consideration in its next GRA”.

Yukon Energy has proceeded with the purchase of the Diesel units as a condition of the Power Purchase Agreement with Minto and has included an assessment of the additional issues the Board asked to be considered in Order 2007-5 at Tab 5 of its 2008/2009 General Rate Application.

(d)

The financing arrangement for the Minto Diesels is set out in detail in YEC's PPA with the Minto Mine. It does not involve YDC and there is no agreement between YEC and YDC to finance, or be involved in any way in, YEC's purchase of the diesels.

REFERENCE: **Application, Page 3-20**

ISSUE/SUB-ISSUE: **Cost of Debt, YDC Flexible Promissory Note**

The face interest rate on the note is 6.55% and, due to the present substantial benefits to ratepayers arising from the Mayo-Dawson line given current forecast diesel prices, the full 6.55% face-interest rate is forecast to be paid in 2008 and 2009.

QUESTION:

a) Are the "present substantial benefits to ratepayers" based on the forecast costs of the MD line or based on the actual costs of that line?

b) Please provide the calculations of the "substantial benefits to ratepayers" (include the electronic version in your response), based on the fuel prices in effect at the end of 2008.

c) Based on the reduced current fuel prices (December 31, 2008) what does YEC forecast the interest rate for 2009 to be on this note?

ANSWER:

(a)

The "present substantial benefits to ratepayers" are based on the actual costs of the line.

(b)

For 2008, the Mayo Dawson line resulted in benefits to ratepayers of $4.700 million in avoided diesel fuel (16.488 GW.h of baseload diesel saved, at 3.8 kW.h/litre efficiency and an average price of $1.0832 per litre) and a further $0.263 million in avoided diesel O&M costs (at 1.6 cents/kW.h for 16.488 GW.h of diesel saved) as well as $0.314 million in avoided diesel capital costs as set out in the Mayo-Dawson financing agreement. Total diesel savings were therefore $5.278 million. This does not include the benefits to YECL of being able to purchase wholesale power from YEC at Stewart Crossing and avoid the use of diesel gensets.

Total costs for the Mayo-Dawson line with an equity return at approved fair ROE levels of $0.913 million (project mid-year 2008 rate base at $25.923 million times 40% equity ratio at 9.05% rate of return as last approved by the YUB), interest on the flexible note of $1.052 million, plus depreciation of $0.724 million and O&M cost of $0.073 million. The resulting total costs of the project are $2.762 million.

The net benefits of the Mayo Dawson project in 2008 were $2.516 million.

(c)

YEC forecasts the actual rate of interest in 2009 to be 6.55%. Based on the calculation provided in the promissory note and described in (b) above, as long as the price of diesel remains above approximately 50 cents/litre, the interest on the note is expected to remain at the full 6.55%.

REFERENCE: **Application, Page 3-20**

ISSUE/SUB-ISSUE: **Cost of Debt, TD Canada Trust Note**

QUESTION:

a) Why did YEC acquire this instrument and not obtain unsecured financing from YDC?

b) Does YEC plan on refinancing this note with YDC at a lower interest rate in 2011?

ANSWER:

(a)

YEC acquired this instrument in 1996 to replace a term note with Canada. At the time financing from YDC was not available.

(b)

There are no plans at this time to refinance this note with YDC at a lower interest rate because the pre-payment provisions of the TD loan are prohibitively expensive.

REFERENCE: **Application, Page 3-21**

ISSUE/SUB-ISSUE: **ROE**

In both the YEC 1998 proceeding and 2005 proceeding, efforts were made to permit a cost-effective and simple means to set the fair level of ROE. In particular, in the 2005 proceeding, the fair ROE for test year 2005 was proposed by YEC to be set by reference to the British Columbia Utilities Commission (BCUC) formulaic approach, based on YEC receiving a 52-basis-points premium due to its risk compared to low risk utility.

QUESTION:

a) In Order 2005-12 did the Board determine that the use of the BCUC automated adjustment mechanism for ROE did not impose a precedent in Yukon?

b) Is it YEC's view that that determination should serve/impose a precedent for Yukon?

c) Has anything changed that would lower the risk premium for YEC closer to that of FortisBC?

d) Has the BCUC determined the base ROE for 2009? If so, what is it?

ANSWER:

(a)

Yes. In Appendix A to Order 2005-12, the Board determined that an appropriate rate of return on common equity for Yukon Energy was 9.05%, based on the BCUC benchmark for a low risk utility with an added risk premium of 52% (less 0.50% per OIC 1998/32). The Board noted at that time that "using the BCUC automated adjustment mechanism as a proxy of rate of return on equity does not impose a precedent in the Yukon and is an expedient means of determining return for the current one-year period."

(b)

Not necessarily. In the 2005 Required Revenues and Related Matters Application, Yukon Energy used a simplified approach that relied upon the detailed, expert analysis undertaken by the BCUC to determine the return on equity for a benchmark low risk utility. As noted in the Application (at Tab 8 pages 8-9 and 8-10, and in responses to information requests during the review of the Application), Yukon Energy proposed this simplified approach to setting the fair return on equity for 2005 in order to reduce costs related to preparing and reviewing expensive and contentious cost of capital evidence that would have to be borne by ratepayers.[1]

At that time Yukon Energy was clear to distinguish the difference between using the BCUC benchmarking approach for determining the revenue requirement for 2005 alone, and adopting fully the system of annual ROE adjustments implemented in BC, noting as follows:[2]

- The Application for review at the time only addressed revenue requirement and rates for that year (2005); under the orderly approach towards regulation adopted by Yukon Energy in bringing forward its application at that time further rate changes and revenue requirement reviews would be deferred until 2007 at the earliest.

- To establish an annual ROE adjustment mechanism in Yukon would require a more rigourous review of the merits of moving towards such an annualized approach; this would likely be undertaken via a generic ROE proceeding that that included both utilities. It was noted that the process utilized in British Columbia evolved over several years, applied to the entire jurisdiction, and although complex was understood by all utilities and intervenors in that jurisdiction.

[1] In its 2005 Required Revenues and Related Matters Application Yukon Energy noted at page 3-23, "In recent years, many jurisdictions in Canada have adopted approaches to setting the fair return on equity that eliminate the routine requirement in rate requirement hearings for specific rate of return evidence from independent experts. Preparation of such expert evidence is costly and time-consuming. Yukon Energy believes that it is appropriate to adopt approaches that can avoid the need for such expert evidence when setting the fair return on equity for regulated power utilities in Yukon."

[2] These concerns were discussed in the 2005 Required Revenues and Related Matters Application at Tab 8 and in response to YUB-YEC-1-22 provided during that proceeding.

- Any annualized adjustment process for determining ROE would require practical implementation issues to be investigated and some efficient review process determined that would allow for timely review and participation by interested parties.

In this regard, Yukon Energy acknowledged that the use of the BCUC benchmarking approach should not set a precedent with regard to setting an annual ROE.

However, it is noted that the precedent of relying upon a benchmarking mechanism for determining the return on equity for a single application extends beyond the 2005 proceeding. The YUB did use this approach to a limited extent in determining Yukon Energy's fair return for 1998 during the 1998 hearing where the 1998 ROE was set based on adjusting the approved 1997 ROE by an approach similar to the BCUC approach (except that 100% of the change in long Canada bonds was applied rather than the 80% sliding scale factor used by the BCUC).[3]

Yukon Energy's position regarding the use of the BCUC benchmarking methodology continues to be as follows:

- It does not set (and should not be viewed as setting) a precedent in this jurisdiction regarding the implementation of an ongoing annual ROE adjustment process (even in non-GRA years) as is used in British Columbia.

- Relying upon the BCUC low risk utility benchmark along with a reasonable risk premium of 52% as previously approved by the Board in Order 2005-12 is a fair and efficient means of determining a fair return on equity for the utility for the current test period, and is a simplified approach that reduces the overall cost to the ratepayer through eliminating the requirement for costly expert assessment and testimony.

(c)

No.

[3] This was discussed during the 2005 Required Revenues and Related Matters proceeding in response to MCMAHON-YEC-1-35 and MCMAHON-YEC-1-18(c).

In the 2005 Required Revenues and Related Matters Application, YEC provided a table (Table 8.2 in that application) that compared certain operating and financial statistics for YEC and utilities regulated by the BCUC. At that time, YEC noted that Aquila Networks Inc (now FortisBC) had approximately 92,000 customers and approximately $440 million in ratebase. This compared to YEC's 2005 forecasts of 1,750 customers and $143 million in ratebase. YEC's customer counts and ratebase were approximately 2 per cent and 22 per cent of Aquila's at the time.

YEC notes that FortisBC's 2009 Revenue Requirements Application[4] forecasts approximately $914 million in ratebase and 112,000 customers in 2009. This compares to YEC's forecasts of 1,889 customers (2 per cent of FortisBC's) and proposed mid-year rate base of $153 million (17 per cent of FortisBC's) for 2009.

In the 2005 Required Revenues and Related Matters Application, YEC provided another table (Table 8.3 in that application) that compared the nature of business for YEC and utilities regulated by the BCUC. YEC noted that it had a somewhat greater business risk than the relevant BC utilities based on its reliance on its own generation (far higher than for FortisBC), and its lack of any interconnection with external electricity markets. Since the 2005 application these material differences have not changed – and YEC's business risk has increased somewhat due to connection of a new industrial customer.

Based on this, in YEC's view there is no information available that would suggest YEC's business risk today is closer to FortisBC's than at the time of the 2005 Required Revenues and Related Matters Application.

(d)

BCUC Letter No. L-55-08 provides a 8.47% benchmark return on equity for a low risk utility. Considering the 0.52% risk premium for Yukon Energy approved in Board Order 2005-12 together with the 0.50% deduction directed by OIC 1998/32, the 2009 fair ROE for Yukon Energy is 8.49%.

[4] Preliminary 2009 Revenue Requirements Application dated September 2008.

REFERENCE: **Application, Page 3-21**

ISSUE/SUB-ISSUE: **ROE**

Absent implementation of the approvals and consequential rate reductions proposed in this application, YEC's forecast return on equity for the test years is 9.55% for 2008 and 11.03% for 2009.

QUESTION:

a) How does this statement reconcile with the requested ROEs?

ANSWER:

(a)

Absent a rate reduction, the ROEs that would arise are above the level for Yukon Energy requested in the Application. The requested ROEs provide a key factor in determining the actual rate reduction proposed in the Application.

Yukon Energy has brought forward for Board review and approval a revenue requirement application that implements overall rate reductions for the test years in order to reflect benefits secured from the timely completion of Stage One of the Carmacks-Stewart Transmission Project and connection of Minto mine to the grid through the approved Power Purchase Agreement with Minto. As noted, without Board approval of the proposed rate decreases as requested at pages 2 and 3 of the Application (and discussed in Tab 4, pages 4-14 to 4-16), Yukon Energy's forecast would indicate that but for YEC's Application YEC would be earning higher revenues and a higher return on equity than YEC is proposing in its Application.

To be clear, the present YEC Application process is designed to implement a rate reduction that will align the utility's earnings with a fair level of ROE as determined utilizing the method adopted in 2005 (2008 at 8.64% and 2009 at 8.49%). As explained in the Application, YEC's proposed rate reduction passes back to retail customers throughout Yukon (including YECL retail customers) the net benefits secured from connecting the new Minto mine load.

REFERENCE: **Application, Page 4-2**

ISSUE/SUB-ISSUE: **Pelly Crossing Connection**

The current level of existing firm rates (including Rider J and the fixed component of industrial Rider F, as reviewed in Section 4.3) provides $0.359 million excess revenue in 2008 and $1,334 million excess revenue in 2009 compared to revenue requirements set out in Tab 3.

QUESTION:

a) Based on the actual connection date for Pelly Crossing, please update the excess revenue forecast for 2008.

ANSWER:

(a)

The 2008 financial statements are in the process of being finalized but are not yet complete and therefore the requested information based on final 2008 results is not available at this time. However, the Yukon Public Utilities Act sets out a requirement at section 25(1) for each utility to file a statement showing various financial information for the preceding year by March 31. Yukon Energy is currently preparing (unaudited) financial statements for this purpose and expects to meet the requirements of the Act. Once that material has been prepared, it will be possible to update and confirm the 2008 unaudited results in the form of Tab 7 to the Application. As was done in 2005, these schedules will be updated as soon thereafter as possible prior to the May hearing. It is presently expected that these updates will be filed in late March or early April.

Following the same approach as footnote 2 at page 4-3 of the Application (which provided an example of a $197,000 reduction in the excess from a one month delay), an initial estimate of the updated excess revenues forecast for 2008 is approximately $43,300 (versus $359,000 as shown in Table 4.1 of Application). This estimate reflects an overall reduction in YEC 2008 net revenues by approximately $315,700 (estimated $431,500 loss of industrial sales plus an estimated $20,200 loss of Pelly Crossing wholesale revenues, less estimated savings of about $136,000 in depreciation and related cost (lower rate base and reduced Flexible Term Note)).

REFERENCE: **Application, Page 4-5**

ISSUE/SUB-ISSUE: **Secondary Sales Interruptions**

Only one term for the secondary energy service (Rate Schedule 32) is proposed to be changed in this Application. In the 2005 proceeding, YEC received approval for a procedure related to determining the timing of scheduled secondary sales interruptions based on forecasting the quantity (hours) of diesel generation expected to be required over the coming seven day period in winter (i.e. interruptions were to be initiated if YEC forecast a requirement to dispatch diesel generation for more than 10% of the hours over the coming seven-day period).

QUESTION:

a) At the time of the 2005 proceeding, what source(s) was YEC using for the seven-day forecast?

b) Are there alternative sources YEC can use other than Environment Canada?

ANSWER:

(a)

Yukon Energy did not have a forecast for seven days. The proposal was made based on the assumption that a seven day forecast was ideal for planning secondary sales interruptions. However, once required to implement the proposal, Yukon Energy was made aware that no forecast readily fit the rate schedule as proposed. In order to implement the procedure, Yukon Energy was required to extrapolate the sixth and seventh days out of the Environment Canada data, which is not a preferred method for implementing the rate.

(b)

There are no practical alternative sources that have been identified.

REFERENCE: **Application, Page 4-6**

ISSUE/SUB-ISSUE: **Low Grade Ore Processing Secondary Energy**

QUESTION:

a) In Order 2007-5, did the Board only approve Rate Schedule 35 on an interim basis?

b) Did the Board express concerns about a lack of cost of service (COS) associated with this new rate?

c) Did the Board direct YEC, with YECL, to provide electronic COS models for the next GRA?

ANSWER:

(a)

Confirmed.

The Board provided the following directives specific to Rate Schedule 35:

- **Directive 4:** Upon review of the negotiated rate, the Board observes that it is close to the level set for Rate 32. This does provide some comfort to the Board as Rate 32 does not appear discriminatory. The Board is prepared to approve, on an interim basis, the level of Rate 35 as applied for by YEC.

- **Directive 5:** Should Minto pursue Rate 35, proposed audit and control measures and reporting requirements must be established between YEC and Minto, and then YEC is to file these with the Board. YEC is not to implement Rate Schedule 35 until such approval has been granted.

- **Directive 6:** The Board directs YEC to amend the wording for Rate Schedule 35 when such an opportunity arises.

The Board reiterated that Rate Schedule 35 was only approved on an interim basis in Order 2008-13, noting that "the Board is of the view that all matters with respect to Rate Schedule 35 remain outstanding" and stating at page 2:

> YEC is to apply to the Board for approval of Rate Schedule 35 and any related matters at such time as when all outstanding directions with respect to Rate Schedule 35 have been fulfilled and when YEC is in a position to implement Rate Schedule 35.

Yukon Energy has not forecast any sales under Rate Schedule 35 for the test years and in the current application is not requesting final approval of Rate Schedule 35. Tab 4 (page 4-6) notes that Minto Explorations has not provided Yukon Energy with the further information regarding specific auditable reporting and control mechanisms required to be reviewed by the Board prior to final approval of the rate. The Application notes that "because the YUB prerequisites for this rate have not been met, and the forecast quantities of power available for such service are very limited, Yukon Energy forecasts do not include any Rate Schedule 35 sales in the test years."

(b) and **(c)**

Confirmed.

The Board in Order 2007-5 approved Rate Schedule 35 on an interim basis, and noted in its Reasons for Decision (Appendix A to the Order) that while it drew comfort from the fact the Rate Schedule 35 requested a rate be set at a similar level to Rate Schedule 32, it was concerned about rates being set in the absence of a cost of service study, noting that a complete COS study would enable testing of costs to serve all rate classes, including Rate 35.

The Board provided the following general directive that YEC and YECL were to provide a COS study and Rate Design with the next GRA, noting that it would enable testing of Rate Schedule 35:

- **Directive 3:** The Board reiterates its earlier direction that YEC and YECL to provide a complete COS study and rate design with their next GRA. The COS is to include updated studies on allocators and to look at the feasibility of direct assigning assets, where applicable to certain rate classes. Further, the Board

> expects to see justification on the allocation of transmission assets. The Board questions the rationale of defining the CSTP project as one of diesel displacement in light of YEC's comments that the project is a project to serve system requirements. For the next GRA (Phase II), the Board directs both YEC and YECL to provide their electronic COS models and to distinctly show costs as being related to generation, transmission and distribution. Further, generation costs are to be separated based on each generation type (i.e. hydro, diesel, wind etc).This will enable testing of costs to serve all rate classes, including Rate 35.

As noted in the 2005 Required Revenues and Related Matters hearing process, as well as in response to interrogatories filed during the PPA hearing process, secondary energy rates are not cost based rates and are not set based on a cost of service study. Secondary sales are interruptible and not firm and pursuant to Rate Schedule 32, the power must be "in excess of normal consumption and represents incremental electric usage displacing an alternative fuel source by an appliance primarily installed in order to provide space or process heating". As noted at page 4-5 of the Required Revenues and Related Matters Application:

> The intent of the secondary sales retail rate is to maximize the amount of revenue available to offset ongoing fixed Yukon Energy costs while still leaving the secondary sales customer with some energy cost savings compared with what the customer would otherwise pay for heating fuel (typically heating oil). All revenue secured from secondary sales directly reduces the amounts needed to be recovered from firm rates.

The Required Revenues and Related Matters Application (at page 4-5) and the response to YUB-YEC-1-12 (12.1) (also provided during the Required Revenues and Related Matters hearing) describe the rate design process used to set the secondary sales rate (Rate Schedule 32) noting, "the rate design for this rate is based on a value for service basis. **It is not a cost-based rate"** (emphasis added).

This view was reiterated during the PPA Interrogatory process where it was noted in response to UCG-YEC-1-26(3) that "a cost of service is not required to determine a secondary energy rate, i.e., it was not used or suggested to be needed to determine the current rate Schedule 32."

As noted in Section 4.1.3 of the Power Purchase Agreement Application, the Low Grade Ore Processing Secondary Energy Rate (Rate Schedule 35) is an interruptible rate supplied from surplus hydro to Industrial Primary customers (who are supplied under Rate Schedule 39). As defined, this rate is to be limited to the processing of low grade copper ore. YEC proposes that unlike Rate Schedule 32 (Secondary Energy), where the rate is adjusted quarterly (based on changes in heating oil prices), Rate Schedule 35 will remain fixed. Finally, to underline how Rate Schedule 35 remains connected to Rate Schedule 32, any Rate Schedule 35 sales are subject to surplus hydro generation being available after service of Rate Schedule 32 customers.

More generally, in respect of the Board's expectation that YEC and YECL would file a COS study in the next GRA, see also YUB-YEC-1-20.

REFERENCE: **Appendix A to YUB Board Order 2007-5**

ISSUE/SUB-ISSUE: **Page 5 of 27**

Therefore, the Board reiterates its earlier direction that YEC and YECL must provide a complete COS study and rate design with their next GRA.

QUESTION:

a) How does YEC interpret the above quoted direction?

ANSWER:

(a)

I. Overview

YEC interprets the above quoted sentence in the context of the circumstances at that time (including the cost of service related issues under the PPA reviewed in Order 2007-5 and the earlier Resource Plan recommendation to the Minister), and the Board's modified ratemaking mandate since Order 2007-5.

In the context of the issues being dealt with by the Board in Board 2007-5, and the Board's legislated mandate in place at that time, the Board's expectation is clear. The Board clearly expected at that time (as did YEC) that YEC and YECL would file a complete cost of service study and rate design in the next General Rate Application ("GRA"). However, the Board's ratemaking mandate has been materially revised since that time by OICs 2007/94 and 2008/149 obviating the need for a cost of service (COS) study in order to deal with YEC's current GRA. As outlined in more detail below, this is the primary reason why YEC did not file a cost of service study as part of its current GRA.

In order for the Board and all stakeholders to fully understand why a cost of service study was not filed in YEC's current GRA, YEC believes it would be helpful to review the history of this issue and the material changes in the Board's mandate which has occurred since Board 2007-5 was rendered.

II. First Reference to Joint YEC/YECL Filing Made in Context of Cost of Serving Minto Mine

To be precise, although the Board refers to "its earlier direction" in Order 2007-5 -- in fact the reference is not to a direction but a recommendation the Board made in its report to the Executive Commissioner on YEC's 20 Year Resource Plan ("Report"). At page 50 of the Report the Board's recommendation relating to COS was as follows:

> Now is an appropriate time for YEC and YECL to have a complete review of all GRA Phase 1 and Phase 2 matters. The Board ***recommends*** that YEC and YECL file a full GRA application before October 31, 2007. The application should include a full cost of service, rate design and an update of the electric service regulations. (Emphasis added)

This recommendation was made in the context of a discussion relating to Industrial Contribution policy and issues arising out of Minto Mine's potential capital contribution to the Carmacks-Stewart Transmission Line. The issue of the appropriate level of contribution and the cost of serving that customer would clearly be informed by a COS study. Although the recommendation was framed more generally -- YEC understood and appreciated the Board's interest in reviewing a full COS study when dealing with those issues.

III. Direction in Order 2007-5 Made in Context of Reviewing Proposed Minto Mine Rate

Board Order 2007-5 followed the Report. The Board's direction in that order relating to COS was made during its review of Yukon Energy's proposed Minto Mine Rate under the Power Purchase Agreement.

Immediately prior to reiterating its direction in regard of cost of service, and after quoting Section 6(1) of OIC 1995/90 direction to ensure that rates charged to major industrial customers are sufficient to recover cost of service to that class, the Board stated as follows (at page 5):

> The Yukon regulatory environment is one that prefers a direction of standardized utility practice in regards to rates. ***Such standardized utility practice includes providing a full COS calculation when***

> ***designing new rates*** . . . The Board understands that YEC has faced strict time constraints with respect to this CSTP.
>
> YEC acknowledges 'the Board alone has the power to set rates and determine COS methods used for rate setting purposes pursuant to its constituent legislation and regulations'. However, YEC recognizes the jurisdiction of the YUB, the timing YEC has requested presented challenges for the Board and Intervenors and establishing and participating in the proceeding. Recognizing the time constraints faced by YEC the Board has endeavoured the meet these timelines; ***however, as a result, YEC's evidence in some areas is not as complete as the Board*** would normally expect, in particular, with respect to COS. (Emphasis added)

Accordingly, the Board's direction was made in the context of the need for a COS study when reviewing the appropriateness of the rate being proposed for the Mine. Its concern in this regard led to the Board setting the Minto Mine rate on an interim basis until such time as a decision is rendered in the next GRA, which (in the context of the Board's other expectations) would allow that rate to be tested in the next GRA using a cost of service study before finalizing it.

IV. Intervening Events Since 2007-- Board's Ratemaking Mandate Materially Changed Since 2007 Direction

In both the Report and in Order 2007-5, the Board recognized the importance of a COS study given its general ratemaking jurisdiction in existence at that time under the *Public Utilities Act* and related OIC directions. However, for the purposes of the Board's review of YEC's GRA things have changed. The Board's ratemaking mandate has been materially changed by OIC 2007/94 and OIC 2008/149.

(i) OIC 2007/94 - Makes COS Irrelevant to Rate Schedule 39 Until 2012

Soon after Order 2007-5, OIC 2007/94 was passed. In that OIC, the YTG directed that Rate Schedule 39 be specifically fixed thereby making the cost of service issues discussed in the Report no longer relevant in relation to industrial rates until after 2012. OIC 2007/94 states as follows:

> The Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to the Rate Schedule 39, Industrial Primary, attached hereto as Schedule A.

(ii) YEC/YECL Worked Towards a Joint Cost of Service Filing Until OIC 2008/149

Following the Board's direction in Order 2007-5 and notwithstanding OIC 2007/94, YEC and YECL did undertake discussions relating to comprehensive GRA filings, including a joint COS and redefined filing targeted for late 2008. In correspondence filed with the Board Yukon Energy noted its expectation to efficiently address COS matters within GRA filings to occur in 2008. In a letter to the Board dated December 17, 2007, Yukon Energy informed the Board that its revenue requirement filing would be delayed until August/September, 2008 (see the letter as quoted in Order 2009-1). YEC's letter also outlined YEC's understanding that the then planned "Consolidated Phase 2 cost allocation and rate design filing" by YEC and YECL would be concurrent with Yukon Energy's revenue requirement.[1]

(iii) OIC 2008/149 - Makes COS Irrelevant to All Rates Until 2012

Before the filing of Yukon Energy's General Rate Application, Yukon Energy became aware of OIC 2008/149, setting out YTG's direction to ensure that there be no rate rebalancing between rate classes at this time. YEC's Application conforms with OIC 2008/149.

Like OIC 2007/94 did in relation to Rate Schedule 39, OIC 2008/149 obviated the need for producing a cost of service study for all other rates until at least 2012. It states:

> The Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers.

[1] YECL subsequently, without discussion with Yukon Energy, filed its own GRA with statements that differed from this understanding as set out by Yukon Energy in December, 2007.

The OIC notes that this provision expires on December 31, 2012.

Since OICs 2008/149 and 2007/94 do not expire until December 31, 2012, cost of service cannot be used for rate rebalancing at this time. A joint filing, as contemplated by the Board in Order 2007-5 and previously discussed by YEC and YECL, is not feasible or efficient at this time, and a full cost of service filing is not required for the Board's review of the current YEC Application. These realities and the material change in the Board's ratemaking mandate are the primary reasons why YEC filed its GRA without a cost of service study.

(iv) YEC GRA Dealing Simply with Meeting Rate Design Criteria in OIC 1995/90

In its Application YEC has attempted to address immediate concerns related to runout rates that presently do not meet the rate design criteria for the Yukon established by OIC 1995/90 by promoting "economy and efficiency". In this vein, YEC has not embarked upon any new rate redesign initiative at this time. As reviewed in more detail in response to YUB-YEC-1-21, YEC has merely sought to ensure that current runout rates are modestly adjusted, where feasible, to better meet the regulated requirements and past practices for the Yukon jurisdiction as regards runout rates applicable on a uniform basis to retail residential customers of both YEC and YECL. YEC believes that this concern can be effectively and efficiently addressed via review of Yukon Energy's current GRA Application.

REFERENCE: **Runoff (or "Second Block") Rates**

QUESTION:

a) Please describe the consultation process YEC utilized when developing its principles on runoff rates.

b) What is YEC's understanding of YECL's views on this new rate structure?

c) Given that YECL directly serves a significantly larger customer base than YEC, should YECL's views been considered?

d) How were the criteria for runoff rates developed?

ANSWER:

(a)

It is unclear what consultation process the question envisages. YEC did not "develop" some new set of principles on runoff rates for its Application – to the contrary, it began to re-apply principles, directions and precedents well established in Yukon through past joint YEC/YECL GRAs and related YUB decisions.

To be clear, in adjusting the runoff rates to better reflect the requirements of OIC 1995/90, Yukon Energy did not develop new rate design principles for runoff rates. It applied established Yukon rate design principles. Such principles are required to comply with OIC 1995/90, and have been consistently applied in Yukon GRAs and YUB Reports extending as far back as 1992, including extensive previous reviews by the Board and previous Board Orders.

The rate design principles related to runoff rates were subject to a full hearing process in 1992 where YEC and YECL provided a joint submission on Cost of Service and Rate Design which set out the utilities' joint positions on the subjects. The rate design principles examined during that proceeding were summarized in the Yukon Utilities Board report to the Minister in Executive Council pursuant to the 1992 review process.
The Rate Design and Cost of Service filing that was reviewed by the Board in 1992 was developed jointly by Yukon Energy and YECL, and the two utilities were full participants

in the proceeding. These principles were practically implemented in subsequent OIC directions to the YUB (including OIC 1995/90, which extended the relevant runoff rate setting principles to all rate zones) and in joint YEC/YECL rate applications (the 1993/94 GRA and the 1996/97 GRA filing).

(b)

As noted in (a) above, this rate design premise is not a "new" rate structure to Yukon or to YECL.

The rate design principles for runoff rates were fully reviewed and concurred with by YECL in 1992 (via a joint submission of YEC and YECL) and in the last joint GRA filing of YEC/YECL (1996/97 GRA) in accordance with the regulatory framework in the Yukon at that time with OIC 1995/90 (subsection 4(3)). During the 1992 Cost of Service and Rate Design Review process YEC and YECL jointly took the position that in order to make rational decisions regarding the use of electricity the consumer should be aware of the long run marginal cost of supply and noted that the runoff rate should at least reflect short-run incremental costs to promote efficiency (see page 38 of report attached as response to YUB-YEC-1-21(d)). In subsequent joint GRA filings in 1993/94 and 1996/97, the utilities applied for runoff rates adjusted to reflect short run incremental (i.e., diesel) costs, initially in diesel-served rate zones and then (in 1996/97) also in the hydro grid rate zone.

(c)

As noted, YECL's views regarding these rate design principles were fully considered during the 1992 process that reviewed rate design and cost of service in Yukon, and have subsequently been fully considered in past joint GRA filings where the rate design principles underlying the runoff rate were reviewed by the Board.

In Yukon, as a result of OIC 1995/90 (and predecessor OICs going back to the time before YEC's first rate application), all retail ratepayers of YEC and YECL have an equal and direct interest in the revenue requirements of each utility and in related retail rate design issues. The Board is required to establish equalized rates for each retail rate class that do not vary as between YEC and YECL, reflecting the combined revenue requirement of the two utilities and a common rate design for customers of both utilities.

After 1997 (when YEC's management agreement with YECL ended), efforts have been made by both utilities to resume discussion and joint planning on various matters. To be effective, a joint and sustained commitment is needed in this regard.

(d)

Please see Attachment 1 to this response which provides the YUB's report to the Minister in Executive Council provided June 1, 1992, and sets out the principles regarding rate design in Yukon. Rate design related to setting runoff rates that promote "economy and efficiency" are discussed at pages 37-40 of the attached report. As noted, this report followed a joint submission by both utilities as well as an oral hearing in 1992.

In sum, the Board made the following comments and recommendations related to runoff rates in its report:

- "The Board considers the efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decision regarding the future and current use of electricity."

- "The Board considers that runout rates should reflect short-run incremental costs in each of the rate zones as specified in the OIC and that fixed costs incurred by the Companies should be recovered by demand charges, fixed charges and energy charges in the first energy block. The Board recognizes that this will result in an increase in the hydro zone runout rate."

- The Board recommended that the runout rates for all zones should be adjusted to reflect short-run incremental costs.

In Decision 1993-8, regarding the 1993 General Rate Application, the Board reiterated its view that the cost of service methodology and proposed rates designed in accordance with OIC 1992/62 and the 1992 Cost of Service and Rate Design hearing remained appropriate.

Following the YUB's 1992 Report, the following rate design principles related to runoff rates for the Yukon were subsequently included in Rate Policy Directive in OIC 1995/90:

- **4(2)** The Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.

- **4(3)** The Board must fix runoff rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency, and separate runoff rates may be allowed in this regard for customers in different communities or rate zones, provided that such runoff rates for customers in each non-government retail customer class are fixed for each community or rate zone throughout Yukon in accordance with the same rate design principles.

The application of these rate design principles was last reviewed and approved by the YUB during the 1996/97 GRA. As noted at page 4-10 to 4-12 of the Application, the principles as approved in that GRA filing underlie the current filing.

REVIEW OF
COST OF SERVICE TO
AND
RATES CHARGED TO
ELECTRICITY CUSTOMERS IN YUKON

RECEIVED
JUN 0 8 1992

REPORT TO
COMMISSIONER IN EXECUTIVE COUNCIL
BY
YUKON UTILITIES BOARD

JUNE 1, 1992

TABLE OF CONTENTS

Page

EXECUTIVE SUMMARY

1. INTRODUCTION 1

2. PROCEDURES FOLLOWED BY THE BOARD 3

2.1 Community Meetings 5

2.2 Public Hearing 6

3. RATE DESIGN PRINCIPLES AND ISSUES 7

4. COST OF SERVICE PRINCIPLES 8

5. COST OF SERVICE STUDY PREPARED BY YEC/YECL 10

5.1 Functionalization 10

5.2 Classification 11

5.2.1 Classification of Plant 11
5.2.2 Classification of O&M Expenses 12

5.3 Allocation of Costs to Customer Classes 13

6. COST OF SERVICE - CANADIAN PRACTICE 14

7. COST OF SERVICE - CURRAGH 16

8. COST OF SERVICE - DISCUSSION OF MAJOR ISSUES 18

8.1 General 18

8.2 Classification of Generating Plant 19

8.2.1 Classification of Hydro Generating Plant - General (Excluding Whitehorse Unit #4) . . 19
8.2.2 Classification of Hydro Generating Plant - Whitehorse Unit #4 24
8.2.3 Classification of Diesel Generating Plant . . 25

Page

8.3 Allocation of Transmission Plant 26

8.4 Classification of Generation O&M Expenses 30

8.5 Marketing Expense 31

8.6 Classification and Allocation of Other Costs of Service 32

9. RATE DESIGN 32

9.1 Revenue to Cost Ratios 32

9.2 Phase-In of Rate Changes 36

9.3 Promotion of Economy and Efficiency in the Use of Electricity 37

9.3.1 Long-Run Marginal Costs 38
9.3.2 Other Rate Design Factors which Promote Economy and Efficiency in the Use of Electricity 41

9.4 How Can Rate Design Respond to Environmental or Other Costs Not Included in Cost of Service 45

9.5 Extent to Which Rate Design Responds to the Current Costs Required to Develop New Power Sources 47

9.6 How Should Demand-Side Management Activity be Reflected in Rate Design 47

10. CURRAGH CONTRACT 48

SUMMARY OF RECOMMENDATIONS

GLOSSARY OF TERMS

EXECUTIVE SUMMARY

Pursuant to Order-in-Council 1991/62, the Board conducted a cost of service and rate design review. As part of this review, the Board conducted community meetings in Haines Junction, Carmacks, Dawson City, Teslin, Watson Lake and Whitehorse.

The principal recommendations made to the Board at the community meetings were that rates for electricity in Yukon should be cost based, general service - government rates should not be applied to municipal governments, conservation of electricity should be encouraged, and the use of multiple increasing block rates should be considered. A written submission was received from the City of Dawson.

The technical aspects of the review were examined at a public hearing in the City of Whitehorse on May 4th to 7, 1992. Prior to the public hearing, YEC/YECL provided a written submission on their cost of service and rate design to all interested parties.

Curragh Resources Inc. also filed expert evidence, and submissions were received from the City of Whitehorse, the Association of Yukon Communities, the Yukon Conservation Society and Gary McRobb, Esq.

The Companies submitted that the primary criteria for rate design are the need for rates sufficient to meet the revenue requirement, the fair apportionment of costs to customer classes, and the promotion of economy and efficiency in the use of electricity.

The fair apportionment of costs to each of the customer classes requires a cost of service study. A cost of service study usually proceeds in three steps, functionalization, classification and allocation, in order to estimate the costs caused by each customer class.

The Companies' cost of service study followed Yukon's rate policy as set forth in the Order-in-Council in that, generally, the same rates would prevail for each customer class throughout Yukon.

The Companies examined cost of service practices of other Canadian hydro electric utilities, and concluded that they followed generally accepted Canadian practices.

The following three major cost of service issues were examined:

(1) Classification of hydro generating plant;

(2) Classification of Whitehorse Hydro Unit #4; and

(3) Allocation of the Whitehorse/Faro transmission line.

The Companies classified hydro generating plant 40% to demand and 60% to energy on the basis of cost causality and the practices of other Canadian hydro electric utilities.

Curragh advocated classifying all fixed costs to demand and all variable costs to energy and, thus, recommended classifying 100% of hydro generating assets to demand. Curragh recognized that not all of the hydro generating capacity can be used to meet system peak and, thus, suggested allocating 70% of the hydro generating plant costs on the basis of coincident peaks and 30% of the costs on the basis of energy.

The Board recommends hydro generating plant, excluding Whitehorse Unit #4, be classified 40% to demand and 60% to energy.

The Companies classified Whitehorse Unit #4 100% to energy on the basis that it had been constructed for the purpose of displacing diesel generation and that its construction had not resulted in any increase in the ability of the Companies to meet demand at the time of system peak.

Curragh submitted that Whitehorse Unit #4 should be classified 100% to demand.

The Board recommends that Whitehorse Unit #4 be classified 100% to energy and that the Companies be directed to perform a study of the impact of Whitehorse Unit #4 on the ability of the Aishihik dam to provide capacity at the time of system peak.

The Companies assigned 85% of the cost of the Whitehorse/Faro transmission line to Curragh. The remaining transmission costs were allocated to all customer classes, including Curragh.

Curragh submitted that either the transmission costs allocated to Curragh should be limited to 85% of the Whitehorse/Faro transmission line or Curragh should be allocated only its proportionate share of total transmission costs.

The Board recommends that the Companies' allocation of transmission costs is appropriate.

The Board recommends that a target range for revenue to cost ratios of 90% to 110% be established for all customer classes other than the industrial class, and that the Companies take the necessary steps to improve the quality of their cost of service study so that a target revenue to cost ratio of 95% to 105% will be attainable.

The Companies indicated that they intend to move the industrial rate class revenue to cost ratio close to 100% at the time of the next general rate application.

Curragh submitted that, while a cost of service study provides a guide for rate making, other considerations may require pricing a customer at rate levels less than those indicated by a cost of service study. Curragh advocated that its rates should be established through a negotiation process between Curragh and YEC.

The Board notes that revenue to cost ratios for large industrial customer classes typically are at or above 100%. The Board recommends that a target revenue to cost ratio of 100% be established for the industrial rate class, and that the rates to be charged to Curragh should be determined by the Board only after a public hearing.

The Board recommends that the changes to rates required to bring the revenue to cost ratios within the ranges established be phased-in over a reasonable period of time, and that the Board monitor the progression of revenue to cost ratios toward the acceptable range in future general rate applications.

The Board considers the efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decisions regarding the use of electricity.

The Companies submitted that, to make rational decisions, customers should be aware of the long-run marginal costs, and advocated that the runout rate should reflect such costs.

The Board recognizes that the Order-in-Council requires the runout rates to reflect short-run incremental costs. The Board recommends that the runout rates for all zones should be adjusted to reflect the short-run incremental costs, and that the Companies undertake a study for the purpose of identifying long-run marginal costs that should be included in the runout rates.

The Board makes several other recommendations with respect to the promotion of the efficient use of electricity.

The Board recommends that the Companies be encouraged to monitor ways in which rate design can be used to reflect environmental or other costs not included in cost of service.

The Board recommends that Demand-Side Management issues be addressed at the time of the Companies' upcoming capital hearing.

The Board concurs with the City of Whitehorse's recommendation that it is not appropriate to cast cost of service studies and rate design principles in stone. The Board recommends that it be provided with the flexibility to react to future changes in circumstances, and to determine the appropriate cost of service and rate design practices to be used in Yukon.

1. INTRODUCTION

This report is submitted to the Commissioner in Executive Council pursuant to Section 11 of Order-in-Council, 1991/62 ("OIC"). Section 11 of the OIC states:

> "(1) The Board shall conduct a full review of costs of service to and of rates charged to all classes of customers within the Yukon and shall recommend appropriate methods of determining costs of service and appropriate principles for establishing rates to be used for rate applications made after 1991.
>
> (2) When conducting its review and making its recommendations the Board shall observe the following guidelines:
>
> (a) cost of service for each customer class must be determined on a Yukon-wide basis that is consistent with Yukon's rate policy, having the same rate for the same class of customer throughout the Yukon, no rate differentiation between utilities, and provision for runoff rate variations in accordance with the principles set out in subsection 6(2);
>
> (b) customer classes examined must include each class currently used for rate making purposes;
>
> (c) costs must be determined on a prospective basis for a test period conforming to the period for which the Board approves rates as a result of Yukon Energy Corporation's and The Yukon Electrical Company Limited's 1991 general rate applications;
>
> (d) the review must investigate principles and methods currently applicable in Canada for similar hydro based and northern diesel service areas and must examine the implications of any options in this regard that may merit adoption in Yukon;
>
> (e) the review must investigate the extent to which regulated rates reflect cost of service for different customer classes in Yukon and in other Canadian jurisdictions;

(f) the review must examine implications of adjusting future rates in order to bring rates closer to costs for all customer classes in Yukon.

(3) The review must also investigate the extent to which rate design should respond to factors other than cost of service for each customer class such as:

(a) promotion of economy and efficiency in the generation, transmission, distribution, and use of power;

(b) environmental or other costs that are not currently included in cost of service for the utilities;

(c) current cost required to develop new power supplies; and

(d) demand-side management activities carried out in accordance with the principles set out in subsections 5(1) and (2).

(4) The Board must begin its review by soliciting submissions from Yukon Energy Corporation and The Yukon Electrical Company Limited as part of their 1991 general rate applications and shall direct the companies to prepare such submissions in accordance with the guidelines set forth in subsection 11(2).

(5) The Board shall deliver its report to the Executive Council Member on or before June 1, 1992."

The principles set out in subsection 5(2) referred to above are as follows:

"(2) Separate runoff rates must be allowed for non-government retail customers to reflect short-term incremental energy costs in communities supplied primarily by generation other than hydro, but

(a) for residential non-government retail customers, the runoff rate may be applied only to consumption in excess of 1,000 kWh per month, and

(b) for general service non-government retail customers, the runoff rate may be applied only to whichever of the following the Board approves:

(i) consumption in excess of 2,000 kWh per month, or

(ii) consumption in excess of a level which would, for an average customer of that class, be equivalent to 2,000 kWh per month for general service non-government retail power customers."

2. PROCEDURES FOLLOWED BY THE BOARD

The procedures followed by Yukon Utilities Board ("Board") in the conduct of its review pursuant to the OIC were as follows:

(1) The Board began its review by soliciting submissions from Yukon Energy Corporation ("YEC") and The Yukon Electrical Company Limited ("YECL") ("the Companies") as part of their 1991/92 general rate applications.

Inasmuch as the Board had determined that the matters to be investigated during the course of the review would be dealt with in a separate proceeding, these matters were not addressed in detail during the course of the 1991/92 general rate applications of the Companies.

(2) After the hearing of a Notice of Motion from Curragh Resources Inc. ("Curragh") dated February 19, 1992 the Board published a Notice of Public Hearing indicating that the review would take place in the City of Whitehorse commencing on May 4, 1992.

(3) On March 11, 1992 YEC/YECL distributed updated information respecting their cost of service and rate design to all Intervenors in the preceding general rate application, all Yukon communities, special interest groups and all First Nations.

It should be noted that the rate setting process is usually divided into two phases. The first phase is the determination of the revenue requirement. The second phase is the determination of rates; the subject of this review. The Companies' interest in the second phase is the establishment of "just and reasonable" rates, and they are generally neutral as to what rates are paid by each of the customer classes.

(4) All Intervenors were provided with the opportunity to make written interrogatories to the Companies respecting their methods and procedures to which the Companies provided written responses.

(5) All Intervenors were provided with the opportunity of filing evidence respecting the matters to be reviewed. The only party which filed expert evidence in the review proceedings was Curragh who called Dr. Malcolm Jackson, a consultant in the field of public utility regulation. Both YEC/YECL and the Board made written interrogatories to Curragh.

(6) The Board conducted community meetings at various locations in Yukon and a public hearing in the city of Whitehorse.

2.1 Community Meetings

The Board conducted community meetings in Haines Junction, Carmacks, Dawson City, Teslin, Watson Lake and Whitehorse over the period April 6th to May 4, 1992. The City of Dawson presented a written submission to the Board at the community meeting in Dawson City. The Board prepared a report on these community meetings which was filed as an exhibit in the public hearing. The principal recommendations made to the Board at the community meetings were as follows:

(1) Rates for electricity in Yukon should be cost based. Subsidies to specified groups of customers subject to very high rates should be dealt with as a direct subsidy.

(2) General service - government rates should not be applied to municipal governments.

(3) The conservation of electricity should be encouraged. Although the charging of an equalized rate for a basic block of energy was acceptable, the size of the basic block should gradually be reduced.

(4) The use of multiple increasing block rates should be considered.

The issues raised at the community meetings were examined at the public hearing and will be dealt with by the Board in this report.

2.2 Public Hearing

The technical aspects of the review were examined at a public hearing in the City of Whitehorse on May 4 to 7, 1992. Those participating in the hearing were YEC, YECL, Curragh, the City of Whitehorse, the Association for Yukon Communities, Peter Percival, Esq. and Gary McRobb, Esq.

The Board provided an opportunity to the public to make presentations to the Board at the end of each day of the scheduled sittings. One such presentation was made by Mr. Bob Van Dijken representing the Yukon Conservation Society. During the course of the proceedings a presentation was made by His Worship Mayor Peter Jenkins on behalf of the Association of Yukon Communities.

At the conclusion of the hearing, the Companies and Intervenors were provided with an opportunity to make final submissions to the Board.

3. RATE DESIGN PRINCIPLES AND ISSUES

As explained in the YEC/YECL evidence, rate design involves establishing the prices that each customer will pay for electricity. Rate design principles typically refer to a requirement for "just and reasonable" rates, recognizing that rate design involves a balancing of different objectives which may, from time to time, be in conflict.

The Companies outlined the primary criteria for rate design. These criteria include the need for rates which would provide sufficient revenue to meet the revenue requirement approved by the Board, as well as the requirement for revenue stability and predictability. The rates should fairly reflect the costs incurred by the utility to serve the various classes of customers.

A further objective is the promotion of economy and efficiency in the generation, transmission, distribution and use of electricity, and involves the structuring of rates so as to provide price signals to users of electricity which will encourage optimum use of the utilities' facilities.

The Companies also noted that rates should reflect the value of service provided to the customers, that rates should be stable and reasonably predictable allowing customers to make realistic cost projections, and that rates, generally, should be practical and not overly complicated.

Regulators of Canadian electric utility corporations typically consider the fair cost apportionment criteria to be of primary importance in determining rates and, accordingly, utilize cost of service studies as one of the major factors to be considered in the determination of rates.

4. COST OF SERVICE PRINCIPLES

The determination of the cost incurred by a utility to provide service to its customer classes is achieved through a cost of service study. Such a study usually proceeds in three steps as follows:

(1) Functionalization:

Functionalization refers to the segregation of capital assets and operating expenses into groupings which represent the specific functions carried on by a utility. These four functions are generally generation, transmission, distribution and general. They comprise the major tasks which a utility must perform to provide electric service.

(2) Classification:

Classification refers to the division of the costs associated with each of the functions into components which reflect the relationship between the services provided by the utility and the principal cause of the related costs. The principal causes of costs are the customers' demand requirements, their energy use and the number of customers served. The classification components most commonly used are demand, energy and customer.

(3) Allocation:

Allocation is required to distribute the demand, energy and customer costs associated with each function to the utilities' customer classes. Allocations are made on the basis of various demand, energy and customer allocation factors. The customer classes commonly used are residential, general service, industrial, wholesale and street light.

Through the processes described above, the utility obtains a measure of the costs incurred to serve each of the customer classes. This cost information typically becomes a starting point in the design of just and reasonable rates.

5. COST OF SERVICE STUDY PREPARED BY YEC/YECL

For the purpose of this proceeding, YEC/YECL prepared a detailed cost of service study. The Companies followed Yukon's rate policy as set forth in OIC Section 11, subsections (2)(a) to (2)(f) in that it was proposed that the same rate for each customer class would prevail throughout Yukon and customer classes examined were those currently used for rate making purposes. Also, costs contained in the cost of service study reflected forecast costs for the test year 1992 which had been allowed by the Board as a result of a recent general rate application by the Companies. During the review, the extent to which rates currently reflect cost of service for different customer classes in Yukon and the implications of adjusting future rates in order to bring them closer to costs were investigated.

5.1 Functionalization

The Companies functionalized their plant and operating expenses among the four basic functions of generation, transmission, distribution and general. The functionalization process carried out by the Companies did not raise any controversy at the hearing and appears to the Board to be in compliance with generally accepted practices. Therefore, this issue will not be discussed further in this report.

5.2 Classification

The second step in the cost of service study carried out by the Companies was the classification of plant and operating expenses.

5.2.1 Classification of Plant

The basic principle followed by the Companies was that plant should be classified on the basis of intended use. This is generally referred to as the cost causation principle. The Companies classified the cost of general hydro assets 40% to demand and 60% to energy based on their examination of classification practices by other hydro electric utilities in Canada.

Whitehorse Hydro Unit #4 was classified 100% to energy on the basis that the unit was constructed for the sole purpose of displacing diesel generation and did not in any way increase the Companies' capacity at the time of system peak.

The cost of diesel plant was classified 100% to demand on the basis that diesel plants are constructed to provide capacity and that in other jurisdictions in Canada they are generally classified 100% to demand.

Transmission plant was classified 100% to demand as transmission assets were sized to meet the expected coincident peak demand of the system.

Distribution assets, which account for approximately 20% of costs assigned to customer classes, were classified to customer and demand on the basis of what the Companies described as commonly accepted utility practice. Classification of distribution plant and operating expenses involved the exercise of considerable judgement in determining the appropriate classification bases.

5.2.2 Classification of Operating and Maintenance Expenses

The Companies stated that the classification of Operating and Maintenance ("O&M") expenses also followed the principle of cost causation. A major operating expense, fuel, was allocated 100% to energy following generally accepted practice. Other generating O&M expenses were allocated 50% to demand and 50% to energy on the basis of the experience of YECL's parent which operates in Alberta.

Transmission O&M was classified 100% demand consistent with the classification of transmission plant.

The classification of distribution O&M was performed on an account by account basis to reflect the Companies' view of the causation of the various components. Similarly, marketing O&M, customer accounting, general plant O&M, and administrative and general O&M were classified on a cost causation basis as determined by the Companies.

Depreciation expense was classified on the basis of corresponding gross plant while return and income taxes were classified on the basis of rate base less customer contributions. This base forms the foundation for calculation of total return and income tax. Municipal taxes and all-risk insurance were classified on the basis of gross assets.

9.3 Allocation of Costs to Customer Classes

The Companies allocated generation demand related costs on the basis of the coincident peak of the various customer classes. Energy related generating costs were allocated to customer classes on the basis of energy produced to serve the customer classes. Except for 85% of the cost of the Whitehorse/Faro transmission line which was assigned specifically to Curragh, transmission costs were allocated on the basis of the coincident peak of the various customer classes. Generation and transmission O&M were allocated on the same basis as generation and transmission plant.

The allocation of distribution plant and O&M expenses was performed on a number of bases. Demand related costs were allocated on the basis of non-coincident peak demands of the customer classes and customer related costs were generally allocated on the basis of the average number of customers in each customer class.

6. COST OF SERVICE - CANADIAN PRACTICE

The position taken by the Companies in the proceedings was that they followed generally accepted Canadian practice in the functionalization, classification and allocation of their costs. This position was not disputed by the Intervenors except with respect to two major items: the classification of hydraulic generating plant and the allocation of the Whitehorse/Faro transmission line. These differences will be discussed later in this report.

The Companies based their statement that they complied with generally accepted Canadian practice on their experience in the industry and on a review of practices of other electric generating utilities in Canada which had predominantly hydro based generation. The Companies examined the current practices of B.C. Hydro, Quebec Hydro, Manitoba Hydro and Ontario Hydro and concluded that these utilities classified from 56.5% to 71% of hydro generating costs as energy. The Companies concluded from this review that it would be appropriate for them to classify 60% of hydro generating costs (excluding Whitehorse Unit #4) to energy.

The Companies took the position that Whitehorse Unit #4 was unique in character in that it had been constructed for the purpose of displacing diesel generation and that its construction had not resulted in any increase in the ability of the Companies to meet demand at the time of system peak. Due to the unique nature of this generating unit, the companies did not submit any precedent from other jurisdictions to support its treatment. The Board has not been able to find any precedent.

The Companies submitted that the allocation of costs relating to the Whitehorse/Faro transmission line was in accordance with generally accepted practice in Canada. Under generally accepted practice in Canada, assets devoted to serve a specific customer class are assigned to that specific class. In determining the proportion of the Whitehorse/Faro transmission line to be specifically assigned to the industrial class, the Companies relied on the conclusions of the National Energy Board ("NEB") in its decision regarding Northern Canada Power Commission ("NCPC") dated June 1985. At Page 43 of that report the NEB determined that it was reasonable that 85% of the costs of the Whitehorse/Faro transmission line should be assigned to Cyprus Anvil Mining Corporation ("Cyprus Anvil"), and that this proportion took into consideration the fact that the Companies' remaining transmission costs would be allocated to all customer classes on the basis of their coincident peak demand.

7. COST OF SERVICE - CURRAGH

Curragh called Dr. Malcolm Jackson to present evidence on the appropriate methodology for the preparation of the cost of service study and the determination of rates. Dr. Jackson's evidence centered around two principal issues: the classification of the cost of hydro generating assets and the allocation of the cost of transmission facilities.

Dr. Jackson advocated the fixed variable method of classifying the cost of hydro generating plants. Dr. Jackson justified his choice of the fixed variable method on the use of this method by electric utilities in Alberta, Maritime Electric Company, Limited and Nova Scotia Power Corporation. Under the fixed variable method, all fixed costs are allocated to demand and all variable costs are allocated to energy. The result of Dr. Jackson's recommendation is to classify 100% of hydro generating assets, including Whitehorse Unit #4, to demand.

Dr. Jackson recognized that, due to natural changes in water flow, not all of the hydro generating capacity can be used to meet the demand at system peak. For this reason, Dr. Jackson allocated 70% of the costs to customer classes on the basis of their coincident peak demands and 30% of the costs to customer classes on the basis of energy.

Dr. Jackson's recommended treatment of the cost of transmission lines was to pool all transmission costs and allocate them to all customer classes on the basis of their coincident peak demands. Dr. Jackson's position was that, prior to the arrival of Curragh in Yukon, these costs were "sunk costs" and as such were required to be recovered from existing electric consumers in Yukon and the taxpayers of Canada. He considered that at the time of Curragh's arrival in Yukon any contribution by Curragh in excess of incremental costs associated with serving it would benefit other Yukon customers. He advocated that there should be no specific assignment of costs associated with the Whitehorse/Faro transmission line to Curragh.

As an alternative, Dr. Jackson recommended that 85% of the cost of the Whitehorse/Faro transmission line be assigned to Curragh but that Curragh not be held responsible for any portion of other transmission facilities and related costs.

In addition, Dr. Jackson recommended that the Companies' marketing expenses, which were ultimately allocated by the Companies 85% on the basis of energy and 15% on the basis of the number of customers, should be ultimately allocated 50% on the basis of each of these factors.

8. COST OF SERVICE - DISCUSSION OF MAJOR ISSUES

8.1 General

There was little controversy between the participants during the review on many of the cost of service study issues; the controversy having been restricted mainly to the classification of hydro generating plant, the allocation of transmission costs and the classification of marketing expenses. The Board will deal with each of these issues separately in this report.

The Board considers that the practices followed by the Companies with respect to all other issues relating to the cost of service study follow generally accepted practice in Canada and have, in the Board's opinion, been appropriately applied in Yukon.

The Board recognizes the position taken by the City of Whitehorse that it would not be prudent:

> "... to cast electric cost of service studies and rate design principles in stone. Recommendations to the Yukon government as a result of this review should recognize this constant state of change and provide for the ability of the Public Utilities Board to react to this change on a timely basis." [Tr.764]

Recommendation #1:
The Board recommends that it be provided with the flexibility to react to future changes in circumstances, and to determine the appropriate cost of service and rate design practices to be used in Yukon.

8.2 Classification of Generating Plant

8.2.1 Classification of Hydro Generating Plant - General (Excluding Whitehorse Unit #1)

In order to recognize that hydro generating plant was constructed for the dual purpose of providing capacity to meet the peak demands of its customers and the energy required by its customers over time, the Companies classified 40% of the cost of hydro generating plant to demand and 60% to energy. The basis of this classification was a review by the Companies of practices of other Canadian generating utilities with a high proportion of hydro facilities.

On cross-examination, Company witnesses acknowledged that there were a number of ways of determining the appropriate proportion of hydro generating plant costs to be allocated to energy. One such method is the plant factor method, wherein a portion of plants costs are allocated to energy on the basis of capacity required for average demand requirement and the cost associated with the remaining capacity are classified as demand. Company witnesses explained that in their experience the plant factor method has not been used for anything other than hydro facilities and that they have concerns with its use even for hydro facilities due to potential instability in the results it produces from one period to another. The witnesses indicated that this method had been used in Manitoba and British Columbia and had gone out of favour in these jurisdictions.

A second alternative method is to classify waterways, dams and reservoirs as being energy related. This method recognizes that certain portions of hydro plant were constructed for the purpose of storing water to make the resource available for the production of firm energy when needed. Investment in these facilities has, in some cases, been classified as being energy related.

On cross-examination, Company witnesses indicated that, due to inadequacies in historical records, they would not be able to make the appropriate breakdown of costs of hydro generating facilities and they had certain reservations as to the reliability of estimates.

The Board considers that the applicability of this method may be restricted to the Aishihik dam due to the run-of-the-river nature of the Whitehorse generating facility.

Another method used for classification of hydro facilities is based on a comparison of available energy under normal and adverse water conditions. Company witnesses indicated that this method would not be readily applicable in Yukon because of a significant shortage of hydrological data.

Company witnesses were also examined on their views of the fixed variable method proposed by Curragh. On cross-examination the witnesses explained that:

> "...the fixed variable method is appropriate at best in systems that are thermal based, ..." [Tr.345]

Company witnesses also stated that:

> "... it transmits a message that there is no behaviourial relationship between energy use and the costs that are being dealt with, ..."
> [Tr.345]

Company witnesses recognized that there were steps that could be taken to modify the fixed variable approach, such as Dr. Jackson's method of allocating 70% of the demand costs on the basis of coincident peak demands and 30% on the basis of energy. However, they stated:

> "There are lots of steps that ought to be taken after that to correct that message, but why start off with the wrong message?"
> [Tr.345]

With respect to Dr. Jackson's statement that the fixed variable approach was used in Alberta, counsel for YECL stated in his final submission that:

> "Alberta Power does not use a fixed variable method. Because of the capacity demand constraint thermal base system that exists in Alberta at this time, the results of using a cost causation method, which is why did we -- what was the planning for, and what was, why was the particular unit built, which is what Mr. Stout spent countless times discussing, when that cost causation principle is put into effect with the type of system in place in Alberta, the results may end up looking very close to a fixed variable, but Alberta Power does not use the fixed variable method."
> [Tr.789-790]

The Companies used what they described as "cost causation" for the purpose of classifying the cost of generating facilities between demand and energy. The position taken by the Companies was that the cause of costs related to the reasons for constructing the facilities in the first place, and did not in any way relate to the manner in which the facilities were operated. In arriving at the 40% demand/ 60% energy classification, the Companies relied on the classification of similar hydro facilities in British Columbia, Manitoba, Ontario and Quebec. The Companies' prefiled evidence and evidence on examination provided considerable data on the manner in which this comparative group of utilities operated their generating facilities. The witnesses were unable to provide the Board with any specific information relative to the manner in which these other utilities had planned their construction of generating plant.

It appears to the Board that, although the Companies take the position that cost causation relates to the original reason for constructing the generating facilities, the witnesses were not in a position to support their proposed ratio other than by an analysis of the use of the facilities by these other companies. This requires the Board to accept the premise that the actual operation by those utilities was in accordance with their planned operations. The Board, however, does not have any evidence to indicate that these two differ.

The Board notes that the City of Whitehorse supported the Companies' approach to the classification of hydro generating plant costs.

The Board considers the approach taken by YEC/YECL to the classification of hydro generating plant costs to be appropriate. The Board recognizes that the Companies have examined alternative methods of classification, and that they have given due recognition to practices prevailing in Canada by utilities with similar assets. The Board recognizes that the methodology adopted by the Companies reflects the fact that hydro facilities are normally built because of the low cost of energy from these plants. However, it considers that the fixed costs of hydro generation should not be ignored when considering the cost of energy produced therefrom.

Recommendation #2:
The Board recommends that the appropriate method of classifying the cost of existing hydro generating plant (excluding Whitehorse Unit #4) is 40% to demand and 60% to energy.

8.2.2 Classification of Hydro Generating Plant - Whitehorse Unit #4

YEC/YECL have taken the position that Whitehorse Unit #4 was constructed solely for the purpose of displacing high cost diesel generation. Company witnesses also stated that the unit did not add to the capacity of the Whitehorse generating plant, and thus did not increase the Companies' ability to meet customers' demand at the time of system peak. This position is supported by evidence proffered to this Board in March 19, 1982.

Dr. Jackson considered the cost of Whitehorse Unit #4 to be demand related solely for the reason that it represented a fixed cost. Under the fixed variable method advocated by Dr. Jackson, the reason for constructing the plant and the manner in which the plant is operated are not considered. Curragh also supported its position on the basis that Whitehorse Unit #4 is used during the off-peak period so that water can be stored at Aishihik and be used at the time of system peak.

The Board is persuaded by the evidence adduced during this review that the purpose of constructing Whitehorse Unit #4 was to displace high cost diesel generation and, accordingly, it is appropriate to classify the cost of Whitehorse Unit #4 as being energy related. However, the Board considers that the use of Whitehorse Unit #4 during the off-peak period may increase the capacity available at Aishihik during system peak and recommends that the Companies

be directed to perform a study of the impact of Whitehorse Unit #4 on the capacity available at Aishihik to meet demand at the time of system peak.

Recommendation #3:

Based on the available evidence, the Board recommends that the appropriate method of classifying the costs associated with Whitehorse Unit #4 is 100% to energy.

The Board also recommends that the Companies perform a study of the impact of Whitehorse Unit #4 on the capacity of Aishihik at the time of system peak and provide the results of the study to the Board at the time of their next general rate application for its further consideration.

8.2.3 Classification of Diesel Generating Plant

YEC/YECL classified the cost of diesel generating plant, whether operating on an isolated system or on the Whitehorse/Aishihik/Faro system, as being demand related. During the course of cross-examination, YEC/YECL witnesses acknowledged that diesel generating plant was built not only for the purpose of meeting peak capacity but also for the provision of energy, and that in theory a number of the alternative classification methods discussed above in the context of hydro generating plant might be used to classify a portion of diesel generating plant as being energy related.

However, the YEC/YECL witnesses indicated that diesel generating plant was typically classified as demand related in Canada, and that due to the relatively minor cost of diesel generating plant an alternative classification process would not yield a materially different result. The Board accepts the Companies' position on the classification of diesel generating plant.

Recommendation #4:
The Board recommends that the appropriate method of classifying costs associated with diesel plant is 100% to demand.

8.3 Allocation of Transmission Plant

YEC/YECL took the position that, inasmuch as the Whitehorse/Faro transmission line was constructed specifically for the purpose of serving the Faro mine operated by Cyprus Anvil, a substantial portion of the cost of the line should be allocated to the industrial class. YEC/YECL submitted that it was appropriate to allocate 85% of the cost of this line to Curragh, and relied in this connection on the June 1985 decision of the NEB respecting NCPC. As noted by the NEB in that decision:

> "Because of the unusual circumstances surrounding the construction of the transmission line from Whitehorse to Faro, where NCPC, as a result of an agreement between CAMC and the federal government, was instructed to build the transmission line, the Board recommends that this line be treated as a specific asset. The Board further recommends that 85 percent of the annual cost be assigned specifically to CAMC and that the remaining 15 percent be rolled in with the pooled costs in the Yukon hydro rate zone to be allocated to all customer classes based on their respective demands. The 85 percent figure for CAMC reflects the fact that, under this arrangement, CAMC would also be assigned its share of the pooled costs." [Page 43]

On cross-examination Company witnesses acknowledged that, at certain times of the year, the transmission line from Aishihik to Whitehorse (part of the Whitehorse/Aishihik/Faro transmission system) is used to supply Curragh and, accordingly, that Curragh benefits from the existence of the Whitehorse/Aishihik/Faro transmission system. Company witnesses also acknowledged that a more interconnected system can be expected to be more stable.

Company witnesses also explained during cross-examination that only the original cost of the Whitehorse/Faro line was being specifically assigned to Curragh, and that the costs of the rebuild of the Faro substation and other upgrades were pooled and allocated to all customer classes.

Dr. Jackson, on behalf of Curragh, submitted that either the transmission costs allocated to Curragh should be limited to 85% of the Whitehorse/Faro transmission line or, in the alternative, Curragh should be allocated its proportionate share of total transmission costs based on its proportion of total demand on the system at the time of system peak.

Dr. Jackson's evidence was that the cost of the Whitehorse/Faro line should be considered as a "sunk cost" which was being borne by other consumers in Yukon and Canadian taxpayers, and that these parties benefited at the time Curragh came onto the system to the extent that any costs in excess of incremental costs incurred as a result of Curragh being added to the system were recovered from Curragh.

The Board is persuaded that the Companies' position on this issue is reasonable. The Board is not satisfied that Curragh should be treated as an incremental customer for the purpose of the cost allocation study. Cost allocation studies typically consider the characteristics of customer classes being served by a utility and assign or allocate costs to reflect the manner in which the customer classes cause the costs to be incurred.

The Board is satisfied that Curragh receives a benefit from the existence of the transmission system and concurs with the conclusion reached by the NEB that, because of the unusual circumstances surrounding the construction of the transmission line from Whitehorse to Faro, the line should be treated as a specific asset. The Board also considers it appropriate that 85% of the annual cost of that line be assigned specifically to Curragh and that the remaining 15% be pooled with other transmission costs and borne by all customers, including Curragh.

Recommendation #5:
The Board recommends that the appropriate method of allocating transmission costs is to specifically assign 85% of the costs of the Whitehorse/Faro line to Curragh, and to allocate all remaining transmission costs to all customer classes, including Curragh, on the basis of demand at the time of system peak.

8.4 Classification of Generation Operating and Maintenance Expenses

The Companies classified their generation operating and maintenance expenses 50% to demand and 50% to energy based on the experience of YECL's parent company in Alberta. YEC/YECL witnesses acknowledged that the nature of the operating expenses in Yukon differ from those in Alberta due to the difference in the nature of the generating plant. This issue was not addressed by any of the Intervenors.

The Board is not satisfied that it is appropriate to import the classification ratios used by an electric utility in Alberta, whose generating plant is almost exclusively thermal, for the purpose of classifying operating expenses in Yukon where a sizable portion of the plant is hydraulic. Accordingly, the Board considers that it would be appropriate for YEC/YECL to perform a study to determine a more appropriate method of classifying generation operating and maintenance expenses between demand and energy. The Board recommends that, for current purposes, the 50/50 relationship is adequate.

Recommendation #6:

The Board recommends that the Companies be directed to perform a study to determine a more appropriate method of classifying generation O&M expenses and file the results of the study with the Board at the time of their next general rate application.

8.5 Marketing Expense

The Companies allocated marketing expense 85% on the basis of energy and 15% on the basis of the number of customers. The Companies placed heavier emphasis on energy sales as larger customers have more interaction with marketing than do smaller customers.

Dr. Jackson recommended that marketing costs should be allocated 50% on the basis of energy and 50% on the basis of the number of customers. Dr. Jackson supported his position on the basis that the primary focus and target of marketing is on customers and not on units of energy. Dr. Jackson acknowledged that the Companies may expend more marketing effort on the large customers, but in the absence of a more detailed tracking of marketing costs the allocation should be 50% customer / 50% energy.

The Board notes that the impact on customer classes of changing the allocation of marketing expenses from 85%/15% to 50%/50% is not significant. The Board considers the Companies' allocation of marketing expenses to be appropriate.

Recommendation #7:
The Board recommends that the appropriate method of allocating marketing expense is 15% on the basis of the number of customers and 85% on the basis of energy.

8.6 Classification and Allocation of Other Costs of Service

The Board notes that no cost of service issues, other than those discussed in Sections 8.1 to 8.5 of this report, were raised during the review. The Board has reviewed the Companies' classification and allocation of other costs of service and considers the methods used by the Companies to be appropriate.

> Recommendation #8:
> The Board recommends that the appropriate methods of dealing with cost of service issues, other than those discussed in Sections 8.1 to 8.5 of this report, are those proposed by the Companies.

9. RATE DESIGN

9.1 Revenue to Cost Ratios

YEC/YECL in their evidence indicated that, with the exception of the industrial rate class, given the nature of cost of service studies a target revenue to cost ratio range of 90% to 110% would be appropriate. The Companies based this range on their view that it was doubtful if any cost of service study could be considered accurate by more than plus or minus 10%.

YEC/YECL advised the Board that several regulatory regimes consider 95% to 105% to be a reasonable revenue to cost ratio target range for all classes. They indicated further that Manitoba Hydro had submitted targets which were initially 85% to 115%, with the provision for the subsequent narrowing to 90% to 110%. They indicated that, in contrast, the Ontario Energy Board has established a target revenue to cost ratio of 100%.

When questioned on cross-examination, Company witnesses indicated that there was no conflict between their position that industrials should have a revenue to cost ratio of 100% and that other classes should have a target revenue to cost ratio range of 90% to 110%, because demands for industrial customers were measured while the demands for other customer classes were typically not measured but rather estimated from the experience of other utilities.

The position advanced by Curragh on the subject of revenue to cost ratios is that a cost of service study provides a guide for rate making, and that other considerations may require pricing a customer at rate levels less than indicated by a fully distributed cost of service study. Dr. Jackson proposed that rates should be set to cover the incremental costs which the customer will impose on the utility.

The Board recognizes the difference in the determination of peak demands of industrials and other customer groups. However, the Board is not satisfied that the inaccuracies of the cost of service study of plus or minus 10% stated by the Companies are entirely due to this factor.

The Board is satisfied that, at the present time, a target range for revenue to cost ratios of 90% to 110% is satisfactory. However, it urges the Companies to take the necessary steps to improve the quality of their cost of service studies so that a target revenue to cost ratio of 95% to 105% would be attainable.

The Board also considers that to the extent possible, within the constraints of good rate setting practice, rates for the various customer classes should be altered over time to approach a 100% revenue to cost ratio and not the extremities of the range of reasonableness advocated by the Companies.

Recommendation #9:

The Board recommends that a target range for revenue to cost ratios of 90% to 110% be established for all customer classes other than the industrial class, and that the Companies take the necessary steps to improve the quality of their cost of service studies so that a target revenue to cost ratio of 95% to 105% will be attainable.

With respect to the industrial rate class, the Board notes from the Companies' evidence that revenue to cost ratios for large industrial customer classes typically are at or above 100%. The Board also recognizes that the recovery of 100% of costs from the industrial class is particularly important when this class represents some 43% of the Companies' energy output. If industrial customers representing 43% of the Companies' energy output are to be charged rates which do not recover the cost of serving them, then a substantial number of customers will be required to pay rates in excess of their cost.

The Companies indicated that they intend to move the industrial rate class revenue to cost ratio close to 100% at the time of their next general rate application.

The Board does not accept Curragh's position that rates should be based on incremental costs which customers impose on the utility. The application of an incremental approach to all customers of the utility would result in the utility collecting from its customers an amount which is substantially less than its total revenue requirement allowed by the Board.

Recommendation #10:
The Board recommends that a target revenue to cost ratio of 100% be established for the industrial rate class.

9.2 Phase-In of Rate Changes

YEC/YECL witnesses acknowledged that, over time, rates to certain customer classes should be adjusted to bring their revenue to cost ratios within acceptable bounds. They emphasized that there is no definitive period over which rates should be adjusted to accomplish this objective, and that factors such as the over-all rate increases required, the inflation rate, general economic conditions, specific economic circumstances of a particular rate class and recent rate history, should all be considered in determining the appropriate phase-in period.

None of the Intervenors in the proceeding commented on this issue.

The Board acknowledges that the factors outlined by the Company witnesses should be considered in determining an appropriate phase-in period for the purpose of bringing revenue to cost ratios within acceptable limits. However, the Board notes that it is important for the regulator to continuously monitor the progression of revenue to cost ratios toward the acceptable range in future general rate applications by YEC and YECL. The Board is not satisfied that, in the absence of compelling circumstances, revenue to cost ratios for certain customer classes should remain outside of the acceptable range for an extended period of time.

Recommendation #11:

The Board recommends that the changes to rates required to bring the revenue to cost ratios within the ranges established be phased-in over a reasonable period of time, and that the Board monitor the progression of revenue to cost ratios toward the acceptable range in future general rate applications by YEC/YECL.

9.3 Promotion of Economy and Efficiency in the Use of Electricity

The Board considers the efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decisions regarding the future and current use of electricity.

The Companies stated that runout rates reflecting long-run incremental costs, fuel cost adjustment riders, the past use of interruptible rates when appropriate conditions exist and recent amendments to the Curragh Resources contract all contributed to the promotion of economy and efficiency in the use of electricity.

Rate characteristics which could lead to the promotion of further economy and efficiency in the use of electricity were stated by YEC/YECL to include higher customer charges to reflect actual customer costs, more widespread use of demand charges, higher demand charges to reflect the higher marginal (as opposed to embedded) cost of supply, higher runout energy charges in the hydro rate zone to match long-run marginal costs, interruptible rates to provide "valley filling" and "peak shaving" and time differentiated rates, and the introduction of a special surcharge for space heating use.

9.3.1 Long-Run Marginal Costs

The Companies took the position that the consumer should be aware of the long-run marginal cost of supply to make rational decisions, and that the runout rate should reflect the long-run marginal costs. During cross-examination, Company witnesses indicated that the runout rate should at least reflect short-run incremental costs to promote efficiency.

Company witnesses explained that, although the Order-in-Council required the utilities to charge runout rates which reflected the short-run incremental costs in each rate zone, the actual runout rates being charged by the Companies were generally designed to reflect the long-run marginal costs which included not only the short-run incremental costs of fuel and other operating costs but also long-run costs including costs relating to future capacity additions.

Company witnesses acknowledged on cross-examination that no formal studies had been performed to determine long-run marginal costs for each rate zone in Yukon, however, the witnesses noted that the runout rate on the hydro zone was lower than the incremental cost of fuel and, accordingly, should be adjusted upward. It was also acknowledged that for the remaining rate zones the runout rate is in excess of short-run incremental costs and thus not in compliance with the OIC.

The Board acknowledges the Companies' objective of promoting economy and efficiency in the use of electricity by including long-run marginal costs in runout rates. The Board notes that, to the extent that runout rates include compensation for costs relating to future construction, either the Companies will earn revenue in excess of their revenue requirements or will find it necessary to reduce rates in other blocks in order to balance total revenues with the revenue requirements. Furthermore, if fixed costs incurred by the Companies are not recovered in the demand charges, fixed charges and charges in the first energy block, then an element of revenue instability is introduced.

The Board notes that Company witnesses indicated that in Yukon, because diesel generation is utilized, the difference between short-run incremental costs and long-run marginal costs is not that big.

The Board considers that runout rates should reflect short-run incremental costs in each of the rate zones as specified in the OIC and that fixed costs incurred by the Companies should be recovered by demand charges, fixed charges and energy charges in the first energy block. The Board recognizes that this will result in an increase in the hydro zone runout rate.

The Board also considers that the Companies should undertake a study for the purpose of identifying long-run marginal costs that should appropriately be included in runout rates, and the results of this study should be presented to the Board by the Companies at the time of their next general rate application. At that time, the Board should consider the appropriate manner in which long-run marginal costs should be reflected in runout rates.

It was noted that, on cross-examination, Company witnesses indicated that no provision was included in the rate to Curragh for the excess of long-run marginal costs over short-run incremental costs.

Recommendation #12:
The Board recommends that the runout rates for all zones should be adjusted to reflect short-run incremental costs, and that the Companies should undertake a study for the purpose of identifying long-run marginal costs that should be included in the runout rates for consideration by the Board.

9.3.2 Other Rate Design Factors Which Promote Economy and Efficiency in the Use of Electricity

During the course of cross-examination, YEC/YECL witnesses discussed the other factors that contributed to the promotion of economy and efficiency in the use of electricity. It was indicated that a fuel adjustment rider enabled the Companies to communicate the current cost of fuel to their customers in the form of rate adjustments, and that this knowledge of current costs by customers was of assistance in the promotion of economy and efficiency.

The Companies also indicated that existing rates to be charged to Curragh include a significant demand charge which encourages efficient use of capacity by Curragh as well as actual incremental diesel fuel and operating costs for energy consumption in excess of 18,784 kWh for each hour (averaged on a monthly basis).

During the course of the proceedings, the Companies and Intervenors raised the possibility of using interruptible rates, time-of-use rates and a special electric heating rate for the purpose of increasing economy and efficiency. On cross-examination, Company witnesses stated that interruptible rates had been used in certain circumstances in the past and are currently available on the Mayo hydro system due to a surplus of energy on that system. They explained that the use of interruptible rates where generation is by diesel would not promote economy and efficiency because the interruptible rate

would have to be equal to the runout rate in order to recover the cost of generation.

Company witnesses also explained that time-of-use rates would not be of assistance in promoting economy and efficiency if the energy was produced from diesel generating plants because the generating cost would not be altered by the time of use.

Company witnesses indicated that the Companies were presently contemplating introduction of a hookup charge of approximately $4,000 for service to new electric space heating customers. The witnesses also estimated that approximately 25% of existing residential customers in the hydro area were, to some extent, electric space heating customers.

A further issue discussed in the proceeding was the incidence of residential government customers who do not directly receive the bill related to their consumption. It was agreed that such an arrangement definitely had a negative impact on the promotion of economy and efficiency in the use of electricity.

The City of Whitehorse and residents from Haines Junction indicated that the Companies should carefully examine the size of the initial block of energy (1,000 kWh/month/residential customers and 2,000 kWh/month for general service customers) with a view to reducing it to provide an added incentive to all customers on the system to use electricity more wisely. Company witnesses indicated that this matter would require considerable study.

The Board considers that, to the extent possible, interruptible and time-of-use rates should be used if it can be established that their use will result in the promotion of economy and efficiency in the use of electricity. However, it appears to the Board that under current circumstances there is a very limited opportunity to use these rate features.

Recommendation #13:
The Board recommends that interruptible and time-of-use rates should be used if it can be established that their use will result in the promotion of economy and efficiency in the use of electricity.

The Board wishes to encourage the Companies to further study the introduction of a special surcharge for new electric space heating customers with a view to reducing inefficient and uneconomic use of electricity for space heating purposes. The Board would also encourage the Companies to investigate methods by which the use of electricity for space heating by existing customers can be equitably discouraged.

Recommendation #14:

The Board recommends that the Companies further study the introduction of a special surcharge for new electric space heating customers and report to the Board the results of this study at the time of their next general rate application.

The Board also recommends that the Companies investigate methods by which the use of electricity for space heating by existing customers can be equitably discouraged and report to the Board the results of this study at the time of their next general rate application.

The Board also would encourage the Companies to examine alternative billing mechanisms in consultation with government agencies to ensure that residential government customers are receiving appropriate price signals designed to encourage the wise use of electricity.

Recommendation #15:

The Board recommends that the Companies examine alternative billing mechanisms in consultation with government to ensure that residential government customers are receiving appropriate price signals.

The Board considers it appropriate that the Companies conduct studies to determine the optimum size of the first energy rate block and to propose, if considered desirable, an additional energy rate block to ensure that rates are designed to result in the maximum promotion of economy and efficiency in the use of electricity. The Board also considers that details of energy consumption by rate block and the related cost on customers' bills will promote the economic and efficient use of electricity.

Recommendation #16:

The Board recommends that the Companies be directed to conduct studies to determine the optimum size of the first energy block and propose, if considered useful, multiple energy blocks.

The Board also recommends that the Companies be directed to examine the feasibility of providing on customers' bills information with respect to energy consumption by rate block and the related cost.

9.4 How Can Rate Design Respond to Environmental or Other Costs Not Included in Cost of Service

On this issue, Company witnesses explained that the existing rate design does not reflect environmental or other costs that are not currently included in cost of service and that rates are designed to recover only the costs recognized in the approved revenue requirement.

Company witnesses explained that in some Canadian jurisdictions recognition is given to environmental and other costs by reflecting them in the criteria used for the planning of system additions. They explained that environmental costs are not recognized in traditional utility accounts, are virtually impossible to quantify and the subject is currently very controversial.

The Board considers that the Companies should be encouraged to continue to monitor ways in which rate design can be used to reflect environmental or other costs not included in the cost of service. The Companies should also be encouraged to consider this factor in their applications for capital expansion and in their general rate applications.

Recommendation #17:
The Board recommends that the Companies be encouraged to monitor ways in which rate design can be used to reflect environmental or other costs not included in cost of service, and the Companies should be encouraged to consider environmental costs in future general rate applications and capital expansion applications.

9.5 Extent to Which Rate Design Responds to the Current Costs Required to Develop New Power Sources

This issue has been dealt with at length in Section 9.3 above in the context of reflecting long-run marginal costs in consumer rates.

9.6 How Should Demand-Side Management Activity be Reflected in Rate Design

It was agreed by the parties that the subject of Demand-Side Management ("DSM") activities would be discussed at length at the upcoming capital hearing.

The Board considers that the subject of DSM activities of the Companies fall into three distinct categories. First, the criteria used in determining what DSM activities should be undertaken by the Companies; second, the treatment of DSM expenditures for the purpose of determining the Companies' revenue requirements; and third, the manner in which DSM capital expenditures, operating expenses and sales reductions should be reflected in the Companies' rate design. The Board considers it important that all three of these aspects be addressed, in detail, by the Companies at the time of their upcoming capital hearing.

Recommendation #18:

The Board recommends that, at the time of the Companies' upcoming capital hearing, the following should be addressed:

(i) criteria used in determining the investments in DSM activities;

(ii) the appropriate treatment of DSM expenditures for the purpose of determining the Companies' revenue requirements; and

(iii) the manner in which DSM capital expenditures, operating expenses and sales reductions should be reflected in rate design.

10. CURRAGH CONTRACT

Counsel for Curragh stated in argument that:

> "...Curragh submits that the board should recommend that rates to be charged to Curragh should be based on an arms-length negotiation between Curragh on the one hand and Y.E.C./Y.E.C.L. and the Yukon Territorial Government on the other. And that that contract be treated in the same way as the June 1st, 1991 amending agreement and 1986 contract had been treated, namely, that the governor in council direct the board that the rate should be those agreed upon at arms length. Curragh will be happy to come before the board when that contract is in an order in council for the G.R.A. and answer questions about that contract within reason."
> [Tr.772-773]

Counsel for Curragh also made the following statement at the conclusion of his argument:

> "Curragh rejects those arguments put forward by the company for the reasons that I have given earlier and projects it on the merits, and Curragh in addition requests the board to send this message to the Yukon Territorial Government. And this message, and I am instructed to give it in this way, is that Curragh regards Y.E.C./Y.E.C.L. proposals on costing to be nothing more than an attempt by Y.E.C./Y.E.C.L. to position itself for negotiations Curragh may be disposed to enter for the period after March 31'93. In other words, the game is that Y.E.C./Y.E.C.L. wants this board to adopt its views and then have you recommend that to the Yukon Territorial Government. The Yukon Territorial Government than presumably will make those Yukon law by order in council through direction to this board. Then in negotiations Y.E.C./Y.E.C.L. will come to Curragh and say, 'You have got to cover the costs as defined by law.' ... Curragh, for all the reasons I have given, does not believe that these principles are appropriate. They believe that you should have a level playing field of costs for the fixed variable method, and do not stack the deck against Curragh in the way the company is urging you to do, and the way this process enables them to urge you that you do.
>
> Curragh's position is that if this board and the Y.T.G. accept Y.E.C./Y.E.C.L.'s methodology, that Curragh will regard this as an unfair, unwelcoming and hostile action towards it by Yukon. Curragh cannot afford to pay more than it is paying under the existing agreement in G.R.A. at present, and Curragh will not feel bound in any way by any order in council cost definitions in planning future actions." [Tr. 786-787]

Counsel for the City of Whitehorse dealt with the same issue in his argument and stated:

> "Dealing with the matter of the current rate, we believe that Curragh ought to be part of the rates which this board adjudicates on. If after setting of the rates by this board Curragh then of its own volition goes to either level of the government, territorial or federal for assistance, then that's a matter for Curragh and the government. In the meantime in the setting of the rates by this board, it is for Curragh to come before this board with its rates and it should be paying its fair share in that respect." [Tr.764]

Counsel for YEC, in response to submissions by Curragh, stated:

> "The final point I would like to deal with, Madam Chair, is the issue raised by Dr. Jackson in his recommendation. And that is that he indicated that the board perhaps should take other considerations into account in deciding whether or not a certain rate that might come out of a cost of service study should be, should be set for a company like Curragh that was having, for example, financial difficulties. What I would like to say to that, Madam Chair, is that since any preferential rate that would be granted to any company or any customer on any basis would affect the other customer classes, if the board was inclined to want to get into that exercise, it would have to carefully analyse a significant amount of information to satisfy itself that indeed the allegation that was being made about financial problems was in fact true." [Tr.808-809]

As discussed earlier, the Board is satisfied that a revenue to cost ratio for the industrial class customers should be approximately 100%. The Board is not satisfied that Curragh should be given any special treatment in the procedure followed for the establishment of its rates as opposed to those charged to other customers of YEC/YECL.

Accordingly, the Board considers that, although certain aspects of the relationship between YEC/YECL and Curragh can be appropriately covered in a contract between those two parties, such a contract should not be determinative of the price to be charged by YEC/YECL. The Board concurs with the position of the City of Whitehorse that Curragh rates are a matter to be determined by the Board only after a public hearing. The Board also concurs with the representation of counsel for the City of Whitehorse and the submission by the City of Dawson that any subsidy flowing to Curragh from the Government of Yukon should be in the form of a direct subsidy and not by way of a special rate for electricity.

Recommendation #12:
The Board recommends that the rates to be charged to Curragh should be determined by the Board only after a public hearing.

RESPECTFULLY SUBMITTED
ON BEHALF OF THE
YUKON UTILITIES BOARD

Edith D. Walters, Chairman

GLOSSARY OF TERMS

ALLOCATION:

The apportionment of the total cost of service between customer classes.

CAPACITY:

The load for which a generating unit, generating station or other electrical apparatus is rated either by the user or by the manufacturer.

CLASSIFICATION (COST):

The division of costs into components which reflect the relationship between the services provided by the utility and the principal cause of the related costs. Examples would be demand related, energy related and customer related.

COST OF SERVICE:

The total cost incurred to provide utility service, including expenses, taxes and return on investment. The cost of service may be thought of as an annual revenue requirement.

COST OF SERVICE STUDY:

An analytical process wherein the utility cost of service is functionalized, classified and allocated or assigned to the various customer classes.

DEMAND (ELECTRIC):

The rate of flow of electricity demanded at one point in time and the maximum size (capacity) of facilities required to serve the demands of electric customers, usually expressed in kilowatts.

COINCIDENT PEAK:

The sum of the demands of all customer classes at the time of system peak.

NON-COINCIDENT PEAK:

The sum of customer classes' peak demands irrespective of their time of incurrence.

DISTRIBUTION:

A network of electrical circuits which supply electricity to the customer from the transmission system.

ENERGY:

The consumption of electricity over a period of time by customers of an electric system, usually expressed in kilowatt hours.

FIXED COSTS:

Those costs that do not vary with the number of kilowatt hours supplied. Examples would be depreciation and return on investment.

FUNCTIONALIZATION:

The arrangement of costs according to major functions, such as production, transmission, distribution and general.

GENERAL RATE APPLICATION:

A request by a utility to a regulatory board to set new customer rates based on a forecasted revenue requirement for a specific test year(s).

KILOWATT:

One kilowatt equals 1,000 watts, where a watt is an electrical unit of real power or rate of doing work. One kilowatt is equivalent to approximately 1.34 horsepower.

KILOWATT HOUR:

The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatt hour equals 1,000 watt hours.

PEAKING GENERATION:

Generating equipment normally operated only during the hours of highest daily, weekly or seasonal loads, to meet a portion of the system load that is above the base load.

PEAK SHAVING:

Reducing customer demand at the time of system peak.

REVENUE REQUIREMENT:

The total of all revenues required to be collected from utility customers. Revenue requirement is determined as the total of the following costs:

- cash operating expenses
- depreciation
- income tax
- return on investment

REVENUE TO COST RATIO:

The ratio of revenues for a particular customer class to the cost of service for that particular customer class.

SUNK COST:

A cost resulting from an irreversible past decision.

SYSTEM PEAK:

The maximum aggregate demand imposed on the system by all customers.

TIME-OF-USE RATES:

Energy rates which vary by time of day and time of year, generally introduced to encourage shifting of demand.

TRANSMISSION:

Facilities provided to carry electricity from the point of generation to the distribution system.

VALLEY FILLING:

Shifting of consumption from times of high peak demand (Winter) to times of lower demand (Spring, Summer, Fall).

VARIABLE COSTS:

Those costs, such as fuel costs and variable maintenance costs, that vary with the number of kilowatt hours supplied.

SUMMARY OF RECOMMENDATIONS

The Board makes the following recommendations to the Commissioner in Executive Council:

1. That the Board be provided with the flexibility to react to future changes in circumstances, and to determine the appropriate cost of service and rate design practices to be used in Yukon.

2. That the appropriate method of classifying the cost of existing hydro generating plant (excluding Whitehorse Unit #4) is 40% to demand and 60% to energy.

3. That, based on the available evidence, the appropriate method of classifying the costs associated with Whitehorse Unit #4 is 100% to energy.

   That the Companies perform a study of the impact of Whitehorse Unit #4 on the capacity of Aishihik at the time of system peak and provide the results of the study to the Board at the time of their next general rate application for its further consideration.

4. That the appropriate method of classifying costs associated with diesel plant is 100% to demand.

5. That the appropriate method of allocating transmission costs is to specifically assign 65% of the costs of the Whitehorse/Faro line to Curragh, and to allocate all remaining transmission costs to all customer classes, including Curragh, on the basis of demand at the time of system peak.

6. That the Companies be directed to perform a study to determine a more appropriate method of classifying generation O&M expenses and file the results of the study with the Board at the time of their next general rate application.

7. That the appropriate method of allocating marketing expense is 15% on the basis of the number of customers and 85% on the basis of energy.

8. That the appropriate methods of dealing with cost of service issues, other than those discussed in Sections 8.1 to 8.5 of this report, are those proposed by the Companies.

9. That a target range for revenue to cost ratios of 90% to 110% be established for all customer classes other than the industrial class, and that the Companies take the necessary steps to improve the quality of their cost of service studies so that a target revenue to cost ratio of 95% to 105% will be attainable.

10. That a target revenue to cost ratio of 100% be established for the industrial rate class.

11. That the changes to rates required to bring the revenue to cost ratios within the ranges established be phased-in over a reasonable period of time, and that the Board monitor the progression of revenue to cost ratios toward the acceptable range in future general rate applications by YEC/YECL.

12. That the runout rates for all zones should be adjusted to reflect short-run incremental costs, and that the Companies should undertake a study for the purpose of identifying long-run marginal costs that should be included in the runout rates for consideration by the Board.

13. That interruptible and time-of-use rates should be used if it can be established that their use will result in the promotion of economy and efficiency in the use of electricity.

14. That the Companies further study the introduction of a special surcharge for new electric space heating customers and report to the Board the results of this study at the time of their next general rate application.

That the Companies investigate methods by which the use of electricity for space heating by existing customers can be equitably discouraged and report to the Board the results of this study at the time of their next general rate application.

15. That the Companies examine alternative billing mechanisms in consultation with government to ensure that residential government customers are receiving appropriate price signals.

16. That the Companies be directed to conduct studies to determine the optimum size of the first energy block and propose, if considered useful, multiple energy blocks.

That the Companies be directed to examine the feasibility of providing on customers' bills information with respect to energy consumption by rate block and the related cost.

17. That the Companies be encouraged to monitor ways in which rate design can be used to reflect environmental or other costs not included in cost of service, and the Companies should be encouraged to consider environmental costs in future general rate applications and capital expansion applications.

18. That, at the time of the Companies' upcoming capital hearing, the following should be addressed:

    (i) criteria used in determining the investments in DSM activities;

    (ii) the appropriate treatment of DSM expenditures for the purpose of determining the Companies' revenue requirements; and

    (iii) the manner in which DSM capital expenditures, operating expenses and sales reductions should be reflected in rate design.

19. That the rates to be charged to Curragh should be determined by the Board only after a public hearing.

REFERENCE: **Application, Page 4-18**

ISSUE/SUB-ISSUE: **ERA**

QUESTION:

a) Would the current lower prices for diesel fuel alter YEC's recommendation for this item?

ANSWER:

(a)

The level of the ERA needs to be set consistent with the price of diesel fuel in Yukon Energy's Revenue Requirement. To the extent the revenue requirement is changed to reflect "current lower prices for diesel fuel", then the ERA would be similarly updated.

Under the Rider F mechanism, differences between the GRA fuel price and actual fuel prices will affect the Rider F account and not YEC earnings.

As noted at page 4-18 of the Application, "the structure of the ERA is designed to ensure both that YECL receives a full pass through of the incremental costs of diesel generation (when diesel is on the margin) driven by increases in the volume of wholesale sales, and second to ensure that Yukon Energy is able to recover its costs (as required by OIC 1995/90 section 7(b)) when diesel generation is on the margin".

The problem created in the current situation, even with acceptance of all residential runoff rates as proposed in the Application, is that Yukon Energy would be severely prejudiced when diesel generation for whatever reason becomes needed to supply wholesale load growth. The approved run out rate today (and for at least 2009) for non-government residential service in the Hydro zone is lower than would apply based on the full short-term incremental cost of diesel; accordingly, Rate Schedule 42 as approved in the 1996/97 GRA needs to be amended to set an ERA charge that is not tied to the current approved run out rate for non-government residential service in the Hydro zone.

REFERENCE: **Application, Page 6-1**

ISSUE/SUB-ISSUE: **Order 2005-1**

In response, YEC/YECL jointly filed a required report with the Board in August 2005 that provided information on the revenue to cost ratios by customer class for both companies using the most recent cost of service allocation study, including comments on the implementation of a rate shift program over 10 years.

QUESTION:

a) Please provide a copy of that report.

b) When did the most recent COS study occur that was referenced in the above quote?

c) Was the previous COS study undertaken before the closure of the Faro mine?

d) Why has no action been taken with respect to Order 1996-7 with respect to a rate-rebalancing program?

ANSWER:

(a)

Please see Attachment 1 to this response which provides the 2005 Cost of Service Report, including the cover letter and Appendix A filed with the report. In addition, Attachment 2 provides the YEC/YECL October 27, 2005 response to intervenor comments on Attachment 1.

(b)

The 2005 Report provided as Attachment to YUB-YEC-1-23(a), notes that “the most recent full cost-of-service study for both Companies that was balanced (reflected overall system revenues equal to costs) was filed during the 1996/97 GRA for the year 1997.”

After the 1996/97 GRA hearing, a cost of service allocation assessment was undertaken by Yukon Energy as part of the 1998 application regarding the closure of the Faro mine.[1] As noted in the 2005 Report to the Board, this later filing was not a full cost of service but was undertaken to determine the "cost of service shortfall" due to the closure of the Faro mine. The study was based on 1997 GRA approved costs and revenues (excluding Faro mine shutdown impacts and a few other specific adjustments) and was utilized only to assess cost of service for the Faro mine during its partial years operations in 1997 and 1998. The shortfalls calculated using the study were adopted by the Board as part of the rate setting approach used in that proceeding.

The Power Purchase Agreement Application between Yukon Energy and Minto mine also included as Attachment A: 2008 Yukon Industrial Cost of Service which reviewed in detail the principles, methods, information and assumptions adopted to prepare the 2008 Yukon Industrial COS estimates used to determine the 2008 Firm Mine Rate included in the PPA application.

(c)

As noted in response to (b) above, the most recent full Cost of Service study for both companies was undertaken in relation to the 1996/97 GRA prior to the closure of the Faro mine.

(d)

This is reviewed briefly in Section 1.1.1 of the Application, when the Board addressed a motion to require both Yukon Energy and YECL to file a GRA. As a result, Order 2005-1 required YEC/YECL to prepare the report provided as Attachment 1 plus the subsequent response in Attachment 2.

In summary, as discussed in 2005, conditions since 1996 have not allowed this directive to be addressed. The key conditions in this regard prior to 2008 have been the absence of revenue requirement reviews, let alone concurrent reviews of both companies, and the prevailing impact of Yukon Government RSF subsidies (particularly to non-government residential customers) and the structure of such subsidies for many of these years.

[1] Yukon Energy Corporation: Revised 1997 and 1998 Rate Application to the Yukon Utilities Board Related to Board Order 1997-6 and Related to the Closure of the Faro Mine.

YEC/YECL in Attachments 1 and 2 state that a fundamental requirement for a rate shift program is the need for revenue requirement and billing determinants to be established for both companies for the same test period; in addition, the companies note the relevance of ongoing government bill relief in affecting timing of any such a rate shift program. Since 1996, the current 2008-2009 GRA filings by both companies are the first opportunity for the same test year revenue requirement and billing determinant requirement to be met – but today OIC 2008/149 further defers implementation of any such rate shift program until after 2012.

Please also see response to YUB-YEC-1-20.

YUKON ENERGY

The Yukon Electrical Company Limited
An ATCO Company

August 24, 2005

Mr. Brian Morris
Yukon Utilities Board
19-1114 First Avenue
Whitehorse, YT
Y1A 1A3

Board Order 2005-1 set out in section 4.0 a joint YEC/YECL requirement regarding cost-of-service information, as follows:

> The Board requires the Companies to jointly file a report by Thursday September 1, 2005, that provides information on the revenue to cost ratios by customer class for both Companies utilizing the most recent cost of service allocation study. If the report indicates that the revenue to cost ratios by customer class are outside the range of 90 percent to 110 percent, then the Companies are to provide their views on whether an updated cost of service allocation study should be undertaken or if a rate shift proposal can be made based on the most recent cost of service allocation study.

Most Recent Cost of Service Allocation Study

Attached is a Report on the Most Recent Cost of Service Study. This Report indicates that the most recent full cost-of-service allocation study for both Companies was filed with the Board during the 1996/97 GRA for the 1997 test year. This study indicated that the residential non-government class for both Companies was the only customer class with rates below 90 percent of costs (at 80.2% of the costs to serve them), and the general service government class was the only customer class for both Companies with rates above 110% (at 142.8% of the costs to serve them). All other remaining customer classes for both Companies were inside the 90% to 110% range.

The attached Report notes that a partial cost-of-service study for both Companies was prepared by Yukon Energy only for its *Revised 1997 and 1998 Rate Application to the Yukon Utilities Board Related to Board Order 1997-6 and Related to the Closure of the Faro Mine.* This 1998 study, however, was based on the 1997 GRA approved costs and revenues (excluding Faro mine shutdown impacts and a few other specific adjustments) and was utilized only to assess cost of service for the Faro mine during its partial year operations in 1997 and 1998.

The attached Report reviews implications for revenue to cost ratios for both Companies related to adjustments to costs and revenues since the 1996/97 GRA.

Companies' views on whether an updated study should be undertaken today

Based on the information as set out in the attached Report, the Companies do not view that a cost of service study is required to begin a rate shift program. This is for two reasons.

First, following the rate adjustments implemented in 1996, only two customer classes appear to have been routinely outside the 90%-110% revenue to cost ratio (R/C) range – residential non-government at well below 90% and general service government at well above 110%. It is unlikely that the revenue to cost ratios have improved since 1997 and 1998 for these two customer classes. The key first steps of any rate shift program will need to focus on directional improvements in the revenue to cost ratios for these two classes.

Second, although a cost of service study will be required to refine the ratios when each of the classes is approaching the 90%-110% range, these two customer classes are currently far outside the range targeted by the Board. Accordingly, in order to prevent giving rise to concerns over rate shock as noted below, it will likely take a number of years in any rate shift program to begin to approach the target range. There is no apparent need for a new cost of service study to begin these initial steps in any rate shift program.

Issues to be addressed with respect to a rate shift proposal

Although the lack of a recent cost of service study is not an impediment to the Board exercising its jurisdiction to initiate a rate shift program today, the Companies note that there are a number of other matters that suggest against initiating such a rate shift in the near term. A fundamental requirement to any rate shift program is the need for revenue requirement and billing determinants to be established for both companies for the same test period. This information has not yet been established. As well, the following three matters will need to be considered prior to designing or implementing any rate shift program.

1) **Rate relief (and Rate Redistribution Fund):** The 1996/97 GRA did not result in any material adjustments for rates to residential non-government customers. YEC/YECL argued in the 1996/97 GRA, in their Reply Argument at page 8, that this was appropriate (despite an R/C ratio below 90%) as "any movement toward the 90-110% target will only increase the amount of bill relief paid by the government and the residential customers will not see any change in their bills". The Board, in not moving to initiate a rate shift program at that time, acknowledged the constraints related to the then existing rate relief.

The situation regarding rate relief constraints has not materially changed from the 1996 situation. The Yukon Government recently announced the continuation of the Rate

Stabilization Fund (RSF) until March 31, 2007, and similar to the earlier rate relief programs, this mechanism prevents most residential non-government customers from seeing any related to rate shifts on their bills:

- **1997 rate relief and Residential customers:** Overall, 1997 rate relief levels yielded an effective R/C ratio (as to bills paid) for Residential Non-Government customers of 73% based on approved 1997 costs of service (costs per Exhibit 206 in the 1996/97 GRA hearing). This rate relief was focused on the customer charge and the first block energy use. Accordingly, the effective bill increase required for most residential customers to reach 90% R/C ratio based only on the 1997 GRA costs was far greater than appears solely upon inspection of Exhibit 206 (likely greater than 25%). This assessment ignores any need for additional rate increases after 1997 related to other factors such as closure of the Faro mine, higher fuel costs or other cost increases.

- **Current Rate Stabilization Fund Impacts:** The above 1997 revenue cost ratios after rate relief would need to be changed today to reflect current levels of RSF payments to residential non-government customers. The current RSF subsidies on a dollar value basis are well in excess of those received by customers in 1997. Given the current RSF program, there will not be any real impact on the bills paid by most residential customers under a rate shift program. Higher rates could be set for non-government residential customers, but this will not impact the customers' bills for any consumption under 1000 kW.h per month (a large majority of the current residential non-government consumption is below 1000 kW.h per month).

The Board's Order 1996-7 from the 1996/97 GRA also noted that the Companies are to design a rate shift program over a ten year period, but further noted that "these proposals may include the setting up of a Rate Redistribution Fund which would hold a portion of the total rate relief in a particular year so that it can be used in subsequent years to mitigate a rate increase to a specific class". This part of Order 1996-7 clearly linked rate shift proposals to the matter of rate relief removal. Under the current RSF, however, there is no basis whereby the Companies could establish a Rate Redistribution Fund as envisaged in Order 1996-7.

2) **Rate Shock:** The YEC/YECL Reply Argument in the 1996/97 GRA at page 8 also noted that "the Companies submit that the time period required to move the ratio into the target range is 10 years at the minimum and this time period must be reviewed continuously to ensure that the customers do not experience rate shock". When a rate shift program is considered, rate shock will remain a key constraint and suggested timeframes for transition will need to reflect this constraint.

In addition, given the degree of rate relief in place today, implementation of a rate shift program that raises residential non-government rates but not the underlying bills will only exacerbate the potential for "bill shock" for customers in the event that the RSF is

materially redesigned or terminated in future. It does not appear to be in customers' interests to increase their exposure to this financial shock.

3) **Rate Design:** The current structure of retail rates in Yukon results in three separate charges to each customer class in addition to any rate riders that are in place at a given time. For residential customers, the charges consist of a customer charge, a base energy rate and a runoff rate. For general service customers, the charges are a demand charge, a base energy rate and a runoff rate. Each of these components is required to be set based on principles set out in OIC 1995/90, with rates being established on an integrated basis for Yukon Energy and YECL customers.

Current rates reflect rate designs approved in the 1996/97 GRA combined with subsequently established rate riders (Rider J and Rider F). The current rates in Yukon (excluding rate riders) were set such that all "runoff" consumption (above 1000 kW.h for residential customer and above 2000 kW.h for general service customers) was priced in each rate zone based on the effective incremental cost of energy produced by diesel generation in that rate zone as forecast in the 1996/97 GRA.

When a rate shift program is designed and implemented, a key first task will be to determine the rate design approach to be used in implementing the rate shift, including the related requirements of OIC 1995/90. Based on previous rate designs, rate shift impacts as between customer classes would focus, after the runoff rates are established, on first block energy rates and customer charges or demand charges. A possible first assessment then would be the impact of adjusting the runoff block to move towards incorporating the current price of diesel fuel (which would affect all customers as runoff rates in each rate zone currently are equal between the various classes). This level of detail regarding rate design has not been considered by the Companies in recent years, and would likely be a necessary precondition to implementing a differential rate shift program at this time.

Issues to be addressed with respect to any new cost of service study

Preparation of a new cost of service study when directed by the Board will require a number of key matters to be satisfied that are not in place at this time. First, there will need to be an approved revenue requirement for each of the two utilities on a consistent test year basis as well as the determination of billing determinants and load characteristics by customer class. As YEC's recent application was for the 2005 test year only and YECL has not made an application recently, this information is not currently available.

Second, the methods employed in the Yukon integrated cost of service studies prepared to date (since 1989) have been effectively based on the system and its cost drivers and load profiles with the Faro mine as a customer. With the Faro mine closed and surplus hydro on the WAF system, it would be appropriate to review a number of the key methods (such as classification of generation and transmission assets) to ensure the cost of service approach properly tracks the costs imposed on the system by each class of

customer. The completion of the Mayo-Dawson transmission line will also require some assessment to ensure appropriate cost of service methodologies are applied in dealing with the costs on that system.

We trust this Report satisfies the requirements of Board Order 2005-1. Please feel free to contact us if you have any questions.

Yours truly,

David Morrison
President & CEO
Yukon Energy Corporation

Doug Tenney
General Manager
Yukon Electrical Company Ltd.

YUKON ENERGY

The Yukon Electrical Company Limited
An *ATCO* Company

Report on the Most Recent Cost of Service Study

Yukon Energy Corporation
and
Yukon Electrical Company Limited

August, 2005

Board Order 2005-1 set out in section 4.0 a joint YEC/YECL requirement regarding cost-of-service information. In respect of Cost of Service Study results, the Order states as follows:

> The Board requires the Companies to jointly file a report by Thursday September 1, 2005, that provides information on the revenue to cost ratios by customer class for both Companies utilizing the most recent cost of service allocation study.

This report provides an overview of the "most recent cost of service allocation study" for Yukon and the implications for revenue to cost ratios for both Companies related to adjustments to costs and revenues since the 1996/97 GRA.

Recent Cost of Service Studies

The most recent full cost-of-service study for both Companies that was balanced (reflected overall system revenues equal to costs) was filed during the 1996/97 GRA for the year 1997. The results of this cost-of-service study were provided as Exhibit 206 in the 1996/97 General Rate Application Hearing. The relevant sections of Exhibit 206 are attached as **Attachment A** (Attachment A excludes the detailed rate schedules that were included in Exhibit 206). This exhibit reflects the cost-of-service study filed in the original GRA application documents at Binder 2 Tabs 4 and 5, as updated for the negotiated settlement and final approvals given the Board in that GRA .

The information on the revenue to cost coverage (R/C) ratios by customer class for both Companies utilizing this most recent cost of service study allocation for 1997 is in summary as follows:

Table 1: Revenue to Cost Coverage (RCC) Ratios for 1997

	Final 1996/97 GRA - 1997		
Customer class for both Companies	**Costs** ($000)	**Revenue** ($000)	**RCC Ratios**
Residential Government	645	642	99.6%
Residential Non Government	17,178	13,777	80.2%
General Service Government	5,586	7,978	142.8%
General Service Non Government	8,665	9,507	109.7%
Industrial	14,985	14,983	100.0%
Street Lights	537	591	110.0%
Space Lights	150	165	110.0%
Total	47,746	47,643	100.0%

Source: 1996/97 GRA, Exhibit 206, Schedule C (including unbilled)

As indicated in Table 1, the R/C ratios for the Residential Non-Government and General Service Government were the only two results that were outside the 90:110% range. These R/C ratios reflect rates as approved by the Board[1].

After the 1996/97 GRA hearing, the only cost of service allocation assessment carried out was by Yukon Energy as part of its 1998 application regarding the closure of the Faro mine during January 1998 (the *Yukon Energy Corporation: Revised 1997 and 1998 Rate Application to the Yukon Utilities Board Related to Board Order 1997-6 and Related to the Closure of the Faro Mine*). The 1998 filing, which is reviewed below, did not constitute a full and balanced cost of service allocation study for all rate classes relevant for the purpose of this report.

The 1998 filing by Yukon Energy updated the 1996/97 GRA cost-of-service study on a limited-scope basis to reflect the 1997 and 1998 impact of the mine closure. The sole purpose of this updated cost-of-service study was to determine the "cost of service shortfall" related to the Faro mine; that is, to determine the full fair cost of service allocation to the mine in each of 1997 and 1998 given the actual consumption of the mine, as compared to the amounts actually paid by the mine. The shortfalls calculated using this study as filed by Yukon Energy were ultimately adopted by the Board as part of the rate setting approach in that proceeding, i.e., based on this cost of service, the Industrial rate class (of which the Faro mine was the only member) was assigned a cost of service shortfall for 1998 in accordance with Board Order 1998-5 of $3.298 million per Schedule 6D of Exhibit 83.[2]

Yukon Energy did not file details with the Board on its updated 1998 cost of service study, beyond the information relating to cost of service for the Industrial class. Accordingly, updated information was not filed for other customer classes such as the Residential Non-Government or Government General Service classes. Furthermore, this was not a fully balanced cost of service study (it reflected an overall cost-of-service revenue shortfall for the system), it incorporated various adjustments not ultimately adopted by the Board in that hearing, and it did not yet reflect the revenue impacts of rate changes approved in the 1998 hearing in the form of Rider J.

Implications of Adjustments after 1997

Rates today remain as set for 1997, subject only to the effects of Rider J (Faro mine closure rider) and Rider F (fuel cost adjustment rider). The most significant system adjustment since 1997 has been the closure of the Faro mine. In addition, fuel costs (which have approximately

[1] However, as a practical matter beyond Board approved rates, after rate relief funded by the Yukon Government for 1997, overall Residential Non-Government class bills would have covered approximately 73% of residential utility costs approved by the Board as set out in Table 1.

[2] The limited scope assessment in the 1998 filing (as provided for the Faro mine in Schedule 6D of Exhibit 83) compared to the 1996/97 GRA addressed a reduction in industrial loads at the Faro mine of 166,088 MW.h (from 180,000 MW.h forecast in the 1997 GRA), with a consequent reduction in industrial revenue of $13.728 million and a partially offsetting reduction in system costs (some of which the Board did not ultimately adopt).

doubled since the 1997 GRA numbers) and the completion of the Mayo-Dawson transmission facility are other significant changes.[3]

Overall, there is no reason to believe that these (or other) adjustments have reduced materially since the 1997 GRA the extent to which R/C ratios for the Residential Non-Government and General Service Government remain outside the 90:110% target range.

The closure of the Faro Mine in 1997 will impact on the cost of service studies for the consolidated Yukon system to result in the cost of service for each remaining customer class being adjusted to absorb a greater share of the Yukon's significant fixed costs for generation and transmission facilities. In response, Rider J has also increased the revenue to be collected from each remaining firm customer class. Under these circumstances, R/C ratios for customer classes would change only to the extent that the per cent rate and cost increases differ materially between customer classes.

- **Rate changes:** The rate change implemented in response to the Faro mine closure (Rider J) was implemented on an equal percentage basis to all customer classes. As a result, no material differential impact on revenue:cost ratios is expected from this rate change.

- **Changes in Allocated Costs:** No new cost of service allocation study has been performed based on the Faro closure in 1998. In 1993, when the Faro mine was previously closed, detailed cost of service information for each customer class for both Companies was presented to the Board for 1994 (Tab 5 of filings) with and without Faro mine electric power sales. The analysis demonstrated that closure of the Faro mine resulted in increased costs of service being assigned to each remaining customer class, with these cost increases ranging between 16 and 20 per cent (with Residential Non Government at the lower end of this range and Government Commercial at the higher end of this range). There is no reason to expect that the cost allocation impacts of the Faro mine closure in 1998 to be materially different from the closure in 1993. As a result, the closure of the Faro mine in 1998 was likely generally neutral to revenue:cost ratios.

On balance, no major R/C ratio changes are anticipated to result from the closure of the Faro mine for the two classes that were outside the target 90%-100% R/C range in the most recent cost of service study (1996/97 GRA analysis for 1997).

[3] Rate relief has also been adjusted during this period to in effect ensure that most Residential Non Government customers have not paid for rate increases (Rider J or F) that exceed 9% over their charges (after rate relief) in January 1997. For a Residential Non Government customer using 1,000 kW.h in a month, the effective bill ceiling after GST is $105.87 per month. For this same customer the bill without rate relief would approximate $141 per month with the Rider J and Rider F levels in place in spring 2005.

YUKON ENERGY

JUN 2 4 1996

YUKON ENERGY CORPORATION
#304 - 204 LAMBERT ST.
WHITEHORSE
YUKON Y1A 1Z4
Telephone (403) 667-5028
FAX (403) 668-3327

Our File: 2/825-00

Exhibit 206

June 19, 1996

Yukon Utilities Board
#19, 10014 - 1st Avenue
P.O. Box 6070
Whitehorse, Yukon Y1A 5L7

Attention: Mr. Brian Morris, Chair

Dear Sir:

RE: YEC/YECL 1996/1997 GENERAL RATE APPLICATION - BOARD ORDER 1996-7

Pursuant to Board Decision 1996-7 the Companies enclose herewith, for approval, tariff schedules in compliance with the Board's order. The attached Rate Design document also provides detailed supporting text and working tables that explain how the tariffs have been developed.

We have taken the liberty of alerting the Board's staff to this filing as it is the hope of the Companies to implement the approved rates on July 1, 1996. In order for us to achieve this target, it does require approval from the Board on or before June 24, 1996.

As the circumstances of the 1996/97 Rate Application were somewhat varied from previous applications in that the Board declined to allow the Companies to inaugurate interim refundable rates as of January 1, 1996, we have a unique situation to address. Riders are required to collect or refund amounts that various rate classes have underpaid or overpaid during the period January 1, 1996 to June 30, 1996. Details are set out in the attached Rate Design document.

Decision 1996-7 directed the Companies to design a rate shift program that would target revenue/cost ratios in the range of 90% - 110% over a 10 year period. The proposed tariff schedules for 1996 and 1997 will result in most classes falling within this target range throughout the next two years.

.../2

Further progress will be pursued after 1997 in moving Residential Non-Government and Government General Service ratios within the target ranges directed by the Board, subject to OIC directives relating to rate relief. The Companies will need time in future to consider options with respect to moving all ratios over the next ten years into the Board's target range.

If the Board or its staff have any questions, please contact Brian Milne at 633-7009.

Yours very truly,

YUKON ENERGY CORPORATION

William E. Byers, Q.C.
President

THE YUKON ELECTRICAL COMPANY LIMITED

C. Harvey Kerslake, P.Eng.
Vice-President and General Manager

/dm
c Barry McKinlay, Manager Rates & Finance - Electrical, BCUC (By Fax: (604) 660-1102)

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2.2 Revenue to Cost Ratios

The Companies have recalculated the cost of service for each rate class in 1996 and 1997 to reflect the adjusted revenue requirements. Based on Decision 1996-7, the Companies have retained the cost of service methodology set out in the initial filing. OIC 1995/90 requires that rates charged to the industrial rate class must be sufficient to cover its cost of service. Decision 1996-7 directed that the residential revenue to cost ratio in 1997 be at least 80%, which was expected to occur without any changes to the non-government residential rates prior to elimination of government rate relief. The Companies were also directed to design a rate shift program that would target revenue to cost ratios in the range of 90% to 110% over a ten year period.

Based on the above considerations, the following is a summary of the existing and proposed revenue to cost ratios for each class (see Schedules B and C):

	Revenue/Cost Ratio		
Rate Class	Existing	Proposed 1996	Proposed 1997
Residential Government	102%	100%	100%
Residential Non Government *	84%	84%	81%
General Service Government	159%	133%	143%
General Service Municipal	137%	110%	110%
General Service Non Government **	137%	110%	110%
Industrial	87%	100%	100%
Street Lights	159%	110%	110%
Space Lights	123%	110%	110%

* In 1996, bill/cost ratio on average equals 72% after rate relief. In 1997, if the present rate relief program was fully retained, this ratio would equal 70% (the future of the present rate relief program beyond 1996 has not yet been determined).

** In 1996, bill/cost ratio on average equals 120% after rate relief at existing rates, proposed rate reductions remove rate relief for this class.

The industrial class revenue to cost ratio complies with OIC 1995/90 for each year. Residential non-government exceeds 80% in each test year without any material rate change at this time, as directed by Decision 1996-7. All other classes, except for General Service Government, have revenue to cost ratios for each year that will be within the target range directed by the Board. A reduction, toward the target, has also been achieved in the Government General Service ratio.

Yukon Energy Corporation
The Yukon Electrical Company Limited
1996/97 GRA Refile
Comparision of Costs and Revenues
1997

Costs and Revenues at Existing Rates	Forecast Costs ($000)	Forecast Revenue ($000)	Revenue / Cost Ratio (%)	Surplus/ (Shortfall) ($000)
Residential - Government	644.5	628.7	97.55%	(15.8)
Residential - Non Government	17,177.7	13,831.3	80.52%	(3,346.4)
General Service - Government	5,585.9	8,598.3	153.93%	3,012.4
General Service - Non Government	8,664.9	11,419.6	131.79%	2,754.8
Industrial	14,421.2	12,913.7	89.55%	(1,507.6)
Street Lights	537.3	829.1	154.32%	291.8
Space Lights	150.4	166.3	110.54%	15.9
Total Allocated Cost/ Revenue	47,181.8	48,386.9	102.55%	1,205.1
85% of WAF cost not allocated to Industrial	563.8	563.8	100.00%	0.0
Total Industrial	14,985.1	13,477.5	89.94%	(1,507.6)
Must be included in rate design				
Total Cost / Revenue	47,745.7	48,950.7		1,205.1
Costs and Proposed Revenues				
Residential - Government	644.5	644.5	100.00%	0.0
Residential - Non Government	17,177.7	13,831.3	80.52%	(3,346.4)
General Service - Government	5,585.9	7,999.0	143.20%	2,413.1
General Service - Non Government	8,664.9	9,531.3	110.00%	866.5
Industrial	14,421.2	14,421.2	100.00%	0.0
Street Lights	537.3	591.0	110.00%	53.7
Space Lights	150.4	165.5	110.00%	15.0
Total Allocated Cost/Revenue	47,181.8	47,183.8	100.00%	2.0
85% of WAF cost not allocated to Industrial	563.8	563.8	100.00%	0.0
Total Industrial	14,985.1	14,985.1	100.00%	0.0
Must be included in rate design				
Total Cost / Revenue	47,745.7	47,747.6		2.0
Forecast Growth in Unbilled Revenue		104.4		104.4
Costs and Revenues At Proposed Rates Considering Unbilled				
Residential - Government	644.5	641.9	99.60%	(2.6)
Residential - Non Government	17,177.7	13,776.5	80.20%	(3,401.2)
General Service - Government	5,585.9	7,978.2	142.83%	2,392.4
General Service - Non Government	8,664.9	9,506.7	109.72%	841.8
Industrial	14,421.2	14,419.7	99.99%	(1.6)
Street Lights	537.3	590.9	109.98%	53.6
Space Lights	150.4	165.4	109.98%	15.0
Total Allocated Cost/ Revenue	47,181.8	47,079.4	99.78%	(102.5)
85% of WAF cost not allocated to Industrial	563.8	563.8	100.00%	0.0
Total Industrial	14,985.1	14,983.5	99.99%	(1.6)
Must be included in rate design				
Total Cost / Revenue	47,745.7	47,643.2		(102.5)

YUKON ENERGY

The Yukon Electrical Company Limited
An ATCO Company

October 27, 2005

Mr. Brian Morris
Yukon Utilities Board
19-1114 First Avenue
Whitehorse, YT
Y1A 1A3

Mr. Morris,

RE: Joint Submission regarding the Most Recent Cost of Service per Order 2005-1

The Companies have received responses to the August 24, 2005 Report on the Most Recent Cost of Service Allocation Study from the Ad-Hoc Group of Businesses, Mr. McMahon and UCG. This reply addresses only the relevant matters raised in the submissions, organized using the same headings as the original YEC/YECL submission.

Most Recent Cost of Service Allocation Study

McMahon asserts at page 2 of his submission that "what was expected of the utilities was to take the 7 month period provided to rerun the existing cost allocation study using the most up to date cost and revenue information available to the utilities". This is incorrect. As noted in the Companies submission the Board direction in this regard in Order 2005-1 was as follows:

> "The Board requires the Companies to jointly file a report by Thursday September 1, 2005, that provides information on the revenue to cost ratios by customer class for both Companies utilizing the most recent cost of service allocation study."

The Companies provided the requested information utilizing the most recent Cost of Service Study which was from the 1996/97 GRA.

Companies' views on whether an updated study should be undertaken today

Further contrary to the McMahon's submission that the Board expected a new or rerun cost allocation study, Order 2005-1 explicitly asked the Companies "to provide their

views on whether an updated cost of service allocation study should be undertaken or if a rate shift proposal can be made based on the most recent cost of service allocation study."

On page two of the joint submission, the utilities made two points very clearly: 1) that there is no need for an updated cost of service study today to allow a rate shift proposal to be undertaken if so desired by the Board, and 2) that there are practical impediments to conducting a cost of service study in the near term.

On the matter of the need for the study now, the Companies submitted that no new cost of service study is required today to begin a rate shift program to target a 90-110% revenue to cost ratio range, as there is ample evidence that any such rate shift program simply needs to start with raising Non-Government Residential rates and lowering Government General Service rates. Also there is ample evidence that it will take a number of years of such adjustments (due to practical limitations of rate shock) before these classes will approach the 90-110% range. A cost of service allocation study will not be required until many years after the rate shift begins (i.e., until the ultimate range is being approached).

On the matter of impediments to conducting a study today, the companies were very clear in stating "A fundamental requirement to any rate shift program is the need for revenue requirement and billing determinants to be established for both companies for the same test period." This has clearly not yet happened. In the Companies' submission, the first step remains the review and approval of both Companies' revenue requirements prior to any attempt at providing an updated Yukon cost of service allocation study.

Mr. McMahon states that YECL's "annual report of its most recent year of operations" would "certainly be backed up by enough cost and revenue detail to be able to update the YECL-related data in the cost allocation study". He further states that actual utility results inserted into the historical cost allocation study for YECL and YEC for 2002, 2003 and 2004 would provide a better understanding of any movement in costs and revenues over the last few years. This is incorrect and entirely irrelevant to the issue at hand. Aside from the clear need to establish revenue requirements established by the Board, it is important to note that the actual results produced by the utilities do not include the types of load data regarding coincident and non-coincident demand by rate class and detailed billing determinants required for cost of service analysis. The preparation and determination of this specialized data is only performed as part of the rate design component of a General Rate Application.

Issues to be addressed with respect to a rate shift proposal

In relation to the Companies' comments on the issue of rate relief and its relevance to the cost of service debate McMahon asserts that "As the Board has determined in past decisions, it is not the Board's role to worry about rate relief since this is a matter of public policy".

McMahon's assertion is not supported by the evidence[1]. Firstly, it is not clear what past decisions McMahon is referencing. The Companies' outlined in their submission various quotes from the Board's 1996/97 GRA Decision that demonstrated that the Board was clearly aware of and considering the impacts of rate relief in its decisions. The Companies also noted that the Board need be aware that, given the degree of rate relief in place today, implementation of a rate shift program that raises Residential Non-Government rates but not the underlying bills will only exacerbate the potential for "bill shock" for customers in the event that the RSF is materially redesigned or terminated in future. The Companies reiterate that it does not appear to be in customers' interests to increase their exposure to this financial shock.

Issues to be addressed with respect to any new cost of service study

A number of other issues are mentioned in the intervenor submissions that require comment:

- UCG indicates that cost information is required "for each community by each ratepayer group". However, rates in Yukon are required to be set based on the territory as a single zone, pursuant to OIC 1995/90. Accordingly, there is no relevance nor benefit to rate setting from analyzing cost-of-service on a community-specific basis.

- McMahon suggests that implementation of a rate shift program should include consideration of "customer mitigation measures" such as a levelized or equal billing program, paying deposits in installments and promoting conservation and demand management initiatives. Although all these topics are relevant to utility regulation, none have any relevance to cost-of-service.

- McMahon asserts that "what may be needed is for an independent body (such as the BCUC)" to do a cost-of-service study and design a rate shift program. Such an approach would be entirely inconsistent with normal regulatory principles. It is the utilities that are required to produce cost studies (as required by their regulator) to demonstrate that their rates are just and reasonable. The Board has asked for and now received the Companies' comments. The Companies believe there is no need for, nor would there be any real benefit from, conducting a cost-of-service study or a rate shift program in the near term. Accordingly the Companies submit that the Board should reject McMahon's suggestion. However, if the Board determines that a cost of service study should be undertaken after the determination of revenue requirements and load data for both utilities, the

[1] Also note that the Yukon Government Energy Commission, via Mr. McMahon, intervened in the 1998 hearing and argued that the Board should not adopt certain YEC rate proposals due to the Yukon Government preparing to implement a new program (ultimately the RSF). The Board quoted Mr. McMahon in its Order 1998-5 in deciding not to implement the YEC rate proposals. It is clear that Mr. McMahon and the Board at that time saw it as relevant to the YUB to consider YTG rate relief programs when considering rate issues.

Companies will comply and produce any such reports or recommendations as the Board requires.

Yours truly,

David Morrison
President & CEO
Yukon Energy Corporation

Doug Tenney
General Manager
Yukon Electrical Company Ltd.

REFERENCE: **Application, Page 6-2**

ISSUE/SUB-ISSUE: **Chant Construction**

QUESTION:

a) Based on the claims and counter claims, was YEC required to make further payments? If so where were the payments recorded? Where were legal fees associated with the process recorded?

ANSWER:

(a)

As a result of the negotiated settlement, YEC was required to pay $3 million to Chant Construction. This amount was paid by YDC on YEC's behalf. As well, YEC was required to release $263,813, representing funds held in trust for settlement of an insurance claim that occurred during construction. There was no net impact on YEC's income statement.

Legal expense associated with the defense of these claims is recorded as a regulatory loss on financial statements and, by direction of the YUB, is excluded from calculations of revenue requirement and regulatory results.

REFERENCE: **Application, Page 6-4**

ISSUE/SUB-ISSUE: **Phase II Filing**

OIC 2007/94 in effect defers, until after December 31, 2012, any cost of service based rate rebalancing adjustments or rate shifts affecting major industrial customers. It is noted as well that non-government residential customers are currently experiencing major bill increases due to the phasing out of the Yukon Government's Rate Stabilization Fund subsidies over the period July 2007 through July 2009, and that these changes seriously constrain the extent in the near term to which rate shift program changes could proceed to increase residential revenue to cost ratios.

QUESTION:

a) Without a COS study, how does YEC know, given the significant changes in Yukon since the last COS study, the potential direction of any rate shift changes?

b) In YEC's opinion, does a Phase II proceeding include more that rate design?

c) Without compliance of a COS study, what comfort does YEC have that Rate 35 appropriately covers its costs?

d) Without the direction of the COS study being completed, should the Board allow the continuance of Rate Schedule 35?

ANSWER:

(a)

The 2005 Cost of Service Report filed with the Board by YEC and YECL (provided as Attachment 1 to YUB-YEC-1-23(a)) notes at pages 2-3 as follows:

> The most significant system adjustment since 1997 has been the closure of the Faro mine. In addition, fuel costs (which have approximately doubled since the 1997 GRA numbers) and the completion of the Mayo-Dawson transmission facility are other significant changes.

The joint YEC/YECL report notes at page 3 that, "on balance, no major R/C ratio changes are anticipated to result from the closure of the Faro mine for the two classes that were outside the target 90%-100% R/C range in the most recent cost of service study (1996/97 GRA analysis for 1997)."

At this time, no different conclusion is anticipated. In all likelihood, a full Cost of Service study today would reflect relatively similar RCC ratios (in terms of which classes are below versus above the Zone of Reasonableness) as existed in 1997.

(b)

In YEC's view, Yukon regulatory experience indicates that a General Rate Application, as filed in the 1990s, in full addresses Revenue Requirements, Cost of Service, Rate Design, Electrical Service Regulations, and other issues as appropriate. It is not, however, required to deal with each of these issues at every GRA in the event there is no relevance to the topic or to the requested orders.

The concept of separate Phase I versus Phase II hearings has not been applied in Yukon in YEC's period before the YUB. There is no precedent in Yukon where the utilities have actually had a so called separate "Phase II" hearing. All COS and rate design matters relating to a GRA have been dealt with in one hearing. Given the desire to maintain regulatory costs at a level commensurate with the size of the jurisdiction and the number of ratepayers who must incur the costs, in YEC's view this distinction should be viewed as being of limited value if it means every GRA from here forward will require two or more hearings.

(c) and **(d)**

As noted in response to YUB-YEC-1-19 (b) and (c) secondary sales rates in Yukon are not cost-based but are instead based on value for service. Accordingly, the YUB has not previously sought to assess secondary sales rates such as Rate Schedule 32 based on any cost of service assessment – and the absence of such cost of service information has not prevented the Board to date from allowing the continuance of such rates. Similarly, given this essential difference between interruptible Rate Schedule 35 (with its ranking behind Rate Schedule 32 sales) and other non-interruptible retail rate schedules regulated by the YUB, the absence of a cost of service study would not prevent the Board from approving Rate Schedule 35. In any event, as noted in that response, YEC

and Minto must still develop the specific auditable reporting and control mechanisms required to be reviewed by the Board prior to the final approval of the rate.

REFERENCE: **Application, Page 6-6**

ISSUE/SUB-ISSUE: **Maximum Utility Investment**

QUESTION:

a) Does YEC believe that Electric Service Regulations or Terms and Conditions of Service are a Phase II matter?

ANSWER:

(a)

YEC believes that ESRs and/or Terms and Conditions of Service are part of a full GRA review, although such matters are not always addressed in each GRA. However, the concept of separate Phase I versus Phase II hearings has not been applied in Yukon in YEC's period before the YUB. There is no precedent in Yukon where the utilities have actually had a so called separate "Phase II" hearing. All relevant matters have been dealt with in one hearing. Given the desire to maintain regulatory costs at a level commensurate with the size of the jurisdiction and the number of ratepayers who must incur the costs, YEC believes that it is highly preferred to address all relevant GRA matters in the same hearing.

Please also see response to YUB-YEC-1-25(b).

REFERENCE: **Report to Commissioner in Executive Council: Yukon Energy Corporation 20-Year Resource Plan**

ISSUE/SUB-ISSUE: **Section 6: Assessment of Near-Term Projects**

QUESTION:

a) Subsequent to the 20-Year Resource Plan, has anything caused the status of the Marsh Lake storage project to change?

b) What is the current status and timing of the Aishihik Third Turbine project?

c) What steps has YEC taken with respect to the development of an Independent Power Producers policy?

ANSWER:

(a)

Yes.

Yukon Energy has undertaken studies to confirm the hydrology related to Marsh Lake water levels, and the Yukon Government has completed a Flood Assessment and Abatement Study.

Marsh Lake storage continues to be an attractive resource option, in the event it can be completed without any significant adverse effects on the local residents.

(b)

The Aishihik Third Turbine project is proceeding for an in-service in 2010.

(c)

The development of an Independent Power Producer's policy is being addressed by the Yukon Government as part of the recently released "Energy Strategy for Yukon".

REFERENCE: **YEC Application, page 1-6**

ISSUE/SUB-ISSUE: **Reliability**

Winter peak-generation interruption related to a single major system-risk event (Aishihik transmission interruption) was underlined by the January 29, 2006, Whitehorse-Aishihik-Faro (WAF) grid outage.

PREAMBLE:

The YUB wishes to gain reliability information related to WAF.

QUESTION:

a) Please provide a table showing reliability performance measures on a calendar-year basis with respect to YEC's WAF and MD grids. The table should include such indices as:

- The System Average Interruption Duration Index (SAIDI)
- The System Average Interruption Frequency Index (SAIFI)
- The Customer Average Interruption Duration Index (CAIDI)

Annual averages for the above must be derived from raw data, not by averaging monthly averages.

b) Please identify any formalized evaluation process that YEC has in place in order to identify problem areas on the WAF or MD grids.

c) Please identify protection or reliability studies that have been undertaken over the period 2005 to 2007. If studies were undertaken, please provide details and results, and any work that has been undertaken or may need to be done in order to mitigate shortcomings that may have been identified.

ANSWER:

(a)

Please see table provided below.

YEC Reliability Performance Stats - by Grid

		SAIFI	SAIDI	CAIDI
Mayo Dawson Grid				
	2008	**3.76**	**4.28**	**1.14**
	2007	**9.99**	**5.06**	**0.51**
	2006	**4.99**	**7.39**	**1.48**
	2005	**4.93**	**2.37**	**0.48**
WAF Grid				
	2008	**10.90**	**12.47**	**1.14**
	2007	**6.95**	**9.45**	**1.36**
	2006	**5.34**	**6.45**	**1.21**
	2005	**4.32**	**0.81**	**0.19**

2005 WAF is Faro only
(data not kept on all YEC WAF communities)

(b)

Over the past 5 years YEC has contracted with BC Hydro Engineering for review of generation and substation assets, Acres International for review of Transmission lines, and Northwest Territories Power Corporation and Gygax Engineering Associates Ltd for review of the Whitehorse Diesel plants.

These third party assessments have been used along with staff evaluations to determine issues and problems with YEC assets.

(c)

The following asset assessments were undertaken on the system – these reports were available in 2004 (before the period specified in the IR), and assisted in the preparation of YEC's 20-Year Resource Plan; 2006-2025:

- *Condition assessment of Selected Yukon Energy Corporation Substation Assets* – BC Hydro June 2004.

- *Assessment of Transmission Line for Yukon Energy* Corporation – Acres Intl – Feb.2004 Generation Assets report – BC Hydro – May 2004.

- *Condition Assessment of Selected Yukon Energy Generating Assets* – B.C. Hydro: This assessment was completed in May 2004 and focused on Whitehorse hydro (Units WH1 through WH4), Whitehorse diesel (Units WD1 through WD7) and Aishihik hydro (Units AH1 and AH3). The condition assessment did not review the other diesel plants or the Mayo hydro facility.

- *Condition Assessment of Selected Yukon Energy Corporation Substation Assets* - BC Hydro: This report was completed in June of 2004. The focus of this assessment was on circuit breakers and transformers located at the substations at Aishihik, Takhini, MacIntyre, Whitehorse (all on WAF) plus Mayo.

- *Assessment of Transmission Lines for Yukon Energy Corporation* - Acres International: This report was completed in December 2003 and was commissioned to assess Yukon Energy's transmission assets. The condition assessment by Acres International of Yukon Energy's transmission lines was of a significantly different type than the Generation and Substation assessments. In the Acres assessment, the primary item to be addressed was the expected remaining life of the transmission assets, based on a sampling of the WAF transmission line.

Overall, BC Hydro and Acres International found Yukon Energy's assets to be in good to relatively good condition with a few exceptions. As a result of the Condition Assessment Reports, Yukon Energy developed short to medium term capital investment plans to address the bulk of the items identified by BC Hydro and Acres International. This Yukon Energy plan was submitted to the Yukon Utilities Board as part of the 2005 Required Revenues and Related Matters Application and was approved by the Board on October 18, 2005 (YUB Order 2005-12). Yukon Energy continues to carry out the work recommended by the Condition Assessment Reports.

The following chart provides an overview of the specific recommendations made by BC Hydro and Acres International and Yukon Energy's progress in responding to each recommendation.

Generation Assets Recommendations	**Yukon Energy Progress**
WH4 needs more maintenance and capital spending to deal with Equipment concerns.	Governor work is about 50% complete, will be completed in 2009. WH4 is a priority for 2009 capital spending.
Aishihik fire suppression system and egress system from the generator room.	Being addressed as part of 2009 work plan.
Rewind AH2	Complete.
WD1, 2 &3 at end of life. Evaluate and determine action[1].	WD3 rebuild currently in progress. WD 1&2 planned in future years.
WD 3,4,5,6 &7 should be run regularly to ensure availability.	Practice is in place.
Oil contamination of cooling water, sump oil and asbestos issues need to be addressed.	Asbestos identification is complete. Hydrocarbon separation and disposal system currently being designed for 2009 completion.
Governor testing, starting and synchronizing problems need to be dealt with.	Testing for all Whitehorse units (both diesel and hydro) is currently being done to determine plans. Aishihik will also be done. To be complete in 2009.

Substation Asset Recommendations	**Yukon Energy Progress**
Mayo transformers T1 and T2 need upgrading.	Complete.
Mayo transformer T1 to be replaced in 5 years.	Transformer has been upgraded and will be reassessed in 2009.
Inspect air core reactors.	To be completed in 2009.
34.5 kV HLC and SFE feeder circuit breakers need to be replaced within 20 years.	One complete. Addressing the others.

[1]Yukon Energy is aware that the Mirrlees units are approaching retirement, and earlier resource planning exercises (1992 and 1996) were based on these three units being retired prior to 2006. The units have been retained in-service due to the current system load, which has not required material running time. The units will also be retained in-service into the future at least until the current hydro surplus on the WAF system is consumed by firm load and additional generation resources are developed. On this basis, major refurbishment of the Mirrlees units was required to stave off the risk of a major failure or the inability of these units to supply reliable utility standard service when required.

Disconnect switches in various locations need replacement.	Some complete, continue to replace the remainder.
Surge arrestor protection needs some improvement in several substations.	To be completed in 2009-2010
Transmission Asset Recommendations	**Yukon Energy Progress**
Approx. 0.5% of all transmission line poles were in imminent risk of failure Approx. 5% needed increased maintenance to ensure that their condition didn't deteriorate significantly.	The remaining 94% of all transmission line poles were expected to be able to be maintained "as is" for the next 20 year period. Assessments are ongoing. YEC has spent between $300,000 and $500,000 per year on replacements and upgrades to maintain the condition of the poles.

Line assessments are also undertaken for each of the main transmission lines on the Whitehorse-Aishihik-Faro and the Mayo-Dawson grids. Each main line is assessed at least once every five years to determine the condition of poles, insulators, cross-arms and dead end structures. Reports are then used to prioritize repairs and make budget requests for the next fiscal year. The Mayo-Dawson line was assessed in 2007 and maintenance from that assessment is on-going. The Aishihik section of the WAF line was assessed in the spring of 2008 and as a result several dead end insulators were replaced. The Whitehorse to Faro segment of the WAF grid was assessed in October 2008. A report is currently being drafted and any recommended repairs will be prioritized based on that assessment.

REFERENCE: YEC Application, Page 1-7

ISSUE/SUB-ISSUE: WAF Hydro

In 2005, surplus hydro generation on WAF prior to secondary (interruptible) sales approximated 90 GWh/yr at normal flows; absent new industrial loads, some surplus hydro was forecast to remain at normal flows on both the WAF and Mayo-Dawson ("MD") grids until at least around 2020.

PREAMBLE:

The Board needs to get an understanding of surplus hydro generation.

QUESTION:

a) Please provide load duration curves for the Whitehorse hydro plant for the period 2005 to 2007.

b) Please provide load duration curves for the Aishihik hydro plant for the period 2005 to 2007.

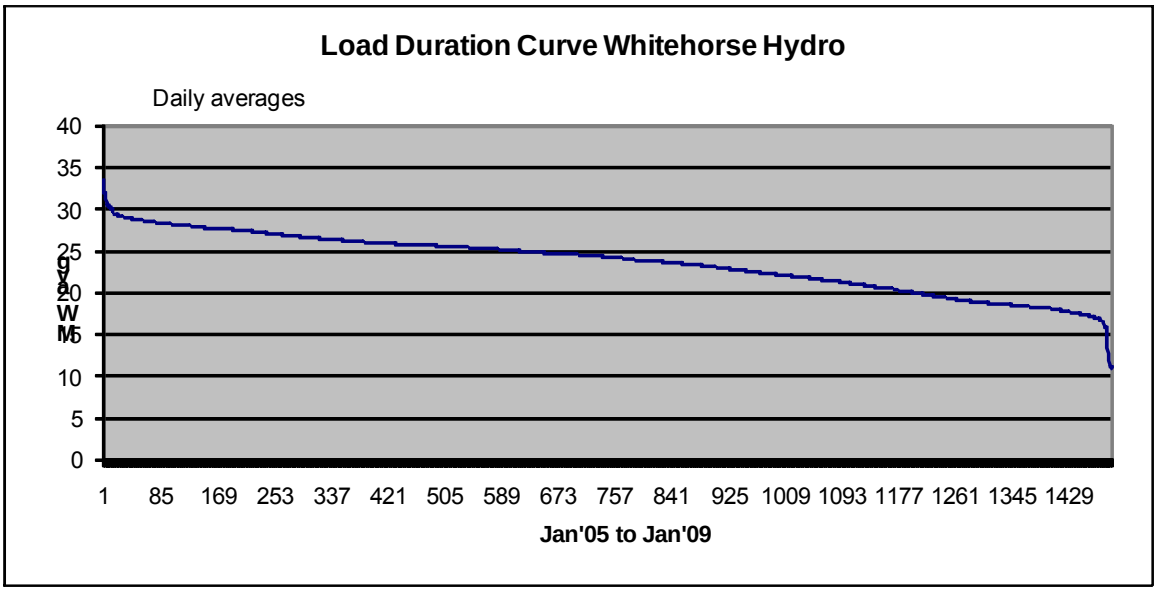
c) Please provide total hydro load duration curves on the WAF grid for the period 2005 to 2007.

d) Please provide total diesel load duration curves on the WAF grid for the period 2005 to 2007

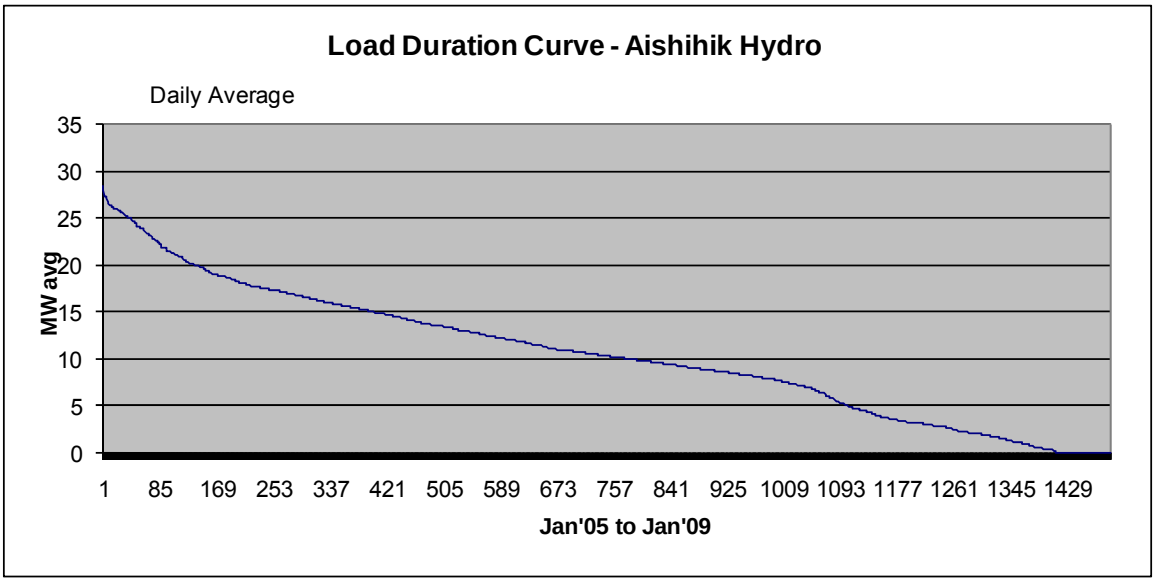
ANSWER:

(a), **(b)**, **(c)** and **(d)**

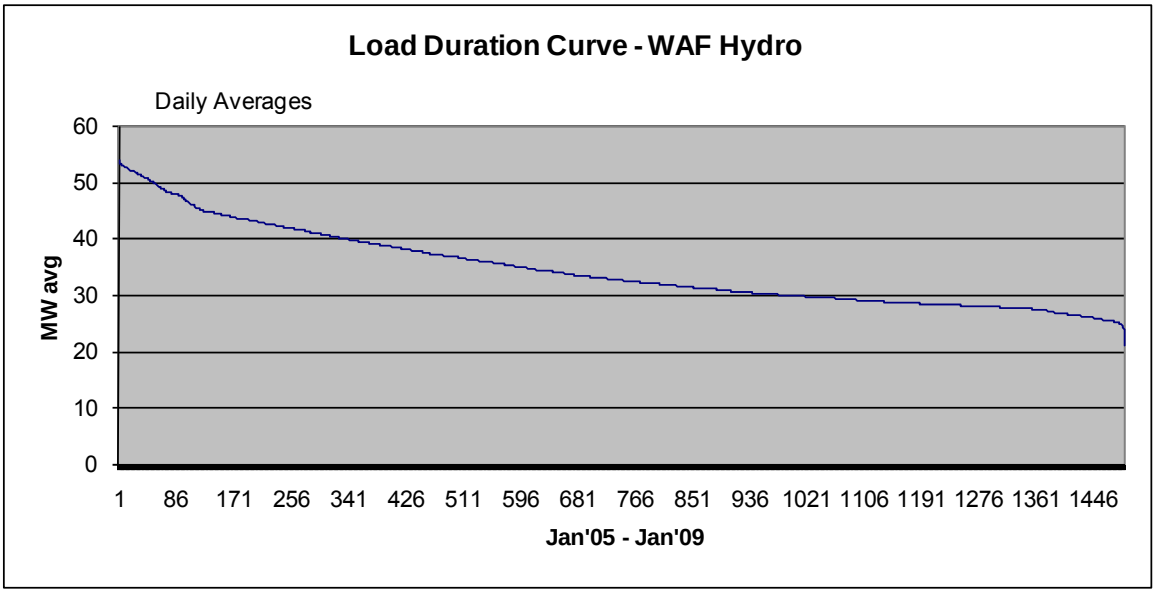
The load duration curve showing daily average generation from Whitehorse, Aishihik, diesel and total WAF load are provided below for the actual period January 2005 to January 2009.


Load Duration Curve Whitehorse Hydro
Daily averages
40
35
30
25
20
15
10
5
0
1 85 169 253 337 421 505 589 673 757 841 925 1009 1093 1177 1261 1345 1429
Jan'05 to Jan'09

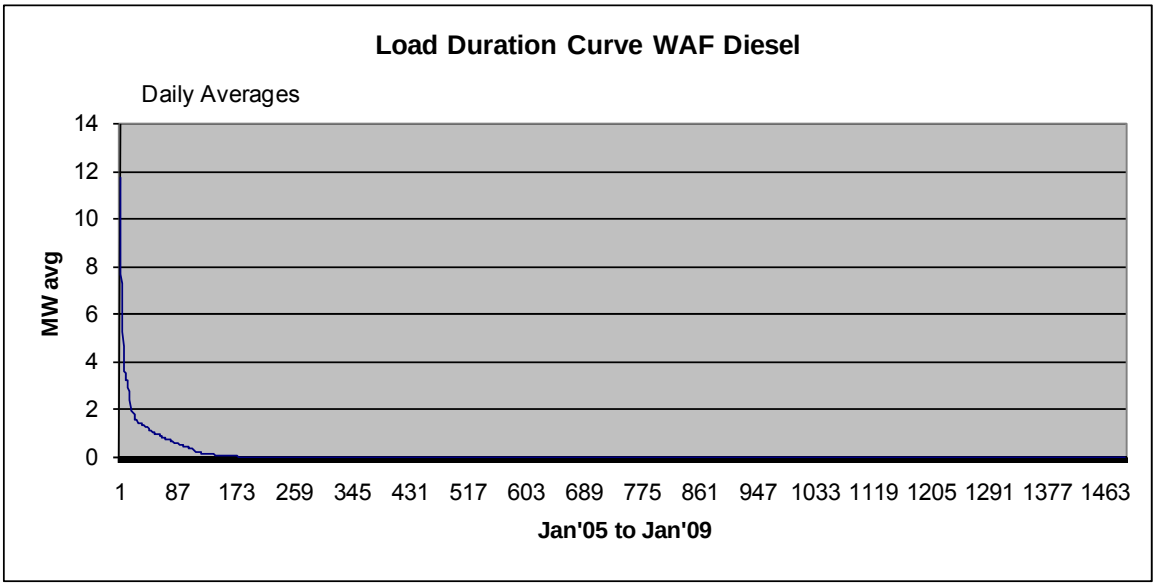
1
2


Load Duration Curve - Aishihik Hydro
Daily Average
MW avg
35
30
25
20
15
10
5
0
1 85 169 253 337 421 505 589 673 757 841 925 1009 1093 1177 1261 1345 1429
Jan'05 to Jan'09

3


Load Duration Curve - WAF Hydro
Daily Averages
MW avg
60
50
40
30
20
10
0
1 86 171 256 341 426 511 596 681 766 851 936 1021 1106 1191 1276 1361 1446
Jan'05 - Jan'09

1
2


Load Duration Curve WAF Diesel
Daily Averages
MW avg
14
12
10
8
6
4
2
0
1 87 173 259 345 431 517 603 689 775 861 947 1033 1119 1205 1291 1377 1463
Jan'05 to Jan'09

3

REFERENCE: **YEC GRA Application, Page 1-8**

ISSUE/SUB-ISSUE: **Higher Oil Prices**

Forecast oil prices for 2009 are materially above levels approved for the 2005 Yukon Energy revenue requirement. Higher oil prices increase test year overall Yukon power system costs to the extent that diesel generation is required in 2009, and highlight the potential importance of timely new renewable resource generation development to minimize any renewed requirements for baseload diesel generation on the WAF and MD grids.

PREAMBLE:

The Board wishes to understand the implications of the above statement.

QUESTION:

a) Considering that fuel prices have dropped significantly, does YEC wish to update its fuel-price forecast for the test period?

ANSWER:

(a)

YEC is not seeking to update its fuel price forecast at this time.

According to past practice, the proposed Application was filed using the best information available at the time. Fuel prices have been volatile since 2008 and are likely to remain uncertain for the future. Within the GRA process, the forecast is typically retained as filed with any subsequent adjustments made, as required, through the Rider F process.

REFERENCE: **YEC GRA Application, Page 2-2**

ISSUE/SUB-ISSUE: **YEC System Sales and Generation Overview**

Yukon Energy hydro generation capability materially exceeded firm sales on both the WAF and Mayo systems after the Faro mine closure in 1998 on WAF and the 1989 closure of the United Keno Hill Mine (UKHM) on the MD system. However, given continued load growth on the WAF system, including new industrial load once grid service to Minto commences in October 2008, WAF surplus generation will have declined markedly by 2009 …

QUESTION:

a) Please provide annual hydro-capacity utilization percentages for the period 1998 to 2008.

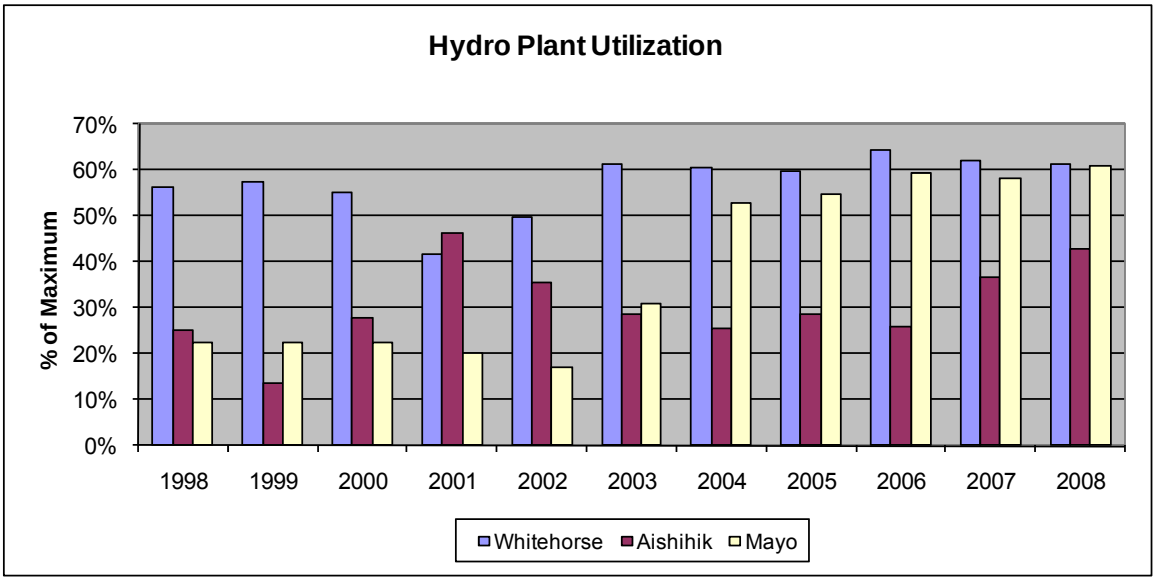
b) With respect to water availability, have drought conditions occurred over the period 1998 to 2008?

c) Considering that "… the forecast for the test years is based on continued ability to supply nearly the entire test generation forecast on both the WAF and MD grids from hydraulic generation (other than for "peaking" requirements):
   i. Describe in detail YEC's hydro plant maintenance programs.
   ii. During the forecast period, is any one hydro unit on the WAF or MD grids expected to be down for an extended or planned maintenance outage period?
   iii. Provide a detailed description of YEC's contingency plan should an extended and unplanned outage occur affecting one of its hydro units.
   iv. Please provide an explanation as to what is meant by the phrase "long-term average capability" of the installed hydraulic generation.

ANSWER:

(a)

Please see chart provided below.



Hydro Utilization is the ratio of the actual annual generation produced for a hydro unit divided by the generation that the unit could have produced if it were run at its rated capacity for the entire year, allowing, in YEC's case, for an average 3 % forced outage rate.

(b)

The lowest inflow year on record for the Aishihik system occurred in 1998, and the calendar year of 1998 would be termed a "drought" for the Aishihik drainage basin. The November 1, 1998 level on Aishihik was lower than the May 1 spring level by 6mm.

(c)

i. Each generator is taken down for a period of time each year. Maintenance issues are accumulated over the year of operation and a scope and schedule of work is developed for each unit. The duration of these outages varies dependent on the work to be done. Major outages occur every 8-10 years, or if other projects are planned that require extended outages. These projects would include runner replacements or bearing changes.

ii. The Aishihik plant will be down for an extended outage in 2009 for work that is part of the Aishihik 3rd Turbine project. It is expected the outage will be in

June or July. A detailed work plan has not been developed for this yet so no dates or duration have been established.

iii. YEC uses an N-1 criteria for backup generation availability, i.e., adequate generation from other sources must be available in the case of the largest impact failure on the system. In the case of the WAF grid it is loss of the Aishihik Generating Station or loss of L172 (30 MW in either case). YEC keeps sufficient diesel generation available to replace this level of loss of hydro generation. For the Mayo-Dawson grid, loss of the Mayo hydro plant is the largest possible and similar to the WAF grid, sufficient diesel is available to replace it.

iv. The phrase is meant to reflect that hydro generation capability depends on water flows (precipitation). A long-term average is used to take into account the variability in hydro generation capability due to variation in water availability.

REFERENCE: **YEC Application**

ISSUE/SUB-ISSUE: **Sales Forecast**

QUESTION:

a) Please provide tables 2.2 to 2.4 in an Excel spreadsheet complete with formulae intact.

b) With respect to YEC's firm retail sales forecast, please provide details, i.e. numbers of customers and usage per customer that forms the basis of YEC's proposed growth in general service sales.

c) Please provide the detail upon which YEC based its forecast respecting the modest growth in the number of residential customers and the consistent use per customer over the period.

d) Please provide metered load for the years 2005 to 2008.

e) Please provide corresponding generation for the same period.

f) Please provide losses on a system-by-system basis, i.e. WAF and MD.

g) Please provide capital and O&M initiatives undertaken by YEC to mitigate losses on the system. If those are not available or YEC has no DSM initiatives, please provide a detailed explanation.

h) Please provide actual sales for YEC's residential and general service customers for the period 1998 to 2008.

ANSWER:

(a)

Please see Attachment 1 to this response.

(b) and **(c)**

Please see LE-YEC-1-7.

(d) and **(e)**

Please see the attachment to part (a) above and Tab 2, Table 2.5.

(f)

Please see YECL-YEC-1-24(a).

(g)

System losses (as shown in Table 2.5 of Tab 2 of the Application) are the sum of generation, transmission and distribution losses. These losses are considered during the planning, design and operating phases of the Corporation's generation, transmission and distribution assets.

During the planning and design stages of major projects, electrical and mechanical losses are key factors in selection of equipment, voltage and conductor sizing.

New generation projects are assessed using a computer-based model that includes assessment of line and hydraulic losses by calculating grid net energy benefits.

During the planning and design stages selection of voltage, conductor size and transformer efficiencies to reduce losses is undertaken on transmission projects. Voltage selection, conductor sizing and transformer selection is undertaken on new distribution projects. Voltage conversions and load re-distribution is undertaken on existing distribution to reduce losses.

(h)

Actual sales for YEC’s residential and general service customers for the period 1998 to 2004 are as provided below. Actuals for 2005 to 2007 are provided in Tables 2.2 to 2.4 from Tab 2 of the Application provided in CW-YEC-1-4(a) Attachment 1. Actuals for 2008 are discussed in response to CW-YEC-1-4(d).

Sales to YEC residential and general service customers (MW.h) 1998 to 2004

	1998	1999	2000	2001	2002	2003	2004
Residential	11,403	10,314	9,889	9,543	9,716	9,968	10,199
General Service	12,981	12,427	12,503	12,513	12,692	13,345	14,016

REFERENCE: **YEC Application**

ISSUE/SUB-ISSUE: **Power Generation**

QUESTION:

a) Please provide annual numbers by unit that form the basis of YEC's long-term average hydro generation capability (WAF grid), as estimated in the 1996-97 GRA and updated to include the period 1998 to 2008.

b) Please describe what YEC terms as "extreme drought conditions". What are the probabilities of such an event occurring?

c) Considering that a) sustained base-loaded diesel generation units have average fuel efficiencies greater than diesel generation units that are used as peak shavers, and the current level of fuel prices, would YEC consider base-loading diesel generation as was done in the mid-1990s? Please explain.

ANSWER:

(a)

The actual annual energy production from each WAF Hydro Plant since 1998 is provided in the table below:

WAF Hydro Production 1998-2008

Year	Whitehorse Hydro Generation (GWh's)	Aishihik Hydro Generation (GWh's)	WAF Hydro Generation (GWh's)
1998	190.4	63.4	253.8
1999	194.7	38.4	233.1
2000	186.7	56.3	243.0
2001	141.1	107.4	248.6
2002	169.2	86.1	255.3
2003	208.3	61.4	269.7
2004	205.9	71.0	276.9
2005	202.0	80.7	282.6
2006	216.9	80.4	297.3
2007	206.4	98.1	304.5
2008	207.5	107.3	314.8
11-Year Average	193.6	77.3	270.9

The hydro facilities have generated during these years less than their long term average capability by an average of 80.2 GW.h per year over this 11-year span reflects the fact that this supply hydro exceeded actual firm and secondary energy sales and losses over this period.

Yukon Energy's annual numbers by unit or plant indicate generation that occurred based on load, water flows and unit availability. On WAF, Whitehorse unit peak capability occurs during summer and fall (peak water flows and spills) with greatly reduced capability during winter and early spring; in contrast, Aishihik unit peak capability is planned to occur during winter months and minimal generation normally planned during summer months. On Mayo-Dawson, the Mayo unit capability tends to reflect year round water flow availability.

Actual hydro unit generation in any year on WAF or Mayo-Dawson can be [and has been during many of the years since 1998] severely reduced due to reduced loads, i.e., due to factors unrelated to long-term average hydro generation at a higher system load level.

Yukon Energy's long-term average hydro estimate at the time of the 1996/97 GRA, given the load levels then being experienced, was 351 GW.h comprised of 105 GW.h for Aishihik and 246 GW.h for Whitehorse Rapids. The 1996/97 GRA long term average hydro energy capabilities were defined as follows on page 2-10 of that application:[1]

- Whitehorse Hydro Facility at 246.3 GWh per year and

- Aishihik Hydro Facility at 104.8 GWh per year

This resulted with a YEC WAF Hydro average generation capability of 351.1 GWh excluding the energy output from YECL's Fish Lake Hydro Facility. The average hydro generation capability was not broken down to individual units as there is flexibility in which units are run to meet specific load requirements and planned outages.

The only update to the 351 GWH value determined during the 1996/97 GRA was during the assessment of the Aishihik Water Licence renewal process, in which it was estimated (using hydrology models) that the terms of the new Aishihik Water Licence

[1] The period of record for the 1996/97 long term average hydro capability numbers used was 1976 to 1995.

would reduce the long-term average capability of this system by 3-6 GW.h depending on the terms of the Fish Act Authorization in effect at any given point in time.

These values are presently being updated as part of ongoing Resource Planning exercises, with the assistance of new system models. The long-term average capability is highly dependent on the loads on the system, and as such will vary under different future load conditions.

Hydro generation forecasts for the Application reflect that forecast loads are still below long-term average capability.

(b)

Yukon Energy noted the concept of “extreme drought conditions” in relation to secondary sales being curtailed during the test years. In this regard, LE-YEC-1-14 notes that even with 50% of average inflows at Aishihik sustained over a 1.5 year period, Yukon Energy would be able to continue secondary sales through the test year period.

The most extreme drought recorded at Aishihik was for 1998, when inflows were 36% of long-term average inflows for a 12 month period.

(c)

No, unless WAF load conditions were similar to those applicable in the mid-1990s, i.e., when diesel generation was on the margin throughout the year. Sustained baseload diesel generation was an efficient solution during the load conditions that prevailed in the mid-1990s.

The primary focus of system planning efforts and operational improvements at the present time is to minimize diesel use and undertake plans to avoid or minimize the need for diesel baseload generation. Units can only be run efficiently as “baseload” when they are relatively heavily loaded for sustained periods of time, which under current conditions results in more diesel generation than operations based on minimizing diesel generation.

REFERENCE: **YEC Application**

ISSUE/SUB-ISSUE: **Peak Demand Forecast**

QUESTION:

a) Please detail and explain the long-term planning assumptions YEC used to develop its peak-demand forecast.

b) Please define what YEC perceives as being long-term.

c) Please provide winter load duration curves for the WAF hydro generating plant for the period 1998 to 2008.

d) With respect to adding generation capacity on the WAF system, please provide details underpinning YEC's determination that the N-1 criteria remains the key requirement when compared to the outcomes of the LOLE criteria.

e) Please provide the business case that led YEC to determine that 6.4 MW of diesel capacity can be added to the system in the best economical manner through purchase of diesel units at the Minto mine site.

f) Subsequent to the re-commissioning of the FD1 unit at Faro and purchase of the Minto diesel units, YEC determined that the most economical option of adding generation capacity to the WAF grid is through an orderly refurbishment of the Whitehorse Mirrlees units. Please provide the business case.

g) Respecting capacity additions on the WAF system, when would the LOLE criteria supplant the N-1 criteria?

h) With respect to Yukon River icing, please provide the study and accompanying results that led YEC to determine that the 24 MW winter peak output for the Whitehorse hydro plant remains valid for planning the system.

ANSWER:

(a)

Yukon Energy's long-term planning models focus on determining the energy requirements of the respective systems. Peak demand is determined based on the energy forecasts as the sum of (a) non-industrial peak demand, which is determined using an assumption of consistent on-peak load factor for these loads over time, and a 100% coincidence factor, plus (b) industrial peak demand, which is estimated for each industrial load as best as can be determined, also assuming a high coincidence factor.

(b)

As noted in the Resource Plan, Yukon Energy's long-term forecasts focus on determining potential supply requirements over 20 years, but extend forecasts to 40 years to ensure decisions that may be required late into the 20 year planning horizon incorporate consideration of how the projects would be used on the system for a reasonable period of time after they come into service.

(c)

Please see YECL-YEC-1-23(b) and YECL-YEC-1-50. In particular, note that Excel data in YECL-YEC-1-23(b) includes all readily available hourly load data since 1998, at the level of YEC generation (i.e., not including Fish Lake).

(d)

During the YEC Resource Plan hearing, Yukon Energy noted that the N-1 criteria was at that time the determining factor on WAF, and would remain the determining factor unless and until one of two things occurred:

a) The Aishihik transmission line was twinned, or a similar resolution to the non-redundancy of this line; or,
b) Addition of 6-7 MW of industrial load to the LOLE calculation (the N-1 calculation specifically excludes industrial load).

Neither of these two events has occurred.

(e)

The business case of the Minto Diesels is provided in the Application at Tab 5, pages 5-7 to 5-11. The business case was also addressed as a component of the Minto PPA hearing in 2007.

In sum, in order for YEC to meet its N-1 planning criteria, additional diesel generation was required (i.e., as noted a total of 30 MW of generation is needed in the case of loss of the Aishihik Generating Station or L172 from Whitehorse to Aishihik). The cost of the 4 units (1.6 MW each) is $2.24 million with an additional $0.95 million in upgrades required. This brings the price to $3.19 million or $0.498 million/MW.

The purchase of new diesels units is estimated at $1.05 million/MW, while the Whitehorse Mirrlees life extension is forecast to cost $0.482 million/MW.

Given the recognized need for Yukon Energy to ensure cost-effective capacity resources are made available (either through new additions, or life extension of generators otherwise scheduled for retirement), this source of capacity is competitive with the other lowest cost option also being pursued over the next few years, the Whitehorse Mirrlees life extension.

(f)

The Whitehorse Mirrlees life extension project was reviewed in the 20-Year Resource Plan (pages 4-28 to 4-33), the Supplemental Materials to the Resource Plan (filed May 2006 at pages 4-9), the Resource Plan Update filed November 2006 (pages 3-5) and is reviewed at pages 5-9 to 5-11 of 2008/2009 General Rate Application.

The Whitehorse Mirrlees project is a cost effective means to secure needed capacity for WAF. This was the basis for extensive review of the project at the 20 Year Resource Plan proceeding, and the basis for the Board's recommendation that "Based on the foregoing, the Board recommends that YEC proceed with the Mirrlees units WD1, WD2, and WD3, as planned." The business case today remains as provided in the Resource Plan proceeding; that is, the Mirrlees life extension project remains the most cost effective way to secure up to 14 MW of capacity in a flexible and staged manner, well below the cost of purchasing and installing new diesel generation.

Specifically, over the course of a number of years, likely to 2012 (perhaps later for WD1), the project will provide 14 MW of capacity (compared to retirement of these units) at a cost of $0.482 million/MW. The purchase of new diesels units is estimated at $1.05 million/MW.

(g)

Please see YUB-YEC-1-34(d).

(h)

The study noted was never finalized, and in any event was oriented at determining the potential for higher flows to be accommodated on the Yukon River. With respect to the firm capacity of the plant at its current configuration and downstream conditions, the attached memo reviews the conclusions arising as they relate to firm capacity planning, including a review of the matter with Dr. Billinton, which confirms the continued use of 24 MW as the appropriate firm winter capacity for the Whitehorse plant.

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Memorandum

DATE:	March 13, 2008	**PROJECT:**	P642.1
TO:	Hector Campbell, Rick Carson KGS		
FROM:	Patrick Bowman		
SUBJECT:	**WHITEHORSE HYDRO ICING STUDY – IMPLICATIONS FOR YEC**		

Summary of Implications

You have asked for a review of the draft KGS ice study dated April 2007, which identifies important considerations for the WAF system. The implications of the study's conclusions for YEC depend heavily on the operating philosophy YEC adopts to address the issues noted in the ice study. At a simple level, two major philosophies are noted:

- A **steady state philosophy**, based on maintaining the WH plant at no more than 21 MW during the early part of winter in order to ensure no cutbacks in output will be required due to adverse icing events. Were YEC to adopt this approach, it appears the requirement for firm capacity on the system would increase under both the N-1 and LOLE criteria, in the range of approximately 3 MW or slightly above, compared to Resource Plan assumptions. In addition, this approach would lead to greater requirements for peaking diesel each year during the 21 MW constraint period, which is roughly estimated as a $0.7 million impact over the 8 year period 2009-2016 (assuming Minto is in-service).
- An **adaptive philosophy**, which maintains output at the 24-25 MW level (within the range of current practice) in early winter, with full knowledge that in some years this may need to be cut back as far at 15 MW to avoid flooding. This philosophy will require some degree of monitoring to know when flooding events are developing. Under this approach, the requirements for added capacity on the system compared to Resource Plan assumptions are either very small (0.3 MW) or zero depending on whether N-1 or LOLE is the driving criteria at any given point in time. Also, the requirement for added peaking diesel compared to Resource Plan approaches is more limited than under the steady state philosophy, roughly calculated at less then $0.3 million over the 8 year period 2009-2016 (assuming Minto is in-service)[1].

[1] Note also that this is peaking diesel that will be required during actual ice events such as occurred in 2000/01. As such even though the Resource Plan did not consider this requirement, neither the ice study nor the choice of operating philosophy *create* this requirement, they simply serve to inform the calculation of a peaking diesel requirement that has existed all along whether it was modelled or not.

The adaptive philosophy also offers the advantage that it appears to drive very little to no changes to the YEC basic operational planning, with the exception of a requirement for ice event monitoring.

A further conclusion of the draft ice study that is relevant for planning purposes is the determination that the effective maximum output of Whitehorse Rapids that could be achieved on a planning basis, by way of enhanced upstream storage, is 30 MW. Were YEC to aggressively pursue upstream storage that would otherwise provide for more than 30 MW of firm flows, it would still not be prudent to dispatch such flows during early winter as, during a bad ice event, YEC would not be able to prevent flooding and still maintain its licenced minimum flows of 85 cms. As a result, such flows would not be firm for capacity planning purposes.

KGS Ice Study

Pursuant to issues raised in the Resource Planning process in 2006, YEC engaged KGS Group engineers to investigate the icing conditions on the Yukon River downstream of the Whitehorse plant, to determine the constraints if any posed by ice on the use of the plant at higher output levels than presently targeted.

The draft KGS study, dated April 2007 (and subsequent presentation dated June 2007), indicates a number of key findings with respect to ice. These conclusions drive implications for the Whitehorse system that require further consideration to understand the full impact on YEC's (a) plant operating philosophy, (b) diesel generation requirements (i.e., fuel) for peaking, and (c) capacity planning criteria. This memo focuses on the implications for capacity planning criteria.

The relevant points raised in the KGS work for the purposes of this review are as follows:

- The ice conditions on the Yukon River are variable from year to year and, not unlike other comparable northern rivers, it is difficult if not impossible to predict with any certainty which years will be 'bad ice' years in advance.
- The last bad ice year was 2000/01, which occurred since the last studies of icing on the river in about 1994. This means that substantially new data has contributed to the present models compared to past reviews.
- YEC can confirm the high water experience in 2000/01, and excellent data is available regarding the water levels and flows at Marwell (locations upstream and downstream of Marwell are not of the same level of completeness[2]). Although the 2000/01 year was the worst year recorded (out of a sample set of about 14 years of good data on ice and water levels), it is not anomalously bad compared to what would be expected on a river of this type (calculated ice roughness values consistent with 2000/01 are approximately equal to the normal top end of the range for roughness values on comparable rivers).
- The implications of bad ice are worst at the time the system is peaking – that is, very cold days in the early part or the middle of winter:
    - During a bad ice event in the worst ice conditions on record, the system output can be cut back by YEC to avoid flooding. However, the amount of cut back required depends on the level of output in advance of the icing event. For example, if the plant output was

[2] KGS has recommended further consideration be given to data monitoring to ensure, among other things, that future data collection focuses on more locations on the river.

25 MW before the icing event, it would need to be cut back to approximately 15 MW to avoid flooding. If the plant were operating at 30 MW in advance of the icing event, the level of cutback would have to be to approximately 10 MW (or approximately equal to the licenced minimum flows). The steady state operating level where no cutbacks would be required is approximately 21 MW. The duration of the cut back would not be for the entire winter, however the precise duration can not be predicted. It is expected that the duration would be for at least a period measured in weeks, and that the ultimate level achievable for that winter would never be as high as in a winter without bad ice (i.e., the effects to some extent linger the entire winter).

- The second worst year on record does not have comparable detailed data, but based on inference from the data available, it would suggest no cut back is necessary at 25 MW output before the event, and cut back to 18 MW based on 30 MW before the event. This is summarized in the following table:

	Level of cutback required during event comparable to worst icing event on record (2000/01)	Level of cutback required during event comparable to second worst icing event on record (1978/79)
Level of output prior to icing event:		
21 MW	None	None
25 MW	15 MW	None
30 MW	Approx 10 MW (approx equal to licenced minimum flows)	Estimated at 18 MW

- The 2000/01 experience is sufficiently likely that future instances of bad ice similar to this year must be incorporated into system planning. However, the plant allows for a flow reduction response to ameliorate flooding, such that the key issue is not physical risks to property and persons, but to the economics related to the plant operating philosophy and firm plant rating.
  - ***Operating philosophy:*** The study effectively indicates that there are two operating philosophies for the plant that could be used. The first is to ensure that, during the key parts of the winter, the plant is operated such that no cutbacks would be required in firm plant output in the event a bad ice year arose. This is equivalent to an operating philosophy of maintaining an output that is no higher than about 21 MW during the first half or so of winter (i.e., a 'steady state' philosophy). The alternate operating philosophy is to maintain output at the levels otherwise indicated by system demand, and be prepared to cut back, potentially dramatically, if an icing event arises (i.e., an 'adaptive' philosophy). Clearly, the first philosophy provides less peaking capability from the Whitehorse plant than the second, which will consequently require more diesel generation (fuel consumption) to meet peak loads during these times [and consequently more frequent interruption of secondary sales].
  - ***Firm Plant Rating:*** Depending on the operating philosophy selected as noted above, concerns arise that the Whitehorse plant may not be as capable as it has previously been assumed (at 24 MW). This is because there are conditions where the plant could be cut

back below 24 MW in an icing event. One initial reaction is that perhaps the plant is only capable of 21 MW at best, which may serve to diminish the measured capability of the system by 3 MW. However, further concerns were noted in the event that the adaptive system operating philosophy were selected from the note above, in which case the plant may in fact risk being cut back to well below 24 MW (perhaps 15 MW) which might be a major adverse impact on measured system capability (loss of 9 MW of firm capacity).

Capacity Implications

In order to understand the appropriate way to address the ice study implications on capacity planning, Dr. Billinton was consulted. Briefly, the discussion noted the following key points:

- **N-1:** Although an icing event is one factor that could affect the availability of capacity on the system, it is not as large as the impact of losing the Aishihik transmission line (30 MW+), and as a result would not change the approach to determining system capability as measured under the N-1 criteria. [Note that the N-1 criteria is the driving factor for new capacity additions today]. So long as the Whitehorse plant retains its 24 MW rating in the N-1 formula (i.e., its capability during non-adverse events is at least 24 MW) the N-1 calculation would not change due to the KGS report. In considering the above two operating philosophies, the following points are noted:
    - **Adaptive:** Under the adaptive philosophy (operate in the range of 24-25 MW for early part of winter, drop to 15 MW as needed for adverse ice conditions) the system would have a new N-1 type of event related to ice (10 MW, related to dropping from 25 MW to 15 MW), but since it is less than the 30 MW due to the Aishihik line, it does not change the N-1 conclusions in regards to the system.
    - **Steady State:** Under the steady state philosophy, the WH Rapids plant would be operated at 21 MW under a standard rule for at a minimum the early part of winter. As a result, the N-1 event driving the system would remain the Aishihik transmission line (loss of 30 MW) but the remaining generation during this even would be 3 MW lower than assumed to date (as WH Rapids only operates at 21 MW, not 24 MW as previously reflected in the N-1 mathematics). In other words, under the N-1 calculations, this would drive a requirement for 3 MW added capacity from other sources compared to calculations used in the Resource Plan filing.
- **LOLE:** The icing events should be considered in the context of an LOLE analysis. However, a number of scenarios should be run using the WAFSREL software to determine the materiality of the impact. This should be done for two scenarios in order to aid in YEC assessing the response to the icing study – once for the steady state operating philosophy (maintaining the WH plant rating at 21 MW) and once for the adaptive operating philosophy (weighting the cases by the calculated probability associated with each case). For example, the worst icing case today is assumed to be a 1 in 14 event, or about 7%; however for output levels above 25 MW to about 30 MW output, the second worst icing event would also cause issue (for a 14% chance of being cut back to some degree). Scenarios with output levels above 30 MW would not be considered as at this output level YEC begins to run risk that maintaining licenced minimum flows while still avoiding flooding may be incompatible (10 MW is approximately equal to licenced minimum flows). The LOLE and LOEE measured under each operating philosophy and scenario should be

compared to determine the appropriate modelling approach, and to determine the net impact of the icing study on the measured Whitehorse capability. This analysis may also aid in assessing the merits of the two alternative operating philosophies.

For the purposes of modelling, Dr. Billinton indicated that compromised winter output levels are likely best modelled in the WAFSREL without the complexity of reflecting partial winter effects (e.g., assuming compromised output in low flow years occurs for the winter in question, rather than partial season effects).

The LOLE/LOEE analysis has now been completed, and the results are summarized as follows:

- All LOLE/LOEE analysis has been performed on the system as it existed at the time of the Resource Plan (i.e., it does not yet reflect the refurbishment of the Faro Mirrlees) but does include the Aishihik 3rd turbine. This assumption appears reasonable, as the analysis at this stage only focuses on the change in peak load carrying capacity using the three different conditions (RP assumptions, new icing constraints under a steady state operating philosophy, and new icing constraints under an adaptive philosophy), not on the absolute carrying capacity.
- The cases run using the modelling software (WAFSREL) are summarized as follows:
    - The ***Resource Plan case*** reflected a 2.0 hours/year LOLE and a 6.5 MWh/year LOEE at a 63.4 MW peak. Given 2.0 hours/year was adopted as the LOLE planning criteria, this was the maximum system peak that could be carried by the system under this criteria.
    - ***If the icing study is adopted using a steady state philosophy*** (assuming 21 MW operating maximum in the early part of winter) the same target LOLE of 2.0 hours/year (and same level of LOEE of 6.5 MWh/year) would occur at a peak load of 59.9 MW to 60.1 MW, or a net negative impact on load carrying capability of 3.4 MW.
    - ***If the icing study is adopted by way of an adaptive philosophy at a maximum 25 MW in early winter*** the system target LOLE would occur at a peak load 63.1 MW, or a reduction in system capability of 0.3 MW. The LOEE equivalent of 6.5 MWh/year would be achieved at a peak load of 62.3 MW, a reduction of 1.1 MW[3]
    - ***If the icing study is adopted by way of an adaptive philosophy at a hypothetic maximum 30 MW in early winter*** the data is not yet fully assessed. This is largely hypothetical as the system is not otherwise today assumed to be capable of this scale of output in winter – it will only be a relevant consideration in the event major new upstream storage is considered for

[3] Note however that this in particular may overstate the full LOEE impact as it is based on the assumption that 7% of the years the system will be limited to 15 MW for the entire winter, which is not correct – as noted above, the peak would be allowed to trend up starting a few weeks after the icing event.

development[4]. The full analysis of this approach would assume 30 MW for 86% of winters, 18 MW for 7% of winters (represented by the second worst year on record) and 10 MW for 7% of winters (represented by the worst year on record). A simplified analysis has been conducted which focuses on only two states – 30 MW for 86% of years, and 10 MW for 14% of years. This yields a carrying capacity at the LOLE target of 2.0 hours/year that is 59.9 MW (3.5 MW below the Resource Plan assumptions) and an LOEE of 6.5 MWh/year at 55.8 MW, 7.6 MW below the Resource Plan assumptions. However note that this simplified "two state" approach is overly pessimistic to some degree compared to a full (but more complicated) "three state" approach (30 MW at 86%, 18 MW at 7%, 10 MW at 7%).

In summary, with respect to capacity, adopting the ice study conclusions by way of implementing a new 21 MW "cap" to output in the early part of winter appears to drive a requirement for on the order of 3 MW of new capacity elsewhere on the system (using Resource Plan assumptions, this impact may be assumed at $0.8 to $0.9 million/MW (2005$) or $2.4 to $2.7 million requirement for incremental capital investment (if achieved through new thermal capacity)). If instead YEC chooses to implement a new adaptive regime based on retaining a 24-25 MW operating target for the early part of winter, knowing that in a certain percentage of years this will be cut back as far as 15 MW on short notice, then the incremental capacity required to address the conclusions of the ice study ranges from 0 MW (during the period N-1 is the driving constraint on capacity additions) to 0.3 MW (when LOLE is the driving constraint) or less than $0.3 million in incremental capital investment (if achieved through new thermal capacity).

Peaking Energy Implications

As noted above, the choice of new operating philosophies for the system to incorporate the conclusions of the ice study may drive some changes to the degree of peaking diesel required to operate the system. To estimate this impact, the 8 year period 2009-2016 inclusive was considered, assuming Minto was on the system at 32.5 GW.h/year, and all other assumptions as per the Resource Plan base case. Under the Resource Plan assumptions, the adoption of a steady state model for the system in the early part of winter (capped at 21 MW) appears to drive added peaking diesel costs over 8 years in the range of $0.7 million (slightly less than $0.1 million per year on average).

In contrast, adoption of an adaptive philosophy would drive no new assumed peaking diesel in 93% of years, and added diesel for the 7% of years where bad ice events occur (as the Whitehorse plant would be limited to 15 MW for sustained periods of time). An rough initial estimate of the impacts of peaking diesel during these bad ice events is less than $0.3 million for the 8 year period (under $0.04 million per year).

[4] The degree of storage would need to be very large (on the range of 6 MW increase in winter outputs – by comparison Marsh Fall/Winter storage was only assumed at 1.6 MW, and large scale Atlin storage schemes from the early 1990s do not even approach this magnitude).

These results require further consideration before using for planning purposes or, for example, in discussions with industrial customers. At a comparative level, however, they support the conclusion that restricting operation to 21 MW in the early part of winter in all years results in adverse impacts on peaking diesel in excess of that occurring if electing to use an "adaptive" approach operating at 24-25 MW in most years, and 15 MW for portions of bad ice years (7% of the years assumed).

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REFERENCE: **Application, Tab 7 Schedule 8**

QUESTION:

a) Please detail what is included in "Trust Liability" and "Deferred revenue".

ANSWER:

(a)

"Trust Liability" primarily includes Diesel Contingency Fund cash balance. Detailed explanation of Diesel Contingency Fund and how it functions are provided on page 9-11 of the Application. In forecast 2008 and 2009, the trust liability also includes scholarship funds and insurance proceeds held on behalf of others.

"Deferred revenue" includes amortized gain reserve on fire insurance proceeds received related to a fire at the Whitehorse Rapids Generating Station in 1997. As noted on page 9-11 of the Application, the gain is being amortized to income at the same rate as the replacement assets which approach was approved by the Board in Board Order 2000-3.

REFERENCE: **YEC Application**

ISSUE/SUB-ISSUE: **Capital Projects, Section 5.2.1**

QUESTION:

a) Are Yukon ratepayers responsible for the $3.744 million cost overrun related to the Stage One CS/MS development? If so, please explain how this fulfills the condition that ratepayers would not be adversely affected by this project.

b) Please provide an updated business plan related to the CSTP.

c) What are the incremental costs with respect to purchasing the Minto diesel units if YEC chooses to relocate the units to another location on the system? Please provide detailed cost-benefit analyses with but not limited to the following three options: existing substation, a new substation or sale.

d) Please provide a detailed comparison between forecast and actual costs related to the Faro Mirrlees (FD1) re-commissioning project and variance explanations.

e) Provide a cost-benefit analysis respecting the timing of refurbishment of Whitehorse Unit #1 (Mirrlees unit) that includes the option of "mothballing".

f) Please describe YEC's policy in regard to the expensing or capitalizing "… early planning and feasibility work (as well as permitting work …).

g) Is it YEC's view that the use of its diesel units is limited to one that of peak shaving unless an emergency exists on the grid? In the answer, please provide a detailed explanation and business case as to YEC's strategy in the near- and long-term.

h) Considering the current cost of fuel, is the addition of the third turbine at Aishihik still an economically viable option? Please provide an updated business case.

ANSWER:

(a)

Yes. Yukon Energy's business plan for Stage 1 CSTP as set out in the filing for an Energy Certificate allowed for such added costs, if they occurred, to be borne by ratepayers, subject to the constraint that the Project had to result in an overall net benefit savings for ratepayers after consideration of the new connected Minto Mine and Pelly Crossing loads being served by surplus WAF hydro generation.

Yukon ratepayers have not been adversely affected by the CSTP. The 2008/2009 General Rate Application incorporates net benefits to ratepayers due to provision of grid service to Minto mine and Pelly Crossing through the proposed rate reduction of $0.360 million in 2008 and $1.334 million in 2009 (3.48%). As noted in the table provided below, absent the additional revenues provided through grid service to Minto mine and Pelly Crossing through completion of CS Stage 1, Yukon Energy's retail rate revenue requirement would be $0.567 million and $2.572 million higher in 2008 and 2009 respectively. In summary, without CS Stage 1 Yukon Energy's retail rate revenue requirement would require a firm retail rate increase in 2009 of $1.238 million (+3.23% if applied as an across-the-board retail rate rider).

As shown in the table below, the absolute amount of the revenue requirement would be lower without the Minto connection in service (due to removal of the CSTP net cost referenced in the IR). However, due to the materially decreased sales volumes absent the Minto and Pelly Crossing connections (31,323 MW.h lower total sales in 2009), the overall net impact on ratepayers absent CSTP would be a requirement for a rate increase to meet the revenue requirement.

The approximate quantified details of benefits and costs to ratepayers of the Stage 1 CSTP (including the Minto and Pelly Crossing connections) are provided in the table below. This table does not include more minor effects of CSTP and related Minto load, such as potentially modestly higher use of diesel for peaking or incremental transmission O&M, but also does not include the full benefits of CSTP from connecting Pelly Crossing – only the new wholesale revenues are included (at 6.84 cents) and not the full benefits of taking Pelly off of diesel (which accrue to ratepayers via a lower YECL revenue requirement, not YEC's revenue requirement).

Approximate Impact of CSTP on YEC retail rate revenue requirement ($000s)

	2008			2009		
	w/o CSTP	with CSTP	Difference	w/o CSTP	with CSTP	Difference
Lost Revenues w/o CSTP						
Sales (MW.h)						
Primary wholesale	*258,439*	*258,989*	*-550*	*264,626*	*266,926*	*-2,300*
Primary major industrial	*0*	*6,845*	*-6,845*	*0*	*29,023*	*-29,023*
Industrial Revenue (incl "fixed" Rider F)	0	749	-749	0	3,312	-3,312
Wholesale Revenue	17,681	17,719	-38	18,130	18,287	-157
Change in Revenues at Existing Rates			**-787**			**-3,469**
Cost Savings w/o CSTP						
Net CSTP Depreciation (per YUB-YEC-1-9)			-30			-118
Rate base (adjustment per YUB-YEC-1-9 and UCG-YEC-1-73)	*144,283*	*145,212*	*-929*	*147,749*	*151,415*	*-3,666*
Change in return on rate base (using average cost of capital in GRA - 6.86% and 7.17% respectively)			-64			-263
Canada Flexible Term Note savings						
Interest expense (due to lower WAF sales)	1,129	1,255	-126	1,195	1,712	-517
Approximate Change in GRA Rev Req			**-220**			**-897**
Net Impact of situation with no CSTP Retail Rate Revenue Requirement would be higher by:			**567**			**2,572**

(b)

The Application (Section 5.2.1.1) provided update information on the business plan for Stage 1 CSTP which the Board had previously reviewed; the overall Application addressed the matter of overall net benefits that resulted in the proposed rate decrease for all retail Yukon ratepayers. Further updated information consolidating and summarizing information on ratepayer net benefits is provided in the table included above in **(a)**.

(c)

Under the terms of the PPA, YEC is obligated to keep all four units at the existing location adjacent to the Mine for two years. After that, two units must be at that site for an additional six years, or until YEC's security interests are discharged, whichever is earlier. Under all scenarios, Minto has certain rights to repurchase the units if and when YEC wants to move them from the site. YEC would not intend to move a unit from the site except under these conditions and supporting analysis that such a move was beneficial to Yukon Energy's ratepayers.

Analysis of the incremental cost of moving any of the skid-mounted units has not been undertaken to date, and detailed cost-benefit analysis of the options identified cannot be provided at this time. Such costs and benefits could vary depending on when and where the units would be moved (i.e. enhancement to an existing YEC diesel plant compared to developing a new YEC diesel site), what the system planning model for firm supply requirement were indicating at the time of the move, and what options Yukon Energy could consider at that time. Sale options, beyond sale back to Minto, would depend on then current market conditions.

(d)

The original budget for this project in total, as set out in the November update to the Resource Plan, and reviewed in section 6.9 of the Board's Recommendations on the Resource Plan, was $2.3 million.

The project in total comprises a number of small activities as well as the major task of performing a major overhaul on the unit. The 2007 spending comprises $0.407 million spent on the unit (as shown in Table 5.2 under Major Projects) plus a series of other items recorded in the Generation component of Table 5.2, totaling $0.225 million, for a total 2007 spending of $0.631 million. The forecast 2008 spending in the GRA was $1.158 million to complete the project. While the project was not completed by year-end 2008, the total spending required to complete the project is still forecast at approximately this same level, and remains below the $2.3 million level forecast in the Resource Plan.

(e)

The timing of the refurbishment of Diesel Unit #1 at Whitehorse (WD1) is not a cost benefit question per se, it is a question of when the required firm capacity is needed. If not required under the N-1 standby criteria, a later date for the refurbishment is preferable since the funds would not need to be expended until later. No cost estimate of mothballing the unit has been developed at this time. As set out at Tab 5, page 5-9, no decisions regarding rebuild versus mothball are expected to be made until closer to 2012, based on resources and load then expected to be on the system.

(f)

The reference is in the context of planning for new generation. In this instance, the cost of early planning and feasibility are recorded in a capital work-in-process (WIP) account. This WIP account accumulates costs until a construction decision point is reached (i.e., a go/no-go decision). If the decision is made to proceed with the project, these costs will be included in the overall final cost of the project. If the decision is made to not proceed, the costs will be written off over five years on a straight line basis.

(g)

In the test years, Yukon Energy is forecasting that diesel generation requirements will be for peaking and other non-baseload generation as described in the Application. These units would also be used as required to address emergency conditions.

Beyond the test years, Yukon Energy has noted that reduction/utilization of the hydro generation surplus may occur and would require Yukon Energy to use some of these diesel units for baseload generation, absent new or expanded renewable power sources being brought on line. It is well known, however, that under sustained baseloaded conditions, there can be an opportunity to develop new renewable generation on an economic basis for long-term benefits related to cost savings, environmental aspects, and development of local resources. Yukon Energy is working to minimize the need for baseload generation through timely development of additional renewable energy generation. The business case for each such addition needs to be assessed on its own merits. For example, see YUB-YEC-1-38(a).

(h)

Yes.

Updated cost and contribution information is provided in the Application, Section 5.2.1.5.

The Resource Plan reviewed the economics of an Aishihik 3rd turbine on the basis of diesel at $0.70 to $0.75 per litre and concluded it was an economic project even without government funding. Since that time, $5 million of government funding has been committed.

Current and projected fuel prices imply an increase, rather than a decrease, in these net benefits.

Please see response to UCG-YEC-1-17.

REFERENCE: **YEC GRA**

ISSUE/SUB-ISSUE: **Capital Additions, Section 5.2.2**

QUESTION:

a) Please provide Table 5.2 in an Excel spreadsheet complete with formulae that underpin the calculations.

b) Please provide an explanation as to why the Mirrlees Electrical Upgrades expenses are not included in the associated Mirrlees project that is greater than $1 million (Section 5.2.1.3).

c) Please provide a business case that justifies the $1-million Financial Systems Software Replacement expenditure.

d) With respect to L170 Line Assessment Phase 2 Carmacks - Faro, please explain what is included in the line assessment and how often a transmission line assessment is performed. Please present the findings of the 2006-07 line assessment and what type of maintenance that is required on the line.

e) Please describe YEC's pole-replacement and brushing programs in detail.

ANSWER:

(a)

As noted in response to UCG-YEC-1- 81(a), page 5-25 in the Application, which shows customer extension spending for 2005 to 2007, contains an error in the categorization of certain elements of distribution spending. A corrected version of Table 5.2 will be provided once available.

(b)

The Whitehorse Mirrlees Refurbishment is not one single project, but involves a staged refurbishment of three separate units (WD3, WD2 and WD1) over a period of years, as well as separate smaller projects (i.e., less than $1 million) involving upgrades to

common systems. Page 5-9 of Tab 5 of the 2008/2009 General Rate Application details the Mirrlees Refurbishment being undertaken by Yukon Energy at this time, noting in addition to refurbishment activities specific to each of unit #3, unit #2 and unit #1, "a series of projects on "common" systems occurring in 2007 (0.468 million), 2008 ($0,450 million) and anticipated for the following years (2010 – 2012, $1.465 million)."

(c)

Yukon Energy purchased and installed the JDEdwards financial package in 1999. Since that initial installation, JDE & Co has been "acquired" twice – once by Peoplesoft who were in turn bought out in a hostile takeover by Oracle Corporation in late 2004. At the time of the acquisition, Oracle announced intention to amalgamate the three products into one. These acquisitions created concern for Yukon Energy around:

1. How long JDEdwards would be supported as a stand-alone product. The current version that Yukon Energy uses (XE) has not been supported by Oracle since February 2007;

2. The fact that Oracle database structures are not compatible with Yukon Energy's current database structure; and

3. The perception that Oracle products are too "up-scale" for a small company like Yukon Energy.

Management made the decision at that point not to invest in large scale upgrades of the existing system, with the view that a replacement system would be necessary in the next few years. In addition, the quote below is an extract from the Business Impact Assessment, dated January 2006:

> While the financial systems are based on JDEdwards One World, it is not fully utilized but is in place and managed internally with some help from outside contractors. On more than one occasion the corporation has unsuccessfully tried to modify JDEdwards to fit its mode of operations. As a result of these failed attempts and the perceived rigidity of the product YEC finds itself with a sub-optimal JDEdwards configuration. Furthermore, One World is at end of life and a replacement is planned for 2008. One World is the source of several challenges from a Business

Impact Assessment point of view. With a chart of accounts that is described by users as clumsy or awkward, there is little incentive to use JDE as it is intended to be used, a fully functional Enterprise Resource Planning (ERP) system which touches most, if not all aspects of the business. Because of this, a number of isolated stand alone systems are also in use – HRManager for example which disintegrates the business functionality of the Human Resources group. A fully disintegrated model might even be preferable to the patchwork that is now in place supported by spreadsheets and errant databases. Without JDE Finance would find functioning to be a challenge but the system is not used for the tasks required of it.

Specifically, the purchase of a new system is planned to correct a number of deficiencies in existing programming:

1. Integrated system will eliminate duplication of data in key areas such as budgeting, forecasting, inventory and maintenance;

2. New system will have the functionality to track projects against committed costs;

3. New system will have enhanced reporting capabilities that will allow project managers to access data on a more timely basis without intervention from Finance staff;

4. Eliminate manual processes and “work-arounds”; and

5. Optimize chart of accounts for utility business.

(d)

Yukon Energy’s transmission line assessments involve a ‘fine toothed comb’ field inspection and audit of every structure, pole, and piece of hardware on the line. The inspectors are trained and experienced to spot hardware issues on each component of the line, and to rate issues from ‘fix immediately’ to ‘repair/replace in 5-10 years’, or ‘information only’. A photographic library of each structure at the time of inspection is compiled, and GPS location data of each asset recorded to include in our mapping system. As the line is quite old (original construction in 1968), certain components either

wear out, become loose, degrade, or succumb to stress over time and need to be repaired or replaced. A detailed inspection is a way of finding those issues, tracking the condition of the line, and prioritizing repair and replacement of defects to avoid an in-service failure.

The priority system used by the consultant is as follows:

Priority 1
Indicates a very serious reliability or safety concern. Repairs or modifications should be made immediately (probably within 1 to 2 days). Examples - broken pole or cross-arm, trees burning in the line, etc.

Priority 2
Indicates a reliability or safety concern which is serious enough it should be rectified in the not too distant future (possibly within 3 months). Condition is serious enough that it would probably be dealt with prior to the next scheduled routine maintenance. Examples include trees within limits of approach to line, ground clearances which do not appear to meet the ECUC, seriously damaged conductor, etc.

Priority 3
Indicates a reliability or safety concern which should be corrected, but that is minor enough that it could be rectified as part of a planned maintenance program (possibly within the next 1 to 5 years). Examples include cross-arms which do not appear to be in good shape but will probably last a few more years, loose hardware, synthetic insulators with corona damage, etc.

Priority 4
Indicates a reliability or safety concern which is minor enough it would only be corrected if convenient to do so. Corrections would only be made if other work were being done in the same area or on the same pole. Examples include flashed or chipped insulators, danger trees which appear stable, etc.

Priority 5
Indicates a comment which is recorded for information only – no corrective action is required. Examples include synthetic insulators which have corona rings, swamp guys which are slightly slack, etc.

Priority 9

Indicates work was minor enough that it could be completed as part of the inspection being done. In this case it is a list of corrective work which was completed by EHV Line Consultants when doing the line inspection. Examples include re-tensioning guys, replacing structure number tags, digging out buried pre-form grips, etc.

Based on the above-noted priority system, the number of priority issues found are as follows:

1- 0
2- 120
3- 1280
4- 1890
5- 449
9- 586

A plan is being formulated to deal with the highest priority of these issues.

(e)

All transmission lines are inspected both from the air (annually) and on the ground (particular sections identified from the air). Brushing requirements and any other issues or problems, such as poles that need replacement, are identified. These inspections are then converted into work plans for the highest priority areas and issues. All transmission line right-of-ways are brushed every 3-4 years.

REFERENCE: YEC GRA

ISSUE/SUB-ISSUE: Deferred Cost, Section 5.3

QUESTION:

a) Considering current fuel prices, please provide a cost-benefit analysis for the near-term Mayo B hydro generation expansion.

b) Please provide details as to what customers can expect in regard to YEC's proposed "Other Generation Feasibility" significant $7.6 million expenditure over the test years?
   ii. Please define what is meant by a "pre-feasibility study".
   iii. Does YEC perform the studies or are these third-party studies? Please explain.
   iiii. Please provide a cost-benefit analysis for the $7.6 million expenditure.

ANSWER:

(a)

The Mayo Hydro Enhancement Project ("Mayo B" or "the Project") involves enhancements to the existing Yukon Energy Mayo hydroelectric facilities to increase power production. It comprises the construction of a new powerhouse and related facilities, as well as adjustments to the management of water on the Mayo River system. The Project has a planned in-service date of late 2011.

Yukon Energy Corporation (Yukon Energy) is undertaking all required planning, consultation, environmental, engineering and other related activities in order to obtain authorizations and approvals necessary to allow for a decision to commence construction of the Project in 2010. At this time, Yukon Energy has made no final decision to proceed with the Project.

Yukon government and Federal government regulatory approvals and decisions are required before any construction activities may be undertaken; however, these approvals and decisions may only be made after the required screening assessment by the Executive Committee of the Yukon Environmental and Socio-economic Assessment

Board (YESAB) of the Project Proposal Submission (Project Proposal). On February 27, 2009, Yukon Energy submitted the Project Proposal to YESAB.

As noted in the Project Proposal, the Project cost estimates to date reflect a period of study oriented to confirming the technical ability to construct the Project, and the timing and configuration of major Project components. The estimates reflect activities oriented towards a "Level 3 – Feasibility" stage of study, and are subject to design refinement, and changing market conditions (including general economic conditions for construction in western Canada).

The cost of the Project is presently estimated at $120 million (including escalation, interest during construction, and contingencies of 15% to 25% depending on the Project component). This estimate has been subjected to a preliminary third-party review. This review indicated that there may be a potential upward adjustment to the cost of up to 5%.

Similar to other hydro projects, a material component of the Project costing cannot be confirmed with reasonable certainty until the Project is tendered. The selection of a canal format (as opposed to a tunnel) likely reduces the degree of tender price risk, and future geotechnical risk to Project costs, but this uncertainty cannot be eliminated prior to the tendering process being completed.

At $120 million (and ignoring potential government infrastructure funding), the full assumed output of the plant of 38.4 GWh (under full long-term load conditions) yields a levelized cost of energy ("LCOE") for the capital cost of the project of $0.142/kW.h. In the near-term under reasonably foreseeable load conditions, integration of the Project into Yukon power systems would be expected to yield a somewhat smaller net firm energy benefit, potentially as low as approximately 30 GW.h of firm energy (plus up to 10 GW.h of enhanced potential secondary energy should there be loads available to purchase this supply). In such a case the levelized cost of energy would approximate $0.182/kW.h. By comparison, diesel costs in the application are forecast at $0.3737/kW.h, and per UCG-YEC-1-62 remains at $0.248/kW.h at today's fuel prices.

In order to enhance the opportunity for stakeholders to secure benefits from the Project including Canada, Yukon, ratepayers and NND, a variety of possible financing approaches are being considered. No further details on the precise form and source of financing are available at this time. However, in order to keep costs and risks to Yukon

ratepayers within acceptable bounds (e.g., more in line with B.C green market power purchase costs of 8 to 10 cents/kW.h) it is anticipated that government infrastructure funding will be secured for a material portion of the project costs. Also there are ongoing discussions with NND relating to the possibility of NND investing in the Project.

(b)

The other supply options category comprises $0.7 million in 2008 and a further forecast $6.8 million in 2009. The current plan adopted by Yukon Energy for 2009 is reduced from the level assumed at the time of the GRA, to a level of $4.3 million, approximately as follows based on current draft plans:

- **Aishihik Diversions (Gladstone):** $800,000. This project has the potential of increasing Aishihik output by up to 18 GW.h/year on average, at a relatively low capital cost.

- **Atlin River:** $700,000. This small scale storage project has the potential to increase Whitehorse Rapids average annual output by up to 18 GW.h/year.

- **Marsh Lake Fall/Winter Storage:** $300,000. This project, previously reviewed by the YUB, is an attractive source of enhanced output at Whitehorse Rapids (up to 7.7 GW.h) and an update is required based on the new results of work completed by the Yukon Government, as well as Yukon Energy, with respect to the effects of high water levels on Marsh Lake.

- **Geothermal:** $1 million. This project remains in investigatory stages. No specific energy output has been identified.

- **Other Larger Hydro:** $600,000. Yukon Energy has updated its inventory of hydro sites in the 50-100 GW.h range, but has not done comparable work for larger sites in Yukon.

- **Existing System Operating Studies:** $220,000. Both Mayo and Aishihik plants have operating issues that may serve to alter the generation potential of the plants in future. For example, Aishihik's long-term output is currently constrained by the conditions of a Fish Act Authorization, which is subject to review based on

ongoing fisheries work. The impact of more restrictive fish conditions could readily be 5 or more GW.h per year on average, depending on load conditions.

- **Wind:** $30,000. Develop longer-term monitoring plan and assess the results of pre-feasibility work completed in 2008.

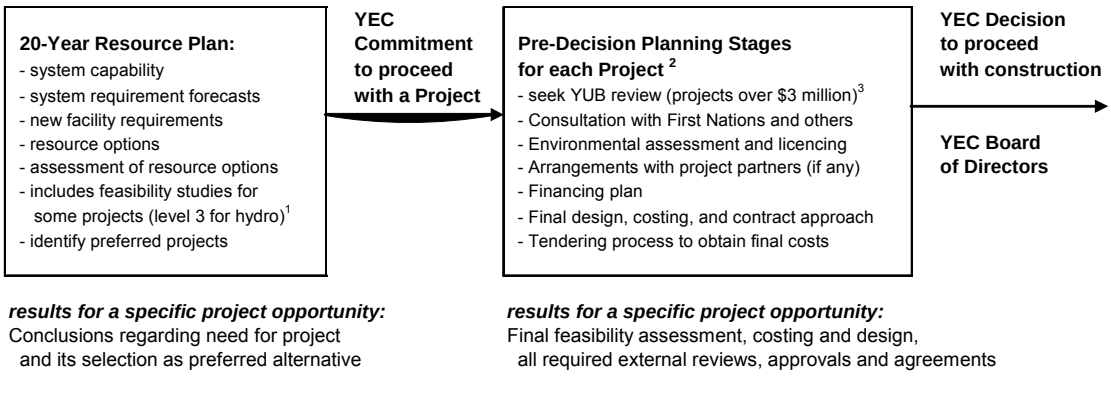
- **Internal Efficiency Projects and Overall Management:** $650,000. Budgets for internal reviews of the potential for significantly improving the output of existing facilities from re-runnering or other similar improvements in the generation or electrical areas.

(i)

Pre-feasibility studies are consistent with the activities noted in Figure 1.1 from the 20 Year Resource Plan (repeated below) as the activities leading to the selection of a specific project as a "preferred alternative" and the initiation of "pre-decision planning stages".

Figure 1.1 from 20 Year Resource Plan

20-Year Resource Plan and Decisions on Specific Projects



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

(ii)

Yukon Energy staff are involved in the studies, but typically they involve significant external expertise and support, particularly for generation projects.

(iii)

As noted above, the expenditure is now slated at the lower value of $4.3 million in 2009. No cost-benefit analysis is possible as the specific cost and output values associated with each project are not yet available, nor is the technical or environmental/licencing feasibility established (this is the basis for the pre-feasibility work).

REFERENCE: **Report to Yukon Minister of Justice, YEC Application for an Energy Project Certificate and Energy Operation Certificate Regarding the CSTP (May 31, 2007)**

ISSUE/SUB-ISSUE: **Costs of Stage One of CSTP**

On Page 13 of 17 of the report: The Board recommends that the Minister direct YEC to consult with the Minister before making any decision to proceed if the tendering process results in a capital cost that is materially above the high end of YEC's estimate of $25.9 million or if schedule delays result in the in-service date slipping beyond the end of 2008.

PREAMBLE:

During the process (Application for an Energy Project certificate …) financial details were not available to the Board.

QUESTION:

a) Please provide a copy of the winning tender for the CSTP project.

b) Given the capital costs exceeded $25.9 million, please provide a copy of the letter to the Minister where YEC sought consultation to proceed with the project.

c) What was YEC's stop point for the project? That is, at what capital cost was YEC not going to proceed? Please show all calculations on how that point was determined.

ANSWER:

(a)

There were several key tenders (rather than only one winning tender) that were let as part of the construction phase of this project. Each tender/contract document covers a wide range of issues and is not suited to being copied for distribution here. Information is provided below on the tender process and key outcomes related to financial information.

Focusing on the financial budget related elements of the tenders and contracts, the table below summarizes the contracts tendered[1] and related cost awards estimated for Minto Spur and CSTP Stage I portions at the time the YEC's Board decided in September 2007 to proceed with the project (subject to receipt of all required permits and approvals):

Work Description[2]	**Minto Spur**	**CSTP Stage I**	**Contract Total**
Project Management	311,645	686,165	997,810
Survey	157,863	534,616	692,479
Clearing	456,273	2,945,852	3,402,125
Line Construction	2,166,010	13,551,626	15,717,636

The above line survey, clearing and construction estimates reflected tenders based on YEC's proposed route, and did not reflect subsequent adjustments needed in response to the subsequent Final YESAB Recommendations affecting the Tatchun Creek CSTP re-route and finalizing the Yukon River crossing (and related MS line location leading to this crossing). See response to YECL-YEC-1-9(b) regarding the financial impact of these specific scope changes.

As at September 2007, YEC had initial engineering cost estimates for substation civil and electrical work; beyond an early order for the major transformer, other tenders and contracting for this substation work was deferred until early in 2009, reflecting the fact that this work had to be deferred until that time and the overall costs for this component were expected to be a relatively small portion of the overall project budget.

The figures in the above table were included in the accumulated budget package approved for construction by the YEC Board of Directors in September 2007. The total approved budget for CSTP Stage I at that time was as follows (contingencies included in the above assessments were pooled under one category below):

[1] The clearing contract was awarded, pursuant to the Project Agreement with NTFN, to a nominee of the NTFN. The other contracts listed were each awarded after a competitive tender or RFP process.

[2] The successful Consultant/Contractors for all winning tenders are identified in response to YECL-YEC-1-16(d), along with the current YEC Board approved contact amounts.

Project Management	686
Survey	535
Clearing	2,945
Line Construction	13,552
Substations	1,654
Owner's Costs & Contingency	6,034
Planning	2,382
Total	**$27.788**

In spring 2008**,** tenders were issued for the substation work and for the commissioning work, thereby completing the package of contracts awarded for the CSTP/MS project.[3]

(b)

In compliance with the YUB's recommendation YEC met with both the Minister of Justice and the Minister of Energy and reviewed in detail the project costs when it became apparent that the capital costs of the Project would exceed $25.9 Million. No letter was sent to the Minister in this regard. Prior to start of construction of the CSTP Stage 1, YEC received the necessary Energy Certificate from the Minister of Justice.

(c)

There was no specific stop point ever adopted by the Board of Directors. Instead the Board focused on confirming, based on the available information, that Yukon ratepayers would indeed still secure net benefits from connection of the Minto load and Pelly Crossing.

The project was planned throughout using a phased approach whereby the Board could review results at defined decision points prior to putting more budget dollars at risk. At the September 2007 meeting where the construction was approved, the Board had tendered costs for the items in (a) above, approved funding from YG and YDC and an approved PPA from Minto committing to a $7.2 million contribution to the project. At that point, the Board concluded that there was acceptable risk given the future revenue

[3] See YECL-YEC-1-16(d) for successful contractors and the current YEC Board approved contact amounts. See YECL-YEC-1-9(b) regarding the cost increases associated with the substation contract awards. See YUB-YEC-1-40(a) for a review of cost increases affecting the Minto Spur, including substation cost increase impacts. See response to LE-YEC-1-46 and 47 for review of CSTP and MS budgets (at time of last YUB review, and at time of September 2007 YEC Board decision to proceed) and final costs.

stream versus the expected in-service cost (net of contributions), and allowing for reasonable contingencies. In the end, the project cost was within 5% of the above budget (excluding YESAB-ordered scope changes).

REFERENCE: **Application, Page 5-7**

ISSUE/SUB-ISSUE: **Minto Spur**

QUESTION:

a) Does YEC consider a 161% increase in the cost for the Minto Spur acceptable?

b) What processes or reviews has YEC undertaken to prevent such low estimates from happening in the future?

c) Will the cost for the Minto Spur be subject to an audit from the federal government?

ANSWER:

(a)

The estimated cost of $3.83 million was prepared in the fall of 2006 as an input to the Power Purchase Agreement (PPA) negotiations and the basis for this amount was provided in the YUB review of the PPA in early 2007.

The Minto Spur project is a 27 km 25kV Spur Line from Minto Landing to Minto Mine, including a crossing of the Yukon River and substations as needed at Minto Landing and Mine Site.

The line cost estimate was prepared by YEC internal engineers after discussions with contractors and consulting engineers on recent experience. Based on these discussions, it was determined that a reasonable estimate of cost in 2005 dollars was $3.421 million. This was based on the following:

- $0.085 million/km for line construction times 27 km (clearing etc all included beyond planning); plus

- extra of $0.900 million for 350m Yukon River Crossing; plus

- allowance of $0.500 million for substation costs; plus

- 10% on all of the above for planning costs.

To arrive at 2008 in-service dollars, this estimate was escalated by 11.9%. This increased the estimate to $3.828 million. The escalation assumed the following:

- 2.5% inflation in 2006 and 3.0% in 2007.

- 6.0% escalation for interest during construction and further escalation.

Breaking out final ISD costs for comparison, the above break down roughly to:

- $2.93 million line construction

- $0.56 million for substation

- $0.35 million for planning

This estimate was provided to Minto Explorations as part of the PPA negotiations. Minto completed its own due diligence process and accepted this amount as reasonable.

At this point in the process, no engineering had been completed. Design engineers started in approximately March 2007, with updated estimates to the Board of Directors in June 2007. At this point the revised estimate for the Spur was $7.67 million determined as follows:

- Substation construction costs now $2.18 million (excluding project management and other owner costs;

- Line construction increased to $3.78 million;

- $0.960 million other owner costs during construction; and

- $0.760 for planning cost allocation.

At the September 2007 Board of Directors meeting, this estimate had increased to $8.8 million. This amount was based on tendered costs for most major components (excluding substations). The construction decision was based on this figure, not $3.83

million. Updated economics assessments confirmed that even with the final cost number, the project still yields Minto material cost savings over its life.

There were essentially two key contributing factors to this result:

(1) Line construction costs: At the time of the early estimates, it was assumed the cost of the spur line would be materially less per kilometer to construct than the higher-voltage main line.

(2) Substation costs: Engineered costs and costs of building in remote areas contributed to materially higher costs.

(b)

Yukon Energy intends to build on its experiences on the CS Stage 1 project to better ensure the accuracy of cost estimates in the future. This includes undertaking more analysis in initial estimates (pre-engineering) based on Yukon-specific experience. Of critical importance is the need to have detailed engineering and, where possible, contractor tenders included in estimates.

(c)

No. The costs of the Minto Spur will be subject to normal audit procedures conducted by the Office of the Auditor General as part of the annual audit process. YEC is not aware of any special audit process for this project at this time.