

YUKON ENERGY CORPORATION

2012/2013 GENERAL RATE APPLICATION
INTERROGATORY RESPONSES FILED

July 27, 2012
&
August 1, 2012

City of Whitehorse
(CW)

ISSUE: **Industrial Sales**

REFERENCE: **Application page 1-6, lines 12-17**

YEC states:

> **More specifically, from 2005 to 2010, grid non-industrial sales steadily increased from 273 GW.h/year to 314 GW.h/year (a 41 GW.h increase over the period reflecting higher growth than was even forecast in the 2006 Resource Plan), while grid industrial sales were minimal until late 2008 when the Minto mine was connected to the grid. Industrial sales grew thereafter to 30 GW.h in 2010 and 43 GW.h in 2011 (including the Alexco mine which connected to the grid in October 2010). Industrial load growth to date continues to bring higher revenues that tend to more than offset any related incremental costs.**

PREAMBLE:

The City wishes to test the benefits associated with YEC's industrial sales.

QUESTION:

a) Please quantify by year any excess or deficiency of industrial revenues over incremental costs that YEC experienced during the 2005-2011 period. Please distinguish between capital and operating expenses.

ANSWER:

(a)

The response to YUB-YEC-1-2 shows the incremental revenue and cost impacts of industrial load, as well as other classes of load.

However, YEC must also note that it is an inappropriate test of the "deficiency" of any firm power customer to compare new revenues to incremental costs in this manner (it is, however, an appropriate approach for a secondary power customer).

The appropriate test of surplus or deficiency for any firm power customer is the allocation of embedded costs and revenues, as reviewed in the 2009 Phase II GRA, where it was noted that the industrial customers provided revenues well in excess of allocated costs. In that case, an industrial class revenue:cost ratio of 113.7% was estimated (revenues exceeded costs by 13.7%).

TOPIC: **Secondary Sales**

REFERENCE: **Application page 1-8, footnote 18**

YEC states:

> **The 2008/2009 GRA forecast secondary sales for the test years, but noted the opportunity to sell secondary energy on an interruptible basis would be basically eliminated. The application noted at page 11 that 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 September 2010, due to low water conditions on the WAF and Mayo Dawson grids secondary sales were required to be shut off for an extended period (until August 2011) resulting in a loss of $1 million in net revenue compared to 2009 (however, approximately only half of this revenue was included in 2009 rates). Secondary sales were briefly available in fall 2011 and are only expected to be available on a limited basis going forward.**

PREAMBLE:

The City wishes to test YEC's secondary sales forecast.

QUESTION:

a) Please confirm that the reference to page 11 of the 2008/2009 Application should be to pages 10-11 of that application.

b) What was the volume of forecast secondary sales approved in YEC's 2008/2009 Application? What was the actual volume of secondary sales in 2009?

c) How did YEC dispose of or recover any revenue difference between 2009 actual and forecast Secondary Sales?

d) What was the actual volume of secondary sales in 2010? How did YEC dispose of or recover any revenue difference between 2010 actual and forecast Secondary Sales?

e) What was the actual volume of secondary sales in 2011? How did YEC dispose of or recover any revenue difference between 2011 actual and forecast Secondary Sales?

ANSWER:

(a)

Confirmed.

(b) through **(e)**

In 2008/2009 GRA YEC's approved secondary sales forecast were 17.5 GW.h for 2008 and 7.6 GW.h for 2009.

The actual volumes of secondary sales for 2009 to 2011 were as follows:

- 2009: 17.4 GW.h;
- 2010: 10.5 GW.h; and
- 2011: 0.6 GW.h.

YEC does not "dispose of" nor "recover" any revenue difference between actual and forecast secondary sales. During this period, all variation between actual secondary sales and the forecast in the 2009 GRA was a risk borne by YEC, the outcome of which is reflected in YEC's Income Statement.

TOPIC: **Industrial Sales**

REFERENCE: **Application page 1-12, lines 21-22**

YEC states:

> **In 2008/2009 GRA it was noted that diesel would soon be "on the margin" on the integrated grid due to ongoing growth.**

PREAMBLE:

The City requires confirmation of this statement.

QUESTION:

a) Please provide the specific reference or references in the 2008/2009 Application where "it was noted that diesel would soon be 'on the margin' on the integrated grid due to ongoing growth."

ANSWER:

(a)

"With completion of CSTP Stage I and connection of the Minto mine, Yukon Energy's 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" (2008/09 GRA Application page 9, 10).

TOPIC: **International Financial Reporting Standards (IFRS)**

REFERENCE: **Application page 1-14**

YEC states:

> **In lieu of earning a rate of return on assets under construction, the utility charges WIP projects at the weighted average cost of capital during the period the asset is being constructed. Under IFRS, entities are not permitted to charge projects for equity returns; accordingly, Yukon Energy has amended this policy to use a debt-only rate for AFUDC (Allowance for Funds Used During Construction) starting in 2011. At current rates, this will result in lower charges to capital (debt rates are less than equity); the overall impact is not expected to be material.**

PREAMBLE:

The City wishes to determine the effect of IFRS on revenue requirement.

QUESTION:

a) If IFRS results in lower charges to capital, will IFRS correspondingly raise revenue requirement by a reduction in the AFUDC component of operating income (Tab 7, Schedule 6, line 12) when large projects are undertaken?

b) If yes, please quantify the charges that have been shifted from capital to revenue requirement due to the implementation of IFRS.

c) What are the costs that YEC incurred in implementing IFRS by year? How does YEC propose recovering these costs? Please cross-reference to Appendix 6.2.

ANSWER:

(a) and **(b)**

No. Yukon Energy has traditionally financed the sum of all capital needs by a balance of 60% long-term debt and 40% equity (except in rare cases where project specific short-term debt was made available to YEC – in those cases the residual financing for the company remained 60% long-term debt and 40% equity). In this manner, by applying equal allocations of capital to each component of YEC's balance sheet (e.g., rate base, WIP, etc.) the rate base was capitalized by way of a 60%:40% debt:equity ratio.

The updated approach as required by IFRS means there is no allocation of equity to WIP, resulting in an effective "first allocation" of debt (short-term or, if needed, long-term) to Work in Progress. However, YEC intends to finance all remaining capital requirements with 60%:40% debt:equity. As such rate base remains financed 60%:40%, and there is no effective change to revenue requirement from the IFRS implementation of this provision.

(c)

YEC has incurred the following costs by year related to the implementation of IFRS:

Table 1:
Historical IFRS Costs: 2008 to 2011

YEAR	2008	2009	2010	2011	2008-2011 Total
Labour		52,065	52,467	53,425	157,956
Travel		2,035	2,832	2,591	7,458
Consultants	17,960	170,728	108,843	66,344	363,875
Legal	348				348
		1,495	16		1,511
ES&G	458	5,658	2,629		8,745
AFUDC	58	4,303	12,054	9,461	25,875
Total	**18,823**	**236,283**	**178,841**	**131,821**	**565,769**

The utility would propose to add this item to rate base at completion and amortize over a five year period. This treatment is proposed for this unique item that is a) non-recurring in nature, b) material to the financial results of the company and c) is non-discretionary (i.e. is a direction of a regulatory body with jurisdiction over the company). Therefore it is appropriate that these costs be recovered from ratepayers. The five year amortization period is considered a reasonable balance between recovery of costs to the utility against avoidance of a rate shock for customers.

TOPIC: **Secondary Sales**

REFERENCE: **Application page 2-2, lines 18-21**

YEC states:

> **Secondary sales have been interrupted on a sustained basis since September 2010 (except for temporary resumption in September 2011 due to high water in Aishihik Lake), and as a result of this sustained interruption a number of secondary sales customers have converted to primary supply for their electric heating loads.**

PREAMBLE:

The City requires quantification of the amount of secondary sales converted to firm load.

QUESTION:

a) What was the firm demand added by secondary sales customers converting to primary supply? Please provide converted sales by year for 2009, 2010, 2011 and 2012 to date.

b) Are there still secondary sales contracts? If yes, what is the total demand of these remaining secondary sales contracts?

ANSWER:

(a)

YEC has one secondary sales customer located in Mayo. This customer has not converted to primary supply. All secondary sales customers that have converted to primary supply are customers of YECL thus YEC does not have this information for these customers.

(b)

There are no secondary sales contracts. Secondary Sales customers have a customer account number with their retail service provider (YECL or YEC). The total demand of YEC secondary sales customers is estimated to be 400 kW. All of the secondary sales customers in the Whitehorse area are customers of YECL thus YEC does not have this information for these customers.

TOPIC: **Wholesale Sales**

REFERENCE: **Application page 2-3, line 22 to page 2-4, line 7**

YEC states:

> **Each year Yukon Electrical provides Yukon Energy with an Integrated Grid firm wholesale purchase power forecast reflecting its forecast grid firm retail sales less its forecast generation from its Fish Lake hydro plant. Yukon Energy reviews and adjusts the Yukon Electrical forecasts in light of the most recent information available.**
>
> **For GRA forecast purposes, available preliminary actual results for 2011 were considered and the 2011 actual YECL wholesale sales were adjusted to reflect expected in-service of a new Fish Lake hydro unit #1 in 2013 and to reflect adjustments for weather conditions based on 10 year average Heating Degree Days (HDD). A percentage growth increase of 2.26% per year was then applied to the adjusted 2011 actual wholesale sales (normalized assuming operation of both Fish Lake units) for each of 2012 and 2013 and additional sales were included for 2012 to reflect continuing shut down of Fish Lake Unit #1 until January 2013.**

PREAMBLE:

The City wishes to examine the basis for YEC's retail sales forecast.

QUESTION:

a) Please provide in detail YECL's actual retail sales forecast for each test year and the adjustments YEC applied to YECL's forecast to develop the wholesale sales forecast contained in this Application.

b) Did YEC consult with YECL concerning these adjustments? Please document the consultations.

c) Does YECL use the 10 year average Heating Degree Days to normalize its retail sales? Please explain the need to adjust YECL's forecast for Heating Degree Days.

d) Has the YUB approved the use of 10 year average Heating Degree Days as a method of normalizing temperature-sensitive sales?

ANSWER:

(a)

Please see response to YECL-YEC-1-3 and YECL-YEC-1-15.

(b)

Yes, in general terms.

(c)

YEC is not aware of the methods used by YECL to prepare its load forecast for 2012 and 2013. YEC is only provided with the end result of the forecast.

(d)

YEC is not aware of any Yukon Utilities Board's Order approving the use of 10-year average Heating Degree Days as a method of normalizing temperature-sensitive sales.

TOPIC: **Industrial Rate 39**

REFERENCE: **Application page 2-5, lines 1-4**

YEC states:

> **The GRA forecast also does not include any potential reduction in revenues related to use of the peak shaving rate option included in Rate Schedule 39 Industrial Primary. Electing to take service under this provision requires at least six months advance notice from the customer, and to date, such notice has not been provided.**

PREAMBLE:

QUESTION:

a) Why, in YEC's opinion, have industrial customers not elected to take the peak shaving rate option?

b) What could YEC do within the test years to make this option more attractive and what would be needed to gain approval for these changes?

ANSWER:

(a)

YEC cannot speculate on the reasons for the industrial customer decisions.

(b)

YEC cannot amend the provision. The Rate Schedule 39, which sets out this provision, is fixed by OIC until the end of 2013.

TOPIC: **Demand Side Management (DSM)**

REFERENCE: **Application page 2-5, lines 5-9**

YEC states:

> **Yukon Energy is working to develop and deliver an audit pilot program as part of ongoing DSM initiatives. At the current time, an audit of the Alexco mine facilities has been undertaken. However, audit recommendations have not yet been implemented, and consequently, no provision for savings has been forecast in the test years.**

PREAMBLE:

The City wishes to understand YEC's Industrial DSM initiative.

QUESTION:

a) What were the audit recommendations for the Alexco mine facilities?

b) Can any of these recommendations be implemented during the test years? If not, why not?

c) What revenues does YEC expect from the Alexco pilot program? What would be the cost of implementing any or all of these measures?

ANSWER:

(a) and **(b)**

Alexco is a private corporation. The results of the audit and audit recommendations contain confidential corporate data that is considered proprietary to Alexco and cannot be made publically available by YEC. It is Alexco's responsibility to share the outcome of their audit with interested parties.

(c)

YEC will not see any increased revenues from this pilot project. The energy audit of Alexco's Bellekeno mine was completed with a 50/50 cost sharing agreement – there is potential for an additional 25% contribution from YEC pending the implementation of audit recommendations. Implementation costs are the responsibility of Alexco Resource Corp

TOPIC: **Industrial Load**

REFERENCE: **Application page 2-6, lines 4-9**

YEC states:

> **Alexco is expected to develop further mines and mills in the Mayo-Keno area (as described in Figure C-1 Schedule C of the PPA) during its operating life; however, at this time due to uncertainty regarding the timing of such developments, power requirements for additional mines are not assumed in the load forecast. These additional mines are also expected to require development of mine electrical distribution facilities (that pursuant to the Alexco PPA would be fully paid for by the mine). Such facilities have yet to be developed.**

PREAMBLE:

The City wishes to evaluate this uncertainty surrounding YEC's Industrial load forecast.

QUESTION:

a) Is it possible that any expansion of the Alexco facilities will occur within the test years?

b) Are there any electrical facilities that will be required by the Alexco mines that will not be fully paid for by Alexco?

c) What would be the capital and operating costs of these additional assets including the assets contributed by Alexco.

ANSWER:

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

As indicated at page 2-6 of Tab 2, it is expected that Alexco mine will develop further mines and mills in the Mayo-Keno area; however the exact timing of such developments

is not known at this time. It is possible that a further development at the Alexco mine site may occur in the test years; however, current available information does not support this as a certainty at this time. In this regard, until further specific information is provided by Alexco as to requirements for future Mine Facilities Spurs, the specific capital and operating costs for such assets cannot be provided.

Were new information to become available prior to the hearing that would materially change the load forecasts in this regard, an update would be provided to the Board.

Pursuant to the Alexco mine Power Purchase Agreement approved by the Yukon Utilities Board in Order 2010-14 and 2011-01, Alexco will be required to pay to YEC the capital costs for any subsequent Mine Facilities Spurs that YEC agrees to develop (see Section 4.5 and Part 5, section 5.2). The Alexco mine PPA specifically includes provision for Alexco mine to pay 50% of YEC's estimated costs for such facilities prior to YEC ordering equipment for, or construction of such new Mine Facilities Spurs, with the balance of such Capital Costs to be paid by Alexco to YEC within 30 days of notice by YEC that such Mine Facilities Spurs are commissioned and available to receive Grid Electricity to provide to Alexco.

TOPIC: **Industrial Load**

REFERENCE: **Application page 2-6, lines 19-21**

YEC states:

> **It is expected that Whitehorse Copper Tailings would commence service in Q3 of 2013 as an industrial customer of Yukon Energy and that a PPA will be negotiated in 2012 in order to facilitate delivery of power to the mine site. The expected forecast load requirement for 2013 is 4.8 GW.h per year from the start of July to the end of November with 2.0 MW of peak demand.**
>
> **The expected mine life is six to seven years commencing in July 2013. After 2013, the mine is expected to operate nine months out of each year (March through November) at a typical annual load of 8.6 GW.h.**

PREAMBLE:

The City wishes to examine the effect of Whitehorse Copper Tailings on required facilities and rates.

QUESTION:

a) When in 2012 does YEC expect to execute a PPA with Whitehorse Copper Tailings?

b) Is it anticipated that Whitehorse Copper Tailings will trigger the need for any additional diesel generation in the months they will operate?

c) Will the PPA provide the customer with a credit for using any surplus hydro power during the months of operation?

ANSWER:

(a) through **(c)**

YEC does not have a specific date by which it expects to execute a PPA with Whitehorse Copper Tailings. The forecast load for this customer is included in the GRA 2013 forecasts, including provision for the seasonal load shape of the customer (which avoids any service in peak winter months). The customer will be required to pay Rate Schedule 39 on the same basis as any other Industrial customer.

TOPIC: **Industrial Load Forecast**

REFERENCE: **Application page 2-8, lines 7-10**

YEC states:

> **Victoria Gold has filed its Project Proposal with YESAB (December 2010), and on December 16, 2011, commenced the Screening Report stage of review. Victoria Gold has also announced a Letter of Intent with Yukon Energy and is expected to enter into a Power Purchase Agreement with Yukon Energy in 2012[20].**
>
> **Footnote 20 states:**
>
> **Victoria Gold announced LOI with Yukon Energy February 7, 2011 noting expectation to complete PPA by Q2 2011.**

PREAMBLE:

The City wishes to examine the difference between the text and the footnote.

QUESTION:

a) Please explain the difference between the expected dates of the Victoria Gold PPA provided at line 10 with the expected date provided in footnote 20.

ANSWER:

(a)

Victoria Gold announced an LOI with Yukon Energy noting an expectation to complete a PPA with Yukon Energy by Q2 2011 – this announcement occurred in February 2011. The GRA document was completed approximately a year after the noted announcement and reflects information current to the date of preparing the GRA. PPA discussions between YEC and Victoria Gold remain ongoing as Victoria Gold completes its YESAB review.

TOPIC: **Retail Load Forecast**

REFERENCE: **Application page 2-8, lines 16-23**

YEC states:

> **Yukon Energy firm retail sales are comprised of sales to residential, general service, street light and space light customer classes served directly by Yukon Energy. The 2013 forecast indicates a 2.6% average annual increase in Yukon Energy's non-industrial retail sales over 2009 (actual).**
>
> **In sum, retail sales grew by 7.95% in 2010 over 2009 (actual), declined by 0.26% in 2011 over 2010, and are forecast at the same level for 2012 as in 2011. Retail sales are expected to grow by 2.9% in 2013 over 2012. The decline in retail sales in 2011 relates primarily to a decrease in retail sales in the general service class due to a decrease in Faro mine dewatering sales in combination with Alexco mine commencing service as an industrial customer in October 2010.**

PREAMBLE:

The City wishes to understand YEC's retail sales forecast.

QUESTION:

a) Please demonstrate in detail how YEC developed its retail load forecast from the economic growth and historical growth factors employed in forecasting.

b) Please explain in detail how "a decrease in Faro mine dewatering sales in combination with Alexco mine commencing service as an industrial customer in October 2010" caused a decline in retail sales.

ANSWER:

(a)

YEC's 2012 and 2013 retail base load forecasts (i.e., retail customers served directly by YEC) are based on prior years' actual sales and forecast customer numbers. Customer data for the prior 3 years have been reviewed 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 baseload forecast sales by month by rate class.

For smaller areas where there are fewer General Service Customers (Braeburn, Champagne, N. Klondike, Johnsons Crossing) the load is forecast based on a customer by customer review of usage plus provision for any new customers.

The 3 year period is chosen as it most closely reflects the current use per customer (i.e. includes recent additions for residential electric heating customers, has seasonal variation for the past 3 winters and is representative of recent economic activity levels for general service customers).

In order to incorporate any incremental load forecast 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 major customer connections and forecast additional load that they will represent. For example, the 2013 General Service forecast includes about 2.4 GWh of sales to the new hospital, sewage plant and other larger additions in Dawson area.

Streetlights and Sentinel Lights are assumed at the same level as prior years with some minor adjustments.

(b)

Prior to commencing operation as an industrial customer pursuant to Rate Schedule 39 Industrial Primary Rate, Alexco received service as a general service customer of YEC on the Mayo Dawson grid, purchasing power in the Keno Hill area to carry out exploration, bulk sampling, management and other mine development activities.

After commencing Alexco operation as an industrial customer, all sales to Alexco started to be reported under Rate Schedule 39 which resulted in a decrease in general service sales.

The statement regarding Faro mine dewatering sales was incorrect as the sales numbers for 2011 were preliminary and there was a data transfer error. The actual Faro mine dewatering sales were 4.9 GW.h in 2011 compared to 4.7 GW.h in 2010.

TOPIC: **Secondary Sales Forecast**

REFERENCE: **Application page 2-10, lines 10-14**

YEC states:

> **To the extent secondary sales become available in the test years, YEC proposes to credit the secondary sales revenue directly to the Diesel Contingency Fund (DCF). It is expected that secondary sales would only become available due to higher water flows. Crediting any additional revenues on this basis is consistent with the principles underlying the DCF and would serve to stabilize revenues and rates in the test years.**

PREAMBLE:

The City wishes to understand YEC's proposal for the disposition of secondary sales revenue.

QUESTION:

a) What are the "principles underlying the DCF" that YEC's proposal for secondary sales is consistent with?

b) Please provide a numerical example of how YEC's proposal would "stabilize revenues and rates in the test years". Would YEC's proposal provide similar stability beyond the test years?

c) Would a deferral account solely for secondary sales revenue provide similar stability in the test years and beyond? Please provide a numerical example in support of YEC's answer.

ANSWER:

(a)

The key principle underlying the DCF is that rates should be set based on normal (long-term average) water conditions (or a percentage thereof) and costs related to variations in water flow should flow through the DCF. On a long-term average forecast basis, YEC's rates would now include provision for material baseload diesel generation and would not assume secondary sales would be made available. Opportunities for secondary sales will now, by definition, arise only under specific short-term conditions.

YEC's proposal to credit secondary sales revenue directly to the DCF is consistent with the above DCF principle, i.e., that that rates should be set based on normal (long-term average) water conditions (or a percentage thereof) and costs related to variations in water flow should flow through the DCF. Any secondary sales revenues that do arise only come about due to better than average water flows, and as such are a water flow related variations in the same way diesel costs for low water are a water flow related variation. Under YEC's proposal, these short-term water variations will not affect rates that are based on long-term average water conditions, but will help to fund the DCF costs during periods with below average water conditions.

(b)

Under a hypothetical situation where short-term secondary sales revenues that happened to be forecast in 2012 due to present higher-than-average water conditions were included in the revenue requirement, there would be a need to adjust this back out of rates in 2013 and 2014, etc. as water conditions vary to some other level (e.g., normal or below average). This would drive complexity and rate instability.

YEC's proposal continues to provide stability beyond the test years, i.e., the DCF's operation is not limited to the test years.

(c)

Potentially yes, depending on the design of the deferral account. The YEC proposed approach is to defer secondary sales revenues to the benefit of customers via the DCF. This could also be done, on the same underlying premise in a separate deferral account

(i.e., assume $0 in revenues for the purposes of setting the revenue requirement, and any variations from this level are deferred) but there would be no apparent benefit as compared to YEC's proposal.

Similar stability would not be achieved if secondary sales revenues were "fixed" at a given dollar value in the test years and any variations from this dollar value were deferred, as there is no level of secondary sales that can be reasonably forecast to be the new or future "normalized" level of revenues. Such a deferral account would likely quickly move into a negative position and require some form of rate increase or rider to recover the uncollected balance.

At this time, the DCF is low in funding relative to the potential future cost claims on this account. Placing secondary sales revenues directly into the DCF will support rate stability and ensure that these funds go directly toward funding of DCF costs during years with below average water conditions.

TOPIC: **System Generation**

REFERENCE: **Application page 2-11, lines 13-15**

YEC states:

> **Seasonal water storage is typically needed for hydro facilities to be fully utilized in winter. In Yukon, controlled seasonal storage exists at Aishihik and to a much lesser extent at Mayo, but is largely unavailable at Whitehorse.**

PREAMBLE:

The City wishes to understand the operation of the Integrated System.

QUESTION:

a) Is seasonal hydro at both Aishihik and Mayo or just Mayo "largely unavailable at Whitehorse"? Please explain fully.

b) In either case, please demonstrate by a numerical example how seasonal hydro from both Aishihik and/or Mayo is not available at Whitehorse.

ANSWER:

(a) and **(b)**

Both the Aishihik plant and the Mayo plant have storage that permits their full installed capacity to be used in supplying winter load, consistent with the plant's design criteria (Aishihik as a plant with major peaking capability, Mayo as a much more baseloaded plant). None of the water stored at Aishihik or Mayo can physically be used at Whitehorse as they are on different river systems.

In contrast, Whitehorse does not have sufficient storage to permit use of the plant's full installed capacity (40 MW) in winter. The storage available at Whitehorse only sustains between 24 MW and 28 MW of winter capacity, depending on the inflows to Marsh Lake occurring during the winter.

TOPIC: **Fuel Price Forecast**

REFERENCE: **Application page 3-5, line 8 to 11**

YEC states:

> **Forecast fuel prices for the 2012/2013 test years are $1.0513 per litre for Whitehorse, $1.0885 per litre for Faro, $1.168 per litre for Dawson and $1.0966 per litre for Mayo and reflect the most recent fuel prices for YEC. This is higher than the fuel price forecast at the 2009 approved fuel prices of $0.96/litre, $0.992/litre, $0.975/litre and $0.967/litre respectively.**

PREAMBLE:

The City wishes to analyze YEC's salary increases.

QUESTION:

a) When YEC states "Forecast fuel prices…. reflect the most recent fuel prices for YEC", what was the actual price of fuel at the time this forecast was made?

b) What was the actual price of fuel for Whitehorse, Faro, Dawson and Mayo for the first six months of 2012?

c) Is the 2012 and 2013 fuel price forecast based on any acknowledged forward price such as the NYMEX Refined Product Futures? If not, what is the transportation differential for Whitehorse, Faro, Dawson and Mayo compared to the NYMEX price?

d) Does YEC undertake to revise its fuel price forecasts at the time of the hearing?

ANSWER:

(a) and **(b)**

Fuel prices used in the Application were fixed during preparation in February 2012. Prices used were the actual contract price paid by YEC in that month.

Please see Table 1 below for the actual contract fuel prices for the first six months of 2012.

Table 1:
Actual Diesel Fuel Price per Litre for January 2012 to June 2012

Month	Whitehorse	Faro	Mayo	Dawson
Jan-12	$ 1.0343	$ 1.0715	$ 1.0796	$ 1.0998
Feb-12	$ 1.0513	$ 1.0885	$ 1.0966	$ 1.1168
Mar-12	$ 1.1473	$ 1.1845	$ 1.1926	$ 1.2128
Apr-12	$ 1.1713	$ 1.2085	$ 1.2166	$ 1.2368
May-12	$ 1.1443	$ 1.1815	$ 1.1896	$ 1.2098
Jun-12	$ 1.0683	$ 1.1055	$ 1.1136	$ 1.1338
Average	**$ 1.1028**	**$ 1.1400**	**$ 1.1481**	**$ 1.1683**

Please note that the GRA document contains a typographical error at page 3-5, line 9 in regards to the Dawson fuel price (cited as "$1.168 per litre", should be $1.1168 per litre" as per Table 1). This change has no effect on the GRA numbers.

(c)

The 2012 and 2013 fuel price forecast is not based on any forward price.

The fuel price forecast is based on the actual Vancouver rack market price (not NYMEX price) in February 2012 plus a delivery differential. The differential charged under this contract are as follows (in cents per liter):

Whitehorse	0.1613
Dawson	0.2268
Mayo	0.2066
Faro	0.1985

(d)

No. Yukon Energy does not intend to revise its fuel price forecasts at the time of the hearing.

TOPIC: **Employee Salaries**

REFERENCE: **Application page 3-6, line 19 to 3-7, line 1**

YEC states:

> **The average annual increase in salaries per FTE is 4.3% from 2009 approved to 2013 forecast.**

PREAMBLE:

The City wishes to analyze YEC's salary increases.

QUESTION:

a) Please provide a table similar to Table 3.4 that provides percentage salary increases by year by department. Please add an additional line that provides the Yukon CPI by year and the forecast inflation rates used in this application.

ANSWER:

(a)

Please see Table 1 below for percentage salary increases by year by department. Table 1 includes all payments to employees in the respective departments for salaries and benefits in the year (e.g., Box 14 of T4 slips). These percentages include changes due to employee complement, vacancies, and all other factors affecting payroll expenses.

Table 1:

Percentage Salary Increase by Year by Department

Department	% Change 2009 Compliance/ 2009 Actual	% Change 2009Actual/ 2010 Actual	% Change 2010 Actual/ 2011 FYF	% Change 2011FYF/ 2012 Forecast	% Change 2012 Forecast/ 2013 Forecast
President	9.2%	-11.4%	6.5%	-42.9%	2.25%
Communications	7.9%	-5.4%	7.5%	12.9%	2.25%
HR & IT	-27.6%	10.3%	9.6%	12.5%	2.25%
Resource Planning & Environment	41.7%	1.2%	44.3%	33.1%	2.25%
Finance, Cust. Acctg & Purchasing	-0.7%	1.7%	7.0%	19.5%	2.25%
Operations	9.1%	10.3%	11.0%	-7.9%	2.25%
Engineering Services	-20.2%	-7.4%	-16.7%	41.5%	2.25%
Health, Saftey & Environment	33.8%	-3.1%	9.6%	14.5%	2.25%
Total	**2.3%**	**4.3%**	**8.7%**	**8.6%**	**2.25%**

Please refer to IR YUB-YEC-1-13(e) for the Yukon CPI by year.

TOPIC: **Operating and Maintenance (O&M) Expenses**

REFERENCE: **Application page 3-8, Table 3.4**

YEC provides the following table:

Table 3.4
Employee Complement History

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
President	2.50	4.50	5.50	5.50	4.50	4.50
Communications	1.00	1.00	1.00	1.00	1.00	1.00
Human Resources & Info. Mgmt.	7.00	5.00	6.00	7.10	6.25	6.25
Resource Planning and Environment	1.00	2.00	2.00	6.00	7.00	7.00
Finance, Cust. Acctg. & Purchasing	12.81	14.08	13.69	15.75	17.00	17.00
Operations	40.10	40.61	41.49	41.44	41.25	41.25
Engineering Services	12.00	12.00	15.44	14.00	13.00	13.00
Health, Safety & Environment	3.33	2.00	2.00	2.00	2.00	2.00
Total	79.74	81.19	87.12	92.79	92.00	92.00

Note:
1. The employee complement numbers are net of allocation to YDC.

PREAMBLE:

The City wishes to understand YEC's employee complement.

QUESTION:

a) Please provide a detailed explanation of the FTE additions or decreases to each department by year and why the additions were necessary.

b) Please provide the FTE vacancies in each department by year.

c) Please provide a current organization chart for the corporation and indicate which positions are currently vacant.

ANSWER:

(a)

Please refer to Section 3.3.5 of the Application for a detailed explanation and justification of the FTE changes.

(b)

Please see the response to YECL-YEC-1-46(c) for annual vacancy rates by department.

(c)

Please see the response to YECL-YEC-1-46(a). The currently vacant positions are as follows:

- Supervisor Electrical Engineering;
- Capital Electrician;
- Leadhand, T&D;
- SCC operator;
- Financial Administrator; and
- Manager Resource Planning.

TOPIC: **Operating and Maintenance (O&M) Expenses**

REFERENCE: **Application page 3-8, Table 3.6**

YEC provides the following table:

Table 3.6
Transmission Costs
($000)

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Labour	$ 482	$ 453	$ 319	$ 396	$ 431	$ 431	$ 440	$ 440
Brushing	377	387	268	434	505	505	639	639
Other Non-Labour	235	369	208	280	255	255	214	214
Total Transmission	$ 1,094	$ 1,208	$ 795	$ 1,110	$ 1,190	$ 1,190	$ 1,293	$ 1,293

PREAMBLE:

The City wishes to analyze YEC's transmission costs.

QUESTION:

a) Please provide a detailed explanation of the increases/decreases year by year for Transmission Labour, Brushing and Other Non-Labour expenses in Table 3.6.

b) Please provide Table 3.6 showing each category of annual transmission costs on a $/km of transmission line basis.

ANSWER:

(a)

Labour – Actual 2009 is about 6% less than compliance; no specific cause is noted for this variance. In 2010, labour drops $0.134 million from 2009; the primary cause of this is the loss of two power line technicians in June of that year. In 2011, these positions

were successfully re-staffed and labour costs recovered close to 2009 levels. Costs continue to increase in 2012 and 2013, primarily due to union agreement increments.

Brushing – Please see YUB-YEC-1-17(b) for analysis of brushing variances.

Non-labour – 2009 actual expense is materially higher than forecast due to higher than planned maintenance on overhead transmission line 170 (about ($0.060 million) and unplanned substation maintenance in Whitehorse and communities ($0.075 million). 2010 results were fairly close to budget although some unexpected charges were incurred to service the Mayo to Keno transmission line ($0.030 million). The 2012 and 2013 forecasts are best estimates by transmission line and average in line with previously reviewed budgets.

(b)

Please see Table 1 below for the requested information.

Table 1:
Transmission Costs per km of Transmission Line ($000)

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	Existing 2012	GRA 2012	Existing 2013	GRA 2013
Labour	482	453	319	396	431	431	440	440
Brushing	377	387	268	434	505	505	639	639
Other Non-Labour	235	369	208	280	255	255	214	214
Total	1,094	1,209	795	1,110	1,191	1,191	1,293	1,293
Km of Transmission Lines	849	849	931	935	935	935	935	935
Cost per Km of Transmission Line								
Labour	0.57	0.53	0.34	0.42	0.46	0.46	0.47	0.47
Brushing	0.44	0.46	0.29	0.46	0.54	0.54	0.68	0.68
Other Non-Labour	0.28	0.43	0.22	0.30	0.27	0.27	0.23	0.23
Total	1.29	1.42	0.85	1.19	1.27	1.27	1.38	1.38

TOPIC: **Operating and Maintenance (O&M) Expenses**

REFERENCE: **Application page 3-9, Table 3.7**

YEC provides the following table:

Table 3.7
Distribution Costs
($000)

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Labour	$ 521	$ 546	$ 477	$ 473	$ 579	$ 579	$ 592	$ 592
Brushing	46	17	16	68	93	93	113	113
Other Non-Labour	132	97	96	116	108	108	113	113
Total Distribution	$ 699	$ 660	$ 588	$ 657	$ 780	$ 780	$ 819	$ 819

PREAMBLE:

The City wishes to analyze YEC's distribution costs.

QUESTION:

a) Please provide a detailed explanation of the decreases in brushing and other non- labour costs from that forecast for 2009 and actually incurred in 2009 and 2010.

b) Please provide Table 3.7 showing each category of annual distribution costs on a $/km of distribution line basis.

ANSWER:

(a)

See Table 1 attached to YECL-YEC-1-45. Actual expenses were lower in 2009 and 2010 for several reasons: brushing – completed with internal labour as opposed to contractors; both meter and street light maintenance were lower than planned.

(b)

Please see Table 1 below for the requested information.

Table 1:

Distribution Costs per km of Transmission Line ($000)

	2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	Existing 2012	GRA 2012	Existing 2013	GRA 2013
Labour	521	546	477	473	579	579	592	592
Brushing	46	17	16	68	93	93	113	113
Other Non-Labour	132	97	96	116	108	108	113	113
Total Distribution	699	660	588	657	780	780	819	819
Km of Distribution Lines	407	407	409	412	421	421	426	426
							est.	est.
Cost per Km of Distribution Line								
Labour	1.28	1.34	1.17	1.16	1.43	1.43	1.46	1.46
Brushing	0.11	0.04	0.04	0.17	0.23	0.23	0.28	0.28
Other Non-Labour	0.32	0.24	0.24	0.29	0.27	0.27	0.28	0.28
Total Distribution	1.72	1.62	1.45	1.61	1.92	1.92	2.01	2.01

TOPIC: **Insurance and Reserve for Injuries & Damages**

REFERENCE: **Application page 3-17, Table 3.10**

YEC provides the following table:

Table 3.10
Insurance and Reserve for Injuries & Damages
($000)

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Insurance	$ 952	$ 787	$ 787	$ 774	$ 835	$ 835	$ 895	$ 895
Reserve Appropriation (RFID)	100	100	100	100	100	231	100	231
Total	$ 1,052	$ 887	$ 887	$ 874	$ 935	$ 1,066	$ 995	$ 1,126

Note:
1. Actual 2009 reserve appropriation was reduced from $0.150 million to $0.1 million to comply with YUB Order 2009-8.

PREAMBLE:

The City wishes to analyze YEC's insurance costs.

QUESTION:

a) Please provide a detailed explanation of the variances in insurance costs between that approved in 2009 and the actual amounts in 2009, 2010 and 2011. How did YEC dispose of the difference between the forecast and actual Insurance costs?

b) Please provide the invoice for insurance for 2012.

c) Please provide a continuity schedule in Excel format of the Reserve for Injuries and Damages account from its inception to date (2Q 2012) that clearly sets out all additions, charges, opening and closing balances on a yearly basis.

d) Please provide a history of claims against the existing property and liability policies with an explanation as to why a claim was made rather than charging the loss to the Reserve for Injuries and Damages.

ANSWER:

(a)

There was an assumption in the 2009 GRA forecast of an increase in costs in 2009 as part of a potential change in brokers. The increase in costs did not occur.

YEC did not "dispose of the difference" -- all expenses regardless of whether they are more or less than the forecast for the GRA become part of the regulatory return YEC files with the YUB.

(b)

Please see Attachment 1 to this response.

(c)

Please see response to CW-YEC-1-43(b) and YECL-YEC-1-51(b).

(d)

There have been no claims during the 2009 to 2012 period.

INVOICE NO. 3260000121127

INVOICE

Aon Reed Stenhouse Inc.
900 Howe Street
P.O. Box 3228
Vancouver, BC V6B 3X8
tel 604-688-4442 *fax* 604-682-4026

Account No.	320000032535
Invoice Date	08-Jun-2012
Currency	CANADIAN DOLLAR
Account Executive	Anhalt,Edward F.

Yukon Energy Corporation
P. O. Box 5920
Whitehorse, YT Y1A 6S7

Name of Insured	Yukon Energy Corporation and Yukon Development Corporation		
Policy Number	A2600373/3		
Effective Date	01-Jun-2012	**Expiry Date**	01-Jun-2013

Particulars

Renewal Commercial Package

"All Risks" Property Package
June 1, 2012 to June 1, 2013

Total for Insurers	674,763.00
Invoice Total	**674,763.00**

Placements with exposures outside of Canada may be subject to self-assessment for taxes and/or fees in foreign jurisdictions. Please consult your independent tax advisor.

1

Premiums are due and payable in full by the effective date of insurance coverage. Policies must be returned at once if not required.

Please Detach here. Retain top portion for your records and return bottom portion with your payment.

Account No.	Invoice No.	Amount Due	Invoice Currency
320000032535	3260000121127	674,763.00	CANADIAN DOLLAR

Please make cheque payable to Aon Reed Stenhouse Inc.

Aon Reed Stenhouse Inc.
900 Howe Street
P.O. Box 3228
Vancouver, BC V6B 3X8

Yukon Energy Corporation
P. O. Box 5920
Whitehorse, YT Y1A 6S7

TOPIC: **Regulatory Costs**

REFERENCE: **Application page 3-22, lines 19-22**

YEC states:

> **Regulatory costs ($0.972 million in 2012 and $1.252 million in 2013 compared to $0.489 million in 2009 approved), including the impacts of amortizing the current GRA over 2 years, 2008/09 Phase II GRA costs over 2 years, the Resource Plan cost over 5 years and DSM proceeding over 10 years and other projects as set out in Tab 5.**

PREAMBLE:

The City wishes to analyze YEC's regulatory costs**.**

QUESTION:

a) Please provide a continuity schedule in Excel format of YEC's regulatory costs account showing additions, amortizations and opening/closing balances. Please provide cross-references for additions.

b) What is the basis for YEC's forecast of regulatory costs for 2012 and 2013?

ANSWER:

(a)

Please see Attachment 1 for continuity schedule of YEC's regulatory costs in Excel format.

(b)

The regulatory cost forecasts for 2012 and 2013 include the following cost as outlined in Tab 5 of the 2012/13 GRA Application:

- $1.1 million for 2012/13 GRA Phase I review. This is a placeholder forecast cost of preparing and filing a 2012/2013 Phase I GRA, as well as a full regulatory review, and all required payments to the Board and intervenors, all of which is ultimately subject to the Yukon Utilities Board's decisions.

- $0.23 million spending forecast in 2012 for Resource Plan Update. This spending forecast includes the preparation of the 2011 Resource Plan Update required to facilitate decision making on major infrastructure projects by providing new additional information on load forecasts, generation and transmission options as well as an assessment of alternatives.

- $1.074 million in 2012 and $1.635 million in 2013 for DSM. A material portion of DSM costs incurred to date, and expected to be incurred in the test years, relate to internal DSM within YEC. This includes feasibility study, planning and implementation of conservation improvements at Yukon Energy's existing buildings and facilities. In 2011, Yukon Energy retained a third party consultant to conduct an energy audit of 25 of its buildings to determine significant areas where energy reductions could be made (of this, 6 were selected based on ease of access and opportunities for savings). Specific internal DSM activities will be undertaken in the test years and may include lighting upgrades, upgrades to building envelope and replacement of fixed pumps with variable speed pumps. The benefit of this form of DSM is that since Yukon Energy is carrying out the changes there is assurance that the activities will be undertaken and targeted savings achieved.

YUKON ENERGY CORPORATION **Table 5.7**
Continuity Schedule of Deferred Costs (2013)
($000S)

	Total Expenditures					Accumulated Amortization		
	Dec 31	Forecast 2013		Forecast	Amortization Rate and Method	Dec 31	2013 Forecast	Forecast
	2012	Additions	Transfers/ Write-offs	2013		2012	expenses	2013
Rate Case								
Completed projects:								
YUB 2007-7 & 9 - Resource Plan	642,853			642,853	SL-10 years	321,427	64,285	385,712
YUB 2007-7 & 9 - PPA Review	243,045			243,045	SL-12 years	101,269	20,254	121,522
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years	20,557	4,111	24,668
Reserve for Injuries & Damages - Study	42,500			42,500	SL-2 years	21,250	21,250	42,500
2008/2009 GRA Phase 2	312,537			312,537	SL-2 years	156,269	156,269	312,537
Brushing & ROW Veg Management	173,227			173,227	SL-2 years	86,614	86,614	173,227
Alexco PPA Regulatory Costs	53,854			53,854	SL-5 years	10,771	10,771	21,541
DSM	2,111,179	1,635,000		3,746,179	SL-10 years	30,262	137,662	167,925
DSM Contributions	(734,554)			(734,554)	included in above			
Rate Schedule 39 Inflation Update	25,691			25,691	SL-2 years	12,846	12,846	25,691
Rider F Policy Review	31,535			31,535	SL-2 years	15,768	15,768	31,535
Resource Plan Update	858,906			858,906	SL-5 years	-	171,781	171,781
2012/2013 GRA Phase I	1,100,000			1,100,000	SL-2 years	550,000	550,000	1,100,000
Total Rate Case Closed	5,045,784	1,635,000	-	6,680,784		1,327,030	1,251,610	2,578,640

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

TOPIC: **Depreciation Study**

REFERENCE: **Application page 3-23, lines 15-7**

YEC states:

> **Yukon Energy has undertaken a review of its depreciation rates and provisions, using an external expert (KPMG). The result of this review is a significant change in the Corporation's service lives for certain major assets. The updated Yukon Energy depreciation study is provided in Tab 10 of this filing.**

PREAMBLE:

The City requires more information to analyze YEC's proposed changes in depreciation and amortization.

QUESTION:

a) Please prepare a summary table that compares YEC's existing depreciation rates by asset class to YEC's proposed depreciation rates, the reasons for each change and a cross-reference to the depreciation study in Tab 10.

b) Does YEC retain its Fund for Removal, Salvage and Remediation (FRSR)? If yes, please provide a continuity schedule in Excel format of additions, withdrawals and opening and closing balances since 2009.

ANSWER:

(a)

Please see Table 1 for a comparison. For reasons for the changes, please see YECL-YEC-1-55.

Table 1:
Comparison of Existing versus Proposed Depreciation Rates
(Where proposed is blank, no change is proposed)

		Existing Depreciation Rate	Proposed Depreciation Rate
Land			
Hydro Plant (140003)			
Structures and Improvements	200	2.5	1.39
Reservoirs, dams and waterways	205	2	0.97
Waterwheels and turbines	506	1.54	1.18
Accessory electric equipments	600	2.22	
Misc power equipment	700	3.33	
Fencing	730	2.5	
Diesel Plant (140004)			
Structures and improvements	200	2.5	1.39
Buildings and improvements	201	2.5	1.82
Fuel holders and products	403	4	
Generating equipment	500	3.33	2.5
25 Kv Minto spur- Generating Equipments	508	8.333	
Accesory electric equipments	600	2.22	
Misc power plant equip	700	3.33	
Wind Turbine		3.33	
Main Transmission (140006)			
Poles and fixtures	300	2	1.54
Brushing	304	2	
Survey costs	305	2	
Overhead conductors - Poles	402	2	
Overhead conductors - Towers	404	2	
Substation equipment	710	2.5	1.85
Substations building	720	2.5	1.82
Fencing	730	5	
Sub Transmission (140007)			
Poles and fixtures	300	2.22	
25Kv Minto Spur- Structure	301	8.333	
Brushing	304	8.333	
Survey costs	305	8.333	
25 Kv Minto Spur - Clearing Costs	306	8.333	
25 Kv Minto Spur - Survey Costs	307	8.333	
Overhead conductors - Poles	401	2.22	
Underground conductors	405	2.22	
25Kv Minto Spur- Overhead Conductor	407	8.333	
Substation equipment	710	8.333	
Minto Mine Substation	711	8.333	

Table 1:
Comparison of Existing versus Proposed Depreciation Rates
(Where proposed is blank, no change is proposed) - continued

		Existing Depreciation Rate	Proposed Depreciation Rate
Distributions (140008)			
Poles and fixtures	300	2.86	
Brushing	304	2	
Survey costs	305	2.86	
Overhead conductors - Poles	401	2.86	
Overhead - services	410	2.5	
Underground services	510	2.5	
Meters	610	3.33	
Meters equipment	620	3.33	
Sub-station equipment	710	2.5	
Substation buildings	720	2.22	1.82
Street lights	815	2.5	
Line transformers	905	2.5	
Sentinel lights	961	3.33	
Building & Equipments (140009)			
Survey costs	110	2	
Structures and improvements	200	2.5	
Buildings and improvements	201	2.5	1.82
Office furniture and equipment	202	5	
Communication site towers	210	3.33	
Communication site fences	220	5	
Main Frame Computer (APL Share)	310	16.29	
Computer hardware	320	16.29	
Computer software	330	20	
Tools and instruments	505	5	
Wind monitoring equipment	507	5	
Communication equipment	605	5	
Company owned housing - land	810	2.83	
Company owned housing - buildings	820	2.83	
Transportation (140014)			
Utility vehicles	411	8.75	
Sedans & wagons	412	11.43	
Trucks and Pole Trailers	420	3.2	
Pole trailers > 10,000 lbs	430	3.2	
Trucks 3/4 to 2 ton	440	8	
Trucks > 3 ton	470	4	
Foremost	490	4	

(b)

Please see Table 2.

Revised Response August 1, 2012

Since filing interrogatories July 27, 2012, the response to part (b) has been revised to correct an error in Table 2. The column for 2011 was missing a charge for 2011. A revised version is provided below and provided as an Excel attachment as well.

Table 2:
Reserve for Future Removal and Site Restoration (FRSR)

FRSR Continuity Schedule ($000s)

	2009	2010	2011
Site Restoration Reserve Opening Balance	(5,168)	(5,008)	(4,764)
Additions			
Withdrawals	160	243	53
Ending Balance	(5,008)	(4,764)	(4,711)

TOPIC: **Insurance and Reserve for Injuries & Damages**

REFERENCE: **Appendix 3.1, page 3.1-2**

YEC provides the following table:

> **4.0 Criteria**
>
> 4.1 Uninsured and uninsurable losses and associated costs will be charged to the RFID if they meet the following criteria:
> (a) The loss exceeds $10,000;
> (b) The loss was sudden and accidental and not the result of normal wear and tear;
> (c) The incident was of significance to the operation of the unit; and
> (d) The loss was one of low probability, not normally expected to occur in a typical operating year.
>
> 4.2 The deductible portion of insured losses and any portion of a loss not covered by insurance and not related to betterment of the asset, and any extra expense related to an uninsurable or uninsurable unplanned plant outages[3] will also be charged to the RFID.

PREAMBLE:

The City wishes to analyze YEC's insurance costs.

QUESTION:

a) Has YEC applied any of these criteria to its charges to the Reserve for Injuries and Damages? If yes, which criteria were implemented and when were they implemented?

b) When YEC expenses losses and damages under the threshold, what account is charged with the loss?

c) How did YEC determine that $10,000 is the appropriate threshold of materiality?

d) Does YEC propose charging all of a loss exceeding $10,000 to the Reserve for Injuries and Damages or will YEC expense the portion below $10,000?

e) What is the maximum amount that YEC will charge to the Reserve for Injuries and Damages?

f) Please provide examples of the types of losses that YEC proposes charging to the Reserve for Injuries and Damages under criterion 4.2.

g) What losses has YEC experienced in the past that would qualify under criterion 4.2? Did YEC claim these against the Reserve for Injuries and Damages or were these expensed?

h) What losses and damages does YEC's property and liability insurance cover? Please provide the appropriate documentation from YEC's policies.

ANSWER:

(a)

The criteria were applied in reviewing charges to the RFID account for the current Application. Costs that were deemed to not meet the criteria as described in the policy were not charged to the Reserve.

(b)

Generally, small dollar losses below the threshold will be absorbed by the responsible budget area.

(c)

The $10,000 threshold was established based on a review of historical losses and comments received during the previous regulatory proceeding (2008/09 GRA).

(d)

YEC will charge the full value of the loss to the reserve.

(e)

There is no maximum; all qualifying charges will be recorded against the reserve.

(f) and **(g)**

Examples of charges to the Reserve under criteria 4.2 include:

- Uninsured loss: Insurance is unavailable for transmission lines. In 2008 an insulator on L172 was vandalized. The cost of the incident was charged to the reserve.

- Loss below deductible: In 2007 a high water event damaged the Lewes control structure. The costs of the event were lower than the deductible for this type of event.

- Deductible charged to Reserve: The policy specifies insurance deductibles are to be charged to the reserve. In the period 1997 to 1999, the insurance deductible for the Whitehorse Fire was charged to the reserve (however, these amounts were later credited back to the reserve as the recoveries from the insurer ultimately exceeded the direct costs of the event).

(h)

Please see Attachments 1 to Attachment 6 of this response for copies of Yukon Energy's current insurance policies. Specifically the following are provided:

- Attachment 1 – Property Insurance;

- Attachment 2 – Umbrella Liability Policy;

- Attachment 3 – Excess Liability Insurance;

- Attachment 4 – Management Liability, Professional Liability, Crime Coverage and Kidnap and Ransom/Extortion Coverage for Private Companies;

- Attachment 5 – Crime Shield Policy: Comprehensive Dishonesty, Disappearance and Destruction; and

- Attachment 6 – Comprehensive General Liability Policy.

File 0735-06-17A

Declarations

Policy No. A2600373/3

IN CONSIDERATION OF THE PREMIUM CHARGED, THE INSURERS NAMED IN THE LIST OF SUBSCRIBING INSURERS FORMING A PART HEREOF, HEREINAFTER CALLED THE INSURER(S), DO HEREBY SEVERALLY AND NOT JOINTLY AGREE, EACH FOR THE LIMIT OR SUM INSURED (OR PERCENTAGE OF THE TOTAL LIMIT OR SUM INSURED UNDER THIS POLICY) SET AGAINST ITS NAME IN THE LIST OF SUBSCRIBING INSURERS, TO INDEMNIFY THE INSURED FOR LOSS AS HEREINAFTER SET FORTH, SUBJECT TO THE LIMITS OF LIABILITY CITED HEREIN AND FURTHER SUBJECT TO ALL CONDITIONS, TERMS AND LIMITATIONS OF THIS POLICY AS ARE PRESENTLY CONTAINED HEREIN OR WHICH MAY BE ENDORSED HEREON

NAME OF INSURED:	YUKON DEVELOPMENT CORPORATION (hereinafter called the Named Insured) and/or YUKON ENERGY CORPORATION, its parent and/or all Subsidiaries of the foregoing (including Subsidiaries thereof), Associated and Affiliated Companies, Partnerships and Joint Ventures and any company or organization under the Control or Active Management of any of these as now exist or that may hereafter be constituted and those on whose behalf the Named Insured has agreed, in writing to provide insurance, as more fully defined in the Policy Wording.
NOTIFICATION ADDRESS:	Box 5920, #2 Miles Canyon Road Whitehorse, Yukon YIA 657 Canada
PERIOD OF INSURANCE:	From: June 1, 2012 00:01 a.m. Standard Time at the Notification Address of the Named Insured To: June 1, 2013 00:01 a.m. Standard Time at the Notification Address of the Named Insured
LOSS PAYABLE:	Loss, hereunder, if any, payable to the Insured or Insured's Order. IN THE EVENT ANY OF THE LOSS PAYEES ARE REGISTERED MORTGAGEES, THE PROVISIONS OF THE STANDARD MORTGAGE CLAUSE APPLY.
INTEREST:	Real and personal property of every description, whether owned, leased or occupied by the Insured, and/or held in trust and/or property of others for which the Insured has assumed liability or responsibility to effect insurance and/or property in the Insured's care, custody or control and including Transmission and Distribution Lines within 1,000 feet of the property line of the Insured's generating premises and at McIntyre, Aishihik, Takhini, Anvil. Mayo and Dawson substations, Property in Course of Construction, Extra Expense and Contingent Extra Expense, Accounts Receivable, Data Processing and Valuable Papers and Records.
PERILS INSURED:	All Risks of Direct Physical Loss or Damage except as hereinafter excluded.
VALUES DECLARED:	CAD 749,736,900 (not including Transmission and Distribution lines within 1,000 feet of Insured's premises)
CURRENCY:	Canadian Dollars (CAD)

SEVERAL LIABILITY CLAUSE:	The subscribing Insurers' obligations under contracts of insurance to which they subscribe are several and not joint and are limited solely to the extent of their individual subscriptions. The subscribing Insurers are not responsible for the subscription of any co-subscribing Insurer who for any reason does not satisfy all or part of its obligations.		
LIMITS OF LIABILITY:	CAD	250,000,000	Any one accident or occurrence, combined single limit
	CAD	350,000,000	In the annual aggregate in respect of Flood and Earthquake separately
EXCESS OF:	CAD	100,000	any one accident or occurrence, except
	CAD	250,000	any one accident or occurrence in respect of Accident to an Object as defined herein;
	CAD	50,000	any one accident or occurrence in respect of inland transits.
	CAD	50,000	any one accident or occurrence in respect of construction, assembly or installation
PREMIUM:	CAD	674,763	(100%) per annum
SUBLIMITS:	CAD	10,000,000	Extra expense and Contingent Extra Expense;
	CAD	10,000,000	Expediting Expense
	CAD	15,000,000	New Property in Course of Construction, Erection, Assembly or Installation, maximum full contract value $15,000,000;
	CAD	5,000,000	Transmission and Distribution Lines within 1,000 ft of Insured's generating premises and McIntyre, Aishihik. Takhini, Anvil, Mayo and Dawson substations;
	CAD	25,000,000	Accounts Receivable
	CAD	25,000,000	Valuable Papers and Records
	CAD	25,000,000	Fine Arts
	CAD	25,000,000	Newly Acquired Property;
	CAD	25,000,000	or twenty five percent (25%) of loss whichever is greater. In respect of Debris Removal;
	CAD	25,000,000	Off Premises Utilities
	CAD	500,000	Decontamination Expense per Occurrence and in the Annual Aggregate per Endorsement No. 8
	CAD	1,000,000	Professional Fees (excluding public adjusters, defence costs and legal fees)/Claims Preparation Costs;
	CAD	1,000,000	Fire Fighting Materials and Expenses
	CAD	10,000,000	Inland Transit (no Air or Marine transit coverage);
	CAD	50,000	Property of Officers, Employees and Guests Per Occurrence
	In respect of Reservoirs, Dams, Waterways (RDW), the Demolition and Increased Cost of Construction coverage provided hereunder is limited to the declared values plus an allowance not exceeding 25% of the declared location value in the event of loss.		

	CAD	50,000	Lawns, trees, shrubs and other plants;
	CAD	10,000,000	EDP Media per Endorsement No. 2;
	CAD	1,000,000	Technological incompatibility/advancement
	CAD	100,000	Consequential Damage from changes in temperature and humidity;
	Only extensions outlined above are subject to the sublimits indicated which are part of and not in addition to the overall Limit of Liability		
AUTOMATIC ACQUISITION AND PREMIUM ADJUSTMENT:	The coverage provided herein is automatically extended to include all newly acquired property for a limit of not more than the sublimit of Liability shown in the Declarations. However, acquisitions with a total value in excess of CAD 25,000,000 will only be included with advice being given to the Insurers of such acquisition within ninety (90) days and at an additional premium to be agreed by the Insurers.		
JURISDICTION AND LAW:	This policy will be subject to the Law and Jurisdiction of a Canadian Province or Territory as determined by the relevant Insurance Act(s).		

Endorsements attached hereto at inception:

1. War and Terrorism Exclusion Endorsement
2. Electronic Data Endorsement A (Amended)
3. Microorganism Exclusion (Map) Endorsement (Absolute)
4. Radioactive Contamination Exclusion Clause – Physical Damage – Direct
5. Biological or Chemical Materials Exclusion
6. WEH Asbestos Endorsement (1994)
7. Additional Limitations and Conditions Endorsement (Standard)
8. Decontamination Expense
9. Special Cancellation Provisions
10. Terrorism Exclusion (applicable to Northbridge Indemnity Insurance Corporation's participation only)
11. Service of Suit Clause (Canada) (Action Against Insurer)
12. Several Liability Notice

IN WITNESS WHEREOF THE INSURERS, THROUGH THEIR REPRESENTATIVE DULY AUTHORIZED BY THEM FOR THIS PURPOSE, HAVE EXECUTED AND SIGNED THIS POLICY.

Dated at Vancouver, British Columbia: May 31, 2012

Subscribing Insurers

THE INTEREST OF EACH INSURER HEREUNDER IS INDIVIDUAL AND NOT JOINT AND WHEREVER ANY RIGHT OR PRIVELEGE IS RETAINED BY THE INSURERS SUCH RIGHT OR PRIVILEGE MAY BE EXERCISED BY EACH INSURER INDEPENDENTLY.

INSURERS	INTEREST	PREMIUM	AUTHORIZED SIGNATURE
Allianz Global Risks US Insurance Company	50%	$337,381.50	ALLIANZ GLOBAL RISKS US INSURANCE COMPANY
Temple Insurance Company	30%	$202,428.90	JUN - 5 2012
Northbridge Indemnity Insurance Corporation	20%	$134,952.60	
	100%	$674,763.00	

Attached to and forming part of policy number: A2600373/3 issued to Yukon Development Corporation and/or Yukon Energy Corporation, its parent and/or all subsidiaries of the foregoing (including subsidiaries thereof), associated and affiliated companies, partnerships and joint ventures and any company or organization under the control or active management of any of these as now exist or that may hereafter be constituted and those on whose behalf the Named Insured has agreed, in writing to provide insurance, as more fully defined in the policy wording.

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Subscribing Insurers

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Subscribing Insurers

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Attached to and forming part of policy number: A2600373/3 issued to Yukon Development Corporation and/or Yukon Energy Corporation, its parent and/or all subsidiaries of the foregoing (including subsidiaries thereof), associated and affiliated companies, partnerships and joint ventures and any company or organization under the control or active management of any of these as now exist or that may hereafter be constituted and those on whose behalf the Named Insured has agreed, in writing to provide insurance, as more fully defined in the policy wording.

Property Insurance

1. Property Insured

Real and personal property of every kind and description not hereinafter excluded, whether owned, leased or occupied by the Insured and/or held in trust and/or property of others for which the Insured has assumed liability or responsibility to effect insurance and/or property in the Insured's care, custody or control and including Property in course of construction and extra expense.

Within the Policy period, this Policy shall attach when the property becomes at the Insured's risk and shall continue until such property ceases to be at the Insured's risk, except that property in transit at the time when this Policy expires shall be held covered until such property has been duly delivered at its destination or until the Insured's interest in such property in transit ceases, whichever occurs first.

2. Perils Insured

This Policy insures against all risks of direct physical loss or damage occurring during the period of insurance to the Property Insured including Accident to an Object as defined herein and Flood and Earthquake except as hereinafter excluded.

3. Territorial Limits

This Policy covers all property insured hereunder anywhere in Canada and the Continental United States, including inland transits within Canada and the Continental United States by any means not hereinafter excluded, and Worldwide in respect of inland transit connected with construction projects.

4. Property Excluded

This Policy does not insure:

(a) Money, currency, notes, securities, stamps, accounts, bills, deeds or evidence of debt or title, jewelry, furs, precious stones, precious metals, bullion, growing crops and standing timber;

(b) Land or land values, however, this exclusion shall not apply to earth-works nor rock-works constructed or excavated for dam construction nor, to the extent included in any original project contract bid documents, the value of earth to be used in completion of the insured project;

(c) Watercraft over 10 metres in length, aircraft or motor vehicles licensed for highway use, but not excluding equipment mounted on vehicles or vehicles while parked on the Insured's premises;

(d) Property otherwise specifically insured;

(e) Water, except water which is usually contained within any type of tank, piping system or other process equipment;

(f) Property in course of ocean marine or air transit;

(g) Locomotives, railroad rolling stock or air supported structures;

(h) Animals, fish or birds;

(i) Offshore property, except this exclusion shall not apply to structures extending from land or shore or floating docks permanently moored to a dock, riverbank or shore and their contents;

(j) Property illegally acquired, kept, stored or transported or property seized or confiscated by order of Public Authority;

(k) Contractors' equipment of every description except scaffolding, temporary structures, wood or metal forms or tarpaulins,

(l) Transmission and distribution lines beyond 1,000 feet of the Insured's generating premises and McIntyre, Aishihik, Takhini. Anvil, Mayo and Dawson substations.

(m) Additionally in respect of Data Processing:

  (i) accounts, bills, evidence of debt, valuable papers, records, abstracts, deeds, manuscripts or other documents except as they may be converted to data processing media form, and

then only in that form, or any data processing media which cannot be replaced with other of like kind and quality.

(ii) property rented or leased to others while away from the premises of the Insured

5. Perils Excluded

The Insurer(s) shall not be liable for claims arising from:

(a) Delay, loss of use or occupancy or loss of market, except as may be provided elsewhere in this Policy;

(b) Wear, tear, gradual deterioration or depreciation, inherent vice, latent defect, rust, corrosion, dampness of atmosphere or contamination, vermin or normal making good, unless physical loss or damage by a peril insured against ensues in which case this Policy will insure loss or damage caused by such ensuing peril;

(c) Loss due to any infidelity, fraudulent, dishonest or criminal act by any Insured, a partner therein, or an officer, director or trustee thereof, while working or otherwise and whether acting alone or in collusion with others or other party of interest, their employees or agents or any person or persons to whom the property may be entrusted (bailees for hire excepted). Vandalism or an act of malicious damage shall not be deemed an act of infidelity;

(d) Loss, destruction or damage caused by political risks including but not limited to hostile or warlike action in time of peace or war, including action in hindering, combating or defending against an actual, impending or expected attack, by any government or sovereign power (de jure or de facto), or any authority maintaining or using military, naval or air forces; or by military, naval or air forces; or by an agent of any such government, power, authority or forces; any weapon of war employing atomic fission or radioactive force whether in time of peace or war; insurrection, rebellion, revolution, civil war, civil commotion, usurped power or action taken by governmental authority in hindering, combating or defending against such an occurrence; seizure or destruction under quarantine or customs regulations; confiscation by or destruction by order of any government or public authority, except destruction by order of public authority to prevent spread of fire or explosion, risks of contraband or illegal trade;

(e) The discharge, seepage or spill of any contaminant or pollutant except as provided in Endorsements No. 7 or 8;

(f) The cost of making good faulty workmanship, construction. material or design, however, this exclusion shall not apply to physical damage to any other property insured hereunder that is caused by or results directly from such faulty material, construction, workmanship or design.

(g) This Policy does not insure any costs, fines, penalties or expenses:

(i) imposed on the Insured;

(ii) incurred by the Insured, or

(iii) sustained by the Insured

at the order of any Government Agency, Government Authority or Court in connection with any kind or description of environmental impairment, including seepage or pollution or contamination from any cause whatsoever beyond the demolition of any damaged portion of any project insured hereunder no longer useful for its intended purpose.

(h) Mysterious disappearance or loss revealed by inventory shortage alone. misappropriation, secretion or conversion;

(i) Normal settling, shrinkage or expansion in walls, ceilings or floors, unless caused by or resulting from physical loss or damage by a peril not otherwise excluded unless physical loss or damage by a peril insured against ensues, in which case this Policy will insure such ensuing loss or damage;

(j) Penalties, fines or damages for breach of contract, non-completion of or delay in completion of contract or noncompliance with contract conditions of whatever nature to which the Insured is a party;

(k) Errors in processing or manufacture of the Insured's products or property while being worked upon, unless physical loss or damage by a peril insured against ensues in which case this Policy shall insure such ensuing loss or damage;

(l) Dryness of atmosphere, shrinkage, evaporation, loss of weight, wet or dry rot, mould, changes in flavour or colour or texture or finish, changes in temperature or humidity;

(m) Loss due to suspension, lapse or cancellation of any lease or license, contract or order to which the Insured is a party.

(n) Additionally in respect of Accounts receivable from:

(i) loss due to bookkeeping, accounting or billing errors or omissions;

(ii) loss, the proof of which as to factual existence, is dependent solely upon an audit of records or an inventory computation: but this shall not preclude the use of such procedures in support of claim for loss which the Insured can prove, through evidence wholly apart therefrom, is due solely to a risk of loss to records of accounts receivable not otherwise excluded hereunder;

(iii) loss due to alteration, falsification, manipulation, concealment, destruction or disposal of records of accounts receivable committed to conceal the wrongful giving, taking, obtaining or withholding of money, securities or other property but only to the extent of such wrongful giving, taking, obtaining or withholding;

(iv) loss due to electrical or magnetic injury, disturbance or erasure of electronic recordings, except by lightning;

(o) Additionally in respect of Valuable Papers and Records:

(i) property held as samples or for sale or for delivery after sales, or property illegally acquired kept, stored or transported, property seized or confiscated for breach of any 'law' or by order of any public authority;

(ii) money or securities;

(iii) loss or damage caused directly or indirectly by electronic or magnetic injury, disturbance of erasure of electronic recordings, except by lightning.

(p) Additionally in respect of Data Processing:

Error or omissions in processing or copying all unless physical damage not excluded by this policy results in which event, only that resulting damage is covered.

(q) Nuclear reaction or radiation or radioactive contamination, however caused. If fire ensues, liability is specifically assumed for direct physical loss or damage by such ensuing fire but not including any loss or damage due to nuclear reaction, nuclear radiation or radioactive contamination;

Exclusions 5 (b) and (f) shall not apply to an Accident to an Object as defined in Clause 7 below

6. Basis of Settlement

(a) Applicable to All Property except as described in items (b) to (h) below:

Replacement cost, being repair, rebuilding, replacement or reinstatement with due diligence and dispatch, with new materials of like kind and quality without deduction for depreciation, including expediting expense. Insured's overhead cost and Insured's Contractors' and Sub-Contractors' regular margin of profit and overhead charges and all other necessary charges in reinstating lost or damaged facilities.

Plus, in either instance, the value of undamaged property which is required by law to be demolished, the cost of demolition, including demolition of undamaged structures and clearing the site, and, if, at the time of loss, repair or replacement, construction or reconstruction is restricted or prohibited by any by-law, regulation, ordinance or law, any increased cost due thereto. Such increased costs shall be limited to the minimum required under such law and the total payable limited to the cost of constructing, repairing, replacing or reinstating the properly insured, plus the cost of demolition, including demolition of any undamaged structures and clearing the site.

The liability of the Insurer(s) shall be limited to the Actual Cash Value of the damaged or destroyed property at the time of loss unless and until the damaged or destroyed property is repaired, replaced, reproduced, constructed or reconstructed and unless repair, replacement, construction or reconstruction is executed with due diligence and dispatch on the part of the Insured.

(b) Applicable to Fuel in Fuel Storage Facilities:

Settlement shall be based upon the replacement value at the time of the loss of fuel oil delivered (emergency or otherwise) to the fuel storage facility(ies) involved in the loss.

(c) In respect of Accounts Receivable as set out in Extensions of Insurance:

In the event that the Insured cannot accurately establish the total amount of accounts receivable outstanding as of the date loss occurs, such amount shall be based on the Insured's monthly statements and shall be computed as follows:

(i) the monthly average of accounts receivable represented by the Insured shall be adjusted in accordance with the percentage increase or decrease in the twelve months average of monthly gross sales of' goods and services which may have occurred in the interim;

(ii) the monthly amount of accounts receivable thus established shall be further adjusted in accordance with any demonstrable variance from that average for the particular month in which the loss occurred, due consideration also being given to the normal fluctuations in the amount of accounts receivable within the fiscal month involved;

but in no event shall the Insurer(s) be liable for more than the maximum monthly amount of accounts receivable represented by the Insured, after adjustment to correspond with the trend in average monthly gross sales of goods and services, nor for more than the limit of insurance provided herein.

(iii) there shall be deducted from the total amount of accounts receivable, however established, the amount of such accounts evidenced by records not lost or damaged, or otherwise established or collected by the Insured, and an amount to allow for probable bad debts which would normally have been uncollectible by the Insured.

(d) In respect of Data Processing as set out in item l of Extensions of Insurance:

In accordance with Endorsement No. 2.

(e) In respect of Valuable Papers and Records as set out in item m of Extensions of Insurance:

The limit of the Insurer(s)' liability for loss shall not exceed the cost to transcribe and/or reproduce including to reassemble, reproduce or regenerate the property at time of loss nor what it would then cost to repair or replace the property with other of like kind and quality, nor the applicable limit of insurance stated in this Policy.

The Insurer(s) may pay for the loss in money or may repair or replace the property and may settle any claim for loss of the property either with the Insured or the owner thereof. Any property so paid for or replaced shall become the property of the Insurer(s). The Insured or the Insurer(s) upon recovery of any such property, shall give notice thereof as soon as practicable to the other and the Insured shall be entitled to the property upon reimbursing the Insurer(s) for the amounts so paid or the cost of replacement.

(f) In respect of Finished Product/Stock:

The limit of the Insurer(s)' liability for loss shall not exceed the Market Value thereof.

(g) In respect of Fine Arts as set out in item o of Extensions of Insurance:

The limit of the Insurer(s)' liability for loss or damage to Fine Arts owned by the Insured at the cost of reasonably restoring the property to its condition immediately prior to the loss, or in the event that the property cannot be restored at the appraised or agreed value prior to the loss. In absence of such appraisal, at the market value at the time of loss, plus the Insured's costs.

On Fine Arts, the property of others, the limit of the Insurer(s)' liability shall be either the cost of reasonably restoring the property to its condition immediately prior to loss, or the Insured's contractual or legal liability.

7. Definitions

Occurrence:

The term "occurrence" shall mean an event or series of events consequent on or attributable to one source or original cause which results in loss of or damage to or the destruction of property. If the inception of the event causing loss or damage occurs prior to the expiration date of this policy, then the Insurer(s) shall be liable for any loss incurred after the expiration of this policy, as a result of the event. Insofar as loss involving in whole or in part the perils of storm, tornado, windstorm, rainstorm, cyclone, hurricane or hail is concerned, any of the aforementioned perils occurring within any consecutive seventy two (72) hours shall be construed to be a single occurrence. The Insured shall select the time from which any such period shall commence but no two selected periods shall overlap.

Earthquake:

Any natural or man-made earth movement including but not limited to earthquake or landslide regardless of any other cause or event contributing concurrently or in any other sequence of loss. All earth movements within a continuous 72 hour period will be considered a single Earth Movement.

Flood:

Flood, surface waters, rising waters, waves, tide or tidal water, the release of water, the rising, overflowing or breaking of boundaries of natural or man-made bodies of water, or the spray therefrom, or sewer back-up resulting from any of the foregoing, regardless of any other cause or event contributing concurrently or in any other sequence of loss. However, physical damage by fire, explosion or sprinkler leakage resulting from Flood is not considered to be loss by Flood within the terms and conditions of this policy. All Flood within a continuous 72 hour period will be considered a single Flood

Accident:

As respects any Object designated and described in this Policy. Accident shall mean a sudden and accidental breakdown of an Object, or a part thereof, which manifests itself at the time of its occurrence by physical damage to the Object that necessitates repair or replacement of the Object or part thereof.

But the term Accident shall not mean:

(i) depletion, deterioration, corrosion or erosion of material;

(ii) wear and tear;

(iii) leakage at any valve, fitting, shaft seal, gland packing, joint or connection;

(iv) the breakdown of any vacuum tube, gas tube or brush;

(v) an explosion of gas or unconsumed fuel within the furnace of any Object or within the passages from the furnace of the Object to the atmosphere;

(vi) the functioning of any safety or protective device;

(vii) the breakdown of any structure or foundation supporting the Object or any part thereof;

(viii) the breakdown of any Object or part thereof while undergoing any pressure test, any insulation breakdown test or while being dried out;

(ix) the breakdown of any electronic computer or any electronic data processing equipment unless used solely to control, monitor or operate an Object.

Object:

The term Object shall mean Object shall mean any boiler, any fired or any unfired pressure vessel, or fiberglass reinforced plastic pressure vessel manufactured to ASME Code, or any refrigerating or air conditioning vessels and piping, or any other piping and its accessory equipment, all normally subject to vacuum or internal pressure other than static pressure of contents, and any condensate return tank. The term Object that also mean any machine or apparatus which generates, transmits, or uses mechanical or electrical energy or power and any fibre optic cable including the optical transmitter and receiver.

But the term Object shall not mean:

(i) Any oven, stove, furnace, incinerator or kiln

(ii) Any hose, any buried vessels or piping, any piping forming part of a sprinkler system or any water piping other than boiler feed water piping, boiler condensate return piping, water

piping forming part of a building heating system, or water piping connecting to or used with a refrigerating or air conditioning system;

(iii) Any refractory or insulating material, non-metallic lining or covering, any boiler setting or any part of a boiler or fired pressure vessel which does not contain a heat transfer medium or it's capors, or any vessel, machinery or apparatus used for research, experimental, demonstration, diagnostic, therapeutic, medical, surgical, dental or other scientific purposes;

(iv) Any part of any vehicle, aircraft, floating vessel or structure;

(v) Any elevator, escalator, crane hoist, power shovel, drafline or conveyor, but not excluding any electrical equipment used with such a machine;

(vi) Any maintenance machine or apparatus, any tool or die, grinding disc, cutting blade, chain, belt, felt, wire, screen, mould or any part or tool subject to frequent, periodic replacement;

(vii) Any well casing, penstock, draft tube or structure or foundation other than a bedplate of a machine

Normal

The word "Normal" shall mean the condition which would have existed had no loss occurred.

Extra Expense

The term "Extra Expense" is defined as the excess. if any, of the total cost during the period of restoration for the purpose of continuing the Insured's business over and above the total cost that would normally have been incurred to conduct the business during the same period had no loss occurred: the cost in each case to include the expense of using other property, temporary facilities, or facilities of other Concerns of other similar necessary emergency expenses and also includes costs and expenses necessitated as a result of the minimum provisions of any Bye-Law. In no event, however, shall the insurer(s) be liable under this Policy for loss of income, nor for extra expense in excess of that necessary to continue as nearly as practicable the normal conduct of the Insured's business. The Insurer(s) shall also be liable for extra expense incurred in obtaining property for temporary use during the period of restoration necessarily required for the conduct of the Insured's business; any salvage value of such temporary property remaining after resumption of normal operations shall be taken into consideration in the adjustment of any loss hereunder.

Expediting Expense

Shall include the extra cost of temporary repair and of expediting the repair or replacement of such damaged property, including overtime and the extra cost of express or other rapid means of transportation.

Money

The word "Money" means currency, coins, bank notes and bullion, travelers cheques, register cheques and money orders, held for sale to the public;

Securities

The word "Securities" means all negotiable and non-negotiable instruments or contracts representing either money or other property and includes revenues and other stamps in current use, tokens and tickets, but does not include "Money."

Contributing Properties

A contributing property shall be the premises, property and the like of a supplier or another party upon whom the Insured relies, or when it wholly or partially prevents the acceptances of product(s) produced or services provided by the Insured in order to maintain normal operation of the Insured's business.

8. Extensions of Insurance

(a) Lawns, trees, shrubs and other plants:

Subject to the sublimit as shown in Policy Declarations any one loss, this Policy insures loss or damage to lawns, trees, shrubs and other plants at Insured's premises caused by a peril insured.

(b) Consequential Damage:

This Policy insures up to the sublimit shown in Policy Declarations against physical loss or damage to property insured hereunder due to change in temperature resulting from damage caused by the perils insured against, to property used for refrigerating, cooling, humidifying, dehumidifying, air conditioning or heating including connections or supply pipes and apparatus furnishing power therefor.

(c) Fire Fighting Materials and Expenses:

This Policy insures up to the sublimit shown in Policy Declarations all fire fighting expense incurred by the Insured including, but not limited to, materials, personal costs and expenses assessed against the Insured. This Policy also insures all fire extinguishing materials lost, expended or destroyed in fighting fire involving property insured hereunder or exposing the property insured hereunder, including the loss of similar materials which may be brought on to the premises for the purpose of extinguishing a fire already in progress at the time such materials are ordered and delivered.

(d) Technological Incompatibility:

Subject to the sublimit shown in Policy Declarations any one loss, this Policy is extended to insure the cost of purchasing and installing technologically current equipment which is necessitated by incompatibility between:

(a) New equipment installed to replace damaged or destroyed equipment; and

(b) Undamaged existing equipment at the same or an interdependent location;

Provided that:

(i) Damage or destruction was caused by a peril insured against;

(ii) The Insurer(s) shall be liable under this extension only for an amount sufficient to enable the Insured to resume operations in substantially the same manner as before the destruction or damage:

(iii) The Insurer(s) shall be liable for only the difference between:

The highest sales value of the undamaged existing equipment at the same or an interdependent location, and

The installed cost of the technologically current equipment:

(iv) For the purpose of the Deductible clause, the damage or destruction and the necessity to replace incompatible equipment shall be regarded as one occurrence.

(e) Personal Property of Directors, Officers and Employees:

This insurance, up to the sublimits shown in Policy Declarations at the option of the Insured, is extended to include tools, wearing apparel and personal property of officers and employees of the insured while engaged in performing duties pertaining to their employment, and property of the Insured's guests, when such property is not covered by any other insurance.

Loss, if any, to be adjusted with and payable to the insured.

(f) Improvements and Betterments:

Improvements and betterments shall be deemed to belong to the Insured and all losses involving such improvements and betterments will be adjusted in the Insured's favour notwithstanding any contract or lease to the contrary.

(g) Civil Authority:

Property insured under this Policy is also insured against the risk of damage or destruction by civil authority during a conflagration or other catastrophe within five statute miles of insured premises, except when such damage or destruction is caused or contributed to by an excluded peril.

In respect of Extra Expense and/or Expediting Expense, this insurance is extended to include such loss, during the period of time, not exceeding eight (8) weeks , while access to the property insured is prohibited by order of Civil Authority.

(h) Off-Premises Utilities:

This Policy, subject to the sublimit shown in the Policy Declarations, shall include physical loss or damage to the property insured as a result physical of loss, damage, or destruction, caused by the perils insured against by this Policy, to any utility (including but not limited to plants, gas meter stations or switching stations, substations, transformers, pumping stations, transmission lines, telecommunication lines or water mains) furnishing heat, light, power, gas, communications or water to an insured location upon which the operation of the insured's business may be dependent.

(i) New Property in Course of Construction or installation subject to the sublimit shown in the Policy Declarations.

This Policy shall include the following for which construction commences during the period of this policy:

(i) All New Property in Course of Construction, erection, assembly or installation

(ii) Property of Every Kind and Description including, but not limited to, tenants' improvements, materials and supplies, inventories, management fees. financing costs, taxes and related interim charges, architects', engineers' and other professional fees (whether required to be specifically mentioned by the conditions of this Policy or not), and without limiting the generality of the foregoing, all property of the Insured or for which the Insured may be responsible, used or to be used in a part of or incidental to the construction operations wherever the said property may be located and whilst in transit.

(iii) Property of others used or to be used in, part of, or incidental to, the construction operations. for which the Insured may be responsible or shall, prior to any occurrence for which claim may be made hereunder, have assumed responsibility.

The property insured under this Extension shall be deemed at the risk of the Insured during the period of the Construction Operations and until date the said property has been formally completed and accepted by the owner subject always to the expiration of this Policy.

"New Property in the course of construction, erection, assembly or installation" shall not include additions, extensions, repairs, alterations, tenants improvements and plant changes to existing property of the Insured, at the existing insured locations.

(j) Extra Expense and Expediting Expense

(i) If the Property Insured is destroyed or damaged by the perils insured against during the term of this Policy so as to necessitate the incurrence of Extra Expense, as defined herein, the Insurer(s) shall be liable for the Extra Expense so incurred for not exceeding such length of time, commencing with the date of the damage or destruction and not limited by the date of expiration of this Policy, as shall be required with the exercise of due diligence and dispatch on the part of the Insured to repair, rebuild or replace such part of such property as has been destroyed or damaged.

(ii) If the Property Insured is destroyed or damaged by the perils insured against during the term of this Policy so as to necessitate the incurrence of Expediting Expense, as defined herein, the Insurer(s) shall be liable for any increase in cost of working, any and all charges incurred by the Insured in order to expedite and/or facilitate repairs, replacement or rebuilding of damaged or destroyed property insured hereunder.

(iii) Coverage hereunder shall include any increased costs incurred due to any additional period of time that would be required for repair, replacement, construction or reconstruction.

In case of loss or damage, the Insured is authorized and permitted immediately to carry out repairs which can conveniently and advantageously be undertaken by them, and charges so arising, including labour and overtime charges and extra cost of expenses and temporary repairs and other rapid means of transportation (including airfreight), shall form part of the loss as detailed below.

This Policy. subject to the applicable sublimits, conditions and limitations herein set forth, is extended to cover the necessary Extra Expense and Expediting Expense incurred by the Insured in order to resume or continue as nearly as practicable the Normal conduct of the Insured's operations following damage or destruction by the perils insured by this Policy, occurring during the term of this Policy, to any part or all of the Property insured under this Policy.

This insurance is further extended to insure the actual loss as covered under this Policy as a result of loss or damage to Contributing Properties, which wholly or partially prevents the Insured from carrying on the normal operations of the business and necessitates the incurrence of Extra and/or Expediting Expense in order to resume or continue, as nearly as practicable, the normal conduct of the Insured's operations.

With respect to this extension, the Insurer(s) shall not be liable for more than the sublimit shown in the policy declarations any one loss.

As soon as practicable after any loss, the Insured shall resume complete or partial business operations and, insofar as practicable, reduce or dispense with such Extra and/or Expediting Expenses as are being incurred.

This extension includes the actual loss as a result of loss or damage to internal or external data processing systems including equipment, and component parts thereof and data processing media therefor, owned, leased, rented or under the control of the Insured. Coverage shall include actual loss as covered hereunder:

(a) when the premises in which the property is located is so damaged as to prevent access to such property; or

(b) when the air-conditioning system or electrical system necessary for the operation of the internal or external data processing equipment is so damaged as to reduce or suspend the Insured's ability to actually perform the operations normally performed by the data processing system.

The Insurer(s) agree to pay the Insured, subject to a waiting period of forty eight (48) hours from the time of accident, the loss as defined herein for the period of restoration during which the Insured is wholly or partially prevented from producing goods or from continuing business operations or services as a result of the lack of the incoming service as specified elsewhere in this Policy.

(k) Accounts Receivable

This Policy, subject to the sublimit set out in the Declaration and to the conditions and limitations as herein set forth, insures against the perils insured under this Policy for loss or damage to the Insured's records of accounts receivable, occurring during the term of this Policy, except as hereinafter excluded.

(i) all sums due the Insured, provided the Insured is unable to effect collection thereof as the direct result of loss of or damage to records of accounts receivable;

(ii) interest charges on any loan to offset impaired collections pending repayment of such sums made uncollectible by such loss or damage;

(iii) collection expense in excess of normal collection cost and made necessary because of such loss or damage;

(iv) other expenses, when reasonably incurred by the Insured in re-establishing records of accounts receivable following such loss or damage.

(l) Data Processing

Subject to the sublimit set out in the Declarations, this Policy insures:

(i) Data processing systems including equipment and component parts thereof and air conditioning equipment 24,000 BTU/hr. or over used exclusively in data processing operations owned by the Insured or leased, rented or under the control of the Insured.

(ii) Active data processing media including programs, being property of the Insured or property of others for which the Insured may be liable.

Should any lease or rental agreement pertaining to the property insured hereunder state the lessors' liability for loss or damage to said property, coverage afforded hereunder shall be only for the difference in conditions between those contained in said lease or rental agreement and the terms and conditions of this Policy.

(m) Valuable Papers and Records

This Policy is subject to the sublimit set out in the Declarations and to its terms and conditions insures against the perils insured under this policy for loss or damage to the Insurer's valuable papers and records, consisting principally of but not limited to written, printed or otherwise inscribed documents and records, including abstracts, deeds, mortgages, manuscripts, books, drawings, sketches, maps. plans, surveys, blueprints, films, linens, scale models, photographic reproductions, and similar property.

(n) Rent and Rental Income

This Policy, subject to the sublimit set out in the Declaration and to its terms and conditions and as result of physical loss or damage to property insured under this Policy, is extended to cover the actual rent which remains available for the unexpired term of the lease if such property becomes wholly or partially untenantable or unusable but the lease agreement requires continuation of the rent payable.

(o) Fine Arts

This Policy, subject to the sublimit set out in the Declaration and to its terms and conditions, insures Fine Arts owned by the Insured or for which the Insured is responsible.

The insured property may be owned by the Insured or held by them in any capacity; provided, the insurance applies only to the interest of the Insured in such property, including the Insured's liability to others, and does not apply to the interest of any other persons or organizations in any of said property unless included in the Insured's proof of loss.

Policy Conditions

1. Agency

It is understood and agreed that the Named Insured who obtained this Policy and paid the premium therefore did so on his own behalf and as agent for the others insured hereby, including those referred to by general description. It is further acknowledged and agreed by the Insurers as evidenced by their acceptance of the premium paid that any person, firm or corporation coming within the description of an Additional insured by this Policy may ratify such agency at any time subsequent to the issuance of the Policy for the purpose of entitlement to coverage granted by its terms for good consideration. This insurance shall not be invalidated should the interest of the Insured or any one of them be other than sole or unconditional ownership.

2. No Control

This Policy shall not be invalidated by any act or neglect of which the Insured has no knowledge or no control.

3. Automatic Reinstatement

Any loss hereunder shall not reduce the Limit of Liability of this Policy, except for annual aggregate limits as described in the declarations pages.

4. Breach of Conditions

If any breach of a clause or condition in this Policy shall occur prior to a loss under this Policy, such breach shall not void the Policy or avail Insurer(s) to avoid liability, unless such breach shall exist at the time of such loss under this Policy; it being understood that such breach of a clause or condition is applicable only to the specific property affected thereby and that the loss was caused by or contributed to by the breach of condition.

Notwithstanding anything contained elsewhere in this Policy, any act or any breach of a condition of the Policy by one of the parties hereby insured, shall not prevent recovery by any other party hereby insured who is innocent of such act or breach.

5. Release, Subrogation and Recoveries

Upon the payment of any claim under this Policy, the Insurer(s) shall be subrogated to all the rights and remedies of the Insured arising out of such claim against any person or corporation whatsoever, except with respect to any releases from liability entered into by the Insured where required by written contract.

It is further understood and agreed that the Insurer(s), on paying a loss, hereby waives their right to a transfer of such rights

(a) Of the insured against any person, corporation or organization (including their directors, officers. employees, servants or agents) owned or controlled by any Insured named herein or affiliated or associated with or subsidiary to any Insured named herein, by whose fault or negligence the loss or damage was caused;

(b) Of the Insured named herein against any other Insured named herein (including their respective directors, officers, employees, servants, or agents), by whose fault or negligence the loss or damage was caused:

(c) Of the Insured against any employee of the Insured;

(d) Of the Insured against owners, co-owners, joint venturers or partners having a non-operating interest in property insured hereunder which is operated or managed by the Insured.

Notwithstanding the foregoing, it is specifically agreed, with respect to all property in Course of Construction, the Insurer(s) shall retain their subrogated rights against architects and engineers (who are not employees of the Named Insured) for their liability in the event of loss caused by or resulting from any error in design or any other professional error or omission pertaining to the subject of this insurance.

After payment of loss all amounts recovered by the Insured for which the Insured has been indemnified shall belong and be paid to the Insurer(s) by the Insured up to the total amount of loss paid by the Insurer(s), but all recoveries in excess of such amounts shall belong to the Insured.

6. Permission

Permission is hereby granted:

(a) to keep and use all articles. materials, apparatus, supplies, substances and other contents as are usual, necessary, convenient or incidental to the business carried on:

(b) to demolish, reconstruct and erect new buildings and to make changes, alterations and repairs, without limit of time and the insurance on the property covered under this Policy is hereby extended to cover in or on same, subject to all the terms and conditions of the Policy and to any adjustment of premium deemed necessary, all without detriment to this insurance;

(c) to cease operations in, and for any individual buildings to remain vacant or unoccupied without limit of time;

(d) to store or garage motor vehicles on the Insured's premises or on property described herein without prejudice to this insurance, and for motor vehicles to enter the premises for the purpose of loading or unloading;

All without prejudice to this insurance

7. Effective Time

Where this Policy replaces any other insurance in whole or in part, the period of insurance under this Policy shall be deemed to insure immediately after the effective time of the termination or expiry of such other insurance.

8. Debris Removal

Coverage in respect of Debris removal shall be in accordance with Endorsement No. 7, it being understood that for the purposes of this Insurance, removal of debris is extended to include removal of ice and dewatering of insured property.

9. Demolition and Increased Cost of Construction

If at the time of any direct physical loss or damage insured against by this policy there is in force any law, ordinance, rule or regulation regulating the construction, repair, replacement or use of buildings or structures, then this policy is extended to cover:

(a) the additional loss sustained in demolishing any undamaged portion of the buildings or structures necessitated by such law, ordinance, rule or regulation; and

(b) the cost incurred in actually rebuilding both the damaged and demolished portions of such buildings or structures in a manner to satisfy such law, ordinance, rule or regulation.

No liability is assumed under this provision for any increase of loss associated with the enforcement of any law or ordinance, which requires the Insured, or others, to:

(a) test for, monitor, clean up, remove, contain, treat, detoxify or neutralize, or in any way respond to, or assess, the effects of Hazardous Substances or Contaminants; or

(b) install process improvements or process modifications to property, when either is required or performed to comply with either OSHA regulations or other similar workplace safety regulations, or EPA, or other similar environmental regulations.

The total liability under this provision shall not exceed the actual expenditure incurred in demolishing the undamaged portion of the building(s) or structure(s) involved, plus the lesser of the following:

(a) the actual expenditure incurred, not including the cost of land, in rebuilding on another site; or

(b) the cost of rebuilding on the same site

10. Ownership

This insurance shall not be invalidated if the interest of the Insured be other than sole or unconditional ownership, and all property insured hereunder is also covered whether owned by the Named Insured or by others where the Insured shall be liable by law or shall have specifically assumed liability therefor, but loss thereon to be adjusted with and payable to the Insured named in this Policy.

11. Professional Fees

The Insurer(s) shall be liable up to the sublimit shown in the Policy Declarations for the cost of expert assistance for producing and certifying particulars of the Insured's business including claim preparation documentation, however, excluding fees or costs payable to any public adjuster or attorney.

12. Notice

Any notice required by the terms and conditions of this Policy, to be given to Insurer(s) will be forwarded by the insured to Aon Reed Stenhouse Inc. or the insurer(s) as soon as practicable after discovery by the Named Insured

Upon the occurrence of a loss that might give rise to a claim under this Policy, the Insured give notice thereof as soon as practicable to the Insurer(s) or Aon Reed Stenhouse Inc. and, if the loss is due to a violation of law, also to the police; (b) file detailed proof of loss, duly sworn to, with the Insurer(s) promptly on expiration of ninety (90) days from the date of loss or damage.

13. Interim Payments

When loss or damage has been admitted as a valid claim under this Policy, and the exact quantum has not been definitely determined, the Insured, upon written request, shall obtain from the Insurer(s), interim partial payments as recommended by Independent Adjusters and agreed to by underwriters hereon. The Insurer($ hereby agree to remit interim partial payments within Thirty (30) days from the date of request, subject to the Insured having filed a satisfactory interim proof of loss.

14. Inspection

Permission is required to inspect the property insured by this Policy. Such permission must be obtained through Aon Reed Stenhouse Inc. and the Named Insured.

15. Adjusted Claims

All adjusted claims shall be paid or made good to the Insured within Sixty (60) days after presentation and acceptance of satisfactory proof of interest and loss.

16. Suit Against the Insurer(s)

No suit, action, or proceeding for the recovery of a claim shall be sustainable in any court of law or equity, unless the same shall be commenced within Twelve (12) months next after presentation of Proof of Loss to the Insurer(s).

Reasonable extension of the Twelve (12) months time limit may be granted provided request for such extension is made in writing by the Insured prior to the expiration of the time limit provided.

17. Other Insurance

This Policy shall not cover to the extent of any other valid and collectible insurance in the name of the Insured, whether prior or subsequent in date covering the same property, and the Insurer(s) shall be liable for loss or damage only for the excess value beyond the amount due from such other valid and collectible insurance, except as otherwise provided in the Policy.

18. Errors and Omissions

Any unintentional error and/or omission by the Insured, in the name of the Insured and/or in title, location, description of the property insured hereunder or failure of notification as required shall not void or impair this insurance. Upon discovery of any error or omission, notice will be given to Insurer(s) as soon as practicable.

19. Occupancy

Any change in the use or occupancy of the property insured shall not prejudice this insurance, and any breach of conditions by any tenant shall not invalidate this insurance.

20. Cancellation

Except as amended by the Premium Payment Clause and the Termination Clause contained herein, the following terms apply.

This Policy can be cancelled by the Insurer(s) giving to the Insured ninety (90) days notice of cancellation by registered letter. The ninety (90) days commences on the day following the receipt of the registered letter at the post office to which it is addressed. If the Insurer(s) cancel this Policy, they shall return a pro rata proportion of the premium.

This Policy can be cancelled by the Insured giving to the Insurer(s) ninety (90) days notice of cancellation by registered letter. The ninety (90) days commences on the day following the receipt of the registered letter at the post office to which it is addressed. If the Insured cancels this Policy, the Insurers they shall retain the customary short rate premium.

21. Statutory and Printed Conditions

The Statutory Conditions of the Province or Territory wherein the Property insured by this Policy is located and the Printed Conditions of the Policy shall be held to apply to this insurance, save and except where such conditions are inconsistent with any terms or conditions appearing in this form, in which case the latter shall be deemed to govern in favour of the Insured

22. Conformance to Statutes

If the conditions of this Policy are revised by statute so as to broaden the insurance without additional premium charge, such extended or broadened insurance shall inure to the benefit of the Insured.

23. Currency

All amounts used herein are in Canadian Currency and premiums shall be paid and all losses adjusted and paid in Canadian Currency.

24. Temporary Removal

The property insured by this Policy (other than stocks if insured hereby) is covered whilst temporarily removed for cleaning, renovation, repair, or other similar purposes, including when endangered by a peril for which indemnity is provided under this Policy; elsewhere on the same or to any other premises and in transit thereto and therefrom by road, rail, air or water.

Notwithstanding anything to the contrary contained herein, in respect of such temporary removal the Territorial Limits of this Policy are extended to Worldwide.

The amount recoverable under this extension in respect of each item of the policy shall not exceed the amount which would have been recoverable had the destruction or damage occurred in that part of the premises from which the property is temporarily removed.

This extension does not apply to property if and so far as it is otherwise insured, nor property held by the Named Insured in trust, care, custody or control other than machinery and plant.

In respect of Accounts receivable, this insurance applies while the records of accounts receivable are being removed to and while at a place of safety because of imminent danger of loss or damage and while being returned from such place, provided the Insured gives written notice to the Insurer(s) of such removal within thirty (30) days thereafter.

25. Preservation of Property Clause

In case of actual or imminent physical loss or damage of the type insured against by this Policy, the expenses incurred in taking reasonable and necessary actions for the temporary protection and preservation of property insured hereunder shall be added to the total physical loss or damage, if any, otherwise recoverable under the Policy and be subject to the applicable deductible and without increase in the limit provisions contained in this Policy.

26. Control of Damaged Goods

It is understood and agreed that the Insured shall have full right to the possession of all goods involved in any loss under this Policy and shall retain control of all damaged goods. The Insured, exercising a reasonable discretion, shall be the sole judge as to whether the goods involved in any loss under the Policy are fit for use, and no goods so deemed by the Insured to be unfit for use shall be sold or otherwise disposed of except by the Insured or with the Insured's consent. But the Insured shall allow the Insurers any salvage obtained by the Insured on any sale or other disposition of such goods.

27. Pair and Set

It is understood and agreed that, in the event of loss or damage to any article or articles which are a part of a set, the measure of loss of or damage to such article or articles shall be a reasonable and fair proportion of the total value of the set, giving consideration to the importance of said article or articles.

28. Extended Expiration

If this Policy should expire or be cancelled while an occurrence giving rise to a loss recoverable under this Policy is in progress, it is understood and agreed that said loss, subject to all other terms and conditions and limit of liability of this Insurance, will be covered under this Policy as if the entire loss had occurred prior to the expiration or cancellation.

29. Titles of Paragraphs

The titles of the various paragraphs of this Policy (and of endorsements and supplemental contracts, if any, now or hereafter attached to this Policy) are inserted solely for convenience of reference and shall not be deemed in any way to limit or affect the provisions to which they relate.

30. Additional Insureds, Loss Payees and Mortgagees' Interest

All third parties having a direct interest in the property insured hereunder shall be automatically named as Additional Insureds hereunder. Such third parties shall be automatically named as Loss Payees, and loss, if any, shall be adjusted with the Insured and payable to the Insured and Loss Payees as their interests may appear or as otherwise directed by the Insured Permission is automatically granted Aon Reed Stenhouse Inc. (or their assignee where required) to issue, on demand, Certificates of Insurance (or equivalent evidence of insurance) as evidence of coverage to such Additional Named Insureds and/or Loss Payees and/or Mortgagees.

Permission is granted Aon Reed Stenhouse Inc. to issue evidence of insurance where required, such evidence may be issued without reference to the Insured's retention or stating a retention less than that scheduled hereunder. The Insured will hereby provide automatic indemnification to Insurers for any difference between those retentions shown of the evidence of insurance and the actual retentions scheduled hereto.

It is agreed to include Lenders Loss Payable Clauses in this Policy as required.

31. Premium Payment Clause

The (Re)Insured undertakes that premium will be paid in full to Underwriters within 60 days of inception of this policy (or, in respect of installment premiums, when due).

If the premium due under this policy has not been so paid to Underwriters by the 60th day from the inception of this policy (and, in respect of installment premiums, by the date they are due) Underwriters shall have the right to cancel this policy by notifying the (Re)Insured via the broker in writing. In the event of cancellation, premium is due to Underwriters on a pro rata basis for the period that Underwriters are on risk but the full policy premium shall be payable to Underwriters in the event of a loss or occurrence prior to the date of termination which gives rise to a valid claim under this policy.

It is agreed that Underwriters shall give not less than 15 days prior notice of cancellation to the (Re)Insured via the broker. If premium due is paid in full to Underwriters before the notice period expires, notice of cancellation shall automatically be revoked. If not, the policy shall automatically terminate at the end of the notice period.

Unless otherwise agreed, the Leading Underwriter (and Agreement Parties if appropriate) are authorized to exercise rights under this clause on their own behalf and on behalf of all Underwriters participating in this contract.

If any provision of this clause is found by any court or administrative body of competent jurisdiction to be invalid or unenforceable, such invalidity or unenforceability will not affect the other provisions of this clause which will remain in full force and effect.

Where the premium is to be paid through a London Market Bureau, payment to Underwriters will be deemed to occur on the day of delivery of a premium advice note to the Bureau.

32. Suspension

On discovery of a material dangerous condition, which the Insurers bring to the attention of the Insured and to which the Insured does not within 48 hours provide a risk analysis and mitigation plan acceptable to the Insurers, the Insurers may then immediately suspend this insurance on the applicable machine, vessel or part thereof by giving written notice to the Insured. The suspended insurance will be reinstated by the Insurers once the dangerous condition is rectified.

Fire Statutory Conditions (Canada)

1. Misrepresentation

If a person applying for insurance falsely describes the property to the prejudice of the Insurer(s), or misrepresents or fraudulently omits to communicate any circumstance that is material to be made known to the Insurer(s) in order to enable it to judge the risk to be undertaken, the contract is void as to any property in relation to which the misrepresentation or omission is material.

2. Property of Others

Unless otherwise specifically stated in the contract, the Insurer(s) is not liable for loss or damage to property owned by any person other than the Insured, unless the interest of the Insured therein is stated in the contract.

3. Change of Interest

The Insurer(s) is liable for loss or damage occurring after an authorized assignment under the Bankruptcy Act or change of title by succession, by operation at law, or by death.

4. Material Change

Any change material to the risk and within the control and knowledge of the insured voids the contract as to the part affected thereby, unless the change is promptly notified in writing to the Insurer(s) or its local agent and, the Insurer(s), when so notified, may return the unearned portion, if any, of the premium paid and cancel the contract, or may notify the Insured in writing that if he desires the contract to continue in force he must, within Fifteen (15) days of the receipt of the notice, pay to the Insurer(s) an additional premium, and in default of such payment the contract is no longer in force and the Insurer(s) shall return the unearned portion, if any, of the premium paid.

5. Termination

(1) This contract may be terminated:

(a) by the Insurer(s) giving to the Insured Fifteen (15) days notice of termination by registered mail or Five (5) days written notice of termination personally delivered (except in the Province of Quebec);

(b) by the insured at any time on request.

(2) Where this contract is terminated by the Insurer(s):

(a) the Insurer(s) shall refund the excess of premium actually paid by the Insured over the pro rata premium for the expired time, but, in no event, shall the pro rata premium for the expired time be deemed to be less than any minimum retained premium specified; and

(b) the refund shall accompany the notice unless the premium is subject to adjustment or determination as to amount in which case the refund shall be made as soon as practicable.

(3) Where this contract is terminated by the Insured, the Insurer(s) shall refund as soon as practicable the excess of the premium actually paid by the Insured over the short rate premium for the expired time, but in no event shall the short rate premium for the expired time be deemed to be less than any minimum retained premium specified.

(4) The refund may be made by money, postal or express company money order or cheque payable at par.

(5) The Fifteen (15) days mentioned in Clause (a) of Sub-condition (1) of this Condition commences to run on the day following the receipt of the registered letter at the post office to which it is addressed.

6. Requirements After Loss

(1) Upon the occurrence of any loss of or damage to the insured property, the Insured shall, if the loss or damage is covered by the contract, in addition to observing the requirements of Conditions 9, 10 and 11:

(a) forthwith give notice thereof in writing to the Insurer(s);

(b) deliver as soon as practicable to the Insurer(s) a proof of loss verified by a statutory declaration:

(i) giving a complete inventory of the destroyed and damaged property and showing in detail quantities, costs, actual cash value and particulars of amount of loss claimed;

(ii) stating when and how the loss occurred, and if caused by fire or explosion due to ignition, how the fire or explosion originated, so far as the Insured knows or believes;

(iii) stating that the loss did not occur through any willful act or neglect or the procurement, means or connivance of the Insured;

(iv) showing the amount of other insurances and the names of other Insurer(s);

(v) showing the interest of the Insured and of all others in the property with particulars of all liens, encumbrances and other charges upon the property;

(vi) showing any changes in title, use, occupation, location, possession, or exposures of the property since the issue of the contract;

(vii) showing the place where the property insured was at the time of loss;

(c) if required, give a complete inventory of undamaged property and showing in detail quantities, cost, actual cash value;

(d) if required and if practicable, produce books of account, warehouse receipts and stock lists, and furnish invoices and other vouchers verified by statutory declaration, and furnish a copy of the written portion of any other contract.

(2) The evidence furnished under Clause (c) and (d) of Sub-paragraph (1) of this Condition shall not be considered proofs of loss within the meaning of Conditions 12 and 13.

7. Fraud

Any fraud or willfully false statement in a statutory declaration in relation to any of the above particulars. vitiates the claim of the person making the declaration.

8. Who May Give Notice and Proof

Notice of loss may be given and proof of loss may be made by the agent of the Insured named in the contract in case of absence or inability of the Insured to give the notice or make the proof, and absence or inability being satisfactorily accounted for, or in the like case, or if the Insured refuses to do so, by a person to whom any part of the insurance money is payable.

9. Salvage

(1) The Insured, in the event of any loss or damage to any property insured under the contract, shall take all reasonable steps to prevent further damage to such property so damaged and to prevent damage to other property insured hereunder including, if necessary, its removal to prevent damage or further damage thereto

(2) The Insurer(s) shall contribute pro rata towards any reasonable and proper expenses in connection with steps taken by the Insured and required under Sub-Paragraph(1) of this Condition according to the respective interests of the parties.'

10. Entry, Control, Abandonment

After loss or damage to insured property, the Insurer(s) has an immediate right of access and entry by accredited agents sufficient to enable them to survey and examine the property and to make an estimate of the loss or damage and, after the Insured has secured the property, a further right of access and entry sufficient to enable them to make appraisement or particular estimate of the loss or damage, but the Insurer(s) is not entitled to the control or possession of the insured property, and without the consent of the Insurer(s) there can be no abandonment to it of insured property.

11. Appraisal

In the event of disagreement as to the value of the property insured, the property saved or the amount of the loss, those questions shall be determined by appraisal as provided under The Insurance Act before there can be any recovery under this contract, whether the right to recover on the contract is disputed or not and independently of all other questions. There shall be no right to an appraisal until a specific demand therefor is made in writing and until after proof of loss has been delivered.

12. When Loss Payable

The loss is payable within Sixty (60) days after completion of the proof of loss, unless the contract provides for a shorter period.

13. Replacement

(a) The Insurer(s), instead of making payment, may repair, rebuild or replace the property damaged or lost, giving written notice of its intention so to do within Thirty (30) days after receipt of the proofs of loss.

(b) In that event, the Insurer(s) shall commence so to repair, rebuild or replace the property within Forty Five (45) days after receipt of the proofs of loss, and shall thereafter proceed with all due diligence to the completion thereof.

14. Action

Every action or proceeding against the Insurer(s) for the recovery of any claim under or by virtue of this contract is absolutely barred unless commenced within One (1) year' next after the loss or damage occurs. * Two (2) years in the Province of Manitoba and the Northwest and Yukon Territories. Three (3) years in the Province of Quebec.

15. Notice

Any written notice to the Insurer(s) may be delivered at or sent by registered mail to the chief agency or head office of the insurer(s) in the Province. Written notice may be given to the Insured named in the contract by letter personally delivered to him or by registered mail addressed to him at his latest post office address as notified to the Insurer(s). In this condition, the expression "registered means registered in or outside Canada.

Mortgage Clause

IT IS HEREBY PROVIDED AND AGREED THAT

BREACH OF CONDITIONS BY MORTGAGOR OWNER OR OCCUPANT	1.	This insurance and every documented renewal thereof—AS TO THE INTEREST OF THE MORTGAGEE ONLY THEREIN—is and shall be in force notwithstanding any act, neglect, omission or misrepresentation attributable to the mortgagor, owner or occupant of the property insured, including transfer of interest, any vacancy or non-occupancy, or the occupation of the property for purposes more hazardous than specified in the description of the risk. PROVIDED ALWAYS that the mortgagee shall notify forthwith the Insurer (if known) of any vacancy or non-occupancy extending beyond thirty (30) consecutive days, or of any transfer of interest or increased hazard THAT SHALL COME TO HIS KNOWLEDGE; and that every increase of hazard (not permitted by the policy) shall be paid for by the mortgagee—on reasonable demand—from the date such hazard existed, according to the established scale of rates for the acceptance of such increased hazard, during the continuance of this insurance
RIGHT OF SUBROGATION	2.	Whenever the insurer pays the Mortgagee any loss award under this Policy and claims that as to the Mortgagor or owner—no liability therefore existed, it shall be legally subrogated to all rights of the Mortgagee against the Insured; but any subrogation shall be limited to the amount of such loss payment and shall be subordinate and subject to the basic right of the Mortgagee to recover the full amount of its mortgage equity in priority to the Insured; or the Insurer may at its option pay the Mortgagee all amounts due or to become due under the mortgage or on the security thereof, and shall thereupon receive a full assignment and transfer of the mortgage together with all securities held as collateral to the mortgage debt.
OTHER INSURANCE	3.	If there be other valid and collectible insurance upon the property with loss payable to the Mortgagee—at law or in equity—then any amount payable thereunder shall be taken into account in determining the amount payable to the Mortgagee.
WHO MAY GIVE PROOF OF LOSS	4.	In the absence of the insured, or the inability, refusal or neglect of the Insured to give notice of loss or deliver the required Proof of Loss under the Policy, then the Mortgagee may give the notice upon becoming aware of the loss and deliver as soon as practicable the Proof of Loss.
	5.	The term of this mortgage clause coincides with the term of the policy; PROVIDED ALWAYS that the Insurer reserves the right to cancel the policy as provided by Statutory provision but agrees that the Insurer will neither terminate nor alter the policy to the prejudice of the Mortgagee without the notice stipulated in such Statutory provision.
***TERMINATION**	5.	The term of this mortgage clause coincides with the term of the policy; PROVIDED ALWAYS that the Insurer reserves the right to cancel the policy as provided by statutory condition 19 as set forth in section 240 of the Insurance Act of Quebec, but agrees that the Insurer will neither terminate nor alter the Policy to the prejudice of tie Mortgagee without fifteen (15) days notice to the Mortgagee by registered letter.
FORECLOSURE	6.	Should title or ownership to said property become vested in the Mortgagee and/or assigns as owner or purchaser under foreclosure or otherwise, this insurance shall continue until expiry or cancellation for the benefit of the said Mortgagee and/or assigns.

SUBJECT TO THE TERMS OF THIS MORTGAGE CLAUSE (and these shall supersede any policy provisions in conflict therewith BUT ONLY AS TO THE INTEREST OF THE MORTGAGEE), loss under this policy is made payable to the Mortgagee.

*Termination Clause applicable to All Provinces except Quebec *'Termination Clause applicable to the Province of Quebec

Endorsement No. 1
War and Terrorism Exclusion Endorsement

Notwithstanding any provision to the contrary within this insurance or any endorsement thereto it is agreed that this insurance excludes loss, damage, cost or expense of whatsoever nature directly or indirectly caused by, resulting from or in connection with any of the following regardless of any other cause or event contributing concurrently or in any other sequence to the loss;

(1) war, invasion, acts of foreign enemies, hostilities or warlike operations (whether war be declared or not), civil war. rebellion, revolution, insurrection, civil commotion assuming the proportions of or amounting to an uprising, military or usurped power; or

(2) any act of terrorism

For the purpose of this endorsement an act of terrorism means an act, including but not limited to the use of force or violence and/or the threat thereof, of any person or group(s) of persons, whether acting alone or on behalf of or in connection with any organization(s) or government(s), committed for political, religious, ideological or similar purposes including the intention to influence any government and/or to put the public, or any section of the public, in fear.

This endorsement also excludes loss, damage, cost or expense of whatsoever nature directly or indirectly caused by, resulting from or in connection with any action taken in controlling, preventing, suppressing or in any way relating to (1) and/or (2) above.

If the Underwriters allege that by reason of this exclusion, any loss, damage, cost or expense is not covered by this insurance the burden of proving the contrary shall be upon the Assured.

In the event any portion of this endorsement is found to be invalid or unenforceable, the remainder shall remain in full force and effect.

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ALL OTHER TERMS AND CONDITIONS REMAIN UNCHANGED.

Endorsement No. 2
Electronic Data Endorsement A (Amended)

1. Electronic Data Exclusion

Notwithstanding any provision to the contrary within the Policy or any endorsement thereto, it is understood and agreed as follows:

(a) This Policy does not insure loss, damage, destruction, distortion, erasure, corruption or alteration of ELECTRONIC DATA from any cause whatsoever (including but not limited to COMPUTER VIRUS) or loss of use, reduction in functionality, cost, expense of whatsoever nature resulting therefrom, regardless of any other cause or event contributing concurrently or in any other sequence to the loss.

ELECTRONIC DATA means facts, concepts and information converted to a form useable for communications, interpretation or processing$ by electronic and electromechanical data processing or electronically controlled equipment and includes programmes, software and other coded instructions for the processing and manipulation data or the direction and manipulation of such equipment

COMPUTER VIRUS means a set of corrupting, harmful or otherwise unauthorized instructions or code including a set of maliciously introduced unauthorized instructions or code, programmatic or otherwise, that propagate themselves through a computer system or network of whatsoever nature. COMPUTER VIRUS includes but is not limited to "Trojan Horses," "worms" and "time or logic bombs."

(b) However, in the event that a peril listed below results from any of the matters described in paragraph (a) above, this Policy, subject to all its terms, conditions and exclusions, will cover physical damage occurring during the Policy period to property insured by this Policy directly caused by such listed peril.

Listed Perils

Fire
Explosion

Mechanical and Electrical Breakdown

2. Electronic Data Processing Media Valuation

Notwithstanding any provision to the contrary within the Policy or any endorsement thereto, it is understood and agreed as follows:

Should electronic data processing media insured by this Policy suffer physical loss or damage insured by this Policy, then the basis of valuation shall be the cost to repair, replace or restore such media to the condition that existed immediately prior to such loss or damage, including the cost of reproducing any ELECTRONIC DATA contained thereon, providing such media is repaired, replaced or restored. Such cost of reproduction shall include ail reasonable and necessary amounts, not to exceed CAD 10,000,000 any one loss, incurred by the Assured in recreating, gathering and assembling such ELECTRONIC DATA. If the media is not repaired, replaced or restored the basis of valuation shall be the cost of the blank media. However this Policy does not insure any amount pertaining to the value of such ELECTRONIC DATA to the Assured or any other party, even if such ELECTRONIC DATA cannot be recreated, gathered or assembled.

ALL OTHER TERMS AND CONDITIONS REMAIN UNCHANGED.

Endorsement No. 3
Microorganism Exclusion (Map) Endorsement (Absolute)

This policy does not insure any loss, damage, claim, cost, expense or other sum directly or indirectly arising out of or relating to:

Mold, mildew, fungus, spores or other microorganism of any type, nature or description, including but not limited to any substance whose presence poses an actual or potential threat to human health.

This exclusion applies regardless whether there is (i) any physical loss or damage to insured property; (ii) any insured peril or cause, whether or not contributing concurrently or in any sequence; (iii) any loss of use, occupancy, or functionality; or (iv) any action required, including but not limited to repair, replacement, removal, cleanup, abatement, disposal, relocation, or steps taken to address medical or legal concerns.

This exclusion replaces and supersedes any provision in the Policy that provides insurance, in whole or in part, for these matters.

ALL OTHER TERMS AND CONDITIONS REMAIN UNCHANGED.

Endorsement No. 4
Radioactive Contamination Exclusion Clause—Physical Damage—Direct
(Approved by Lloyd's Underwriters' Fire and Non-Marine Association)

This Policy does not cover any loss or damage arising directly or indirectly from nuclear reaction nuclear radiation or radioactive contamination however such nuclear reaction nuclear radiation or radioactive contamination may have been caused NEVERTHELESS if Fire is an insured peril and a Fire arises directly or indirectly from nuclear reaction nuclear radiation or radioactive contamination any loss or damage arising directly from that Fire shall (subject to the provisions of this Policy) be covered EXCLUDING however all loss or damage caused by nuclear reaction nuclear radiation or radioactive contamination arising directly or indirectly from that Fire.

* Note—If Fire is not an insured peril under this Policy the words from "NEVERTHELESS" to the end of this Clause do not apply and should be disregarded.

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ALL OTHER TERMS AND CONDITIONS REMAIN UNCHANGED.

Endorsement No. 5
Biological or Chemical Materials Exclusion

It is agreed that this Insurance excludes loss, damage, cost or expense of whatsoever nature directly or indirectly caused by, resulting from or in connection with the actual or threatened malicious use of pathogenic or poisonous biological or chemical materials regardless of any other cause or event contributing concurrently or in any other sequence thereto.

ALL OTHER TERMS AND CONDITIONS REMAIN UNCHANGED.

Endorsement No. 6
WEH Asbestos Endorsement (1994)

A. This policy only insures asbestos physically incorporated in an insured building or structure, and then only that part of the asbestos which has been physically damaged during the policy period by one of these Listed Perils:

Fire; Explosion; Lightning; Windstorm: Hail: Direct impact of vehicle, aircraft or vessel; Riot or civil commotion; vandalism or malicious mischief; or accidental discharge of fire protective equipment.

This coverage is subject to all limitations in the policy to which this endorsement is attached and, in addition, to each of the following specific limitations:

1. The said building or structure must be insured under this policy for damage by that Listed Peril.
2. The Listed peril must be the immediate, sole cause of the damage to the asbestos.
3. The Insured must report to Underwriters the existence and cost of the damage as soon as practicable after the Listed Peril first damaged the asbestos. However this policy does not insure any such damage first reported to Underwriters more than 12 (twelve) months after the expiration, or termination, of the policy.
4. Insurance under this Policy in respect of asbestos shall not include any sum relating to:
   (i) any faults in the design, manufacture or installation of the asbestos.
   (ii) asbestos not physically damaged by the Listed Peril including any governmental or regulatory authority direction or request of whatsoever nature relating to undamaged asbestos.

B. Except as set forth in the foregoing Section A, this policy does not insure asbestos or any sum relating thereto.

ALL OTHER TERMS AND CONDITIONS REMAIN UNCHANGED.

Endorsement No. 7
Additional Limitations and Conditions Endorsement (Standard)

THIS ENDORSEMENT CONTAINS PROVISIONS IN CLAUSES II, V AND VI THAT MAY LIMIT OR PREVENT RECOVERY UNDER THIS POLICY FOR DEBRIS REMOVAL AS PROVIDED IN CLAUSE II AND/OR RESULTING LOSS (AS PROVIDED IN CLAUSE V).

I. Land, Water and Air Exclusion Clause

Notwithstanding any provision to the contrary within the Policy of which this Endorsement forms part (or within any other Endorsement which forms part of this Policy), this Policy does not insure land (including but not limited to land on which the insured property is located), water or air, howsoever and wherever occurring, or any interest or right therein. The foregoing exclusion shall not apply to water which is contained in plumbing or firefighting installations in the Assured's buildings at the time of any damage insured by this Policy.

II. Debris Removal Clause

Nothing contained in this Clause shall override any seepage and/or pollution and/or contamination exclusion or any radioactive contamination exclusion or any other exclusion applicable to this Policy. The inclusion of this Clause shall in no event increase the limit of liability of Underwriters under this Policy or any other endorsement applicable to this Policy.

Any provision within this Policy (or within any other Endorsement which forms part of this Policy) which insures debris removal is cancelled and replaced by the following:

1. In the event of direct physical damage to property for which Underwriters agree to pay hereunder, or which but for the application of a deductible or underlying amount they would agree to pay (hereinafter in this Clause referred to as "Damage"), this Policy also insures, subject to the limitations below and method of calculation in Clause VI of this Endorsement and to all the other terms and conditions of the Policy, expense:

   (a) which is reasonably and necessarily incurred by the Assured in the removal, from the premises of the Assured at which the Damage occurred, of debris which results from the Damage; and

   (b) of which the Assured becomes aware and advises the amount to Underwriters hereon within one year of the commencement of the Damage;

   provided, however, that nothing in this Clause shall insure any expense provided under Clause V of this Endorsement.

2. The maximum amount of expense for removal of debris (subject to the limitations of paragraph 1 above) that can be included in the method of calculation in Clause VI of this Endorsement, shall be the greater of CAD25,000,000 (twenty five million Canadian dollars) or 25% (twenty-five percent) of the amount of the Damage from which such expense results.

III. Seepage and/or Pollution and/or Contamination Exclusion Clause

Notwithstanding any provision to the contrary within the Policy of which this Endorsement forms part (or within any other Endorsement which forms part of this Policy), this Policy does not insure:

1. any loss, damage, cost or expense; or
2. any increase in insured loss, damage, cost or expense; or
3. any loss. damage, cost, expense, fine, penalty or other sum which is incurred, sustained or imposed by, or by the threat of, any judgment, order, direction, instruction or request of, or any agreement with, any court, government agency, any public, civil or military authority or any other person (and whether or not as a result of public or private litigation);

which arises from any kind of seepage or any kind of pollution and/or contamination, or threat thereof, whether or not caused by or resulting from a peril insured, or from steps or measures taken in connection with the avoidance, prevention. abatement. mitigation, remediation, clean-up or removal of such seepage or pollution and/or contamination, or threat thereof.

The term "any kind of seepage or any kind of pollution and/or contamination" as used in this Endorsement includes (but is not limited to):

1. seepage of, or pollution and/or contamination by, anything, including but not limited to, any material designated as a "hazardous substance" by the United States Environmental Protection Agency or as a "hazardous material" by the United States Department of Transportation, or defined as a "toxic substance" by the Canadian Environmental Protection Act for the purposes of part II of that Act, or any substance designated or defined as toxic, dangerous. hazardous or deleterious to persons or the environment under any other law, ordinance or regulation; and
2. the presence, existence, or release of anything which endangers or threatens to endanger the health, safety or welfare of persons or the environment.

IV. Listed Perils Resulting From Seepage and/or Pollution and/or Contamination Clause

This Policy is amended as set forth below. All other terms and conditions of this Policy remain unchanged and continue to apply with full force and effect. Nothing contained in this Clause shall override any radioactive contamination exclusion applicable to this Policy. If any of the perils listed below results from seepage and/or pollution and/or contamination, then such resultant perils shall not be excluded solely by the foregoing Seepage and/or Pollution and/or Contamination Exclusion Clause.

Listed perils

Fire,
Explosion.

Nothing in this Clause, however, shall extend this Policy to insure:

1. loss, damage, cost, expense, fine or penalty, or other sum arising from any kind of seepage or any kind of pollution and/or contamination that causes or results from a listed peril; or
2. loss or damage at any premises other than the premises where the listed peril took place; or
3. property and/or interests other than those insured by this Policy against the listed perils.

V. Limited Seepage and/or Pollution and/or Contamination Resulting From Physical Damage Caused by Listed Perils Clause

THIS CLAUSE IS VOID AND OF NO FORCE OR EFFECT UNLESS AN AMOUNT IS SPECIFIED IN PARAGRAPH 2 BELOW.

This Policy is amended as set forth below. All other terms and conditions of this Policy remain unchanged and continue to apply with full force and effect. Nothing contained in this Clause shall override any radioactive contamination exclusion or, except as set forth herein, the foregoing Seepage and/or Pollution and/or Contamination Exclusion Clause. The inclusion of this Clause shall in no event increase the limit of liability of Underwriters under this Policy or any other endorsement applicable to this Policy.

1. If,
   (a) any of the perils listed below is the sole, immediate and direct cause of physical damage to property insured by this Policy against such listed peril (hereinafter in this Clause referred to as "Original Damage"); and
   (b) the Original Damage is the sole, immediate and direct cause of seepage onto, and/or pollution and/or contamination of property which is:
      (i) at the same premises as the Original Damage; and
      (ii) insured by this Policy against the listed peril causing the Original Damage; and

(c) said property is damaged thereby (hereinafter in this Clause referred to as "Resulting Damage");

then this Policy, subject to the following additional terms and limitations and the method of calculation in Clause VI of this Endorsement, also insures:

(d) the Resulting Damage; and

(e) the reasonable and necessary expense incurred by the Assured for debris removal and/or clean-up which is:

(i) limited to the same premises as the Original Damage; and

(ii) made necessary solely by the Resulting Damage:

but which shall in no event include any expense of clean-up or removal of land, water or air.

(which Resulting Damage and expense of debris removal and/or clean-up, hereinafter in this Clause are referred to as "Resulting Loss");

provided, however, that this Policy only insures the Resulting Loss where:

(f) Underwriters have agreed to pay for the Original Damage or, but for the operation of a deductible or underlying amount, would have agreed to pay for the Original Damage; and

(g) within one year of the commencement of the listed peril which caused the Original Damage, the Assured became aware and advised Underwriters of the amount of:

(i) the Resulting Loss; and

(ii) any other interest to be claimed under this Policy as a result of the Resulting Damage, whether physical damage, business interruption, extra expense or otherwise.

Listed Perils

Fire,
Lightning,
Explosion.

Nothing in this Clause, however, shall extend this Policy to cover any condition that existed prior to the Original Damage nor to insure any loss, damage, cost, expense, fine, penalty, or other sum which is incurred, sustained or imposed by, or by the threat of, any judgment, order, direction, instruction or request of, or any agreement with, any court, government agency, any public, civil or military authority or any other person (and whether or not as a result of public or private litigation) in connection with any kind of seepage or any kind of pollution and/or contamination from any cause.

2. The maximum amount for any Resulting Loss and any other interest claimed under this Policy as a result of the Resulting Damage, whether physical damage, business interruption, extra expense or otherwise, that can be included in the method of calculation in Clause VI of this Endorsement is CAD25,000,000.

VI. Method of Calculation

In calculating the amount, if any, payable under this Policy for a claim including expense of debris removal (as provided for and limited in Clause II of this Endorsement) and/or Resulting Loss (as provided for and limited in Clause V of this Endorsement), the amount of such expense of debris removal and/or such Resulting Loss shall be added to:

(a) the amount of the Damage (as defined in Clause II) or the amount of the Original Damage (as defined in Clause V); and

(b) all other amounts, if any, insured under this Policy as a result of the same occurrence that Underwriters hereon agree to pay or, but for the application of a deductible or underlying amount, they would agree to pay;

then the resulting sum shall be the amount to which first all deductibles and then any underlying amounts to which this Policy is subject shall be applied and the balance, if any, shall be the amount

payable, subject to all other provisions of this Policy and to the applicable limit(s), sublimit(s) and aggregate limit(s).

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ALL OTHER TERMS AND CONDITIONS REMAIN UNALTERED

Endorsement No. 8
Decontamination Expense

This Policy insures up to the sublimit shown in the Policy Declarations costs or expenses incurred or sustained by the Insured in order to clean-up or remove contaminating materials or substances from the premises of the Insured, but only where such clean-up or removal is necessary to repair, rebuild, replace or reinstate property insured hereunder which has been physically lost or damaged as a result of any peril not otherwise excluded under this Policy.

In no case shall this Policy insure any costs or expenses of cleaning-up or removing land or water where these are incurred or sustained by the Insured or imposed upon the Insured by the order of any government agency, government authority or court in the absence of physical loss or damage to property insured.

ALL OTHER TERMS AND CONDITIONS REMAIN UNALTERED.

Endorsement No. 9
Special Cancellation Provisions

1. It is understood and agreed that if:-

   A. any Insurer subscribing to this Insurance:

      i. ceases underwriting or accepting new business, whether entirely or in any class of business which partially or totally includes the coverage under this Policy, or

      ii. enters into a runoff arrangement, or

      iii. is subject to a scheme of arrangement, or

   B. any action is taken in any jurisdiction for the suspension of payments by, or the dissolution, winding up, termination of existence, liquidation, insolvency administration or bankruptcy of any Insurer, or

   C. a provisional liquidator, liquidator, trustee, administrator, receiver, administrative receiver or similar officer is appointed in respect of any Insurer or in respect of any part of its assets, or

   D. any authorisation, approval or consent, licence, exemption, filing, registration or notarisation or other requirement necessary or desirable to enable any Insurer to carry on business is modified, revoked or withheld or does not remain or proves not to have been in full force and effect, or

   E. it becomes unlawful for any Insurer to perform any of its obligations under the Policy or an intention is announced to take any of the actions stated in paragraphs A. to D. above, or

   F. the financial strength rating of any Insurer is downgraded after the issuance of the Policy to below A- by A.M. Best Co., or below BBB by Standard & Poor's Rating Services,

   then the Insured or the Insured's Broker (as agent of the Insured) is entitled at its option to cancel that Insurer's participation in this Policy at any time after the applicable act stated above.

   In that event, the premium due to such Insurer for this Insurance shall be the *pro rata* proportion of the premium allocated to the risks covered under the Policy which corresponds to the period for which the Insurer has been on risk, but after the deduction of that Insurer's proportion of outstanding claims under the Policy.

Endorsement No. 10
Terrorism Exclusion

(Applicable to Northbridge Indemnity Insurance Corporation's participation only)

Notwithstanding any provision to the contrary within this Policy or any endorsement thereto, it is agreed that this Policy excludes loss, damage, cost, or expense directly or indirectly caused by, contributed to by, resulting from, or arising out of or in connection with any act of terrorism, as defined herein, regardless of any other cause or event contributing concurrently or in any other sequence to the loss.

An act of terrorism includes any act, or preparation in respect of action, or threat of action designed to influence the government de jure or de facto of any nation or any political division thereof, or in pursuit of political, religious, ideological, or similar purposes to intimidate the public or a section of the public of any nation by any person or group(s) of persons whether acting alone or on behalf of or in connection with any organization(s) or government(s), de jure or de facto, and which:

(i) involves violence against one or more persons; or

(ii) involves damage to property; or

(iii) endangers life other than that of the person committing the action; or

(iv) creates a risk to health or safety of the public or a section of the public; or

(v) is designed to interfere with or to disrupt an electronic system.

This Policy also excludes loss, damage, cost, or expense directly or indirectly caused by, contributed to by, resulting from, or arising out of or in connection with any action in controlling, preventing, suppressing, retaliating against, or responding to any act of terrorism.

Nothing herein contained shall vary, alter or extend any provision or condition of the Policy other than as above stated.

Endorsement No. 11
Service of Suit Clause (Canada)
(Action Against Insurer)

In any action to enforce the obligations of the Underwriters liable hereunder they can be designated or named as "Lloyd's Underwriters" and such designation shall be binding on the Underwriters liable hereunder as if they had each been individually named as defendant. Service of such proceedings may validly be made upon the Attorney In Fact in Canada for Lloyd's Underwriters, whose address for such service is 1155, rue Metcalfe, Suite 1540, Montreal, Quebec, H3B 2V6.

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Endorsement No. 12
Several Liability Notice

The subscribing insurers' obligations under contracts of insurance to which they subscribe are several and not joint and are limited solely to the extent of their individual subscriptions. The subscribing insurers are not responsible for the subscription of any co-subscribing insurer who for any reason does not satisfy all or part of its obligations.

08/94
LSW 1001 (Insurance)

COMMONWEALTH

COMMONWEALTH INSURANCE COMPANY

(hereafter called the Insurer)

PO Box 49115 Bentall Tower Three, 595 Burrard Street, Suite 1500, Vancouver, BC, Canada V7X 1G4

MANUSCRIPT UMBRELLA LIABILITY POLICY

POLICY NO. CRX 62109
(Replacing CRX 61734)

IN CONSIDERATION of the payment of the premium and subject to the Declarations (made a part hereof), Insuring Agreements, Exclusions, Limits of Liability, Conditions and other terms of this Policy, HEREBY AGREES TO INSURE THE INSURED in the manner and to the extent herein set forth.

DECLARATIONS

1.	NAMED INSURED:	YUKON ENERGY CORPORATION; YUKON DEVELOPMENT CORPORATION	
	MAILING ADDRESS:	PO Box 5920, Whitehorse, Yukon Y1A 6S7	
2.	POLICY PERIOD:	From: September 1, 2011 To: September 1, 2012 12:01 a.m. Standard Time at the mailing address stated hereon	
3.	LIMITS OF LIABILITY:	$ 25,000,000.00 $ 25,000,000.00	Inclusive Each Occurrence In the Aggregate with respect to Products and Completed Operations Liability
4.	RETAINED LIMIT:	$ 10,000.00	
5.	PREMIUM:	$ 35,877.00	
6.	ADJUSTMENT RATE:	$ Nil.	
7.	MINIMUM PREMIUM:	$ 28,700.00	

COPY

Commonwealth Insurance Company

8. SCHEDULE OF UNDERLYING INSURANCE:

CARRIER	POLICY NUMBER	COVERAGE	UNDERLYING LIMITS OF LIABILITY
(a) Commonwealth Insurance Company	CRX 62108	Comprehensive General Liability (including Non-Owned Automobile)	$ 5,000,000.00 Inclusive each Occurrence and in the Aggregate with respect to Products, Completed Operations Liability, Employee Benefits and Forest Fire Fighting Expenses
(b) Royal & Sun Alliance Insurance Company of Canada	CAP020854331	Automobile Liability	$ 5,000,000.00
(c) Global Aerospace Underwriting Managers (Canada) Limited	21900228-YT-11	Non-Owned Aircraft Liability	$ 5,000,000.00

9. ENDORSEMENTS AS PER SCHEDULE: (See Page 23)

10. BROKER: AON REED STENHOUSE INC., Vancouver, BC

In Witness Whereof, the Insurer through its representative duly authorized by it for this purpose has executed and signed this policy.

.....
COMMONWEALTH INSURANCE COMPANY

SR.62109(214)/75075.yukon energy corp.(2230)/IPR.
Issued: September 2, 2011

Commonwealth Insurance Company

INSURING AGREEMENTS

1. COVERAGE:

The Insurer hereby agrees to pay on behalf of the Insured the "Ultimate Net Loss" which the Insured shall become legally obligated to pay for damages because of:

(i) Personal Injury
(ii) Property Damage
(iii) Advertising Liability

caused by an Occurrence anywhere in the world;

or

(iv) Automobile Liability

The provision of automobile insurance by this Policy is confined solely to that provided by, and shall be subject to all the terms and conditions of the Excess Automobile Policy attached to and forming part of this Policy and to Definition 2(c).

2. DEFENCE, SETTLEMENT AND SUPPLEMENTARY PAYMENTS:

With respect to any Occurrence NOT COVERED by underlying insurance described in the Declarations or any other underlying insurance collectible by the Insured, but covered by terms and conditions of this Policy except for the amount of Retained Limit specified in Item 4 of the Declarations, the Insurer will:

(a) defend any suit against the Insured seeking damages on account of Personal Injury, Property Damage or Advertising Liability even if such suit is groundless, false or fraudulent; and may make such investigation, negotiation and settlement of any claim or suit as it deems expedient;

(b) pay premiums on bonds to release attachments in any such suit for an amount not in excess of the applicable limit of liability of this Policy, pay premiums on appeal bonds required in any such defended suit, but without any obligation to apply for or furnish any such bonds;

(c) pay all expenses incurred by the Insurer, all costs taxed against the Insured in any such suit defended by the Insurer and all interest on the entire amount of any judgment therein which accrues after entry of judgment (or, in those jurisdictions where statute prescribes interest from some other date, from such prescribed date) and before the Insurer has paid or tendered or deposited in court that part of the judgment which does not exceed the limit of the Insurer's liability thereon;

(d) pay reasonable expenses incurred by the Insured at the Insurer's request, including actual loss of wages or salary (but not loss of other income) not to exceed Two Hundred ($200.00) Dollars per day because of his attendance at hearings or trials at such request.

Commonwealth Insurance Company

The amounts so incurred, except settlements of claims and suits are payable by the Insurer in addition to the applicable limit of liability of this Policy:

In jurisdictions where the Insurer may be prevented by law or otherwise from carrying out this agreement, the Insurer shall pay any expense incurred with its written consent in accordance with this agreement. The Insured shall promptly reimburse the Insurer for any amount of Ultimate Net Loss paid on behalf of the Insured within the Retained Limit specified in Item 4 of the Declarations.

3. LIMIT OF LIABILITY:

The Insurer shall only be liable for the Ultimate Net Loss in excess of

(a) the limits of the underlying insurances as set out in Item 8 of the Declarations and the amount recoverable under any other underlying insurances collectible by the Insured in respect of each Occurrence covered by said underlying insurance, or

(b) the Retained Limit specified in Item 4 of the Declarations in respect of each Occurrence not covered by said underlying insurances,

and then only up to a further sum not exceeding the amount stated in Item 3 of the Declarations

(i) in respect of each Occurrence, and

(ii) in respect of the Aggregate on account of all Occurrences during each policy period

(1) arising out of the Products Hazard or Completed Operations Hazard or both combined, or

(2) arising out of any coverage contained in an underlying insurance listed in Item 8 of the Declarations if such coverage is subject in such underlying insurance to an aggregate limit of liability for all insured damages, the Aggregate limit under this Policy then to apply separately to each such underlying insurance coverage.

In the event of reduction or exhaustion of the aggregate limits of liability under said underlying insurance by reason of losses paid thereunder, this Policy, subject to all the terms, conditions and definitions hereof shall: -

(i) in the event of reduction, pay the excess of the reduced underlying limit of insurance

(ii) in the event of exhaustion, continue in force as underlying insurance.

The inclusion or addition hereunder of more than one Insured shall not operate to increase the Insurer's Limits of Liability beyond those set forth in the Declarations.

DEFINITIONS

When used in this Policy, including endorsements forming a part hereof:

1. ADVERTISING LIABILITY:

   The term "Advertising Liability" means:

   (i) libel, slander or defamation;

   (ii) any infringement of copyright or of title or of slogan;

   (iii) piracy or unfair competition or idea misappropriation under an implied contract;

   (iv) any invasion of right of privacy;

   committed or alleged to have been committed in any advertisement, publicity article, broadcast or telecast and arising out of the Named Insured's advertising activities.

2. NAMED INSURED AND INSURED:

   The words "Named Insured" include any subsidiary company of the Named Insured and any other company coming under the Named Insured's control of which it assumes active management, provided such subsidiary company or other companies are covered by valid and collectible underlying insurance as described in the Schedule of Underlying Insurance.

   The unqualified word "Insured" means not only the Named Insured but also:-

   (a) any executive officer, director, stockholder, partner or employee of the Named Insured while acting in his capacity as such, and any organization or proprietor with respect to real estate management for the Named Insured;

   (b) any owner, person, firm, organization, trustee, estate or governmental entity to whom or to which the Named Insured has contracted to effect insurance, by virtue of a contract or agreement or by the issuance or existence of a permit. But the insurance provided for such additional Insured is restricted to apply solely to liability arising out of operations performed under said contract and only to the extent required by such contract;

   It is understood and agreed however that the above extension (b) does not apply to subcontractors or contractors working on behalf of the Named Insured.

(c) any Additional Insured (not being the Named Insured under this Policy) included in the underlying insurances, subject to the provisions in Condition (2); but not for broader coverage than is available to such Additional Insured under any underlying insurance as set out in Item 8 of the Declarations.

(d) if the Named Insured is designated in the Declarations as a partnership or joint venture, the partnership or joint venture so designated and any partner or member thereof but only with respect to their liability as such. This Policy does not apply to Personal Injury, Property Damage or Advertising Liability arising out of the conduct of any partnership or joint venture of which the Insured is a partner or member and which is not designated in this Policy as a Named Insured.

The insurance provided for Additional Insureds shall apply only when the Named Insured so directs the Insurer in writing upon a claim being made against such Additional Insured.

3. COMPLETED OPERATIONS HAZARD:

Completed Operations Hazard includes Personal Injury or Property Damage arising out of operations, but only if the Personal Injury or Property Damage occurs after such operations have been completed or abandoned and occurs away from premises owned by or rented to the Named Insured. Operations include materials, parts or equipment furnished in connection therewith. Operations shall be deemed completed at the earliest of the following times:

(i) when all Operations to be performed by or on behalf of the Named Insured under the contract have been completed;

(ii) when all Operations to be performed by or on behalf of the Named Insured at the site of the Operations have been completed;

(iii) when the portion of the work out of which the Personal Injury or Property Damage arises has been put to its intended use by any person or organization other than another contractor or subcontractor engaged in performing operations for a principal as a part of the same project.

Operations which may require further service or maintenance work, or correction, repair or replacement because of any defect or deficiency, but which are otherwise complete, shall be deemed completed.

The Completed Operations Hazard shall not include:

(i) operations in connection with the pick up and delivery of property;

(ii) the existence of tools, uninstalled equipment or abandoned or unused materials.

4. OCCURRENCE:

(a) With respect to Bodily Injury [Definition 5(a)], Property Damage or Advertising Liability, the term "Occurrence" means an accident, happening or event, including continuous or repeated exposure to conditions, which results during the Policy Period in Bodily Injury or Property Damage neither expected nor intended from the standpoint of the Insured.

(b) With respect to Personal Injury [Definitions 5(b) to 5(f)], the term "Occurrence" means an act or offense committed in the conduct of the Insured's business during the Policy Period resulting in Personal Injury.

(c) With respect to advertising liability all ultimate net loss arising out of any advertisements, publicity articles, broadcasts or telecasts or any combination thereof involving the same injurious material or act, regardless of the frequency of repetition thereof, or the number or kind of media used, or the number of persons claiming damages, shall be deemed to arise out of one occurrence.

5. PERSONAL INJURY:

Except when it arises out of Advertising Liability the term "Personal Injury" means the following;

(a) Bodily injury, mental injury, mental anguish, shock, sickness, disease, or disability including death, care and loss of services at any time resulting therefrom, or

(b) False arrest, malicious prosecution, wilful or wrongful detention or imprisonment, or

(c) Libel, slander, defamation of character, or

(d) Invasion of privacy, right of privacy, wrongful eviction or wrongful entry, trespass, or

(e) Discrimination, except where it is a violation of a statute or regulation prohibiting insurance for such, or

(f) Humiliation,

including any other legal action alleging the foregoing by any other name.

6. PRODUCTS HAZARD:

The term "Products Hazard" includes Personal Injury and Property Damage arising out of the Named Insured's products but only if such Personal Injury or Property Damage occurs away from premises owned by or rented to the Named Insured and after physical possession of such products has been relinquished to others.

7. NAMED INSURED'S PRODUCTS:

"Named Insured's Products" means goods or products, other than real property, manufactured, sold, handled or distributed by the Insured or by others trading under his name, including any container thereof (other than a vehicle), but shall not include a vending machine or any property other than such container, rented to or located for use of others, but not sold.

8. PROPERTY DAMAGE:

The term "Property Damage" means (1) physical injury to or destruction of tangible property which occurs during the Policy Period, including the loss of use thereof at any time resulting therefrom, or (2) loss of use of tangible property which has not been physically injured or destroyed provided such loss of use is caused by an Occurrence during the Policy Period.

9. ULTIMATE NET LOSS:

The term "Ultimate Net Loss" means the sum actually paid or payable as damages in the settlement or satisfaction of losses for which the Insured is liable either by adjudication or compromise with the written consent of the Insurer, after making proper deduction for all recoveries and salvages collectible, but excludes all loss expenses and legal expenses (including attorneys' fees, court costs and interest on any judgment or award) and all salaries of employees and office expenses of the Insured, the Insurer or any underlying Insurer so incurred.

10. UNDERLYING INSURANCE:

"Underlying Insurance" means:

(a) The amount of the applicable limits of liability of the underlying insurance as stated in the Schedule of Underlying Insurance, less the amount, if any, by which an aggregate limit of such insurance has been reduced by payment of loss; and

(b) In addition to the amount applicable in paragraph (a), the amount of any other valid and collectible insurance available to the Insured, whether such other insurance is stated to be primary, contributing, excess or contingent (except insurance purchased to apply in excess of the sum of underlying limits described in paragraph (a), or the retained limit, and the limit of liability hereunder); or

(c) If the insurance afforded by the underlying insurance policies stated in the Schedule of Underlying Insurance is inapplicable to the occurrence, the amount stated in the Declarations as the retained limit, or the amount of other insurance stated in paragraph (b), whichever is greater.

The limits of liability of any underlying insurance policy stated in the Schedule of Underlying Insurance shall be deemed applicable irrespective of (1) any defense which the underlying insurer may assert because of the Insured's failure to comply with any condition of the policy subsequent to an occurrence, or (2) the inability of the underlying insurer to pay by reason of bankruptcy or insolvency.

EXCLUSIONS

1. This Policy shall not apply to:

   (a) any obligation for which the Insured or any company as its Insurer may be held liable under any worker's compensation, unemployment compensation or disability benefits law; provided, however, that this exclusion does not apply to liability of others assumed by the Named Insured under contract or agreement;

   (b) Property Damage to property owned by the Insured;

   (c) Property Damage to the Named Insured's products arising out of such products or any part of such products;

   (d) Property Damage to work performed by or on behalf of the Named Insured arising out of the work or any portion thereof, or out of materials, parts or equipment furnished in connection therewith;

   (e) loss of use of tangible property which has not been physically injured or destroyed resulting from:

      (i) a delay in or lack of performance by or on behalf of the Named Insured of any contract or agreement, or

      (ii) the failure of the Named Insured's products or work performed by or on behalf of the Named Insured to meet the level of performance, quality, fitness or durability warranted or represented by the Named Insured;

   but this exclusion does not apply to loss of use of other tangible property resulting from the sudden and accidental physical injury to or destruction of the Named Insured's products or work performed by or on behalf of the Named Insured after such products or work have been put to use by any person or organization;

   (f) damages or expenses claimed for the withdrawal, inspection, repair, replacement or loss of use of the Named Insured's products or work completed by or for the Named Insured or of any property of which such products or work form a part, if such products, work or property are withdrawn from the market or from use because of any known or suspected defect or deficiency therein;

(g) claims made against the Insured with respect to advertising activities for

(i) failure of performance of contract, but this shall not relate to claims for unauthorized appropriation of ideas based upon alleged breach of an implied contract;

(ii) infringement of registered trade mark, service mark or trade name by use thereof as the registered trade mark, service mark or trade name of goods or services sold, offered for sale or advertised, but this shall not relate to title or slogans;

(iii) incorrect description of any article or commodity;

(iv) mistake in advertised price;

(h) Except with respect to occurrences taking place in Canada or the United States of America, its territories or possessions, to any liability of the Insured directly or indirectly occasioned by, happening through or in consequence of war, invasion, act of foreign enemies, hostilities (whether war be declared or not), civil war, rebellion, revolution, insurrection, military or usurped power or confiscation or nationalization or requisition or destruction of or damage to property by or under the order of any government or public or local authority;

(i) Property Damage to property owned or leased by one Insured whilst used by or in the care, custody or control of any other Insured;

(j) (a) "Personal Injury" or "Property Damage" arising out of the actual, alleged, or threatened discharge, emission, dispersal, release, escape, seepage, leakage or migration of pollutants

(i) at or from any premises, site, location, easement or right-of-way, which is or was at any time, owned by, rented to, loaned to or occupied by, any Insured;

(ii) at or from any premises, site or location which is or was at any time, used by or for any Insured or others for the handling, storage, disposal, processing or treatment of waste;

(iii) which are or were at any time transported, handled, stored, treated, disposed of, or processed as waste by or for an Insured or any person or organization for whom the Insured may be legally responsible; or

(iv) at or from any premises, site or location on which an Insured or any contractors or subcontractors working directly or indirectly on any Insured's behalf are performing operations:

A. if the pollutants are brought on or to the premises, site or location in connection with such operations by such Insured, contractor or subcontractor; or

B. if the operations are to test for, monitor, clean up, remove, contain, treat, detoxify, decontaminate, stabilize, remediate or neutralize, or in any way respond to, or assess the effect of pollutants.

Subparagraph (i) of paragraph (a) of this Exclusion DOES NOT apply to Personal Injury if sustained within a building and caused by smoke, fumes, vapor or soot from equipment used to heat that building.

Subparagraph (iv)A of paragraph (a) of this Exclusion DOES NOT apply to Personal Injury or Property Damage sustained within a building and caused by the release of gases, fumes or vapors from materials brought into that building in connection with operations being performed by the Insured or on the Insured's behalf by a contractor or subcontractor.

Subparagraphs (i) and (iv)A. of paragraph (a) of this Exclusion do not apply to "Personal Injury" or "Property Damage" caused by:

(i) heat, smoke or fumes from a hostile fire which becomes uncontrollable or breaks out from where it was intended to be; or

(ii) an unexpected and unintentional spill, discharge, emission, dispersal, seepage, leakage, migration, release or escape of pollutants provided such discharge, emission, dispersal, seepage, leakage, migration, release or escape of pollutants:

A. results in the injurious presence of pollutants in or upon land, the atmosphere, drainage or sewage system, watercourse or body of water; and

B. is detected within 120 hours after the commencement of the spill, discharge, emission, dispersal, seepage, leakage, migration, release or escape; and

C. is reported to the Insurer within 120 hours of being detected; and

D. does not occur in a quantity or with a quality that is routine or usual to the business of the Insured.

(b) Any loss, cost or expense or request for restitution arising out of any governmental direction, action or request that an Insured:

(i) test for, monitor, clean up, remove, contain, treat, detoxify, decontaminate, stabilize, remediate or neutralize or in any way respond to, or assess the effect of pollutants; or

(ii) restore, reclaim or rehabilitate any land, watercourse or body of water.

unless such loss, cost or expense is consequent upon "Personal Injury" or "Property Damage" covered by this Policy.

(c) Fines, penalties, punitive or exemplary damages arising out of the discharge, emission, dispersal, seepage, leakage, migration, release or escape of any pollutants.

"Pollutants" means any solid, liquid, gaseous, or thermal irritant or contaminant, including smoke, vapor, soot, fumes, acids, alkalis, chemicals and waste.

"Waste" includes materials to be recycled, reconditioned or reclaimed.

Nothing contained in this Exclusion shall operate to provide any coverage with respect to clean up, removal, containment, treatment, detoxification or neutralization of pollutants situated on premises the Insured currently owns, rents or occupies or that the Insured formerly owned, rented or occupied.

(k) fines or penalties, for which the Insured is liable by reason of failure to comply with any statute, rule or regulation;

(l) with respect to Personal Injury coverage as defined in Definition 5 (b) to (f) inclusive, and to Advertising Liability,

(i) to injury caused by the wilful violation of a penal statute or ordinance committed by or with the knowledge or consent of the Insured;

(ii) to injury arising out of any publication or utterance if the first injurious publication or utterance of the same or similar material by or on behalf of the Insured was made prior to the effective date of this insurance;

(iii) to injury arising out of a publication or utterance concerning any organization or business enterprise, or its products or services, made by or at the direction of any Insured with knowledge of the falsity thereof.

(m) Personal Injury as defined under Definition 5 (a) caused intentionally by or at the direction of the Insured except when caused to protect persons or property; however, this exclusion shall not apply to any Insured who neither sanctioned, nor had knowledge of, nor was a party to the causing of such Personal Injury;

(n) Personal Injury sustained by any person employed by the Insured in violation of the laws as to age;

(o) It is agreed that this Policy does not apply:

(a) to liability imposed by or arising under the Nuclear Liability Act; nor

(b) to Bodily Injury or Property Damage with respect to which an Insured under this Policy is also insured under a contract of nuclear energy liability insurance (whether the Insured is unnamed in such contract and whether or not it is legally enforceable by the Insured) issued by the Nuclear Insurance Association of Canada or any other insurer or group or pool of insurers or would be an Insured under any such policy, but for its termination upon exhaustion of its limit of liability; nor

(c) to Bodily Injury or Property Damage resulting directly or indirectly from the nuclear energy hazard arising from:

(i) the ownership, maintenance, operation or use of a nuclear facility by or on behalf of an Insured;

(ii) the furnishing by an Insured of services, materials, parts or equipment in connection with the planning, construction, maintenance, operation or use of any nuclear facility; and

(iii) the possession, consumption, use, handling, disposal or transportation of fissionable substances, or of other radioactive material (except radioactive isotopes, away from a nuclear facility, which have reached the final stage of fabrication so as to be usable for any scientific, medical, agricultural, commercial or industrial purpose) used, distributed, handled or sold by an Insured.

As used in this Policy:

(1) The term "nuclear energy hazard" means the radioactive, toxic, explosive, or other hazardous properties of radioactive material.

(2) The term "radioactive material" means uranium, thorium, plutonium, neptunium, their respective derivatives and compounds, radioactive isotopes of other elements and any other substances that the Atomic Energy Control Board may, by regulation, designate as being prescribed substances capable of releasing atomic energy, or as being requisite for the production, use or application of atomic energy;

(3) The term "nuclear facility" means:

(a) any apparatus designed or used to sustain nuclear fission in a self-supporting chain reaction or to contain a critical mass of plutonium, thorium and uranium or any one or more of them;

(b) any equipment or device designed or used for (i) separating the isotopes of plutonium, thorium and uranium or any one or more of them, (ii) processing or utilizing spent fuel, or (iii), processing or packaging waste;

(c) any equipment or device used for the processing, fabricating or alloying of plutonium, thorium or uranium enriched in the isotope uranium 233 or in the isotope uranium 235, or any one or more of them if at any time the total amount of such material in the custody of the Insured at the premises where such equipment or device is located consists of or contains more than 25 grams plutonium or uranium 233 or any combination thereof, or more than 250 grams of uranium 235;

(d) any structure, basin, excavation, premises or place prepared or used for the storage or disposal of waste radioactive material; and includes the site on which any of the foregoing is located, together with all operations conducted thereon and all premises used for such operations.

(4) The term "fissionable substance" means any prescribed substance that is, or from which can be obtained, a substance capable of releasing atomic energy by nuclear fission.

The insurance afforded with respect to liability assumed under contract is subject to the following additional exclusions:

(p) to Personal Injury or Property Damage for which the Insured has assumed liability under any contract, if such injury or damage occurred prior to the execution of the contract;

(q) if the indemnitee of the Insured is an architect, engineer or surveyor, to the liability of the indemnitee, his agents or employees, arising out of:

(i) the preparation or approval of or the failure to prepare or approve maps, drawings, opinions, reports, surveys, change orders, designs or specifications, or

(ii) the giving of or the failure to give directions or instructions by the indemnitee, his agents or employees, provided such giving or failure to give is the primary cause of the Personal Injury or Property Damage.

The insurance afforded to Additional Insureds required to be added to this Policy by contract is subject to this further exclusion:

(r) Personal Injury or Property Damage arising out of the rendering of or the failure to render professional services by such Insured, including:

(i) the preparation or approval of maps, drawings, opinions, reports, surveys, change orders, designs or specifications, and

(ii) supervisory, inspection or engineering services.

2. This Policy shall not apply, except insofar as coverage is available to the Insured in the underlying insurance as set out in the Declarations, and then not for broader coverage than is afforded by such underlying insurance:-

(s) to Personal Injury or Property Damage arising out of the ownership, maintenance, use, operation, loading or unloading by or on behalf of the Insured of any watercraft, if the Occurrence takes place away from premises owned by, rented to or controlled by the Named Insured;

(t) (i) to Personal Injury or Property Damage arising out of the ownership, maintenance, use, operation, loading or unloading by or on behalf of the Insured of:

(1) any aircraft, or

(2) any air cushion vehicle;

(ii) to Personal Injury or Property Damage arising out of the ownership, existence, use or operation by or on behalf of the Insured of any premises for the purpose of an airport or aircraft landing strip and all operations necessary or incidental thereto;

(u) Personal Injury or Property Damage arising out of the rendering of or the failure to render professional services by any architect, engineer or surveyor, except such services as are an integral part of other work performed by or on behalf of the Insured or any associated or affiliated company or are incidental to the manufacture, installation, sale, handling or distribution of the Insured's products or the products of any associated or affiliated company;

(v) Bodily Injury (Definition 5 [a]) arising out of the rendering of or the failure to render medical services by any doctor, physician and/or surgeon in the employ of the Insured, except that this exclusion SHALL NOT apply to the contingent liability of the Named Insured;

(w) to any employee with respect to injury to or the death of another employee of the same employer injured in the course of such employment;

(x) to Personal Injury to any employee of the Insured arising out of and in the course of employment by the Insured;

(y) to punitive or exemplary damages.

3. Where the underlying insurance as set out in the Declarations provides Broad Form Property Damage and/or Broad Form Products Hazard or Completed Operations Hazard coverage exclusions (c) and (d) are deleted and replaced by the following exclusion but in no event for broader coverage than is afforded by such underlying insurance:-

(z) damage to or destruction including loss of use of:

(1) property owned or occupied by or rented to the Insured;

(2) property held by the Insured for sale, property entrusted to the Insured for storage or safekeeping, property loaned to the Insured or personal property in the care, custody or control of the Insured;

(3) that particular part of any property:

(i) upon which operations are being performed by or on behalf of the Insured at the time of the damage thereto or destruction thereof, arising out of such operations, or

(ii) out of which any damage or destruction arises, or

(iii) the restoration, repair or replacement of which has been made or is necessary by reason of faulty workmanship thereon by or on behalf of the Insured;

Paragraphs (2) and (3) do not apply to liability under sidetrack agreements.

Subparagraphs (ii) and (iii) of Paragraph (3) do not apply to property damage included in the Completed Operations Hazard.

(4) property which is being transported by the Insured, including the loading or unloading thereof.

(5) with respect to the Products Hazard, that particular part of the Insured's products out of which an accident arises.

(6) with respect to the Completed Operations Hazard, that particular part of a work performed by or on behalf of the Insured out of which an accident arises due to faulty workmanship.

CONDITIONS

1. PREMIUM COMPUTATION:

The premium for this Policy shall be computed on the basis set forth under Item 6 of the Declarations. At the end of Each Policy Period the earned premium shall be computed as outlined therein. If the earned premium thus computed is more than the advance premium paid, the Named Insured shall immediately pay the excess to the Insurer; if less, the Insurer shall return the difference to the Named Insured; but the Insurer shall receive and retain the minimum premium for Each Policy Period.

2. ADDITIONAL "NAMED INSURED":

In the event of an Additional Named Insured being added to the coverage under the underlying insurance during currency hereof, prompt notice shall be given to the Insurer who shall be entitled to charge an appropriate additional premium hereon.

3. PRIOR INSURANCE AND NONCUMULATION OF LIABILITY:

It is agreed that if any loss covered hereunder is also covered in whole or in part under any other excess policy issued to the Insured prior to the inception date hereof, the limit of liability hereon as stated in Item 3 of the Declarations shall be in excess of any amounts due to the Insured on account of such loss under such prior insurance.

4. INSPECTION AND AUDIT:

(i) The Insurer shall be permitted but not obligated to inspect the Insured's property and operations but neither the Insurer's right to make inspections nor the making thereof nor any report thereon shall constitute an undertaking on behalf of or for the benefit of the Insured or others to determine or warrant that such property or operations are safe.

(ii) The Insurer may examine and audit the Insured's books and records at any time during the Policy Period and extensions thereof and within three (3) years after the final termination of this Policy, as far as they relate to the subject matter of this insurance.

5. CROSS LIABILITY:

In the event of claims being made by reason of Personal Injury and/or Property Damage suffered by one Insured herein for which another Insured herein is or may be liable, this Policy shall cover such Insured against whom a claim is made or may be made in the same manner as if separate policies had been issued to each Insured herein. Nothing contained herein shall operate to increase the Insurer's limit of liability as set forth in Insuring Agreement 3.

6. NOTICE OF "OCCURRENCE":

Whenever it appears that an Occurrence covered hereunder is likely to involve the Insurer, written notice shall be sent to the Insurer as soon as practicable. Such notice shall contain particulars sufficient to identify the Insured and also reasonably obtainable information respecting the time, place and circumstances of the Occurrence.

7. ASSISTANCE AND COOPERATION:

Except as provided in Insuring Agreement 2; the Insurer shall not be called upon to assume charge of the settlement or defence of any claim made, suit brought or proceeding instituted against the Insured; but the Insurer shall have the right and shall be given the opportunity to associate with the Insured in the defence and control of any claim, suit or proceeding reasonably likely to involve the Insurer. In such event the Insured and the Insurer shall cooperate fully.

8. APPEALS:

In the event the Insured or the Insured's underlying insurer elect not to appeal a judgment in excess of the underlying limits, the Insurer may elect to make such appeal at its cost and expense, and shall be liable for the taxable costs and disbursement and interest incidental thereto, but in no event shall the liability of the Insurer for Ultimate Net Loss exceed the amount set forth in Item 3 of the Declarations of any one Occurrence and in addition to the cost and expense of such appeal.

9. ACTION AGAINST INSURER:

No action shall lie against the Insurer unless as a condition precedent thereto the Insured shall have fully complied with all the terms of this Policy, nor until the amount of the Insured's obligation to pay an amount of Ultimate Net Loss in excess of the underlying or retained limit shall have been finally determined either by judgment against the Insured after actual trial or by written agreement of the Insured, the claimant and the Insurer. The Insured shall make a definite claim for any loss for which the Insurer may be liable within twelve (12) months after such final determination. Claim for any subsequent payments made by the Insured on account of the same Occurrence shall be similarly made. All losses covered by this Policy shall be due and payable within thirty (30) days after they are respectively claimed and proven in conformity with this Policy.

10. BANKRUPTCY OR INSOLVENCY:

Bankruptcy or insolvency of the Insured or the Insured's estate shall not relieve the Insurer of any of its obligations hereunder.

11. OTHER INSURANCE:

If other valid and collectible insurance with any other Insurer is available to the Insured covering a loss also covered by this Policy, other than insurance that is specifically stated to be in excess of this Policy, the insurance afforded by this Policy shall be in excess of and shall not contribute with such other insurance. Nothing herein shall be construed to make this Policy subject to the terms, conditions and limitations of such other insurance.

12. SUBROGATION:

Inasmuch as this Policy is excess coverage, the Insured's right of recovery against any person or other entity cannot be exclusively subrogated to the Insurer.

Therefore, in case of any payment hereunder, the Insurer will act in concert with all other interests (including the Insured) concerned, in the exercise of such rights of recovery. The apportioning of any amounts which may be so recovered shall follow the principle that any interests (including the Insured) that shall have paid an amount over and above any payment hereunder, shall first be reimbursed up to the amount paid by them; the Insurer is then to be reimbursed out of any balance then remaining up to the amount paid hereunder; lastly the interests (including the Insured) of which this coverage is in excess are entitled to claim the residue, if any. Expenses necessary to the recovery of any such amount shall be apportioned between the interests (including the Insured) concerned, in the ratio of their respective recoveries as finally settled.

13. CHANGES:

Notice to or knowledge possessed by any person shall not affect a waiver or change in any part of this Policy or estop the Insurer from asserting any right under the terms of this Policy; nor shall the terms of this Policy be waived or changed, except by endorsement issued to form a part hereof, signed by the Insurer.

Commonwealth Insurance Company

14. ASSIGNMENT:

Assignment of interest under this Policy shall not bind the Insurer unless and until its consent is endorsed hereon.

15. CANCELLATION:

(a) This Policy may be cancelled by the First Named Insured stated in the Declarations by giving written notice to the Insurer stating when thereafter such cancellation is to become effective. Return premium shall be computed on the following basis:

(i) if the Premium shown in the Declarations is Flat and not adjustable, then on the customary short rate basis; or

(ii) if the Premium shown in the Declarations is subject to an adjustment rate, then the excess of the Deposit Premium over the actual amount of adjustable earned premium to the date of cancellation, subject in any event to the earned premium so calculated to be not less than what would be earned on a short rate basis;

and in any event subject to the retention by the Insurer in either case of the minimum premium stated in the Declarations.

(b) This Policy may be cancelled by the Insurer for nonpayment of premium by giving to the First Named Insured stated in the Declarations Fifteen (15) days notice of cancellation by registered mail, or Five (5) days written notice of cancellation personally delivered. Notice to the insurance department of the First Named Insured stated in the Declarations shall constitute notice to all Insureds.

(c) Except with respect to nonpayment of premium this Policy may be cancelled by the Insurer giving to the First Named Insured stated in the Declarations Sixty (60) days notice in writing of cancellation by registered mail and refunding the excess of paid premium beyond the pro rata earned premium for the expired time. Notice to the Insurance Department of the First Named Insured stated in the Declarations shall constitute notice to all Insureds.

Repayment of excess premium may be made by money, post office order, postal note or cheque and shall be forwarded to the Insured as soon as practicable after the giving or receiving of such notice of cancellation.

16. MAINTENANCE OF UNDERLYING INSURANCE:

Each Policy referred to in the Schedule of Underlying Insurance, including renewal or replacement thereof, not more restrictive, shall be maintained without alteration of terms or conditions, in full effect during the period of this Policy, except for any reduction of the aggregate limits contained therein solely by payment of losses during the period of this Policy. Failure of the Named Insured to comply with the foregoing shall not invalidate this Policy but in the event of such failure the Insurer shall be liable only to the extent that it would have been liable had the Named Insured complied therewith.

The Named Insured shall give the Insurer written notice as soon as practicable of any change in the scope of coverage or in the amount of limits of insurance under any underlying insurance, and of the termination of any coverage or exhaustion of aggregate limits of any underlying insurer's liability.

17. AGENT FOR NAMED INSUREDS:

If there is more than one Named Insured hereunder, the First Named Insured stated in the Declarations shall be deemed to be the agent for all Named Insureds with respect to notice of cancellation, payment of return premium, and in all other matters pertaining to this insurance.

18. EMPLOYERS' LIABILITY - COMMON LAW DEFENSES:

As a condition to the recovery of any loss under this policy, with respect to personal injury to or the death of any employee arising out of and in the course of employment by the Named Insured, the Named Insured warrants that it has not and will not abrogate its common law defense under any workers' compensation or occupational disease law by rejection thereof, or otherwise. In the event the Named Insured should, at any time during the policy period, abrogate such defense, such insurance as is afforded with respect to such employee shall automatically terminate at the same time.

19. DECLARATIONS:

By acceptance of this Policy the Named Insured agrees that the statements in the application and the Declarations, and in any subsequent notice relating to underlying insurance are its agreements and representations, that this Policy is issued and continued in reliance upon the truth of such representations and that this Policy embodies all agreements existing between the Named Insured and the Insurer relating to this insurance.

EXCESS AUTOMOBILE POLICY

(S.P.F. No. 7 In Applicable Provinces)

ATTACHED TO AND FORMING PART OF THIS UMBRELLA OR EXCESS LIABILITY POLICY:

WHEREAS an application has been made by the applicant (hereinafter called the "Insured") to the Excess Insurer for a contract of excess automobile insurance and the said application forms part of this contract and is as follows:

(Details of Items 1, 2, 4, 5 and 6 hereunder are as stated in the Policy Declarations).

APPLICATION

ITEM 1 Full Name and Postal Address of the Applicant
(Including County or District)

_____

_____

Occupation or Business:

_____

ITEM 2 The Policy Period: from _____ to _____

12:01 a.m. Standard Time at the applicant's address stated herein as to each of said dates.

ITEM 3 The Insured is warned that by statute this excess contract automatically terminates concurrently with the termination of any policy mentioned in Item 5.

ITEM 4 This application is for excess insurance against legal liability for Bodily Injury or Death or Damage to Property of others upon the terms and conditions of the Excess Insurer's Standard Policy form for Excess Insurance and for the following specified limit:

LIMIT

$ _____ (exclusive of costs) excess of

$ _____ being the amount of the first loss and underlying excess insurance described in Item 5, for loss or damage resulting from bodily injury to or death of one or more persons and for loss or damage to property regardless of the number of claims arising from any one accident.

Commonwealth Insurance Company

ITEM 5 (a) Description of First Loss Motor Vehicle Liability Insurance.

Name of Insurer: _____

Policy Number: _____

Type of Policy: (state S.P.F. No.) _____

Limit(s): _____

Policy Period: _____

(b) Description of Underlying Excess Insurance(s) if any.

Name of Insurer(s): _____

Policy Number(s): _____

Limit(s): _____

Policy Period(s): _____

ITEM 6 Premium: $ _____

Minimum Retained Premium: $ _____

ITEM 7 Claims must be reported to: THE BROKER OR THE INSURER

Refer to special provisions 7 and 9 of this Policy.

NOW THEREFORE IN CONSIDERATION of the payment of the premium specified and of the statements contained in the application and subject to the limits, special provisions and conditions herein stated and subject, insofar as applicable to the terms, conditions, general provisions, definitions and exclusions set forth in the first loss policy described in Item 5 of the Application, which said terms, conditions, general provisions, definitions and exclusions are by reference incorporated herein, the Excess Insurer agrees to indemnify the Insured under the first loss motor vehicle liability insurance against liability imposed by law upon the Insured for an amount or amounts in excess of the limit(s) of the first loss insurance and the underlying excess insurance for loss or damage arising from the ownership, use or operation of the automobile(s) covered under such first loss insurance and the underlying excess insurance resulting from Bodily Injury to or Death of any Person or Damage to Property.

SPECIAL PROVISIONS

1. The excess Insurer's ultimate net loss liability shall not exceed the limit stated in Item 4 of the application in excess of the limit(s) of the first loss policy, and the underlying excess policy(ies) stated in Item 5 thereof, or such amount as the first loss Insurer and the underlying excess Insurer shall be liable to pay under statute, whichever is the greater.
The words "ultimate net loss" used in this Policy mean the amount payable in

settlement of the liability of the Insured after making deductions for all recoveries and for other valid and collectible insurances, excepting the first loss and underlying policy(ies) and shall exclude all expenses and costs.

2. The word "costs" used in this Policy means interest accruing after entry of judgment upon that part of the judgment which is within the limit of the Excess Insurer's liability, investigation, adjustment and legal expenses, excluding, however, all office expenses of the Insured, all expenses of salaried employees of the Insured and general retainer fees for counsel normally paid by the Insured.

3. The Excess Insurer agrees to pay costs incurred by or on behalf of the Insured where these costs are not covered by the first loss or underlying excess policy(ies), on the following basis:

   (a) should any claim or claims become adjustable prior to the commencement of trial for not more than the first loss and underlying excess policy limit(s) then no costs shall be payable by the Excess Insurer.

   (b) should, however, the amount for which said claim or claims may be so adjustable exceed the first loss and underlying excess policy(ies) limit(s), then the Excess Insurer shall contribute to the costs incurred on behalf of the Insured in the ratio that the Excess Insurer's proportion of the ultimate net loss as finally adjusted bears to the whole amount of such ultimate net loss;

   (c) in the event that the Insured or the Insurer under the first loss policy elects not to appeal a judgment in excess of the limit(s) of the first loss and underlying excess policy(ies) the Excess Insurer may elect to conduct such appeal and shall be liable for the taxable costs and interest incidental thereto; but in no event shall the total liability of the Excess Insurer exceed the limit of liability stated in Item 4 of the application, plus the expense of such appeal.

4. All recoveries or payments recovered or received subsequent to a loss settlement under this Policy shall be applied as if recovered or received prior to such settlement and all necessary adjustments shall then be made between the Insured and the Excess Insurer, provided always that nothing in this Policy shall be construed to mean that losses under this Policy are not payable until the Insured's ultimate net loss has finally been ascertained.

5. Liability to pay under this Policy shall not attach unless and until the first loss and underlying excess Insurer(s) shall have admitted liability for the first loss and underlying excess limit(s) or unless and until the Insured has by final judgment been adjudged to pay an amount which exceeds such first loss and underlying excess limit(s) and then only after the first loss and underlying excess insurer(s) has/have paid or had/have held liable to pay the full amount of the first loss and underlying excess limit(s).

6. Neither the inclusion of more than one entity in the name of the Insured nor the addition of any Additional Insureds under this Policy shall in any way operate to increase the limit of liability set forth in Item 4 of the application.

7. Notwithstanding Statutory Condition 3(1) contained in the first loss policy the Insured is only required to give the Excess Insurer notice of any accident if the claim or claims possibly arising therefrom appear likely to exceed the first loss insurance, in which case immediate written notice thereof must be given to the person or firm mentioned in Item 7 of the application.

8. This Policy may be terminated in accordance with the provisions of Condition 15 of the Umbrella Liability Policy to which this Excess Automobile Policy is attached.

9. Nothing in this special provision shall in any way effect the provision that where the contract or contracts designated as Underlying Insurance terminates or is terminated, the excess contract is automatically terminated. In the event that this Policy is automatically terminated, the Excess Insurer agrees to refund the excess of premium actually paid over the pro rata premium for the expired term as soon as practicable, but if there is any pro rata premium unpaid the Insured agrees to pay this.

10. Any written notice to the Excess Insurer may be delivered at, or sent by registered mail to, the chief agency or head office of the Excess Insurer in this province. Written notice may be given to the Insured named in this Policy by letter personally delivered to him or by registered mail addressed to him at his latest post office address notified to the Excess Insurer. In this condition the expression "registered" means in or outside Canada.

SCHEDULE OF ENDORSEMENTS

ATTACHED TO AND FORMING PART OF THIS POLICY:

Endorsement No. 1:	Asbestos Exclusion
Endorsement No. 2:	Personal Property CCC Exclusion
Endorsement No. 3:	Real Property CCC Following Form
Endorsement No. 4:	Data Exclusion
Endorsement No. 5:	Employee Benefit Liability Extension
Endorsement No. 6:	Employment Practices Exclusion
Endorsement No. 7:	Forest Fire Fighting Expense
Endorsement No. 8:	Fungus, Mildew and Mould Exclusion
Endorsement No. 9:	Silica Exclusion
Endorsement No. 10:	Terrorism Exclusion
Endorsement No. 11:	All U.S. Exposure Exclusion
Endorsement No. 12:	Uninsured and Underinsured Motorist or No-Fault Coverage Exclusion
Endorsement No. 13:	Polychlorinated Biphenyl (PCB) Exclusion
Endorsement No. 14:	Limited Failure To Supply Extension
Endorsement No. 15:	Excluded Operations - Yukon Electrical Company Limited

SR.62109 (214)

ENDORSEMENT No. 1

ASBESTOS EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This insurance DOES NOT apply to any liability for Property Damage, Personal Injury, sickness, disease, occupational disease, disability, shock, death, mental anguish and mental injury at any time arising out of the manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to asbestos, asbestos products, asbestos fibres or asbestos dust, or to any obligation of the Insured to indemnify any party because of damages arising out of such Property Damage, Personal Injury, sickness, disease, occupational disease, disability, shock, death, mental anguish or mental injury at any time as a result of the manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to asbestos, asbestos products, asbestos fibres or asbestos dust.

It is further understood and agreed that the Insurer is NOT obligated to defend any suit or claim against the Insured alleging Personal Injury or Property Damage and seeking damages, if such suit or claim arises from Personal Injury or Property Damage resulting from or contributed to, by any and all manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to asbestos, asbestos products, asbestos fibres or asbestos dust.

It is further understood and agreed that this Policy DOES NOT apply to any action or claim either for defense or payment of any damages compensatory, punitive or economic arising out of any Insured's failure to disclose the presence or presumed presence of asbestos in any properties owned or occupied by the Insured.

It is further understood and agreed that if the Asbestos Exclusion in the underlying insurance is more restrictive than the exclusion herein, this Policy shall follow the Asbestos Exclusion of the underlying insurance.

SR.62109 (217.97)

Commonwealth Insurance Company

ENDORSEMENT No. 2

PERSONAL PROPERTY CCC EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This Policy shall not apply to any liability for property damage to Personal property

(1) owned or occupied by or rented to the Insured,

(2) used by the Insured, or

(3) in the care, custody or control of the Insured or as to which the Insured is for any purpose exercising physical control.

SR.62109 (221)

Commonwealth Insurance Company

ENDORSEMENT No. 3

REAL PROPERTY CCC FOLLOWING FORM ENDORSEMENT

It is agreed that this Policy SHALL NOT apply to property damage:

(1) to real property owned or occupied by or rented to the Insured,

(2) to real property used by the Insured,

(3) to real property in the care, custody or control of the Insured or such property as to which the Insured is for any purpose exercising physical control, or

(4) to fixtures as the result of any work performed thereon by the Insured or anyone on his behalf;

unless such liability is covered by valid and collectible underlying insurance at the full limits of liability as described in the schedule of underlying insurance, and then only for such hazards for which coverage is afforded under said underlying insurance.

SR.62109 (217.96)

Commonwealth Insurance Company

ENDORSEMENT No. 4

DATA EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This insurance DOES NOT apply to:

(a) Any liability for:

(i) erasure, destruction, corruption, misappropriation, misinterpretation of "Data"; or

(ii) erroneously creating, amending, entering, deleting or using "Data";

including any loss of use arising therefrom.

(b) Any liability arising out of the distribution or display of "Data", by means of an Internet Website, the Internet, an intranet, extranet, or similar device or system designed or intended for electronic communication of "Data".

"Data" means representations of information or concepts, in any form.

It is further agreed that if the "Data" Exclusion in the underlying insurance is more restrictive than the exclusion herein, this Policy shall follow the "Data" Exclusion of the underlying insurance.

SR.62109 (217.98)

Commonwealth Insurance Company

ENDORSEMENT No. 5

EMPLOYEE BENEFIT LIABILITY EXTENSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

It is agreed that the following is ADDED after "Advertising Liability" in Insuring Agreement I - Coverage:

"Employee Benefit Liability."

This insurance shall apply to Employee Benefit Liability Claims which are first made against the Insured during the policy period. If, during the policy period, the Insured shall become aware of any incident which may subsequently give rise to a claim covered hereunder, and shall give written notice to the Insurer as soon as practicable, any claim which may subsequently arise out of that incident shall be deemed to have been first made during the policy period. Claims arising out of any such incident shall not be covered hereunder if a succeeding policy provides coverage, regardless of its adequacy.

The insurance hereunder shall apply only in excess of valid and collectible insurance described in the schedule of underlying insurance, in excess of the limit(s) stated in such schedule, and only for such hazards for which coverage is afforded under said underlying insurance. The Insurer shall be liable only for the Ultimate Net Loss in excess of the limit of the said underlying insurance and of any other underlying insurance, and then only for a further sum not exceeding:

(a) a limit per claim, which limit shall be the same as the limit stated in the Declarations as applicable to each occurrence; and

(b) a limit for all claims hereunder during each policy period, which limit shall be the same as the limit stated in the Declarations as applicable to aggregate.

The words "the insured", "employee benefit program", and "administration" shall have the same meanings under this Policy as in the definition in the said underlying insurance.

Notice of claim must be made by the Insured in accordance with the Condition "Notice of Occurrence" in this Policy.

SR.62109 (217.10)

ENDORSEMENT No. 6

EMPLOYMENT PRACTICES EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

The coverage afforded by this Policy DOES NOT apply to "Personal Injury" arising out of any:

1. Refusal to employ;

2. Termination of employment;

3. Coercion, demotion, evaluation, reassignment, discipline, defamation, harassment, humiliation, discrimination or other employment related practices, policies, acts or omissions; or

4. Consequential "Personal Injury" arising out of 1 through 3 above.

This exclusion applies whether the Insured may be liable as an employer or in any other capacity, and to any obligation to share damages with or repay someone else who must pay damages because of the injury.

SR.62109 (997.51)

ENDORSEMENT No. 7

FOREST FIRE FIGHTING EXPENSE

IT IS HEREBY UNDERSTOOD AND AGREED that:

This policy is EXTENDED to apply to the liability imposed by law upon the Insured for the cost of controlling and extinguishing forest fires, other than any cost incurred directly by the Insured in controlling and extinguishing such fires.

The coverage hereunder shall apply only in excess of valid and collectible underlying insurance described hereunder, and only for such hazards for which coverage is afforded under said underlying insurance. The Insurer shall be liable for Ultimate Net Loss in excess of the limit of the underlying insurance and of any other underlying insurance, and then only for a further sum as stated hereunder, which sum shall be the limit of the Insurer's liability. The limit of the Insurer's liability hereunder shall be part of, and not in addition to, the limit stated in the Declarations as applicable to each occurrence.

Underlying Insurance - Forest Fire Fighting Expense Liability

Policy No.	Insurer	Limit of Liability	
CRX 62108	Commonwealth Insurance Company	$ 5,000,000.00 $ 5,000,000.00	Each Occurrence Aggregate
Limit of the Insurer's liability, hereunder in excess of Underlying Insurances.		$ 25,000,000.00 $ 25,000,000.00	Each Occurrence Aggregate

SR.62109 (217.23)

ENDORSEMENT No. 8

FUNGUS, MILDEW AND MOULD EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This insurance DOES NOT apply to:

1. Any liability arising out of, resulting from, caused by, contributed to, or in any way related to the existence, inhalation or exposure to any "fungus/fungi" and/or "spore(s)";

2. Any legal fees, defense costs or other costs or expenses associated in any way, or arising out of the abatement, mitigation, remediation, containment, detoxification, neutralization, monitoring, removal, disposal, or any obligation to investigate or assess the presence or effects of any "fungus/fungi" or "spore(s)";

3. Any obligation to share with or repay any person, organization or entity, related in any way to items 1. and 2. above,

regardless of any other cause, event, material, product and/or building component that contributed concurrently or in any sequence to the injury or damage.

For purposes of this endorsement, the following definitions apply:

"Fungus/fungi" includes, but is not limited to, any form or type of mould, mildew, mushroom, yeast, or biocontaminant.

"Spore(s)" includes, but is not limited to, any substance produced by, emanating from, or arising out of any "fungus/fungi".

It is further understood and agreed that if the Fungus, Mildew and Mould Exclusion in the underlying insurance is more restrictive than the exclusion herein, this Policy shall follow the Fungus, Mildew and Mould Exclusion of the underlying insurance.

SR.62109 (217.110)

ENDORSEMENT No. 9

SILICA EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This insurance DOES NOT apply to any liability for Property Damage, Personal Injury, sickness, disease, occupational disease, disability, shock, death, mental anguish and mental injury at any time arising out of the manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to silica, silica products, silica fibres or silica dust, or to any obligation of the Insured to indemnify any party because of damages arising out of such Property Damage, Personal Injury, sickness, disease, occupational disease, disability, shock, death, mental anguish or mental injury at any time as a result of the manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to silica, silica products, silica fibres or silica dust.

It is further understood and agreed that the Insurer is NOT obligated to defend any suit or claim against the Insured alleging Personal Injury or Property Damage and seeking damages, if such suit or claim arises from Personal Injury or Property Damage resulting from or contributed to, by any and all manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to silica, silica products, silica fibres or silica dust.

It is further understood and agreed that this Policy DOES NOT apply to any action or claim either for defense or payment of any damages compensatory, punitive or economic arising out of any Insured's failure to disclose the presence or presumed presence of silica in any properties owned or occupied by the Insured.

It is further understood and agreed that if the Silica Exclusion in the underlying insurance is more restrictive than the exclusion herein, this Policy shall follow the Silica Exclusion of the underlying insurance.

SR.62109 (217)

ENDORSEMENT No. 10

TERRORISM EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This Policy DOES NOT cover loss, damage, cost or expense of whatsoever nature caused by, resulting from or in connection with any act of terrorism. For the purpose of this exclusion, "Terrorism" shall mean any unlawful act of any person acting on behalf or in connection with any organization with activities directed towards the overthrowing or influencing of any government, de jure or de facto, by force or violence and/or to put the public, or any section of the public, in fear.

Such act must be declared to have been an act of terrorism by the appropriate law enforcement authority of the country or province or territory where the act or activity occurred. In the event of federal and/or state or provincial legislation becoming effective during the term of this Policy, which names a person, position or office as having the designated authority to make such a declaration of an act of terrorism, then such declaration of such named individual shall apply hereunder.

Unauthorized gaining of access to any information technology system shall only be considered to be an act of terrorism when so declared by the appropriate law enforcement authority.

It is further agreed that if the "Terrorism" Exclusion in the underlying insurance is more restrictive than the exclusion herein, this Policy shall follow the "Terrorism" Exclusion of the underlying insurance.

SR.62109 (217.99)

ENDORSEMENT No. 11

ALL U.S. EXPOSURE EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This Policy DOES NOT cover any operation of the Insured, including the Products Hazard and Completed Operations Hazard as defined in this Policy, performed by or on behalf of the Insured in or to the United States of America, its territories or possessions.

However, this Exclusion SHALL NOT apply in respect of Canadian Employees visiting in or travelling through the United States of America, its territories or possessions for the purpose of business meetings or contract negotiations.

SR.62109 (997.31)

ENDORSEMENT No. 12

UNINSURED OR UNDERINSURED MOTORIST OR NO-FAULT COVERAGE EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This Policy does not apply to sums which the Insured shall be legally entitled to recover under Uninsured Motorists Coverage, Underinsured Motorists Coverage, Personal Injury Protection, Property Protection or any similar no fault coverage by whatever name called.

SR.62109 (217.75)

ENDORSEMENT No. 13

POLYCHLORINATED BIPHENYL (PCB) EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

The insurance provided by this Policy DOES NOT apply to claims arising out of Personal Injury or Property Damage caused by the discharge of, dispersal of, release of, escape of or exposure to Polychlorinated Biphenyl (PCB) with respect to the Insured's products or operations.

SR.62109 (217.52)

ENDORSEMENT No. 14

LIMITED FAILURE TO SUPPLY EXTENSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

The coverage afforded by this Policy DOES NOT apply to any liability for Personal Injury or Property Damage arising out of the failure to supply unless:

1. Such failure is caused by an Occurrence; and

2. The combined capacity of the Insured's installed production facilities and contractual supply arrangements is equal to or greater than One Hundred and Ten percent (110%) of the electricity demand immediately preceding such failure, on the Insured's electric system.

SR.62109

ENDORSEMENT No. 15

EXCLUDED OPERATIONS

IT IS HEREBY UNDERSTOOD AND AGREED that:-

The coverage afforded by this Policy DOES NOT apply to any claim arising out of the operations of Yukon Electrical Company Limited.

SR.62109

gcan INSURANCE

GCAN INSURANCE COMPANY

ENDORSEMENT

POLICY NO: 9139802 **ENDORSEMENT NO:** 11-001 **EFFECTIVE DATE:** Sep 1, 2011

BROKER NO.: 2682 AON REED STENHOUSE INC.

ADDITIONAL PREMIUM: $20,000

NAMED INSURED: YUKON ENERGY CORPORATION AND YUKON DEVELOPMENT CORPORATION
(AS STATED IN THE IMMEDIATE UNDERLYING POLICY)

RENEWAL ENDORSEMENT

In consideration of the additional premium stated above, it is agreed that this policy is continued in force

FROM: Sep 1, 2011 TO: Sep 1, 2012

ALL OTHER TERMS AND CONDITIONS REMAIN UNCHANGED.

AUTHORIZED REPRESENTATIVE

Sep 7, 2011

Page 1 of 1

gcan INSURANCE

COPY

GCAN INSURANCE COMPANY

ENDORSEMENT

POLICY NO: 9139802 **ENDORSEMENT NO:** 10-001 **EFFECTIVE DATE:** Sep 1, 2010

BROKER NO.: 2682 AON REED STENHOUSE INC.

ADDITIONAL PREMIUM: $20,000

NAMED INSURED: YUKON ENERGY CORPORATION AND YUKON DEVELOPMENT CORPORATION
(AS STATED IN THE IMMEDIATE UNDERLYING POLICY)

RENEWAL ENDORSEMENT

In consideration of the additional premium stated above, it is agreed that this policy is continued in force

FROM: Sep 1, 2010 TO: Sep 1, 2011

ALL OTHER TERMS AND CONDITIONS REMAIN UNCHANGED.

AUTHORIZED REPRESENTATIVE

Aug 31, 2010

Page 1 of 1

gcan INSURANCE

GCAN INSURANCE COMPANY

(Hereinafter called the Insurer) HEAD OFFICE: TORONTO, ONTARIO M5H 3M7

EXCESS LIABILITY INSURANCE

DECLARATIONS

POLICY NO. 9139802

In consideration of the payment of the premium, the Insurer agrees to insure the Insured subject to the Declarations, Insuring Agreements, Limits of Liability, Definitions, Exclusions, Conditions and other terms of this policy.

NAMED INSURED:		YUKON ENERGY CORPORATION AND YUKON DEVELOPMENT CORPORATION (AS STATED IN THE IMMEDIATE UNDERLYING POLICY)
POSTAL ADDRESS:		P.O. BOX WHITEHORSE, YT Y1A 6S7
POLICY PERIOD:		September 01, 2009 TO September 01, 2010 (12:01 a.m. standard time at the postal address of the Named Insured)
PREMIUM:		$21,250
PREMIUM BASIS:		FLAT
MINIMUM PREMIUM:		$21,250
BROKER NO.:	2682	AON REED STENHOUSE INC.

COUNTERSIGNATURE DATE: FEB 25, 2010 AT VANCOUVER, B.C.

AUTHORIZED REPRESENTATIVE

Feb 25, 2010

Page 1 of 2

gcan INSURANCE

Policy No. 9139802

DECLARATIONS

COVERAGE

FORM NO.	DESCRIPTION OF COVERAGE	LIMITS OF LIABILITY ($)	
		EACH OCCURRENCE	ANNUAL AGGREGATE (WHERE APPLICABLE)
CA16 (10-98)	EXCESS LIABILITY INSURANCE EXCESS UMBRELLA LIABILITY	20,000,000	20,000,000
	OTHER EXCLUSIONS, LIMITATIONS AND ENDORSEMENTS:		
A44 (03-96)	LIMITED POLLUTION LIABILITY		
A49 (01-02)	TERRORISM EXCLUSION		
A50 (01-02)	DATA EXCLUSION		
A57 (01-03)	TOTAL ASBESTOS EXCLUSION		
A58 (01-03)	FUNGI AND FUNGAL DERIVATIVES EXCLUSION		
A60 (04-03)	WAR EXCLUSION		

UNDERLYING INSURANCE

LIMITS OF LIABILITY IN EXCESS OF PRIMARY POLICIES	25,000,000	25,000,000

SCHEDULE OF UNDERLYING INSURANCE

POLICY NO.	INSURER		
CRX61344	COMMONWEALTH INSURANCE COMPANY UMBRELLA LIABILITY	25,000,000 EXCESS OF PRIMARY POLICIES	25,000,000

Feb 25, 2010

Page 2 of 2

gcan INSURANCE

ENDORSEMENT

LIMITED POLLUTION LIABILITY

Notwithstanding anything to the contrary contained in this policy or in any underlying policy shown in the Declarations, it is agreed that this policy shall not apply to:

A. any liability arising out of the actual, alleged, potential or threatened spill, discharge, emission, dispersal, seepage, leakage, migration, release or escape of pollutants:

1) at or from any premises, site or location which is or was at any time, owned or occupied by, or rented or loaned to any Insured;
2) at or from any premises, site or location which is or was at any time, used by or for any Insured or others for the handling, storage, disposal, processing or treatment of waste;
3) which are or were at any time transported, handled, stored, treated, disposed of, or processed as waste by or for any Insured or any person or organization for whom the Insured may be legally responsible;
4) at or from any premises, site or location on which any Insured or any contractors or subcontractors working directly or indirectly on any Insured's behalf are performing operations:

a) if the pollutants are brought on or to the premises, site or location in connection with such operations by such Insured, contractor or subcontractor; or
b) if the operations are to test for, monitor, clean up, remove, contain, treat, detoxify, decontaminate, stabilize, remediate or neutralize, or in any way respond to, or assess the effect of pollutants.

Sub-paragraphs 1) and 4) a) of paragraph A. of this exclusion do not apply to bodily injury or property damage caused by the following, provided that such bodily injury or property damage is covered by underlying insurance, for the full amount of the underlying limits as set out in the Declarations:

i) heat, smoke or fumes from a fire which becomes uncontrollable or breaks out from where it was intended to be; or
ii) an unexpected or unintentional spill, discharge, emission, dispersal, seepage, leakage, migration, release or escape of pollutants provided such spill, discharge, emission, dispersal, seepage, leakage, migration, release or escape of pollutants:

1) results in the injurious presence of pollutants in or upon land, the atmosphere, a drainage or sewage system, a watercourse or a body of water; and
2) is detected within 120 hours after the commencement of the spill, discharge, emission, dispersal, seepage, leakage, migration, release or escape; and
3) is reported to the Insurer within 120 hours of being detected; and
4) does not occur in a quantity or with a quality that is routine or usual to the business of the Insured.

B. any loss, cost or expense arising out of any request, demand or order that any Insured or others test for, monitor, clean up, remove, contain, treat, detoxify, decontaminate, stabilize, remediate or neutralize, or in any way respond to, or assess the effect of pollutants.

"Pollutants" means any solid, liquid, gaseous or thermal irritant or contaminant, including smoke, odour, vapour, soot, fumes, acids, alkalis, chemicals and waste. Waste includes materials to be recycled, reconditioned or reclaimed.

A44(03-96)

gcan INSURANCE

ENDORSEMENT

TERRORISM EXCLUSION

It is agreed that this insurance does not apply to any liability for any loss, damage, claim, injury, cost or expense caused by or arising directly or indirectly, in whole or in part, out of TERRORISM or out of any activity or decision of a government agency or other entity to prevent, respond to or terminate TERRORISM.

This exclusion applies regardless of any other contributing or aggravating cause or event that contributes concurrently or in any sequence to the loss, damage, claim, injury, cost or expense.

TERRORISM means any ideologically motivated unlawful act, including but not limited to the use of violence or force or threat of violence or force, committed by or on behalf of any group(s), organization(s) or government(s) for the purpose of influencing any government and/or instilling fear in the public or a section of the public.

A49(01-02)

gcan INSURANCE

ENDORSEMENT

DATA EXCLUSION

It is agreed that this insurance does not apply to:

1. any liability for

   (a) the erasure, destruction, corruption, misappropriation or misinterpretation of DATA;

   (b) erroneously creating, amending, entering, deleting or using DATA,

   including any loss of use arising therefrom.

2. Personal Injury Liability arising out of the distribution or display of DATA by means of an Internet Website, the Internet, an intranet, extranet or similar device or system designed or intended for the communication of DATA.

3. Advertising Liability arising out of the distribution or display of DATA by means of an Internet Website, the Internet, an intranet, extranet or similar device or system designed or intended for the communication of DATA, unless such liability is covered by valid and collectible underlying insurance as set out in the Schedule of Underlying Insurance and then only for such hazards for which coverage is afforded under said underlying insurance.

DATA means representations of information or concepts in any form.

A50(01-02)

gcan INSURANCE

ENDORSEMENT

TOTAL ASBESTOS EXCLUSION

It is hereby understood and agreed that this insurance shall not apply to and does not cover any actual or alleged liability whatsoever for any claim or claims in respect of loss or losses, damage, cost or expense directly or indirectly caused by, resulting from or in consequence of, or in any way involving asbestos, or any materials containing asbestos in whatever form or quantity. This exclusion applies regardless of any other contributing or aggravating cause or event that contributes concurrently or in any sequence to the loss, damage, cost or expense.

A57(01-03)

gcan INSURANCE

ENDORSEMENT

FUNGI AND FUNGAL DERIVATIVES EXCLUSION

It is agreed that this insurance shall not apply to:

a. any injury, damage, loss, cost or expense arising directly or indirectly, from the actual, alleged or threatened inhalation of, ingestion of, contact with, exposure to, existence of, presence of, spread of, reproduction, discharge or other growth of any "fungi" or "spores" however caused, including any costs or expenses incurred to prevent, respond to, test for, monitor, abate, mitigate, remove, cleanup, contain, remediate, treat, detoxify, neutralize, assess or otherwise deal with or dispose of "fungi" or "spores"; or

b. any supervision, instructions, recommendations, warnings, or advice given or which should have been given in connection with a. above; or

c. any obligation to pay damages, share damages with or repay someone else who must pay damages because of such injury, damage, loss, cost or expense referred to in a. or b. above.

This exclusion applies regardless of the cause of the injury, damage, loss, cost or expense or whether other causes acted concurrently or in any sequence to produce the injury, damage, loss, cost or expense.

For the purpose of this endorsement, the following definitions are added:

"Fungi" includes, but is not limited to, any form or type of mould, yeast, mushroom or mildew whether or not allergenic, pathogenic or toxigenic, and any substance, vapour or gas produced by, emitted from or arising out of any "Fungi" or "Spores" or resultant mycotoxins, allergens, or pathogens.

"Spores" includes, but is not limited to, any reproductive particle or microscopic fragment produced by, emitted from or arising out of any "fungi".

A58(01-03)

gcan INSURANCE

ENDORSEMENT

WAR EXCLUSION

Notwithstanding anything to the contrary contained in this policy or in any underlying policy shown in the Declarations, it is agreed that this policy does not apply to any injury, damage, loss, cost or expense directly or indirectly due to war, invasion, act of foreign enemy, hostilities (whether war be declared or not), civil war, rebellion, revolution, insurrection or military power.

A60(04-03)

EXCESS LIABILITY INSURANCE

INSURING AGREEMENTS

I. **EXCESS LIABILITY INDEMNITY**
The Insurer agrees to indemnify the Insured for the amount of loss which is in excess of the applicable limits of liability of the underlying insurance stated in the Declarations; provided that this policy shall apply only to those coverages for which a limit of liability is stated in the Declarations; provided further that the Insurer's liability under this policy shall not exceed the applicable limit stated in the Declarations, such limit being an inclusive limit unless otherwise stated.

The provisions of the immediate underlying policy are incorporated as a part of this policy except for any obligation to investigate and defend and pay for costs and expenses incident to the same, the amount of the limits of liability, any "other insurance" provisions and any other provisions therein which are inconsistent with the provisions of this policy.

If the applicable coverage in the immediate underlying policy insures accidents rather than occurrences, then "accident" is substituted for "occurrence" in the applicable coverage of this policy.

II. **POLICY PERIOD: TERMINATION OF UNDERLYING INSURANCE**
This policy applies to injury or destruction taking place during this policy period, provided that when the immediate underlying policy insures occurrences taking place during its policy period, instead of injury or destruction taking place during its policy period, then this policy likewise applies to occurrences taking place during this policy period and "occurrences" is substituted for "injury or destruction" in the Special Provisions section of this policy.

If the immediate underlying policy is cancelled, this policy likewise is cancelled effective on the same date at the same time and without notice to the Insureds. If the immediate underlying policy otherwise ceases to apply (for reasons other than the exhaustion of an aggregate limit of liability), this policy likewise ceases to apply to the same extent on the same date at the same time and without notice to the Insureds.

DEFINITIONS

1. **IMMEDIATE UNDERLYING POLICY**
"Immediate underlying policy" means the policy of the underlying insurance which provides the layer of coverage, whether primary or excess, immediately preceding the layer of coverage provided by this policy.

2. **LOSS**
"Loss" means the sums paid as damages in settlement of a claim or in satisfaction of a judgement for which the Insured is legally liable, after making deductions for all recoveries, salvages and other insurances (whether recoverable or not) other than the underlying insurance and excess insurance purchased specifically to be in excess of this policy. "Loss" does not include investigation, adjustment, defence or appeal costs and expenses nor costs and expenses incident to any of the same, notwithstanding that the underlying insurance may provide insurance for such costs and expenses.

3. **UNDERLYING INSURANCE**
"Underlying Insurance" means all insurance policies (including any renewal or replacement of such policies) preceding the layer of coverage provided by this policy.

SPECIAL PROVISIONS

1. **REDUCTION OF THE AGGREGATE**
This provision applies only if this policy contains an aggregate limit of liability which applies to the occurrence.

If the each occurrence limit of liability of the underlying insurance is less than as stated in the Declarations because the aggregate limits of liability of the underlying insurance have been reduced, this policy becomes excess of such reduced limit of liability if such reduction is solely the result of injury or destruction occurring after the inception date of this policy and not before. Nothing contained herein shall operate to increase the limit of the Insurer's liability.

2. **APPLICATION OF THE AGGREGATE TO SEPARATE PROJECTS**
To the extent that the aggregate limits of liability of the immediate underlying policy apply separately to various operations, projects, locations, hazards or types of injury, the aggregate limits of liability of this policy likewise apply separately to such operations, projects, locations, hazards or types of injury.

3. APPLICATION OF THE AGGREGATE TO PERIODS OF TIME

The aggregate limits of liability of this policy apply separately to each aggregate period. The first aggregate period of this policy begins on the effective date of this policy and ends on the next termination date of the aggregate period of the immediate underlying policy. Any succeeding aggregate period of this policy is concurrent with the aggregate period of the immediate underlying policy unless it is the final aggregate period. The final aggregate period of this policy begins on the termination date of the aggregate period of the immediate underlying policy immediately preceding the expiration date of this policy and ends on the expiration date of this policy.

This paragraph does not apply if the expiration date of this policy and the expiration date or anniversary date of the immediate underlying policy are identical. If this policy is a renewal of a similar policy underwritten by this Insurer, the applicable aggregate limit of liability of this policy for the first period shall be reduced by any amounts paid or payable on account of injury or destruction taking place during the final aggregate period of the policy renewed. The final aggregate period of the policy renewed shall be determined in the same manner as the final aggregate period for this policy.

NUCLEAR ENERGY LIABILITY EXCLUSION

This policy does not apply to:

(a) Liability imposed by or arising under the Nuclear Liability Act; nor

(b) Any liability with respect to which an Insured under this policy is also insured under a contract of nuclear energy liability insurance (whether the Insured is unnamed in such contract and whether or not it is legally enforceable by the Insured) issued by the Nuclear Insurance Association of Canada or any other Insurer or group or pool of Insurers or would be an Insured under any such policy but for its termination upon exhaustion of its limit of liability; nor

(c) Any liability resulting directly or indirectly from the nuclear energy hazard arising from:
  (1) the ownership, maintenance, operation or use of a nuclear facility by or on behalf of an Insured;
  (2) the furnishing by an Insured of services, materials, parts or equipment in connection with the planning, construction, maintenance, operation or use of any nuclear facility; and
  (3) the possession, consumption, use, handling, disposal or transportation of fissionable substances, or of other radioactive material (except radioactive isotopes, away from a nuclear facility, which have reached the final stage of fabrication so as to be usable for any scientific, medical, agricultural, commercial or industrial purpose) used, distributed, handled or sold by an Insured.

As used in this exclusion:

(i) The term "nuclear energy hazard" means the radioactive, toxic, explosive, or other hazardous properties of radioactive material;

(ii) The term "radioactive material" means uranium, thorium, plutonium, neptunium, their respective derivatives and compounds, radioactive isotopes of other elements and any other substances that the Atomic Energy Control Board may by regulation, designate as being prescribed substances capable of releasing atomic energy, or as being requisite for the production, use or application of atomic energy;

(iii) The term "nuclear facility" means:
  (a) any apparatus designed or used to sustain nuclear fission in a self-supporting chain reaction or to contain a critical mass of plutonium, thorium and uranium or any one or more of them;
  (b) any equipment or device designed or used for (1) separating the isotopes of plutonium, thorium and uranium or any one or more of them, (2) processing or utilizing spent fuel, or (3) handling, processing or packaging waste;
  (c) any equipment or device used for the processing, fabricating or alloying of plutonium, thorium or uranium enriched in the isotope uranium 233 or in the isotope uranium 235, or any one or more of them if at any time the total amount of such material in the custody of the Insured at the premises where such equipment or device is located consists of or contains more than 25 grams of plutonium or uranium 233 or any combination thereof, or more than 250 grams of uranium 235;
  (d) any structure, basin, excavation, premises or place prepared or used for the storage or disposal of waste radioactive material;
and includes the site on which any of the foregoing is located, together with all operations conducted thereon and all premises used for such operations;

(iv) The term "fissionable substance" means any prescribed substance that is, or from which can be obtained, a substance capable of releasing atomic energy by nuclear fission.

CONDITIONS

1. UNDERLYING INSURANCE - CHANGES DURING THIS POLICY PERIOD

Any change in coverage in the underlying insurance shall be promptly reported to the Insurer and the Insured shall, upon request, furnish the Insurer with copies of such changes.

Any significant change in the premium for the underlying insurance shall be promptly reported to the Insurer and the premium for this policy, subject to the minimum premium, may at the option of the Insurer be adjusted.

2. NOTICE OF LOSS - PARTICIPATION IN DEFENCE BY THE INSURER

Notice of an occurrence which appears likely to involve this policy shall be given by or on behalf of the Insured to the Insurer or any of its authorized agents as soon as practicable. Failure by the Insured to fulfil this obligation may result in the forfeiture of the right

to indemnity or coverage. In Quebec, in accordance with the Quebec Civil Code, failure by the Insured to fulfil this obligation, thus causing prejudice to the Insurer, will result in the forfeiture of the right to indemnity or coverage.

The Insurer at its own option may, but is not required to participate in the investigation, settlement or defence of any claim or suit against the Insured.

3. **ACTION AGAINST INSURER**
No action shall lie against the Insurer unless, as a condition precedent thereto, the Insured shall have fully complied with all the terms of this policy.

Any person or organization or the legal representative thereof who has secured a judgement against the Insured shall thereafter be entitled to recover under this policy to the extent of the insurance afforded by this policy. Nothing contained in this policy shall give any person or organization any right to join the Insurer as a co-defendant in any action against the Insured to determine the Insured's liability. Any payments by the Insurer under this condition 3 shall discharge the Insurer's obligation to the Insured to the extent of such payments.

Bankruptcy or insolvency of the Insured or of the Insured's estate shall not relieve the Insurer of any of its obligations hereunder.

4. **SUBROGATION AND OTHER RECOVERIES**
In the event of any payment under this policy, the Insurer shall be subrogated to all the Insured's rights of recovery therefor against any person or organization and the Insured shall execute and deliver instruments and papers and do whatever else is necessary to secure such rights. The Insured shall do nothing after the occurrence to prejudice such rights.

Because this policy affords excess coverage, the Insured's right of recovery cannot always be exclusively subrogated to the Insurer. It is therefore agreed that the Insurer shall act in concert with all other interests concerned, including the Insured, in the enforcement of any subrogation rights or in the recovery of amounts by any other means. The apportioning of any amounts so recovered shall follow in the principle that any interest, including the Insured, that shall have paid an amount over and above any payment under this policy shall first be reimbursed up to the amount paid by such interest. The Insurer shall then be reimbursed out of any balance then remaining up to the amounts paid as the result of loss covered under this policy. Lastly, the interests, including the Insured, of whom this coverage is in excess are entitled to claim any residue remaining. Expenses and costs necessary to recovery of any such amounts shall be apportioned between the interests concerned, including the Insured, in the ratio of their respective recoveries or in the event of a totally unsuccessful attempt to recover, in the ratio of the respective amounts sought to be recovered.

5. **OTHER INSURANCE**
This condition does not apply with respect to the underlying insurance or excess insurance purchased specifically to be in excess of this policy.

If, with respect to a loss covered hereunder, the Insured has other insurance, whether on a primary, excess or contingent basis, there shall be no insurance afforded hereunder as respects such loss; provided, that if the applicable limit of liability of this policy is greater than the applicable limit of liability provided by the other insurance, this policy shall afford excess insurance over and above such other insurance in an amount sufficient to give the Insured, as respects the layer of coverage afforded by this policy, a total limit of liability equal to the applicable limit of liability afforded by this policy.

6. **CANCELLATION**
This policy may be cancelled by the Named Insured by mailing to the Insurer written notice stating when thereafter the cancellation shall be effective. This policy may be cancelled by the Insurer by mailing to the Named Insured at the address shown in the Declarations written notice stating when, not less than thirty (30) days thereafter, such cancellation shall be effective. The mailing of notice as aforesaid shall be sufficient proof of notice. The effective date of cancellation stated in the notice shall become the end of the policy period. Delivery of such written notice either by the Named Insured or by the Insurer shall be equivalent to mailing.

If the Named Insured cancels, earned premium or minimum premium, whichever is greater, shall be computed in accordance with the customary short rate table and procedure. If the Insurer cancels, earned premium or minimum premium, whichever is greater, shall be computed pro rata. Premium adjustment may be made either at the time cancellation is effected or as soon as practicable after cancellation becomes effective, but payment or tender of unearned premium is not a condition of cancellation.

7. **FIRST NAMED INSURED**
The Insured first named in the Declarations is authorized to act on behalf of all the Named Insureds and other Insureds with respect to the giving and receiving of notice of cancellation and the receiving of any return premium that may become payable under this policy. The Insured first named in the Declarations is responsible for the payment of all premiums but the other Named Insureds jointly and severally agree to make such premium payments in full if the Insured first named in the Declarations fails to pay the amount due within thirty (30) days after the Insurer gives a written demand for payment to the Insured first named in the Declarations.

8. **NAMED INSURED**
It is hereby agreed that the Named Insured as stated herein is construed to be identical with that of the immediate underlying insurance policy.

9. CONFLICTING STATUTES
If any section of this policy conflicts with any specific statutory provision in the province or state in which it is claimed that the Insured is liable for any such injuries or loss as are covered by this policy, such specific statutory provision shall be substituted for such section.

10. CURRENCY
All limits of insurance, premiums and other amounts as expressed in this policy are in Canadian dollars unless otherwise stated.

In witness whereof, the Insurer has caused this policy to be signed by its President but the same shall not be binding unless countersigned by a duly authorized representative of the Insurer.



President.

IMPORTANT

THE NOTICE BELOW APPLIES TO INSURANCE CONTRACTS CONTAINING NON AUTOMOBILE LEGAL LIABILITY COVERAGE IN PROVINCES WHERE STATISTICAL DATA RELATING TO SUCH CONTRACTS MUST BE REPORTED TO THE SUPERINTENDENT OF INSURANCE.

NOTICE TO INSUREDS pursuant to the Freedom Of Information and Protection Of Privacy Act, 1987

LEGAL AUTHORITY FOR COLLECTION:
INSURANCE ACT. R.S.O. 1990, c.1.8, section 101 (1).

PRINCIPAL PURPOSE FOR WHICH PERSONAL INFORMATION IS INTENDED TO BE USED:
Information collected by insurers from insureds or supplied to insurers pertaining to the attached document will be used:
- to compile aggregate statistical data to be used in monitoring trends in the insurance industry;
- to develop statistical exhibits to be used in monitoring the insurance industry;
- to respond to requests for customized statistical information on the insurance industry
- to respond to inquiries on statistical information made to Office of the Superintendent of Insurance; and
- to use and disclose such information for purposes which are consistent with the previous clauses.

THE PUBLIC OFFICIAL WHO CAN ANSWER QUESTIONS ABOUT THE COLLECTION IS:
Manager, Commercial Liability Statistical Plan, Ontario Insurance Commission, 5160 Yonge Street, 15th Floor, North York, Ontario M2N 6L9. Telephone: (416) 250-7250 Fax: (416) 590-7070.

CHARTIS

Canadian Head Office
145 WELLINGTON STREET WEST
TORONTO, ON M5J 1H8

Chartis Insurance Company of Canada
(herein called the Insurer)

COPY

PrivateEdge Plus

POLICY NUMBER: *05-766-59-66* REPLACEMENT OF POLICY#: *07-189-40-95*

Management Liability, Professional Liability, Crime Coverage and Kidnap And Ransom/Extortion Coverage for Private Companies
DECLARATIONS

NOTICES

[THESE NOTICES ARE APPLICABLE TO ALL COVERAGE SECTIONS OTHER THAN THE CRIME COVERAGE SECTION AND KIDNAP AND RANSOM/EXTORTION COVERAGE SECTION]

COVERAGE WITHIN THIS POLICY IS GENERALLY LIMITED TO LOSS FROM CLAIMS FIRST MADE AGAINST INSUREDS DURING THE POLICY PERIOD AND REPORTED TO THE INSURER AS THE POLICY REQUIRES. DEFENCE COSTS REDUCE THE LIMITS OF LIABILITY (AND, THEREFORE, AMOUNTS AVAILABLE TO RESPOND TO SETTLEMENTS AND JUDGMENTS) AND ARE APPLIED AGAINST APPLICABLE RETENTIONS.

THE INSURER DOES NOT ASSUME ANY DUTY TO DEFEND UNLESS SUCH COVERAGE IS EXPRESSLY PROVIDED WITHIN A COVERAGE SECTION. WHERE THE INSURER HAS NO DUTY TO DEFEND, IT WILL ADVANCE DEFENCE COSTS, EXCESS OF THE APPLICABLE RETENTION, PURSUANT TO THE TERMS OF THIS POLICY PRIOR TO THE FINAL DISPOSITION OF A CLAIM. PLEASE REFER TO THE COVERAGE SECTIONS PURCHASED FOR DEFENCE RELATED DETAILS.

PLEASE READ THE POLICY CAREFULLY AND DISCUSS THE COVERAGE HEREUNDER WITH YOUR INSURANCE AGENT OR BROKER TO DETERMINE WHAT IS AND WHAT IS NOT COVERED.

ITEMS			
1	NAMED ENTITY:	(the "Named Entity")	*YUKON DEVELOPMENT CORPORATION*
		MAILING ADDRESS:	*2 MILES CANYON RD, PO BOX 5920 WHITEHORSE, YT Y1A 6S7*
		JURISDICTION OF INCORPORATION/FORMATION:	*Yukon*
2	POLICY PERIOD:	Inception Date: *September 1, 2011*	Expiration Date: *September 1, 2012*
		12:01 A.M. at the address stated in Item 1	

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ITEMS (continued)

3 COVERAGE SUMMARY

Liability Coverage Section		Separate Limit of Liability	Shared Limit of Liability	Retention/ Deductible*	Continuity/ Retroactive Date	Premium
D&O	D&O Coverage Section	*Inapplicable*	*$10,000,000* Shared With: EPL & FLI	*$50,000*	*Continuity: 12/31/1997*	*$12,634*
EPL	Employment Practices Coverage Section	*Inapplicable*	*$10,000,000* Shared With: D&O & FLI	*$50,000*	*Continuity: 09/01/2008*	*$5,566*
FLI	Fiduciary Liability Coverage Section	*Inapplicable*	*$2,000,000* Shared With: D&O & EPL	*$25,000*	*Continuity: 09/01/2009*	*$3,300*
MPL	Miscellaneous Professional Liability Coverage Section	*Coverage Section Not Purchased*	*Coverage Section Not Purchased*	*Coverage Section Not Purchased*	*Coverage Section Not Purchased*	*Coverage Section Not Purchased*
	Professional Services:					
CCP	Employed Lawyers Coverage Section	*Coverage Section Not Purchased*	*Coverage Section Not Purchased*	*Coverage Section Not Purchased*	*Coverage Section Not Purchased*	*Coverage Section Not Purchased*
Crime	Crime Coverage Section	See Section 5:	None	See Section 5:	N/A	*Coverage Section Not Purchased*
KRE	Kidnap And Ransom/ Extortion Coverage Section	See Section 6:	None	See Section 6:	N/A	*Coverage Section Not Purchased*
*With respect to the D&O, EPL, FLI and CCP Coverage Sections only, no Retention amount is applicable to Non-Indemnifiable Loss. *No Retention amount is applicable to Costs of Investigation for Company Shareholder Derivative Investigation, Crisis Management Events, Voluntary Compliance Loss and HIPAA Penalties.						N/A

4 TOTAL PREMIUM *$21,500*

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ITEMS (continued)

5 CRIME LIMITS OF LIABILITY AND DEDUCTIBLES

Insuring Agreement	Per Occurrence Limit of Liability	Deductible
Insuring Agreement 1.A.: "Employee Theft" Loss	Coverage Section Not Purchased	Coverage Section Not Purchased
Insuring Agreement 1.B.: "Forgery or Alteration" Loss	Coverage Section Not Purchased	Coverage Section Not Purchased
Insuring Agreement 1.C.: "Inside the Premises - Theft of Money or Securities" Loss	Coverage Section Not Purchased	Coverage Section Not Purchased
Insuring Agreement 1.D.: "Inside the Premises - Robbery or Safe Burglary of Other Property" Loss	Coverage Section Not Purchased	Coverage Section Not Purchased
Insuring Agreement 1.E.: "Outside the Premises" Loss	Coverage Section Not Purchased	Coverage Section Not Purchased
Insuring Agreement 1.F.: "Computer Fraud" Loss	Coverage Section Not Purchased	Coverage Section Not Purchased
Insuring Agreement 1.G.: "Funds Transfer Fraud" Loss	Coverage Section Not Purchased	Coverage Section Not Purchased
Insuring Agreement 1.H.: "Money Orders and Counterfeit Paper Currency" Loss	Coverage Section Not Purchased	Coverage Section Not Purchased

If "Not Covered" is inserted above opposite any specific Insuring Agreement, such Insuring Agreement in the Crime Coverage Section and any other reference thereto in this policy is hereby deleted.

CANCELLATION OF PRIOR CRIME INSURANCE: By acceptance of the Crime Coverage Section of this Policy, you give us notice of cancellation for the prior Policy Nos: Not Applicable. Such cancellation shall be effective at the time the Crime Coverage Section of this Policy becomes effective.

6 KRE LIMITS OF INSURANCE \ INSURED PERSON(S)

Loss Component:	Each Loss Component Limit	Annual Aggregate Limit
A. Ransom Monies:	Coverage Section Not Purchased	Coverage Section Not Purchased
B. In-Transit/Delivery:	Coverage Section Not Purchased	Coverage Section Not Purchased
C. Expenses:	Coverage Section Not Purchased	Coverage Section Not Purchased
D. Consultant Expenses:	Coverage Section Not Purchased	Coverage Section Not Purchased
E. Judgments, Settlements and Defence Costs:	Coverage Section Not Purchased	Coverage Section Not Purchased
F. Death or Dismemberment:	Coverage Section Not Purchased	Coverage Section Not Purchased
Each Insured Event Limit:		Coverage Section Not Purchased
Coverage Section Aggregate:		Coverage Section Not Purchased
Deductible (Each Loss):		Coverage Section Not Purchased

Insured Person(s):

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ITEMS (continued)

7	**OTHER LIMITS OF LIABILITY**	
	(a) POLICY AGGREGATE LIMIT OF LIABILITY (For all coverages combined other than the Crime and the KRE Coverage Sections:	*$10,000,000*
	(b) Crisis Management Fund For D&O:	*$10,000*
	(c) Punitive Damages Sublimit of Liability for D&O and/or EPL Coverage Sections:	
	☐ D&O Punitive Damages Sublimit of Liability:	*$0*
	☐ EPL Punitive Damages Sublimit of Liability:	*$0*
	☐ Shared Punitive Damages Sublimit of Liability (D&O and EPL):	*$0*
	☒ No Punitive Damages Sublimit of Liability for D&O or EPL	*Full Limit*
	(d) Costs of Investigation Coverage Sublimit for D&O:	*$150,000*
	(e) Voluntary Compliance Loss Sublimit of Liability for FLI:	*$25,000*
	(f) HIPAA Penalties Sublimit of Liability for FLI:	*$25,000*
8	**DISCOVERY PROVISIONS** (Inapplicable to Crime and KRE Coverage Sections)	
	(a) Percentage of Full Annual Premium for; 1 Year:	*100%*
	(b) 2 Years:	*150%*
	(c) 3 Years:	*175%*
	(d) 4 Years:	*180%*
	(e) 5 Years:	*190%*
	(f) 6 Years:	*200%*
	(g) Percentage of Full Annual Premium for unlimited duration:	*220%*

9(a) **NAME AND ADDRESS OF INSURER**

Chartis Insurance Company of Canada
145 WELLINGTON STREET WEST
TORONTO, ON M5J 1H8

This policy is issued only by the insurance company indicated in this Item 9(a).

9(b) **NOTICE OF CLAIMS AND CIRCUMSTANCES SEND TO:**

Claims Management, Canada
145 WELLINGTON STREET WEST
TORONTO, ON M5J 1H8

Attention: "Financial Lines Claims"
Reference: *05-766-59-66*

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ITEMS (continued)

PRODUCER: *AON REED STENHOUSE INC.*
PRODUCER LICENSE NO.: *On File with Carrier*
ADDRESS: *900 HOWE STREET*
VANCOUVER, BC V6B 3X8

All limits of insurance, premiums and other sums of money as expressed in this policy are in Canadian currency unless otherwise stated in writing

By signing below, the Chief Executive Officer and the Secretary of the Insurer agree on behalf of the Insurer to all the terms of this Policy.

President and Chief Executive Officer
Chartis Insurance Company of Canada

Secretary
Chartis Insurance Company of Canada

TORONTO
SIGNED AT

August 31, 2011
DATE

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CHARTIS

Canadian Head Office
145 WELLINGTON STREET WEST
TORONTO, ON M5J 1H8

Chartis Insurance Company of Canada
(herein called the Insurer)

PrivateEdge Plus

General Terms and Conditions

In consideration of the payment of the premium, and in reliance upon the statements made to the **Insurer** by **Application**, which forms a part of this policy, the **Insurer** agrees as follows:

1. TERMS AND CONDITIONS

These **General Terms and Conditions** shall be applicable to all **Coverage Sections** except: (i) the **KRE Coverage Section**; and (ii) the **Crime Coverage Section**. Terms appearing in these **General Terms and Conditions** which are defined in a **Coverage Section** shall have the meaning provided for such terms in such **Coverage Section** for purposes of coverage provided under such **Coverage Section**. Any reference in these **General Terms and Conditions** to "all **Coverage Sections**" shall not refer to the **KRE Coverage Section** or the **Crime Coverage Section**. The terms and conditions set forth in each **Coverage Section** shall only apply to that particular **Coverage Section** and shall in no way be construed to apply to any other **Coverage Section** of this policy.

2. DEFINITIONS

(a) "**Application**" means each and every signed application, any attachments to such applications, other materials submitted therewith or incorporated therein and any other documents submitted in connection with the underwriting of this policy or the underwriting of any other directors and officers (or equivalent) liability policy, employment practices liability policy, professional liability policy, employed lawyers policy or crime policy issued by the **Insurer**, or any of its affiliates, of which this policy is in whole or part a renewal or replacement or which it succeeds in time.

(b) "**Company**" means the **Named Entity** and any **Subsidiary** thereof. In the event a bankruptcy proceeding shall be instituted by or against a **Company**, the term "**Company**" shall also mean the resulting debtor-in-possession (or equivalent status outside the United States of America), if any.

(c) "**Continuity Date**" means the date set forth in Item 3 of the Declarations with respect to each **Coverage Section**.

(d) "**Coverage Section**" means each **Coverage Section** that is purchased by the **Insured** as indicated in Item 3 of the Declarations.

(e) "**Discovery Period**" means **Discovery Period**, as that term is defined in Clause 8 of these **General Terms and Conditions**.

(f) "**Domestic Partner**" means any natural person legally recognized as a domestic or civil union partner under: (i) the provisions of any applicable federal, state, provincial, territorial or local law; or (ii) the provisions of any formal program established by the **Company**.

(g) "**Insurer**" means the insurance company indicated in the Declarations.

(h) "**Management Control**" means: (i) owning interests representing more than fifty percent (50%) of the voting, appointment or designation power for the selection of a majority of: the board of directors of a corporation, the management committee members of a joint venture or partnership, or the members of the management board of a limited liability company; or (ii) having the right, pursuant to written contract or the by-laws, charter, operating agreement or similar documents of a **Company**, to elect, appoint or designate a majority of: the board of directors of a corporation, the management committee of a joint venture or partnership, or the management board of a limited liability company.

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(i) "**Named Entity**" means the entity listed in Item 1 of the Declarations.

(j) "**Policy Aggregate Limit of Liability**" means the **Policy Aggregate Limit of Liability** stated in Item 7(a) of the Declarations.

(k) "**Policy Period**" means the period of time from the inception date stated in Item 2 of the Declarations to the earlier of the expiration date stated in Item 2 of the Declarations or the effective date of cancellation of this policy.

(l) "**Related Wrongful Act(s)**" means **Wrongful Act(s)** which are the same, related or continuous, or **Wrongful Act(s)** which arise from a common nucleus of facts. **Claims** can allege **Related Wrongful Act(s)** regardless of whether such **Claims** involve the same or different claimants, **Insureds** or legal causes of action.

(m) "**Separate Limit of Liability**" means the applicable **Separate Limit of Liability**, if any, stated in Item 3 of the Declarations.

(n) "**Shared Limit of Liability**" means the applicable **Shared Limit of Liability**, if any, stated in Item 3 of the Declarations, which limit of liability shall be shared between all of the **Coverage Sections** which are listed below such **Shared Limit of Liability** in the Declarations.

(o) "**Subsidiary**" means:

(i) any for-profit entity, whose securities are not publicly traded, of which the **Named Entity** has or had **Management Control** ("**Controlled Entity**") on or before the inception date of the **Policy Period**, either directly or indirectly through one or more other **Controlled Entities**;

(ii) any for-profit entity, whose securities are not publicly traded, of which the **Named Entity** acquires **Management Control** during the **Policy Period**, either directly or indirectly through one or more other **Controlled Entities**; and

(iii) any not-for-profit entity under section 501(c)(3) of the Internal Revenue Code of 1986 or the Income Tax Act, R.S.C. (5th Supp) (as amended) sponsored exclusively by a **Company**.

Notwithstanding the foregoing, coverage as is afforded under this policy with respect to a **Claim** made against any **Subsidiary** or any **Individual Insureds** thereof shall only apply for **Wrongful Acts** committed or allegedly committed after the effective time that the **Named Entity** obtained **Management Control** of such **Subsidiary** and prior to the time that such **Named Entity** ceased to have **Management Control** of such **Subsidiary**.

3. EXTENSIONS

Subject otherwise to the terms hereof, this policy shall cover **Loss** arising from any **Claim** made against: (i) the estates, heirs, or legal representatives of deceased **Individual Insureds**, and the legal representatives of **Individual Insureds** in the event of incompetency, insolvency or bankruptcy, who were **Individual Insureds** at the time the **Wrongful Acts** upon which such **Claims** are based were committed; or (ii) the lawful spouse (whether such status is derived by reason of statutory law, common law or otherwise of any applicable jurisdiction in the world) or **Domestic Partner** of an **Individual Insured** for all **Claims** arising solely out of his or her status as the spouse or **Domestic Partner** of an **Individual Insured**, including a **Claim** that seeks damages recoverable from marital community property, property jointly held by the **Individual Insured** and the spouse or **Domestic Partner**, or property transferred from the **Individual Insured** to the spouse or **Domestic Partner**; provided, however, this extension shall not afford coverage for any **Claim** for any actual or alleged **Wrongful Act** of the spouse or **Domestic Partner**, but shall apply only to **Claims** arising out of any actual or alleged **Wrongful Acts** of an **Individual Insured**, subject to the policy's terms, conditions and exclusions.

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4. LIMITS OF LIABILITY (FOR ALL LOSS IN THE AGGREGATE UNDER THIS POLICY AND UNDER EACH INDIVIDUAL COVERAGE SECTION - INCLUDING DEFENCE COSTS)

The **Policy Aggregate Limit of Liability** is the maximum limit of the **Insurer's** liability for all **Loss** under all **Coverage Sections** combined arising out of all **Claims** first made against the **Insureds** during the **Policy Period** or the **Discovery Period** (if applicable); provided, however, the **Policy Aggregate Limit of Liability** for the Discovery Period shall be part of, and not in addition to, the **Policy Aggregate Limit of Liability** for the **Policy Period**.

If **Separate Limits of Liability** are stated in Item 3 of the Declarations, then each such **Separate Limit of Liability** shall be the maximum limit of the **Insurer's** liability for all Loss arising out of all **Claims** first made against the **Insureds** during the **Policy Period** or the **Discovery Period** (if applicable) with respect to the applicable **Coverage Section** as stated on the Declarations; provided, however, the **Separate Limit of Liability** for the **Discovery Period** shall be part of, and not in addition to, the **Separate Limit of Liability** for the **Policy Period**. Each **Separate Limit of Liability** shall be part of and not in addition to the **Policy Aggregate Limit of Liability** for all **Loss** under this policy and shall in no way serve to increase the **Insurer's Policy Aggregate Limit of Liability** as therein stated.

If **Shared Limits of Liability** are stated in Item 3 of the Declarations, then each such **Shared Limit of Liability** shall be the maximum limit of the **Insurer's** liability for all **Loss** arising out of all **Claims** first made against the **Insureds** during the **Policy Period** or the **Discovery Period** (if applicable) with respect to all **Coverage Sections** for which such **Shared Limit of Liability** is applicable, as indicated on the Declarations; provided, however, with respect to all **Coverage Sections** that have a **Shared Limit of Liability**, the **Shared Limit of Liability** for the **Discovery Period** shall be part of, and not in addition to, the **Shared Limit of Liability** for the **Policy Period**. Each **Shared Limit of Liability** shall be part of, and not in addition to, the **Policy Aggregate Limit of Liability** for all **Loss** under this policy and shall in no way serve to increase the **Policy Aggregate Limit of Liability** as therein stated.

Further, a **Claim** which is made subsequent to the **Policy Period** or **Discovery Period** (if applicable) which pursuant to Clause 6(b) or 6(c) of these **General Terms and Conditions** is considered made during the **Policy Period** or **Discovery Period**, shall also be subject to the **Policy Aggregate Limit of Liability** and subject to any applicable **Separate Limit of Liability** or **Shared Limit of Liability**.

Defence Costs are not payable by the **Insurer** in addition to the **Policy Aggregate Limit of Liability** or any applicable **Separate Limit of Liability** or **Shared Limit of Liability**. **Defence Costs** are part of **Loss** and as such are subject to the **Policy Aggregate Limit of Liability** for **Loss** and any applicable **Separate Limit of Liability** or **Shared Limit of Liability**. Amounts incurred for **Defence Costs** shall be applied against the Retention.

5. RETENTION CLAUSE

The Retentions stated in the Declarations are separate Retentions pertaining only to the **Coverage Section** for which they are stated in the Declarations. The application of a Retention to **Loss** under one **Coverage Section** shall not reduce the Retention under any other **Coverage Section**.

In the event a **Claim** triggers a Retention in multiple **Coverage Sections**, then the following shall apply:

(a) with regard to **Loss** which is payable under any **Coverage Section** which is subject to a **Separate Limit of Liability**, the Retention applicable to such **Loss** pursuant to the Retention Clause of such **Coverage Section** (or pursuant to any applicable endorsement) shall apply separately to such **Loss**, and the applicable Retention for such **Coverage Section** shall not be reduced by payments of **Loss** made towards the Retention required under any other **Coverage Section**; and

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(b) with regard to **Loss** which is payable under any **Coverage Sections** which are subject to a **Shared Limit of Liability**, the highest applicable Retention shall be deemed the Retention applicable to **Loss** arising from such **Claim**.

6. NOTICE/CLAIM REPORTING PROVISIONS

Notice hereunder shall be given in writing to the addressee and at the address identified in Item 9(b) of the Declarations. Notice shall include and reference this policy number as indicated in the Declarations, as well as the **Coverage Sections** under which the **Claim** is being noticed. If mailed, the date of mailing shall constitute the date that such notice was given and proof of mailing shall be sufficient proof of notice.

The following shall apply:

(a) The **Insureds** shall, as a condition precedent to the obligations of the **Insurer** under this policy, give written notice to the **Insurer** of any **Claim** made against an **Insured** or a **Crisis Management Event** as soon as practicable after: (i) the **Company's** Risk Manager or General Counsel (or equivalent position) first becomes aware of the **Claim**; or (ii) the **Crisis Management Event** commences, but in all events a **Claim** must be reported no later than either:

(i) anytime during the **Policy Period** or during the **Discovery Period** (if applicable); or

(ii) within ninety (90) days after the end of the **Policy Period** or the **Discovery Period** (if applicable).

(b) If written notice of a **Claim** has been given to the **Insurer** pursuant to Clause 6(a) above, then any **Claim** which is subsequently made against the **Insureds** and reported to the **Insurer** alleging, arising out of, based upon or attributable to the facts alleged in the **Claim** for which such notice has been given, or alleging any **Wrongful Act** which is the same as or is a **Related Wrongful Act** to that alleged in the **Claim** of which such notice has been given, shall be considered made at the time such notice was given.

(c) If during the **Policy Period** or during the **Discovery Period** (if applicable) the **Insureds** shall become aware of any circumstances which may reasonably be expected to give rise to a **Claim** being made against the **Insureds** and shall give written notice to the **Insurer** of the circumstances, the **Wrongful Act** allegations anticipated and the reasons for anticipating such a **Claim**, with full particulars as to dates, persons and entities involved, then any **Claim** which is subsequently made against the **Insureds** and reported to the **Insurer** alleging, arising out of, based upon or attributable to such circumstances or alleging any **Wrongful Act** which is the same as or is a **Related Wrongful Act** to that alleged or contained in such circumstances, shall be considered made at the time such notice of such circumstances was given.

(d) Any matter which could involve the payment of **Voluntary Compliance Loss** under the **FLI Coverage Section** shall be reported to the **Insurer** in the same manner as a **Claim** under Clause 6(a)(1) and 6(a)(2) above.

7. CANCELLATION CLAUSE

This policy or any individual **Coverage Section** may be cancelled by the **Named Entity** at any time by mailing prior written notice to the **Insurer** stating which **Coverage Sections** are to be cancelled or that the entire policy is to be cancelled and when thereafter such cancellation shall be effective, or by surrender thereof to the **Insurer** or its authorized agent. The mailing of such notice shall be sufficient notice and the effective date of cancellation shall be the date the **Insurer** received such notice or any later date specified in the notice, and such effective date shall become the end of the policy or applicable **Coverage Sections**.

This policy may be cancelled by or on the behalf of the **Insurer** only in the event of non-payment of premium by the **Named Entity**. In the event of non-payment of premium by

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the **Named Entity**, the **Insurer** may cancel this policy by delivering to the **Named Entity** or by mailing to the **Named Entity**, by registered, certified or other first class mail, at the **Named Entity's** address as stated in Item 1 of the Declarations, written notice stating when, not less than ten (10) days thereafter, the cancellation shall be effective. The mailing of such notice as aforesaid shall be sufficient proof of notice. The **Policy Period** terminates at the date and hour specified in such notice, or at the date and time of surrender. The **Insurer** shall have the right to the premium amount for the portion of the **Policy Period** during which the policy was in effect.

If this policy or any **Coverage Section** shall be cancelled by the **Named Entity**, the Insurer shall retain the pro rata proportion of the applicable premium herein. Payment or tender of any unearned premium by the **Insurer** shall not be a condition precedent to the effectiveness of cancellation.

If the period of limitation relating to the giving of notice as set forth above is also set forth in any law controlling the construction thereof, the period set forth above shall be deemed to be amended so as to be equal to the minimum period of limitation set forth in the controlling law.

8. DISCOVERY CLAUSE

If the **Named Entity** shall cancel or the **Named Entity** or the **Insurer** shall refuse to renew this policy or any **Coverage Section**, then, solely with regard to the policy or **Coverage Section** which was cancelled or nonrenewed, the **Named Entity** shall have the right, upon payment of the applicable "**Additional Premium Amount**" described below, to a period of up to six (6) years or of unlimited duration following the effective date of such cancellation or nonrenewal (herein referred to as the "**Discovery Period**"), in which to give the **Insurer** written notice of **Claims** first made against any **Insured** during said **Discovery Period** for any **Wrongful Act** occurring prior to the end of the **Policy Period** and otherwise covered by the cancelled or nonrenewed policy or **Coverage Section**, as applicable. The rights contained in this Clause 8 shall terminate, however, unless written notice of such election together with the **Additional Premium Amount** due is received by the **Insurer** within thirty (30) days of the effective date of cancellation or nonrenewal.

The **Additional Premium Amount** for the elected Discovery Period shall be the "**Full Annual Premium**" (as defined below) multiplied by the applicable percentage amount indicated in Item 8 of the Declarations for the length time of elected for the **Discovery Period**. If the applicable subsection of Item 8 of the Declaration states "to be determined", then the **Additional Premium Amount** for such **Discovery Period** shall be an amount determined by the **Insurer** in its sole and absolute discretion.

As used herein, "**Full Annual Premium**" means:

(a) with regard to a cancelled or nonrenewed policy, the total annual premium charged for this policy; or

(b) with regard to a cancelled or nonrenewed **Coverage Section**, the total annual premium charged for such **Coverage Section**.

In the event of a **Transaction**, as defined in Clause 9 of these **General Terms and Conditions**, the **Named Entity** shall have the right, within thirty (30) days before the end of the **Policy Period**, to request an offer from the **Insurer** of a **Discovery Period** (with respect to **Wrongful Acts** occurring prior to the effective time of the **Transaction**) for a period of up to six (6) years or for such longer or shorter period as the **Named Entity** may request. The **Insurer** shall offer such **Discovery Period** pursuant to such terms, conditions and premium as the **Insurer** may reasonably decide. In the event of a **Transaction**, the right to a **Discovery Period** shall not otherwise exist except as indicated in this paragraph.

The **Discovery Period** is not cancellable, except that the **Insurer** may cancel the Discovery

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Period for non-payment of premium. This Clause 8 and the rights contained herein shall not apply to any cancellation resulting from non-payment of premium.

9. CHANGE IN CONTROL OF NAMED ENTITY

If during the **Policy Period**:

(a) the **Named Entity** shall consolidate with or merge into, or sell all or substantially all of its assets to any other person or entity or group of persons or entities acting in concert; or

(b) any person or entity or group of persons or entities acting in concert shall acquire **Management Control** of the **Named Entity**;

(either of the above events herein referred to as the "**Transaction**"),

then this policy shall continue in full force and effect as to **Wrongful Acts** occurring prior to the effective time of the **Transaction**, but there shall be no coverage afforded by any provision of this policy for any actual or alleged **Wrongful Act** occurring after the effective time of the **Transaction**.

This policy and any purchased **Coverage Section** may not be cancelled after the effective time of the **Transaction**. The **Named Entity** shall also have the right to an offer by the **Insurer** of a **Discovery Period** described in Clause 8 of these **General Terms and Conditions**.

The **Named Entity** shall give the **Insurer** written notice of the **Transaction** as soon as practicable, but not later than thirty (30) days after the effective date of the **Transaction**.

10. SUBROGATION

In the event of any payment under this policy, the **Insurer** shall be subrogated to the extent of such payment to each **Insured's** rights of recovery thereof, and each **Insured** shall execute all papers required and shall do everything that may be necessary to secure such rights, including the execution of such documents necessary to enable the **Insurer** to effectively bring suit in the name of the **Insured**. In no event, however, shall subrogation be had against any **Individual Insured** under this policy, unless such **Individual Insured** has been convicted of a criminal act, or been determined by a final adjudication to have committed a dishonest, fraudulent act or wilful violation of any statute, rule or law, or determined by a final adjudication to have obtained any profit or advantage to which such **Individual Insured** was not legally entitled.

In the event that the **Insurer** shall for any reason pay **Indemnifiable Loss** on behalf of an **Individual Insured**, the **Insurer's** subrogation rights shall include, but not be limited to, the assertion of indemnification or contribution rights with respect to any such payments it makes or advances. Additionally, upon the **Insurer** making any payment of **Loss** within the Retention, the **Insurer** shall have a direct contractual right under this policy to recover from the **Company**, or in the event of the bankruptcy of the **Company**, from the debtor-in-possession (or equivalent status outside the United States) such **Loss** which was paid within the Retention. Such direct contractual right of recovery against the **Company** shall be in addition to and independent of the **Insurer's** subrogation right pursuant to this Clause 10 and any other rights the **Insurer** may have under applicable law.

11. OTHER INSURANCE

With respect to all **Coverage Sections**, other than the **EPL Coverage Section**, such insurance as is provided by this policy shall apply only as excess over any other valid and collectible insurance, unless such other insurance is expressly written to be excess over the **Policy Aggregate Limit of Liability** or any applicable **Separate Limit of Liability** or **Shared Limit of Liability** provided by this policy. This policy specifically shall be excess of any other policy pursuant to which any other **Insurer** has a duty to defend a **Claim** for which this policy may be obligated to pay **Loss**.

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Such insurance as is provided by the **EPL Coverage Section** shall be primary unless expressly written to be excess over other applicable insurance.

With respect to all **Coverage Sections**, in the event of a **Claim** against an **Insured** arising out of his or her service as an **Outside Entity Executive**, or a **Claim** against an **Insured** for the **Insured's** liability with respect to a leased **Employee** or independent contractor **Employee** as described in the definition of "**Employee**" in the applicable **Coverage Section**, coverage as is afforded by this policy shall be specifically excess of any: (i) indemnification provided by such **Outside Entity** or leasing company; and (ii) any other insurance provided to such **Outside Entity**, leasing company or independent contractor.

Further, in the event other insurance is provided to the **Outside Entity**, leasing company or independent contractor referenced in the above paragraph, or is provided under any pension trust or employee benefit plan fiduciary liability insurance policy, and such other insurance is provided by the **Insurer** or any member company of Chartis, Inc. ("**Chartis**") (or would be provided but for the application of the Retention, exhaustion of the limit of liability or failure to submit a notice of a **Claim**), then the **Insurer's** maximum aggregate limit of liability for all **Loss** combined in connection with a **Claim** covered, in part or in whole, by this policy and such other insurance policy issued by **Chartis**, shall not exceed the greater of (i) the **Policy Aggregate Limit of Liability** or any applicable **Separate Limit of Liability** or **Shared Limit of Liability** of this policy, or (ii) the limit of liability of such other **Chartis** insurance policy.

12. NOTICE AND AUTHORITY

Except for the giving of a notice of **Claim**, which shall be governed by the provisions of Clause 6 of these **General Terms and Conditions**, all notices required under this policy to be given by the **Insured** to the **Insurer** shall be given in writing to the **Insurer** at the address stated in Item 9(a) of the Declarations. It is agreed that the **Named Entity** shall act on behalf of its **Subsidiaries** and all **Insureds** with respect to the giving of notice of a **Claim**, the giving and receiving of notice of cancellation and nonrenewal, the payment of premiums and the receiving of any return premiums that may become due under this policy, the receipt and acceptance of any endorsements issued to form a part of this policy, the exercising or declining of the right to tender the defence of a **Claim** to the **Insurer** and the exercising or declining to exercise any right to a **Discovery Period**.

13. ASSIGNMENT

This policy and any and all rights hereunder are not assignable without the prior written consent of the **Insurer**, which consent shall be in the sole and absolute discretion of the **Insurer**.

14. DISPUTE RESOLUTION PROCESS

It is hereby understood and agreed that all disputes or differences which may arise under or in connection with this policy, whether arising before or after termination of this policy, including any determination of the amount of **Loss**, must first be submitted to the non-binding mediation process as set forth in this Clause.

Either the **Insurer** or an **Insured** may elect the type of ADR process discussed below; provided, however, that such **Insured** shall have the right to reject the **Insurer's** choice of the type of ADR process at any time prior to its commencement, in which case such Insured's choice of ADR process shall control.

The Insurer and each and every **Insured** agree that there shall be two choices of ADR process: (1) non-binding mediation administered by any mediator to which the **Insurer** and Insured mutually agree, in which the **Insurer** and any such **Insured** shall try in good faith to settle the dispute by mediation under or in accordance with its then-prevailing commercial mediation rules; or (2) arbitration submitted to an arbitration panel of three (3) arbitrators. The

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Insureds shall select one (1) arbitrator, the Insurer shall select one (1) arbitrator and said arbitrators shall mutually agree upon the selection of the third arbitrator. In either mediation or arbitration, the mediator or arbitrators shall have knowledge of the legal, corporate management, or insurance issues relevant to the matters in dispute.

The dispute or differences considered by the mediator or arbitrators shall be governed by the Ontario *Arbitration Act* 1991, S.O.1991, c. 17. In the event of arbitration, the decision of the arbitrators shall be final and binding and provided to both parties, and the arbitrators' award shall not include legal fees or other costs. In the event of mediation, either party shall have the right to commence a judicial proceeding; provided, however, that no such judicial proceeding shall be commenced until the mediation shall have been terminated and at least 90 days shall have elapsed from the date of the termination of the mediation. In all events, each party shall share equally the expenses of the ADR process.

Either choice of ADR process may be commenced in Toronto, Ontario; or in the province indicated in Item 1(a) of the Declarations as the mailing address for the **Named Entity**. The **Named Entity** shall act on behalf of each and every Insured in deciding to proceed with an ADR process under this clause.

15. ACTION AGAINST INSURER

Except as provided in Clause 14 above, no action shall lie against the **Insurer** unless, as a condition precedent thereto, there shall have been full compliance with all of the terms of this policy, nor until the amount of the **Insured's** obligation to pay shall have been finally determined either by judgment against the **Insured** after actual trial or by written agreement of the **Insured**, the claimant and the **Insurer**.

Any person or organization or the legal representative thereof who has secured such judgment or written agreement shall thereafter be entitled to recover under this policy to the extent of the insurance afforded by this policy. No person or organization shall have any right under this policy to join the **Insurer** as a party to any action against the **Insured** or the **Company** to determine the **Insured's** liability, nor shall the **Insurer** be impleaded by the **Insured** or the **Company** or their legal representatives. Bankruptcy or insolvency of the **Company** or any **Insured** or of their estates shall not relieve the **Insurer** of any of its obligations hereunder.

16. WORLDWIDE TERRITORY

Where legally permissible, this policy shall apply to any **Claim** made against any **Insured** anywhere in the world.

17. HEADINGS

The descriptions in the headings of this policy are solely for convenience, and form no part of the terms and conditions of coverage.

All limits of insurance, premiums and other sums of money as expressed in this policy are in Canadian currency unless otherwise stated in writing

By signing below, the Chief Executive Officer and the Secretary of the Insurer agree on behalf of the Insurer to all the terms of this Policy.

President and Chief Executive Officer
Chartis Insurance Company
of Canada

Secretary
Chartis Insurance Company
of Canada

This Policy shall not be valid unless signed at the time of issuance by an authorized representative of the Insurer, either below or on the Declarations page of the policy.

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CHARTIS

Canadian Head Office
145 WELLINGTON STREET WEST
TORONTO, ON M5J 1H8

Chartis Insurance Company of Canada
(herein called the **Insurer**)

PrivateEdge Plus℠

Directors, Officers and Private Company Liability Insurance ("D&O Coverage Section")

Notice: Pursuant to Clause 1 of the General Terms and Conditions, the General Terms and Conditions are incorporated by reference into, made a part of, and are expressly applicable to this D&O Coverage Section, unless otherwise explicitly stated to the contrary in either the General Terms and Conditions or in this D&O Coverage Section.

In consideration of the payment of the premium, and in reliance upon the statements made to the **Insurer** by **Application**, which forms a part of this policy, the **Insurer** agrees as follows:

1. INSURING AGREEMENTS

With respect to Coverage A, B and D and the Defence Provisions, solely with respect to **Claims** first made during the **Policy Period** or the **Discovery Period** (if applicable) and reported to the **Insurer** pursuant to the terms of this policy, and subject to the other terms, conditions and limitations of this policy, this **D&O Coverage Section** affords the following coverage:

COVERAGE A: INDIVIDUAL INSURED INSURANCE

This **D&O Coverage Section** shall pay the **Loss** of an **Individual Insured** of the **Company** arising from a **Claim** made against such **Individual Insured** for any **Wrongful Act** of such **Individual Insured**, except when and to the extent that the **Company** has indemnified such **Individual Insured**. The **Insurer** shall, in accordance with and subject to Clause 7 of this **D&O Coverage Section**, advance **Defence Costs** of such **Claim** prior to its final disposition.

COVERAGE B: PRIVATE COMPANY INSURANCE

This **D&O Coverage Section** shall pay the **Loss** of the **Company** arising from a:

(i) **Claim** made against the **Company**, or

(ii) **Claim** made against an **Individual Insured**,

for any **Wrongful Act**, but, in the case of Coverage B(ii) above, only when and to the extent that the **Company** has indemnified the **Individual Insured** for such **Loss**. The Insurer shall, in accordance with and subject to Clause 7 of this **D&O Coverage Section**, advance **Defence Costs** of such **Claim** prior to its final disposition.

COVERAGE C: CRISISFUND® INSURANCE

This **D&O Coverage Section** shall pay the **Crisis Management Loss** of a **Company** solely with respect to a **Crisis Management Event** occurring during the **Policy Period** or the **Discovery Period** (if applicable) and reported to the **Insurer** pursuant to the terms of this policy, up to the amount of the **Crisis Management Fund**; provided that payment of any **Crisis Management Loss** under this **D&O Coverage Section** shall not waive any of the **Insurer's** rights under this **D&O Coverage Section** or at law. This Coverage C shall apply regardless of whether a **Claim** is ever made against an **Insured** arising from such **Crisis Management Event** and, in the case where a Claim is made, regardless of whether the amount is incurred prior to or subsequent to the **Claim** being first made.

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COVERAGE D: COSTS OF INVESTIGATION FOR DERIVATIVE DEMAND

This **D&O Coverage Section** shall pay the **Costs of Investigation** of the **Company** arising from a **Company Shareholder Derivative Investigation** in response to a **Derivative Demand**, up to the amount set forth in Item 7(d) of the Declarations. Payment of **Costs of Investigation** to a **Company** shall be made in accordance with and subject to Clause 8 of this **D&O Coverage Section**.

DEFENCE PROVISIONS

The **Insurer** does not assume any duty to defend; provided, however, the **Named Entity** may at its sole option tender to the **Insurer** the defence of a **Claim** for which coverage is provided by this **D&O Coverage Section** in accordance with and subject to Clause 7 of this **D&O Coverage Section**. Regardless of whether the defence is so tendered, the **Insurer** shall advance **Defence Costs** of such **Claim**, excess of the applicable Retention amount, prior to its final disposition. Selection of counsel to defend a **Securities Claim** shall be made in accordance with Clause 9 of this **D&O Coverage Section**.

With respect to Coverage D above, it shall be the duty of the **Company** and not the duty of the **Insurer** to conduct, investigate and evaluate any **Company Shareholder Derivative Investigation** against its own **Executives**; provided, however, that the **Insurer** shall be entitled to effectively associate in the investigation and evaluation of, and the negotiation of any settlement of, any such **Company Shareholder Derivative Investigation**.

2. DEFINITIONS

(a) "**Affiliate**" means: (i) any person or entity that directly, or indirectly through one or more intermediaries, controls or is controlled by, or is in common control with, another person or entity; or (ii) any person or entity that directly, or indirectly through one or more intermediaries, is a successor in interest to another person or entity.

(b) "**Claim**" means:

(i) a written demand for monetary or non-monetary relief (including any request to toll or waive any statute of limitations);

(ii) a civil, criminal, administrative, regulatory or arbitration proceeding for monetary or non-monetary relief which is commenced by:

(1) issuance of a notice of action, statement of claim, writ of summons, complaint or similar pleading;

(2) return of an indictment, laying of an information, the filing of a notice of charges or the issuance or filing of a similar legal document (in the case of a criminal proceeding); or

(3) receipt or filing of a notice of charges; or

(iii) a civil, criminal, administrative or regulatory investigation of an **Individual Insured**:

(1) once such **Individual Insured** is identified in writing by such investigating authority as a person against whom a proceeding described in Definition 2(b)(ii) may be commenced; or

(2) in the case of an investigation by the Securities Exchange Commission ("**SEC**"), a provincial or territorial securities commission, a securities regulatory authority, a self-regulatory organization, an exchange or by any similar federal, state, provincial, territorial or foreign government authority, regulatory authority or body after:

(a) the issuance of a subpoena or filing of a notice of charges upon such **Individual Insured**; or

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(b) the **Individual Insured** is identified in a written "Wells" or other notice from the **SEC** or a formal investigative order or any similar federal, state, provincial, territorial or foreign government authority that describes actual or alleged violations of laws by such **Individual Insured**.

The term "**Claim**" shall also include any **Securities Claim** and any **Derivative Demand**.

(c) "**Cleanup Costs**" means expenses (including but not limited to legal and professional fees) incurred in testing for, monitoring, cleaning up, removing, containing, treating, neutralizing, detoxifying or assessing the effects of **Pollutants**.

(d) "**Company Shareholder Derivative Investigation**" means the investigation by the **Company** or, on behalf of the **Company** by its board of directors (or the equivalent management body) or any committee of the board of directors (or the equivalent management body), as to whether or not the **Company** should bring the civil proceeding demanded in a **Derivative Demand**.

(e) "**Costs of Investigation**" means the reasonable and necessary costs, charges, fees and expenses consented to by the **Insurer** (including but not limited to attorney's fees and expert's fees but not including any settlement, judgment or damages and not including any compensation or fees of any **Individual Insured**) incurred by the **Company** or its board of directors (or any equivalent management body), or any committee of the board of directors (or any equivalent management body), solely in connection with a **Company Shareholder Derivative Investigation**.

(f) "**Crisis Management Event**" means **Crisis Management Event**, as that term is defined in Appendix D attached to this policy.

(g) "**Crisis Management Fund**" means the dollar amount set forth in Item 7(b) of the Declarations.

(h) "**Crisis Management Loss**" means **Crisis Management Loss**, as that term is defined in Appendix D attached to this policy.

(i) "**Crisis Management Services**" means **Crisis Management Services**, as that term is defined in Appendix D attached to this policy.

(j) "**D&O Punitive Damages Sublimit of Liability**" means the **D&O Punitive Damages Sublimit of Liability**, if any, stated in Item 7(c) of the Declarations.

(k) "**Defence Costs**" means the reasonable and necessary fees, costs and expenses consented to by the **Insurer** (including premiums for any appeal bond, attachment bond or similar bond arising out of a covered judgment, but without any obligation to apply for or furnish any such bond), resulting solely from the investigation, adjustment, defence and appeal of a **Claim** against an **Insured**, but excluding compensation of any **Individual Insured**. **Defence Costs** shall not include any fees, costs or expenses incurred prior to the time that a **Claim** is first made against an **Insured**.

(l) "**Derivative Demand**" means a written demand by shareholders upon the board of directors (or equivalent management body) of a **Company** requesting that it file, on behalf of the **Company**, a civil proceeding in a court of law against any **Executive** of the **Company** for a **Wrongful Act** of such **Executive** in order to obtain relief from damages arising out of such **Wrongful Acts**.

(m) "**Employee**" means any past, present or future employee, other than an **Executive** of a **Company**, whether such employee is in a supervisory, co-worker or subordinate position or otherwise, including any part-time, volunteer, seasonal and temporary employee. An individual who is leased to the **Company** shall also be an **Employee**, but only if the **Company** provides indemnification to such leased individual in the same manner as is provided to the **Company's** employees. Any other individual who is contracted to perform

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work for the **Company**, or who is an independent contractor for the **Company** shall also be an **Employee**, but only if the **Company** provides indemnification to such individual in the same manner as that provided to the **Company's** employees, pursuant to a written contract.

(n) "**Executive**" means:

(i) any past, present or future duly elected or appointed director, officer, management committee member or member of the Board of Managers;

(ii) any past, present or future person in a duly elected or appointed position in an entity which is organized and operated in a **Foreign Jurisdiction** that is equivalent to an executive position listed in Definition (n)(i); or

(iii) any past, present or future General Counsel and Risk Manager (or equivalent position) of the **Named Entity**.

(o) "**Financial Insolvency**" means the: (i) appointment by any government official, agency, commission, court or other governmental authority of a receiver, conservator, liquidator, trustee, rehabilitator or similar official to take control of, supervise, manage or liquidate an insolvent **Company**; (ii) the filing of a petition under the bankruptcy laws of Canada; or (iii) as to both (i) or (ii), any equivalent events outside Canada.

(p) "**Foreign Jurisdiction**" means any jurisdiction, other than Canada or any of their territories or possessions.

(q) "**Foreign Policy**" means the **Insurer's** or any other company of Chartis, Inc.'s ("**Chartis**") standard executive managerial liability policy (including all mandatory endorsements, if any) approved by **Chartis** to be sold within a **Foreign Jurisdiction** that provides coverage substantially similar to the coverage afforded under this **D&O Coverage Section**. If more than one such policy exists, then "**Foreign Policy**" means the standard basic policy form typically offered for sale in that **Foreign Jurisdiction** for comparable risks by the **Insurer** or any other company of **Chartis**. The term "**Foreign Policy**" shall not include any partnership managerial, pension trust or professional liability coverage.

(r) "**Indemnifiable Loss**" means **Loss** for which a **Company** has indemnified or is permitted or required to indemnify an **Individual Insured** pursuant to law, contract or the charter, bylaws, operating agreement or similar documents of a **Company**.

(s) "**Individual Insured**" means any:

(i) **Executive** of a **Company**;

(ii) **Employee** of a **Company**; or

(iii) **Outside Entity Executive**.

(t) "**Insured**" means:

(i) an **Individual Insured**; or

(ii) a **Company**.

(u) "**Loss**" means damages, judgments, settlements, pre-judgment and post-judgment interest, **Crisis Management Loss** and **Defence Costs**; provided, however, **Loss** shall not include: (i) civil or criminal fines or penalties imposed by law; (ii) taxes; (iii) any amounts for which an **Insured** is not financially liable or which are without legal recourse to an **Insured**; or (iv) matters which may be deemed uninsurable under the law pursuant to which this policy shall be construed. **Defence Costs** shall be provided for items specifically excluded from **Loss** pursuant to subparagraphs (u)(i) through (u)(iv) above of this Definition, subject to the other terms, conditions and exclusions of this policy.

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Loss shall specifically include, subject to the other terms, conditions and exclusions of this **D&O Coverage Section**, including, but not limited to, exclusions 4(a), 4(b) and 4(c) of this **D&O Coverage Section**, punitive, exemplary and multiple damages. As more fully set forth in Clause 5. "LIMIT OF LIABILITY" of this **D&O Coverage Section**, coverage under this **D&O Coverage Section** for punitive, exemplary and multiple damages is subject to any applicable **D&O Punitive Damages Sublimit of Liability** or **Shared Punitive Damages Sublimit of Liability**. The enforceability of the first sentence of this paragraph shall be governed by such applicable law which most favours coverage for punitive, exemplary and multiple damages.

(v) "**Non-Indemnifiable Loss**" means **Loss** for which a **Company** has neither indemnified nor is permitted or required to indemnify an **Individual Insured** pursuant to law or contract or the charter, bylaws, operating agreement or similar document of a **Company**.

(w) "**Outside Entity**" means:

(i) any not-for-profit organization; or

(ii) any other corporation, partnership, joint venture or other organization listed as an "**Outside Entity**" in an endorsement to this **D&O Coverage Section**.

(x) "**Outside Entity Executive**" means any: (i) **Executive** of the **Company** serving in the capacity as director, officer, trustee or governor of an **Outside Entity**, but only if such service is at the specific request or direction of the **Company**; or (ii) any other person listed as an **Outside Entity Executive** in an endorsement to this **D&O Coverage Section**. It is understood and agreed that, in the event of a disagreement between the **Company** and an individual as to whether such individual was acting "at the specific request or direction of the **Company**," this **D&O Coverage Section** shall abide by the determination of the **Company** on this issue and such determination shall be made by written notice to the **Insurer** within ninety (90) days after the **Claim** is first reported to the **Insurer** pursuant to the terms of the policy. In the event no determination is made within such period, this **D&O Coverage Section** shall apply as if the **Company** determined that such **Individual Insured** was not acting at the **Company's** specific request or direction.

(y) "**Pollutants**" means, but is not limited to, any solid, liquid, gaseous, biological, radiological or thermal irritant or contaminant, including smoke, vapour, dust, fibers, mold, spores, fungi, germs, soot, fumes, acids, alkalis, chemicals and **Waste**. "**Waste**" includes, but is not limited to, materials to be recycled, reconditioned or reclaimed and nuclear materials.

(z) "**Securities Claim**" means a **Claim** made against any **Insured**:

(i) alleging a violation of any federal, state, provincial, territorial, local or foreign regulation, rule, instrument, policy, blanket order, notice, ruling or statute regulating securities, including, but not limited to, the purchase or sale, or offer or solicitation of an offer to purchase or sell securities which is:

(1) brought by any person or entity alleging, arising out of, based upon or attributable to the purchase or sale, or offer or solicitation of an offer to purchase or sell, any securities of a **Company**; or

(2) brought by a security holder of a **Company** with respect to such security holder's interest in securities of such **Company**; or

(ii) brought derivatively on the behalf of a **Company** by a security holder of such **Company**.

(aa) "**Shared Punitive Damages Sublimit of Liability**" means the **Shared Punitive Damages Sublimit of Liability**, if any, stated in Item 7(c) of the Declarations.

(bb) "**Third Party Violation**" means any actual or alleged harassment (including sexual harassment, whether "quid pro quo", hostile work environment or otherwise) or unlawful

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discrimination (including, but not limited to, discrimination based upon age, gender, race, color, national origin, religion, sexual orientation or preference, pregnancy, or disability), or the violation of the civil rights of a person relating to such harassment or discrimination, when such acts are alleged to be committed against anyone other than an **Individual Insured** or applicant for employment with the **Company** or an **Outside Entity**.

(cc) "**Wrongful Act**" means:

(i) with respect to any **Executive** or **Employee** of a **Company**, any breach of duty, neglect, error, misstatement, misleading statement, omission or act by such **Executive** or **Employee** in their respective capacities as such, or any matter claimed against such **Executive** or **Employee** of a **Company** solely by reason of his or her status as an **Executive** or **Employee** of a **Company**;

(ii) with respect to a **Company**, any breach of duty, neglect, error, misstatement, misleading statement, omission or act by a **Company**; or

(iii) with respect to service on an **Outside Entity**, any breach of duty, neglect, error, misstatement, misleading statement, omission or act by an **Outside Entity Executive** in his or her capacity as such.

3. WORLDWIDE EXTENSION

For **Claims** made and maintained in a **Foreign Jurisdiction** for **Wrongful Acts** committed in such **Foreign Jurisdiction**, the **Insurer** shall apply to such **Claims** the provisions of the **Foreign Policy** in the **Foreign Jurisdiction** that are more favourable to such **Insured** in the **Foreign Jurisdiction**; provided however, that this paragraph shall apply only to provisions more favourable by virtue of insuring clauses, extensions, definitions, exclusions, pre-authorized securities or other defence counsel, discovery or extended reporting period, notice and authority, dispute resolution process or order of payments provisions, if any, of the **Foreign Policy** when compared to the same or similar clauses of this **D&O Coverage Section**. This paragraph shall not apply to excess provisions or policy provisions that address non-renewal, duty to defend, defence within or without limits, taxes, claims made and reported provisions or any other provision of this policy intended to govern coverage worldwide.

All premiums, limits, retentions, **Loss** and other amounts under this **D&O Coverage Section** are expressed and payable in the currency of Canada. If judgment is rendered, settlement is denominated or other elements of **Loss** are stated or incurred in a currency other than Canadian dollars, payment of covered **Loss** due under this **D&O Coverage Section** (subject to the terms, conditions and limitations of this **D&O Coverage Section**) will be made either in such other currency (at the option of the **Insurer** and if agreeable to the **Named Entity**) or, in Canada dollars, at the rate of exchange published in The National Post on the date the **Insurer's** obligation to pay such **Loss** is established (or if not published on such date the next publication date of The National Post).

4. EXCLUSIONS

The **Insurer** shall not be liable to make any payment for **Loss** in connection with any **Claim** made against an **Insured**:

(a) arising out of, based upon or attributable to the gaining of any profit or advantage to which any final adjudication establishes the **Insured** was not legally entitled;

(b) arising out of, based upon or attributable to: (i) the purchase or sale by an **Insured** of securities of the **Company** within the meaning of Section 76 of the Ontario *Securities Act,* R.S.O. 1990, c. S. 5, Section 131(4) of the *Canada Business Corporation Act,* R.S.C. 1985, c. C-44, or Section 16(b) of the *Securities Exchange Act of 1934* (or amendments to such statutes), or similar provisions of any provincial, state, or foreign statutory if any final adjudication establishes that such violation occurred; or (ii) the payment to any **Insured** of any remuneration without the previous approval of the stockholders of the **Company**, if any final adjudication establishes such payment was illegal;

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(c) arising out of, based upon or attributable to the committing of any deliberate criminal or deliberate fraudulent or dishonest act, or any willful violation of any statute, rule or law, if any final adjudication establishes that such deliberate criminal, deliberate fraudulent or dishonest act or willful violation of statute, rule or law was committed;

(d) alleging, arising out of, based upon or attributable to the facts alleged, or to the same or **Related Wrongful Act(s)** alleged or contained in any claim which has been reported, or in any circumstances of which notice has been given, under any policy of which this D&O **Coverage Section** is a renewal or replacement of in whole or in part or which it may succeed in time;

(e) alleging, arising out of, based upon or attributable to, as of the **Continuity Date**, any pending or prior: (i) litigation; or (ii) administrative or regulatory proceeding or investigation of which an **Insured** had notice, or alleging any **Wrongful Act** which is the same or **Related Wrongful Act(s)** to that alleged in such pending or prior litigation or administrative or regulatory proceeding or investigation;

(f) with respect to an **Outside Entity Executive**, for any **Wrongful Act** occurring prior to the **Continuity Date** if any **Insured**, as of such **Continuity Date**, knew or could have reasonably foreseen that such **Wrongful Act** could lead to a **Claim** under this D&O **Coverage Section**.

(g) alleging, arising out of, based upon or attributable to any actual or alleged act or omission of an **Individual Insured** serving in any capacity, other than as an **Executive** or **Employee** of a **Company**, or as an **Outside Entity Executive** of an **Outside Entity**;

(h) for any **Wrongful Act** arising out of an **Individual Insured** serving in a capacity as an **Outside Entity Executive** of an **Outside Entity** if such **Claim** is brought by the **Outside Entity** or any **Executive** thereof; or which is brought by any security holder of the **Outside Entity**, whether directly or derivatively, unless such security holder's **Claim** is instigated and continued totally independent of, and totally without the solicitation of, or assistance of, or active participation of, or intervention of the **Outside Entity**, the **Company**, or any **Executive** of the **Outside Entity** or the **Company**; provided, however, this exclusion shall not apply to:

(i) any **Claim** brought by an **Executive** of an **Outside Entity** in the form of a cross-claim or third-party claim for contribution or indemnity which is part of and results directly from a **Claim** that is covered by this D&O Coverage Section;

(ii) in any bankruptcy proceeding by or against an **Outside Entity**, any **Claim** brought by the examiner, trustee, receiver, liquidator or rehabilitator (or any assignee thereof) of such **Outside Entity**;

(iii) any **Claim** brought by any past **Executive** of an **Outside Entity** who has not served as a duly elected or appointed director, officer, trustee, governor, management committee member, member of the management board, General Counsel or Risk Manager (or equivalent position) of or consultant for an **Outside Entity** for at least four (4) years prior to such **Claim** being first made against any person; or

(iv) any **Claim** brought by an **Executive** of an **Outside Entity** formed and operating in a **Foreign Jurisdiction** against any **Outside Entity Executive** of such **Outside Entity**, provided that such **Claim** is brought and maintained outside the United States, Canada or any other common law country (including any territories thereof);

(i) which is brought by or on behalf of a **Company** or any **Individual Insured**, other than an **Employee** of a **Company**; or which is brought by any security holder of the **Company**, whether directly or derivatively, unless such security holder's **Claim** is instigated and continued totally independent of, and totally without the solicitation of, or assistance of, or active participation of, or intervention of, any **Company** or any **Executive** of a **Company**; provided, however, this exclusion shall not apply to:

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(i) any **Claim** brought by an **Individual Insured** in the form of a cross-claim or third-party claim for contribution or indemnity which is part of and results directly from a **Claim** which is covered by this policy;

(ii) in any bankruptcy proceeding by or against a **Company**, any **Claim** brought by the examiner, trustee, receiver, liquidator or rehabilitator (or any assignee thereof) of such **Company**;

(iii) any **Claim** brought by any past **Executive** of a **Company** who has not served as a duly elected or appointed director, officer, trustee, governor, management committee member, member of the management board, General Counsel or Risk Manager (or equivalent position) of or consultant for a **Company** for at least four (4) years prior to such **Claim** being first made against any person; or

(iv) any **Claim** brought by an **Executive** of a **Company** formed and operating in a **Foreign Jurisdiction** against such **Company** or any **Executive** thereof, provided that such **Claim** is brought and maintained outside the United States, Canada or any other common law country (including any territories thereof);

(j) alleging, arising out of, based upon or attributable to any public offering of securities by a **Company**, an **Outside Entity** or an **Affiliate** or alleging a purchase or sale of such securities subsequent to such public offering; provided, however, this exclusion will not apply to:

(i) any purchase or sale of securities exempted pursuant to Section 3(b) of the Securities Act of 1933. Coverage for such purchase or sale transaction shall not be conditioned upon payment of any additional premium; provided, however, the **Named Entity** shall give the **Insurer** written notice of any public offering exempted pursuant to Section 3(b), or any public offering occurring in Canada together with full particulars and as soon as practicable, but not later than thirty (30) days after the effective date of the public offering;

(ii) any public offering of securities (other than a public offering described in subparagraph 4(j)(i) above), as well as any purchase or sale of such securities subsequent to such public offering, in the event that within thirty (30) days prior to the effective time of such public offering: (1) the **Named Entity** shall give the **Insurer** written notice of such public offering together with full particulars and underwriting information required thereto; and (2) the **Named Entity** accepts such terms, conditions and additional premium required by the **Insurer** for such coverage. Such coverage is also subject to the **Named Entity** paying when due any such additional premium. In the event the **Company** gives written notice with full particulars and underwriting information pursuant to subpart 4(j)(ii)(1) above, then the **Insurer** must offer a quote for coverage under this paragraph; or

(iii) any **Claim** for **Loss** alleging a **Wrongful Act** which occurred during the **Insured's** preparations to commence an initial public offering ("**IPO**") and which occurred at any time prior to 12:01 a.m. on the date the initial public offering commences ("**IPO Effective Time**"), including any **Claim** for **Loss** alleging a **Wrongful Act** which occurred during the road show; provided, however that the coverage otherwise afforded under this subparagraph (iii) shall be deemed to be void *ab initio* effective the **IPO Effective Time**; provided further, however, that coverage shall not be deemed void *ab initio* if (1) the **Claim** is first made and reported pursuant to Clause 7(a) of the **General Terms and Conditions** prior to the **IPO Effective Time**, and (2) a public company D&O policy is not applicable to such **Claim**;

(k) alleging, arising out of, based upon or attributable to the purchase by a **Company** of securities of a "**Publicly Traded Entity**" in a transaction which resulted, or would result, in such entity becoming an **Affiliate** or a **Subsidiary** of a **Company**; provided, however, this exclusion shall not apply in the event that within thirty (30) days prior to it becoming an **Affiliate** or **Subsidiary**, the **Named Entity** gives written notice of the transaction to

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the **Insurer** together with full particulars and underwriting information required and agrees to any additional premium or amendment of the provisions of this **D&O Coverage Section** required by the **Insurer** relating to the transaction. Further, coverage as shall be afforded to the transaction is conditioned upon the **Named Entity** paying when due any additional premium required by the **Insurer** relating to the transaction. An entity is a **Publicly Traded Entity** if any securities of such entity have previously been subject to a public offering;

(l) for bodily injury, sickness, disease or death of any person, or damage to, loss of use of or destruction of any tangible property; provided, however, this exclusion shall not apply to **Securities Claims**;

(m) for emotional distress or mental anguish, or for injury from libel or slander, or defamation or disparagement, or for injury from a violation of a person's right of privacy; provided, however, this exclusion shall not apply to any **Securities Claim**;

(n) for: (i) any actual, alleged or threatened discharge, dispersal, release or escape of **Pollutants**; or (ii) any direction or request to test for, monitor, clean up, remove, contain, treat, detoxify or neutralize **Pollutants**; provided, however, this exclusion shall not apply to:

(1) **Non-Indemnifiable Loss**, other than **Non-Indemnifiable Loss** constituting **Cleanup Costs**; or

(2) **Loss** in connection with a **Securities Claim**, other than **Loss** constituting **Clean-up Costs**;

(o) for violation(s) of any of the responsibilities, obligations or duties imposed by the *Pension Benefits Standards Act,* R.S.C. 1985, c. 32, the Ontario *Pension Benefits Act,* R.S.O., c. P.8 (or any equivalent provincial or territorial legislation), the Ontario *Employment Standards Act,* 2000 S.O. 2000, c. 41 (or any equivalent provincial or territorial legislation), the *Canada Labour Code,* R.S.C. 1985, c. L.2 (or any equivalent provincial or territorial legislation), the *Labour Adjustments Benefits Act,* R.S. 1995, c.L- 1 (or any equivalent provincial or territorial legislation), the *Labor Relations Act* 1995 S.O. 1995, Sched. A (or any equivalent provincial or territorial legislation), the *Occupational Health and Safety Act,* R.S.O. 1990, c. 0.1 (or any equivalent provincial or territorial legislation), the *Employee Retirement Income Security Act of 1974,* the *Fair Labor Standards Act,* the *National Labor Relations Act,* the *Worker Adjustment and Retraining Notification Act,* the *Consolidated Omnibus Budget Reconciliation Act,* the *Occupational Safety and Health Act,* or any violation of any federal, provincial, territorial, state, municipal or foreign statutory law or common law that governs the same topic or subject and any rules, regulations and amendments thereto;

(p) alleging, arising out of, based upon or attributable to the ownership, management, maintenance or control by the **Company** of any captive insurance company or entity, including, but not limited, to any **Claim** alleging the insolvency or bankruptcy of the **Named Entity** as a result of such ownership, operation, management or control;

(q) alleging, arising out of, based upon, or attributable to the employment of any individual or any employment practice, including, but not limited to, wrongful dismissal, discharge or termination, discrimination, harassment, retaliation or other employment-related claim;

(r) alleging, arising out of, based upon, or attributable to a **Third Party Violation**; provided, however, this exclusion shall not apply to a **Securities Claim**;

(s) alleging, arising out of, based upon, or attributable to:

(i) payments, commissions, gratuities, benefits or any other favours to or for the benefit of any full or part-time domestic or foreign governmental or armed services officials, agents, representatives, employees or any members of their family or any entity with which they are affiliated;

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(ii) payments, commissions, gratuities, benefits or any other favours to or for the benefit of any full or part-time officials, directors, agents, partners, representatives, members, principal shareholders, owners or employees, or affiliates (as that term is defined in the Securities Exchange Act of 1934, including any of their officers, directors, agents, owners, partners, representatives, principal shareholders or employees) or any customers of the **Company** or any members of their family or any entity with which they are affiliated; or

(iii) political contributions, whether domestic or foreign; or

(t) with respect to Coverage B(i) only:

(i) for any actual or alleged plagiarism, misappropriation, infringement or violation of copyright, patent, trademark, trade secret or any other intellectual property rights;

(ii) for any actual or alleged violation of any law, whether statutory, regulatory or common law, respecting any of the following activities: anti-trust, business competition, unfair trade practices or tortious interference in another's business or contractual relationships;

(iii) alleging, arising out of, based upon or attributable to any actual or alleged contractual liability of the **Company** or any other **Insured** under any express contract or agreement; provided, however, this exclusion shall not apply to liability which would have attached in the absence of such express contract or agreement; or

(iv) seeking fines or penalties or non-monetary relief against the **Company**; provided, however, that this exclusion shall not apply to any **Securities Claim**.

For the purpose of determining the applicability of the foregoing Exclusions, other than exclusions 4(d), 4(e), 4(h), 4(i) and 4(t): (1) the facts pertaining to and knowledge possessed by any **Insured** shall not be imputed to any other **Individual Insured**; and (2) only facts pertaining to and knowledge possessed by any past, present or future chief executive officer, chief operating officer or chief financial officer (or equivalent positions) of the **Company** shall be imputed to the **Company**.

5. LIMIT OF LIABILITY

The following provisions shall apply in addition to the provisions of Clause 4. of the **General Terms and Conditions:**

CRISISFUND® INSURANCE

The maximum limit of the **Insurer's** liability for all **Crisis Management Loss** arising from all **Crisis Management Events** occurring during the **Policy Period** or the **Discovery Period** (if applicable), in the aggregate, shall be the amount set forth in Item 7(b) of the Declarations as the **Crisis Management Fund**. This **Crisis Management Fund** shall be the maximum limit of the **Insurer** under this **D&O Coverage Section** for **Crisis Management Loss**, regardless of the number of **Crisis Management Events** occurring during the **Policy Period**; provided, however, the **Crisis Management Fund** shall be part of and not in addition to the **Policy Aggregate Limit of Liability** stated in the Item 7(a) of the Declarations and any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **D&O Coverage Section** as set forth in Item 3 of the Declarations.

COSTS OF INVESTIGATION FOR DERIVATIVE DEMAND

The maximum limit of the **Insurer's** liability for **Costs of Investigation** arising from all **Company Shareholder Derivative Investigations** occurring during the **Policy Period** or the **Discovery Period** (if applicable), in the aggregate, shall be the amount set forth in Item 7(d) of the Declarations (the "**Costs of Investigation Sublimit of Liability**"). The **Costs of Investigation Sublimit of Liability** is the maximum limit of the **Insurer** under this **D&O Coverage Section** for **Costs of Investigation** regardless of the number of such **Company Shareholder Derivative Investigations** occurring during the **Policy Period** or the **Discovery**

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Period (if applicable), or the number of **Executives** subject to such **Company Shareholder Derivative Investigations**; provided, however, that the **Costs of Investigation Sublimit of Liability** shall be part of and not in addition to the **Policy Aggregate Limit of Liability** set forth in Item 7(a) of the Declarations and any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **D&O Coverage Section** as set forth in Item 3 of the Declarations.

PUNITIVE DAMAGES SUBLIMIT OF LIABILITY

If Item 7(c) of the Declarations indicates that the **D&O Punitive Damages Sublimit of Liability** was elected, then the **D&O Punitive Damages Sublimit of Liability** is the limit of the **Insurer's** liability for punitive, exemplary and multiple damages under this **D&O Coverage Section**. If Item 7(c) of the Declarations indicates that a **Shared Punitive Damages Sublimit of Liability** was elected, then the **Shared Punitive Damages Sublimit of Liability** is the limit of the **Insurer's** liability under both this **D&O Coverage Section** and the **EPL Coverage Section** combined for punitive, exemplary and multiple damages. If Item 7(c) of the Declarations indicates that no sublimit of liability is applicable to punitive damages, then neither the **D&O Punitive Damages Sublimit of Liability** nor the **Shared Punitive Damages Sublimit of Liability** is applicable to punitive, exemplary and multiple damages under this **D&O Coverage Section**. The **D&O Punitive Damages Sublimit of Liability** and the **Shared Punitive Damages Sublimit of Liability**, if applicable, shall be a part of and not in addition to **Policy Aggregate Limit of Liability** stated in the Item 7(a) of the Declarations and any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **D&O Coverage Section** as set forth in Item 3 of the Declarations.

6. RETENTION CLAUSE

The following provision shall apply in addition to the provisions of Clause 5. RETENTION of the **General Terms and Conditions**:

The **Insurer** shall only be liable for the amount of **Loss** arising from a **Claim** which is in excess of the applicable Retention amount stated in Item 3 of the Declarations for this **D&O Coverage Section**, such Retention amount to be borne by the **Company** and/or the **Insureds** and shall remain uninsured, with regard to: (i) all **Indemnifiable Loss**; and (ii) **Loss** of the **Company**. A single Retention amount shall apply to **Loss** arising from all **Claims** alleging the same **Wrongful Act** or **Related Wrongful Act(s)**.

It is further understood and agreed that in the event the **Company** is unable to pay an applicable Retention amount due to **Financial Insolvency**, then the **Insurer** shall commence advancing **Loss** within the Retention; provided, however, that the **Insurer** shall be entitled to recover the amount of **Loss** advanced within the Retention from the **Company** pursuant to Clause 10. SUBROGATION of the **General Terms and Conditions**.

No Retention amount is applicable to **Crisis Management Loss** or **Non-Indemnifiable Loss**.

7. DEFENCE COSTS, SETTLEMENTS, JUDGMENTS (INCLUDING THE ADVANCEMENT OF DEFENCE COSTS)

The **Insurer** does not assume any duty to defend. The **Insureds** shall defend and contest any **Claim** made against them.

Notwithstanding the foregoing, the **Insureds** shall have the right to tender the defence of the **Claim** to the **Insurer**, which right shall be exercised in writing by the **Named Entity** on behalf of all **Insureds** to the **Insurer** pursuant to the notice provisions of Clause 12 of the **General Terms and Conditions**. This right shall terminate if not exercised within thirty (30) days of the date the **Claim** is first made against an **Insured**. Further, from the date the **Claim** is first made against an **Insured** to the date when the **Insurer** accepts the tender of the defence of such **Claim**, the **Insureds** shall take no action, or fail to take any required action, that prejudices the rights of any **Insured** or the **Insurer** with respect to such **Claim**. Provided that the **Insureds** have complied with the foregoing, the **Insurer** shall be obligated to assume the defence of the **Claim**, even if such **Claim** is groundless, false or fraudulent. The assumption

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of the defence of the **Claim** shall be effective upon written confirmation sent thereof by the **Insurer** to the **Named Entity**. Once the defence has been so tendered, the **Insured** shall have the right to effectively associate with the **Insurer** in the defence and the negotiation of any settlement of any **Claim**, subject to the provisions of this Clause 7; provided, however, the **Insurer** shall not be obligated to defend such **Claim** after the **Policy Aggregate Limit of Liability** or any applicable **Separate Limit of Liability** or **Shared Limit of Liability** have been exhausted.

When the **Insurer** has not assumed the defence of a **Claim** pursuant to this Clause 7, the **Insurer** nevertheless shall advance, at the written request of the **Insured**, **Defence Costs** prior to the final disposition of a **Claim**. Such advanced payments by the **Insurer** shall be repaid to the **Insurer** by each and every **Insured** or the **Company**, severally according to their respective interests, in the event and to the extent that any such **Insured** or the **Company** shall not be entitled under the terms and conditions of this **D&O Coverage Section** to payment of such **Loss**.

The **Insurer** shall have the right to fully and effectively associate with each and every **Insured** in the defence of any **Claim** that appears reasonably likely to involve the **Insurer**, including, but not limited to, negotiating a settlement. Each and every **Insured** agrees to provide such information as the **Insurer** may reasonably require and to give the **Insurer** full cooperation, including:

(a) cooperating with and helping the **Insurer**:

  (i) in making settlements, subject to subparagraph 7(b) below;

  (ii) in enforcing any legal rights the **Insured** may have against anyone who may be liable to the **Insured**;

  (iii) by attending depositions, hearings and trials; and

  (iv) by securing and giving evidence, and obtaining the attendance of witnesses; and

(b) taking such actions which, in such **Insured's** judgment, are deemed necessary and practicable to prevent or limit **Loss** arising from any **Wrongful Act**.

Additionally, the **Insured** shall not admit or assume any liability, enter into any settlement agreement, stipulate to any judgment, or incur any **Defence Costs** without the prior written consent of the **Insurer**. If the **Insured** admits or assumes any liability in connection with any **Claim** without the consent of the **Insurer**, then the **Insurer** shall not have any obligation to pay **Loss** with respect to such **Claim**. Only those settlements, stipulated judgments and **Defence Costs** which have been consented to by the **Insurer** shall be recoverable as **Loss** under the terms of this **D&O Coverage Section**. The **Insurer** shall not unreasonably withhold any consent required under this **D&O Coverage Section**, provided that the **Insurer**, when it has not assumed the defence of a **Claim** pursuant to this Clause 7, shall be entitled to effectively associate in the defence and the negotiation of any settlement of any **Claim**, and provided further that in all events the **Insurer** may withhold consent to any settlement, stipulated judgment or **Defence Costs**, or any portion thereof, to the extent such **Loss** is not covered under the terms of this **D&O Coverage Section**. In addition, the **Insured** shall not take any action, without the **Insurer's** written consent, which prejudices the **Insurer's** rights under this **D&O Coverage Section.**

This Clause 7 shall not be applicable to **Crisis Management Loss**.

8. **COSTS OF INVESTIGATION FOR DERIVATIVE DEMAND COVERAGE PROVISION**

It is understood and agreed that the **Company** shall be entitled to payment under Coverage D of this **D&O Coverage Section** for reimbursement of its covered **Costs of Investigation** ninety (90) days after: (i) the **Company** has made its final decision not to bring a civil proceeding in a court of law against any of its **Executives**, and (ii) such decision has been communicated to the shareholders who made the **Derivative Demand** upon the **Company**.

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However, such payment shall be subject to an undertaking by the **Company**, in a form acceptable to the **Insurer**, that the **Company** shall return to the **Insurer** such payment in the event any **Company** or any shareholder of the **Company** brings a **Claim** alleging, arising out of, based upon or attributable to any **Wrongful Acts** which were the subject of the **Derivative Demand**.

Nothing in this **D&O Coverage Section**, including Coverage D, shall be construed to afford coverage under this **D&O Coverage Section** for any **Claim** brought by the **Company** against one or more of its own **Executives**, other than **Costs of Investigation** incurred in a covered **Company Shareholder Derivative Investigation**. Payment of any **Costs of Investigation** under this **D&O Coverage Section** shall not waive any of the **Insurer's** rights under this policy or at law.

9. PRE-AUTHORIZED DEFENCE ATTORNEYS FOR SECURITIES CLAIMS

This Clause 9 applies only to **Securities Claims**.

Affixed as Appendix A hereto and made a part of this **D&O Coverage Section** is a list of Panel Counsel law firms ("**Panel Counsel Firms**") from which a selection of legal counsel shall be made to conduct the defence of any **Securities Claim** against an **Insured** pursuant to the terms set forth in this Clause.

In the event the **Insurer** has assumed the defence pursuant to Clause 7. of this D&O **Coverage Section**, then the **Insurer** shall select a **Panel Counsel Firm** to defend the **Insureds**. In the event the **Insureds** are already defending a **Securities Claim**, then the **Insureds** shall select a Panel Counsel Firm to defend the **Insureds**.

The selection of the **Panel Counsel Firm**, whether done by the **Insurer** or the **Insureds**, shall be from the list of **Panel Counsel Firms** designated for the type of **Claim** and be from the jurisdiction in which the **Securities Claim** is brought. In the event a **Securities Claim** is brought in a jurisdiction not included on the appropriate list, the selection shall be made from a listed jurisdiction which is the nearest geographic jurisdiction to either where the **Securities Claim** is maintained or where the corporate headquarters or state of formation of the **Named Entity** is located. In such instance, however, the **Insurer** shall, at the written request of the **Named Entity**, assign a non-Panel Counsel Firm of the **Insurer's** choice in the jurisdiction in which the **Securities Claim** is brought to function as "local counsel" on the **Securities Claim** to assist the **Panel Counsel Firm** which will function as "lead counsel" in conducting the defence of the **Securities Claim**.

With the express prior written consent of the **Insurer**, an **Insured** may select (in the case of the **Insured** defending the **Claim**), or cause the **Insurer** to select (in the case of the **Insurer** defending the **Claim**), a **Panel Counsel Firm** different from that selected by other **Insured** defendants if such selection is required due to an actual conflict of interest or is otherwise reasonably justifiable.

The list of **Panel Counsel Firms** may be amended from time to time by the **Insurer**. However, no change shall be made during the **Policy Period** to the **Panel Counsel Firms** listed in Appendix A without the consent of the **Named Entity**.

10. REPRESENTATIONS AND SEVERABILITY

In granting coverage under this **D&O Coverage Section**, it is agreed that the **Insurer** has relied upon the statements and representations contained in the **Application** for this D&O **Coverage Section** as being accurate and complete. All such statements and representations are the basis of this **D&O Coverage Section** and are to be considered as incorporated into this **D&O Coverage Section**.

The **Insureds** agree that in the event that the particulars and statements contained in the **Application** are not accurate and complete and materially affect either the acceptance of the

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risk or the hazard assumed by the **Insurer** under the policy, then this **D&O Coverage Section** shall be void *ab initio* as to any **Insured** who knew as of the inception date of the **Policy Period** of the facts that were not accurately and completely disclosed in the **Application** (whether or not such **Insured** knew that such facts were not accurately and completely disclosed in the **Application**). Solely for purposes of determining whether this **D&O Coverage Section** shall be void *ab initio* as to an **Insured**, such aforesaid knowledge possessed by any **Insured** shall not be imputed to any other **Insured**.

11. ORDER OF PAYMENTS

In the event of **Loss** arising from any **Claim** for which payment is due under the provisions of this **D&O Coverage Section** but which **Loss**, in the aggregate, exceeds the remaining available **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this D&O **Coverage Section**, then the **Insurer** shall:

(a) first pay such **Loss** for which coverage is provided under Coverage A of this D&O **Coverage Section**, then with respect to whatever remaining amount of the applicable **Separate Limit of Liability** or **Shared Limit of Liability** is available after payment of such **Loss**,

(b) then pay such **Loss** for which coverage is provided under Coverage B(ii) of this D&O **Coverage Section**, and

(c) then pay such **Loss** for which coverage is provided under Coverage B(i), C or D of this **D&O Coverage Section**.

In the event of **Loss** arising from a **Claim** for which payment is due under the provisions of this **D&O Coverage Section** (including those circumstances described in the first paragraph of this Clause 11), the **Insurer** shall at the written request of the **Named Entity**:

(a) first pay such **Loss** for which coverage is provided under Coverage A of this D&O **Coverage Section**, then

(b) either pay or hold payment for such **Loss** for which coverage is provided under Coverage B, C or D of this **D&O Coverage Section**.

In the event that the **Insurer** withholds payment under Coverage B, C or D of this D&O **Coverage Section** pursuant to the above request, then the **Insurer**, shall at any time in the future, at the request of the **Named Entity** release such **Loss** payment to the **Company**, or make such **Loss** payment directly to the **Individual Insured** in the event of covered **Loss** under any **Claim** covered under this **D&O Coverage Section** pursuant to Coverage A of this **D&O Coverage Section.**

The **Financial Insolvency** of any **Company** or any **Individual Insured** shall not relieve the **Insurer** of any of its obligations to prioritize payment of covered **Loss** under this D&O **Coverage Section** pursuant to this Clause 11.

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CHARTIS

Canadian Head Office
145 WELLINGTON STREET WEST
TORONTO, ON M5J 1H8

Chartis Insurance Company of Canada
(herein called the Insurer)

PrivateEdge Plus℠

Employment Practices Liability Insurance
("EPL Coverage Section")

Notice: Pursuant to Clause 1 of the General Terms and Conditions, the General Terms and Conditions are incorporated by reference into, made a part of, and are expressly applicable to this EPL Coverage Section, unless otherwise explicitly stated to the contrary in either the General Terms and Conditions or in this EPL Coverage Section.

In consideration of the payment of the premium, and in reliance upon the statements made to the **Insurer** by **Application**, which forms a part of this policy, the **Insurer** agrees as follows:

1. INSURING AGREEMENTS

With respect to the Insuring Agreement and the Defence Provisions of this Clause 1, solely with respect to **Claims** first made during the **Policy Period** or the **Discovery Period** (if applicable) and reported to the **Insurer** pursuant to the terms of this policy, and subject to the other terms, conditions and limitations of this policy, this **EPL Coverage Section** affords the following coverage:

This **EPL Coverage Section** shall pay the **Loss** of an **Insured** arising from a **Claim** first made against such **Insured** for any **Wrongful Act**. The **Insurer** shall, in accordance with and subject to Clause 6 of this **EPL Coverage Section**, advance **Defence Costs** of such **Claim** prior to its final disposition.

DEFENCE PROVISIONS

The **Insurer** does not assume any duty to defend; provided, however, the **Named Entity** may at its sole option tender to the **Insurer** the defence of a **Claim** for which coverage is provided by this **EPL Coverage Section** in accordance with Clause 6 of this **EPL Coverage Section**. Regardless of whether the defence is so tendered, the **Insurer** shall advance **Defence Costs** of such **Claim**, excess of the applicable Retention amount, prior to its final disposition. Selection of counsel to defend a **Designated Employment Practices Claim** shall be made in accordance with Clause 7 of this EPL Coverage Section.

2. DEFINITIONS

(a) "**Claim**" means:

(i) a written demand for monetary or non-monetary relief (including any request to toll or waive any statute of limitations);

(ii) a civil, criminal, administrative, regulatory or arbitration proceeding for monetary or non-monetary relief which is commenced by:

(1) issuance of a notice of action, statement of claim, writ of summons, complaint or similar pleading;

(2) return of an indictment, laying of an information, the filing of a notice of charges or the issuance or filing of a similar legal document (in the case of a criminal proceeding); or

(3) receipt or filing of a notice of charges; or

(iii) an administrative or regulatory investigation when conducted by the Equal

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Employment Opportunity Commission ("**EEOC**"), or similar federal, state, provincial, territorial, local or foreign agency, which is commenced by the filing of a notice of charges, service of a complaint or similar document of which notice has been given to the **Insured**.

However, in no event shall the term "**Claim**" include any labour or grievance proceeding which is subject to a collective bargaining agreement.

(b) "**Defence Costs**" means the reasonable and necessary fees, costs and expenses consented to by the **Insurer** (including premiums for any appeal bond, attachment bond or similar bond arising out of a covered judgment, but without any obligation to apply for or furnish any such bond) resulting solely from the investigation, adjustment, defence and appeal of a **Claim** against the **Insureds**, but excluding compensation of any **Individual Insured**. **Defence Costs** shall not include any fees, costs or expenses incurred prior to the time that a **Claim** is first made against an **Insured**.

(c) "**Designated Employment Practices Claim**" means a Claim: (i) alleging discrimination or **Retaliation**; or (ii) that is certified as, or which is seeking certification as, a class action.

(d) "**EPL Punitive Damages Sublimit of Liability**" means the **EPL Punitive Damages Sublimit of Liability**, if any, stated in Item 7(c) of the Declarations.

(e) "**Employee**" means any past, present or future employee, whether such employee is in a supervisory, co-worker or subordinate position or otherwise, including any part-time, volunteer, seasonal and temporary employee in his or her capacity as such. An individual who is leased to the **Company** shall also be an **Employee**, but only if the **Company** provides indemnification to such leased individual in the same manner as is provided to the **Company's** employees. Any other individual who is contracted to perform work for the **Company**, or who is an independent contractor for the **Company**, shall also be an **Employee**, but only if the **Company** provides indemnification to such individual in the same manner as that provided to the **Company's** employees, pursuant to a written contract.

(f) "**Employment Contract**" means any contract relating in any way to, or governing, in whole or in part, any term or aspect of the employment of an **Employee** by the **Organization**, whether oral or written, express or implied.

(g) "**Employment Practices Violation**" means any actual or alleged:

(i) wrongful dismissal, discharge or termination (either actual or constructive) of employment, including breach of an implied contract;

(ii) harassment (including sexual harassment whether "quid pro quo", hostile work environment or otherwise);

(iii) discrimination (including, but not limited to, discrimination based upon age, gender, race, color, national origin, religion, sexual orientation or preference, pregnancy, or disability);

(iv) **Retaliation**;

(v) employment-related misrepresentation(s) to an **Employee** of the **Company** or applicant for employment with the **Company** or an **Outside Entity**;

(vi) employment-related libel, slander, humiliation, defamation or invasion of privacy;

(vii) wrongful failure to employ or promote;

(viii) wrongful deprivation of career opportunity with the **Company**, wrongful demotion or negligent **Employee** evaluation, including the giving of negative or defamatory statements in connection with an employee reference;

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(ix) wrongful discipline;

(x) failure to grant tenure; or

(xi) with respect to any of the foregoing items (i) through (x) of this definition: negligent hiring, retention, training or supervision, infliction of emotional distress or mental anguish, failure to provide or enforce adequate or consistent corporate policies and procedures, or violation of an individual's civil rights;

but only if the **Employment Practices Violation** relates to an **Employee** of a **Company** or an **Outside Entity**, or applicants for employment with a **Company** or an **Outside Entity**, whether committed directly, indirectly, intentionally or unintentionally.

(h) "**Executive**" means:

(i) any past, present or future duly elected or appointed director, officer, management committee member or member of the Board of Managers;

(ii) any past, present or future person in a duly elected or appointed position in an entity which is organized and operated in a **Foreign Jurisdiction** that is equivalent to an executive position listed in Definition (g)(i); or

(iii) any past, present or future General Counsel and Risk Manager (or equivalent position) of the **Named Entity**.

(i) "**Financial Insolvency**" means the: (i) appointment by any government official, agency, commission, court or other governmental authority of a receiver, conservator, liquidator, trustee, rehabilitator or similar official to take control of, supervise, manage or liquidate an insolvent **Company**; (ii) the filing of a petition under the bankruptcy laws of Canada; or (iii), as to both (i) or (ii), any equivalent events outside Canada.

(j) "**Foreign Jurisdiction**" means any jurisdiction, other than Canada or any of its territories or possessions.

(k) "**Indemnifiable Loss**" means **Loss** for which a **Company** has indemnified or is permitted or required to indemnify an **Individual Insured** pursuant to law, contract or the charter, bylaws, operating agreement or similar documents of a **Company**.

(l) "**Individual Insured**" means any:

(i) **Executive** of a **Company**;

(ii) **Employee** of a **Company**; or

(iii) **Outside Entity Executive**.

(m) "**Insured**" means:

(i) an **Individual Insureds**; or

(ii) a **Company**.

(n) "**Loss**" means damages (including back pay and front pay), judgments, settlements, pre- and post-judgment interest and **Defence Costs**; provided, however, **Loss** shall not include: (i) civil or criminal fines or penalties imposed by law; (ii) taxes; (iii) any amounts for which an **Insured** is not financially liable or which are without legal recourse to an **Insured**; (iv) employment-related benefits, stock options, perquisites, deferred compensation or any other type of compensation other than salary, wages or bonus compensation; (v) any liability or costs incurred by any **Insured** to modify any building or property in order to make said building or property more accessible or accommodating to any disabled person, or any liability or costs incurred in connection with any educational, sensitivity or other corporate program, policy or seminar; (vi) matters which may be

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deemed uninsurable under the law pursuant to which this policy shall be construed. **Defence Costs** shall be provided for items specifically excluded from **Loss** pursuant to subparagraphs (m)(i) through (m)(vi) above of this Definition, subject to the other terms, conditions and exclusions of this policy.

Loss shall specifically include, subject to the other terms, conditions and exclusions of this **EPL Coverage Section**, including, but not limited to, Exclusion 3(a) of this **EPL Coverage Section**, punitive, exemplary and multiple damages (including the multiple or liquidated damages awards under the Age Discrimination in Employment Act and the Equal Pay Act). As more fully set forth in Clause 4. "PUNITIVE DAMAGES SUBLIMIT OF LIABILITY" of this **EPL Coverage Section**, coverage under this **EPL Coverage Section** for punitive, exemplary and multiple damages is subject to any applicable **EPL Punitive Damages Sublimit of Liability** or **Shared Punitive Damages Sublimit of Liability**. The enforceability of the first sentence of this paragraph shall be governed by such applicable law which most favours coverage for punitive, exemplary and multiple damages.

(o) "**Outside Entity**" means:

(i) any not-for-profit organization; or

(ii) any other corporation, partnership, joint venture or other organization listed by endorsement to this policy or **EPL Coverage Section**.

(p) "**Outside Entity Executive**" means any **Executive** of the **Company** serving in the capacity as director, officer, trustee or governor of an **Outside Entity**, but only if such service is at the specific request or direction of the **Company**. It is understood and agreed that, in the event of a disagreement between the **Company** and an individual as to whether such individual was acting "at the specific request or direction of the **Company**," this **EPL Coverage Section** shall abide by the determination of the **Company** on this issue and such determination shall be made by written notice to the **Insurer** within ninety (90) days after the **Claim** is first reported to the **Insurer** pursuant to the terms of the policy. In the event no determination is made within such period, this **EPL Coverage Section** shall apply as if the **Company** determined that such **Individual Insured** was not acting at the **Company's** specific request or direction.

(q) "**Retaliation**" means a retaliatory act of an **Insured** alleged to be in response to any of the following activities: (1) the disclosure or threat of disclosure by an **Employee** of the **Company** or an **Outside Entity** to a superior or to any governmental agency of any act by an **Insured** which is alleged to be a violation of any federal, provincial, territorial, local or foreign law, common or statutory, or any rule or regulation promulgated thereunder; (2) the actual or attempted exercise by an **Employee** of the **Company** or an **Outside Entity** of any right that such **Employee** has under law, including rights under worker's compensation laws, the Canada Labour Code, R.S.C. 1985, c. L-2, the Canadian Human Rights Act, R.S.C. 1985, c. H-6, the Employment Equity Act, R.S.C. 1985, c. 23 (2nd supp.), the Family and Medical Leave Act, the Americans with Disabilities Act or any law relating to employee rights; or (4) strikes of an **Employee** of the **Company** or an **Outside Entity**.

(r) "**Settlement Opportunity**" means an **Insurer** recommended settlement that is within the **Policy Aggregate Limit of Liability**, **Separate Limit of Liability** or **Shared Limit of Liability**, if any, and that is acceptable to the claimant.

(s) "**Shared Punitive Damages Sublimit of Liability**" means the **Shared Punitive Damages Sublimit of Liability**, if any, stated in Item 7(c) of the Declarations.

(t) "**Third Party Violation**" means any actual or alleged harassment or unlawful discrimination, as described in subparagraphs 2(f)(ii) and 2(f)(iii) of the definition of **Employment Practices Violation**, or the violation of the civil rights of a person relating to such harassment or discrimination, when such acts are alleged to be committed against

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anyone other than an **Individual Insured** or applicant for employment with the **Company** or an **Outside Entity**, including, but not limited to, students, patients, members, customers, vendors and suppliers.

(u) **"Wrongful Act"** means any actual or alleged (i) **Employment Practices Violation**, or (ii) **Third Party Violation**.

3. EXCLUSIONS

The **Insurer** shall not be liable to make any payment for **Loss** in connection with any **Claim** made against an **Insured**:

(a) arising out of, based upon or attributable to the committing of any deliberate criminal or deliberate fraudulent act by the **Insured** if any final adjudication establishes that such deliberate criminal or deliberate fraudulent act was committed;

(b) alleging, arising out of, based upon or attributable to the facts alleged, or to the same or **Related Wrongful Acts** alleged or contained in any claim which has been reported, or in any circumstances of which notice has been given, under any policy of which this **EPL Coverage Section** is a renewal or replacement of in whole or in part or which it may succeed in time;

(c) alleging, arising out of, based upon or attributable to, as of the **Continuity Date**, any pending or prior: (i) litigation; or (ii) **EEOC** (or similar state, provincial, territorial, local or foreign agency) proceeding or investigation of which an **Insured** had notice, or alleging any **Wrongful Act** which is the same or **Related Wrongful Act** to that alleged in such pending or prior litigation or EEOC (or similar state, provincial, territorial, local or foreign agency) proceeding or investigation;

(d) with respect to an **Outside Entity Executive**, for any **Wrongful Act** occurring prior to the **Continuity Date** if the **Insured**, as of such **Continuity Date**, knew or could have reasonably foreseen that such **Wrongful Act** could lead to a **Claim** under this **EPL Coverage Section**;

(e) alleging, arising out of, based upon or attributable to any actual or alleged act or omission of an **Individual Insured** serving in any capacity, other than as an **Executive** or **Employee** of a **Company**, or as an **Outside Entity Executive** of an **Outside Entity**;

(f) for bodily injury (other than emotional distress or mental anguish), sickness, disease, or death of any person, or damage to, loss of use of or destruction of any tangible property;

(g) for violation(s) of any of the responsibilities, obligations or duties imposed by the *Pension Benefits Standards Act,* R.S.C. 1985, c. 32, the Ontario *Pension Benefits Act,* R.S.O., c. P.8 (or any equivalent provincial or territorial legislation), the Ontario *Employment Standards Act,* 2000 S.O. 2000, c. 41 (or any equivalent provincial or territorial legislation), the *Canada Labour Code,* R.S.C. 1985, c. L.2 (or any equivalent provincial or territorial legislation), the *Labour Adjustments Benefits Act,* R.S. 1995, c.L-1 (or any equivalent provincial or territorial legislation), the *Labor Relations Act* 1995 S.O. 1995, Sched. A (or any equivalent provincial or territorial legislation), the *Occupational Health and Safety Act,* R.S.O. 1990, c. 0.1 (or any equivalent provincial or territorial legislation), the *Employee Retirement Income Security Act of 1974,* the *Fair Labor Standards Act,* the *National Labor Relations Act,* the *Worker Adjustment and Retraining Notification Act,* the *Consolidated Omnibus Budget Reconciliation Act,* the *Occupational Safety and Health Act,* or any rules or regulations of the foregoing promulgated thereunder, and amendments thereto or any similar federal, provincial, territorial, state, municipal or foreign statutory law or common law; provided, however, this exclusion shall not apply to the extent that a **Claim** is for **Retaliation**;

(h) alleging, arising out of, based upon, attributable to or in any way relating to:

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(i) the refusal, failure or inability of any **Insured** to pay wages or overtime pay (or amounts representing such wages or overtime pay) for services rendered (as opposed to tort-based back pay or front pay damages for torts other than conversion);

(ii) improper payroll deductions taken by any **Insured** from any **Employee** or purported **Employee**; or

(iii) failure to provide or enforce legally required meal or rest break periods;

provided, however, this exclusion shall not apply to the extent that a **Claim** is for **Retaliation**;

(i) alleging, arising out of, based upon or attributable to any obligation pursuant to any worker's compensation, disability benefits, unemployment compensation, unemployment insurance, retirement benefits, social security benefits or similar law; provided, however, this exclusion shall not apply to the extent that a **Claim** is for **Retaliation**;

(j) alleging, arising out of, based upon or attributable to any actual or alleged (1) contractual liability of any **Insured**, including liability for breach by any **Insured** of the terms of any **Employment Contract**; or (2) liability of any **Insured** for any amount representing salary, wages, bonus or any other amount of any nature or description, owed or allegedly owed to an **Employee** as a result of the **Organization's** failure or alleged failure to afford:

(i) notice of termination pursuant to the terms of any **Employment Contract**;

(ii) notice of termination of employment as required by any federal, provincial or territorial statute or regulation; and/or

(iii) reasonable notice of termination of employment at common law on any basis whatsoever;

provided, however, this exclusion shall not apply to that portion of **Loss** constituting **Defence Costs** in respect to any such **Claim**.

(k) alleging, arising out of, based upon or attributable to any **Claim** brought by a securities holder of a **Company**, an **Outside Entity** or an affiliate of the **Named Entity** in their capacity as such in the form of a shareholder class, direct or derivative action on behalf of such **Company**, **Outside Entity** or affiliate.

For the purpose of determining the applicability of the foregoing Exclusions, other than exclusions 3(b), 3(c), and 3(d): (i) the facts pertaining to and knowledge possessed by any **Insured** shall not be imputed to any other **Individual Insured**; and (ii) only facts pertaining to and knowledge possessed by any past, present or future chief executive officer, chief operating officer or chief financial officer (or equivalent positions) of the **Company** shall be imputed to the **Company**.

4. **PUNITIVE DAMAGES SUBLIMIT OF LIABILITY**

The following provisions shall apply in addition to the provisions of Clause 4. of the **General Terms and Conditions**:

If Item 7(c) of the Declarations indicates that the **EPL Punitive Damages Sublimit of Liability** was elected, then the **EPL Punitive Damages Sublimit of Liability** is the limit of the **Insurer's** liability for punitive, exemplary and multiple damages under this **EPL Coverage Section**. If Item 7(c) of the Declarations indicates that a **Shared Punitive Damages Sublimit of Liability** was elected, then the **Shared Punitive Damages Sublimit of Liability** is the limit of the **Insurer's** liability under both this **EPL Coverage Section** and the **D&O Coverage Section** combined for punitive, exemplary and multiple damages. If Item 7(c) of the Declarations indicates that no sublimit of liability is applicable to punitive damages, then neither the **EPL Punitive Damages Sublimit of Liability** nor the **Shared Punitive Damages Sublimit of Liability** is applicable to punitive, exemplary and multiple damages under this EPL

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Coverage Section. The **EPL Punitive Damages Sublimit of Liability** and the **Shared Punitive Damages Sublimit of Liability**, if applicable, shall be a part of and not in addition to **Policy Aggregate Limit of Liability** stated in the Item 7(a) of the Declarations and any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **EPL Coverage Section** as set forth in Item 3 of the Declarations.

5. **RETENTION CLAUSE**

The following provision shall apply in addition to the provisions of Clause 5. RETENTION of the **General Terms and Conditions**:

The **Insurer** shall only be liable for the amount of **Loss** arising from a **Claim** which is in excess of the applicable Retention amount stated in Item 3 of the Declarations for this **EPL Coverage Section**, such Retention amount to be borne by the **Company** or the **Insureds** and shall remain uninsured, with regard to all: (1) **Indemnifiable Loss**; or (2) **Loss** of the **Company**. A single **Retention amount shall apply to Loss** arising from all **Claims** alleging the same **Wrongful Act** or **Related Wrongful Acts**.

It is further understood and agreed that in the event the **Company** is unable to pay an applicable Retention amount due to **Financial Insolvency**, then the **Insurer** shall commence advancing **Defence Costs** and pay any other covered **Loss** within the Retention; provided, however, that the **Insurer** shall be entitled to recover the amount of **Defence Costs** and any other **Loss** advanced within the Retention from the **Company** pursuant to Clause 10. SUBROGATION of the **General Terms and Conditions**.

6. **DEFENCE COSTS, SETTLEMENTS, JUDGMENTS (INCLUDING THE ADVANCEMENT OF DEFENCE COSTS)**

The **Insurer** does not assume any duty to defend. The **Insureds** shall defend and contest any **Claim** made against them.

Notwithstanding the foregoing, the **Insureds** shall have the right to tender the defence of the **Claim** to the **Insurer**, which right shall be exercised in writing by the **Named Entity** on behalf of all **Insureds** to the **Insurer** pursuant to the notice provisions of Clause 12 of the **General Terms and Conditions**. This right shall terminate if not exercised within thirty (30) days of the date the **Claim** is first made against an **Insured**. Further, from the date the **Claim** is first made against the **Insureds** to the date when the **Insurer** accepts the tender of the defence of such **Claim**, the **Insureds** shall take no action, or fail to take any required action, that prejudices the rights of the **Insureds** or the **Insurer** with respect to such **Claim**. Provided that the **Insureds** have complied with the foregoing, the **Insurer** shall be obligated to assume the defence of the **Claim**, even if such **Claim** is groundless, false or fraudulent. The assumption of the defence of the **Claim** shall be effective upon written confirmation sent thereof by the **Insurer** to the **Named Entity**. Once the defence has been so tendered, the **Insured** shall have the right to effectively associate with the **Insurer** in the defence and the negotiation of any settlement of any **Claim**, subject to the provisions of this Clause 6; provided, however, the **Insurer** shall not be obligated to defend such **Claim** after the **Policy Aggregate Limit of Liability, Separate Limit of Liability** or **Shared Limit of Liability**, if any, has been exhausted, or after an **Insured's** rejection of (or failure or refusal to accept within the time prescribed in this Clause 6, below) a **Settlement Opportunity**.

When the **Insurer** has not assumed the defence of a **Claim** pursuant to this Clause 6, the **Insurer** nevertheless shall advance, at the written request of the **Insured, Defence Costs** prior to the final disposition of a **Claim**. Such advanced payments by the **Insurer** shall be repaid to the **Insurer** by the **Insureds** or the **Company**, severally according to their respective interests, in the event and to the extent that the **Insureds** or the **Company** shall not be entitled under the terms and conditions of this **EPL Coverage Section** to payment of such **Loss**.

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The **Insureds** shall not admit or assume any liability, enter into any settlement agreement, stipulate to any judgment, or incur any **Defence Costs** without the prior written consent of the **Insurer**. Only those settlements, stipulated judgments and **Defence Costs** which have been consented to by the **Insurer**, in writing, shall be recoverable as **Loss** under the terms of this **EPL Coverage Section**. The **Insurer's** consent shall not be unreasonably withheld, provided that the **Insurer**, when it has not assumed the defence of a **Claim** pursuant to this Clause 6, shall be entitled to fully and effectively associate in the defence and negotiation of any settlement of any **Claim**, and provided further that in all events the **Insurer** may withhold consent to any settlement, stipulated judgment or **Defence Costs**, or any portion thereof, to the extent such **Loss** is not covered under the terms of this EPL Coverage Section.

The **Insurer** shall have the right to effectively associate with the **Company** in the defence of any **Claim** that appears reasonably likely to involve the **Insurer**, including, but not limited to, negotiating a settlement. The **Company** and the **Insureds** shall give the **Insurer** full cooperation and such information as the **Insurer** may reasonably require.

In the event the **Insureds** do not consent to the first **Settlement Opportunity** within thirty (30) days of the date the **Insureds** are first made aware of the **Settlement Opportunity** (or in the case of a **Settlement Opportunity** which arises from a settlement offer by the claimant, then within the time permitted by the claimant to accept such settlement offer, but in all events no later than thirty (30) days after the settlement offer was made), then, subject to the **Policy Aggregate Limit of Liability** and **Separate Limit of Liability** or **Shared Limit of Liability**, if any, the **Insurer's** liability for all **Loss** on account of such **Claim** shall not exceed: (1) the amount for which the **Insurer** could have settled such **Claim** plus **Defence Costs** incurred as of the date such settlement was proposed in writing by the **Insurer** ("**Settlement Opportunity Amount**"), plus (2) eighty percent (80%) of covered **Loss** in excess of such **Settlement Opportunity Amount**, it being a condition of this insurance that the remaining twenty percent (20%) of such **Loss** excess of the **Settlement Opportunity Amount** shall be carried by the **Company** and the **Insureds** at their own risk and be uninsured. Notwithstanding the foregoing, this paragraph shall not apply until the **Settlement Opportunity Amount** exceeds the applicable Retention amount stated in Item 3 of the Declarations.

7. PRE-AUTHORIZED DEFENCE ATTORNEYS FOR DESIGNATED EMPLOYMENT PRACTICES CLAIMS

This Clause applies only to **Designated Employment Practices Claims**.

Affixed as Appendix B hereto and made a part of this **EPL Coverage Section** is a list of Panel Counsel law firms ("**Panel Counsel Firms**") from which a selection of legal counsel shall be made to conduct the defence of any **Designated Employment Practices Claim** against an **Insured** pursuant to the terms set forth in this Clause.

In the event the **Insurer** has assumed the defence pursuant to Clause 6 of this **EPL Coverage Section**, then the **Insurer** shall select a **Panel Counsel Firm** to defend the **Insureds**. In the event the **Insureds** are already defending a **Designated Employment Practices Claim**, then the **Insureds** shall select a **Panel Counsel Firm** to defend the **Insureds**.

The selection of the **Panel Counsel Firm**, whether done by the **Insurer** or the **Insureds**, shall be from the list of **Panel Counsel Firms** designated for the type of **Claim** and be from the jurisdiction in which the **Designated Employment Practices Claim** is brought. In the event a **Designated Employment Practices Claim** is brought in a jurisdiction not included on the appropriate list, the selection shall be made from a listed jurisdiction which is the nearest geographic jurisdiction to either where the **Designated Employment Practices Claim** is maintained or where the corporate headquarters or state of formation of the **Named Entity** is located. In such instance, however, the **Insurer** shall, at the written request of the **Named Entity**, assign a non-**Panel Counsel Firm** of the **Insurer's** choice in the jurisdiction in which

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the **Designated Employment Practices Claim** is brought to function as "local counsel" on the **Designated Employment Practices Claim** to assist the **Panel Counsel Firm** which will function as "lead counsel" in conducting the defence of the **Designated Employment Practices Claim.**

With the express prior written consent of the **Insurer**, an **Insured** may select (in the case of the **Insured** defending the **Claim**), or cause the **Insurer** to select (in the case of the **Insurer** defending the **Claim**), a **Panel Counsel Firm** different from that selected by other **Insured** defendants if such selection is required due to an actual conflict of interest or is otherwise reasonably justifiable.

The list of **Panel Counsel Firms** may be amended from time to time by the **Insurer**. However, no change shall be made during the **Policy Period** to the **Panel Counsel Firms** listed in Appendix A without the consent of the **Named Entity.**

8. REPRESENTATIONS AND SEVERABILITY

In granting coverage under this policy, it is agreed that the **Insurer** has relied upon the statements and representations contained in the **Application** for this **EPL Coverage Section** as being accurate and complete. All such statements and representations are the basis of this **EPL Coverage Section** and are to be considered as incorporated into this **EPL Coverage Section.**

The **Insureds** agree that in the event that the particulars and statements contained in the **Application** are not accurate and complete and materially affect either the acceptance of the risk or the hazard assumed by the **Insurer** under the policy, then this **EPL Coverage Section** shall be void *ab initio* as to any **Insured** who knew as of the inception date of the **Policy Period** of the facts that were not accurately and completely disclosed in the **Application** (whether or not such **Insured** knew that such facts were not accurately and completely disclosed in the **Application**). Solely for purposes of determining whether this **EPL Coverage Section** shall be void *ab initio* as to an **Insured**, such aforesaid knowledge possessed by any **Insured** shall not be imputed to any other **Insured**.

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CHARTIS

Canadian Head Office
145 WELLINGTON STREET WEST
TORONTO, ON M5J 1H8

Chartis Insurance Company of Canada
(herein called the **Insurer**)

PrivateEdge Plus℠

Fiduciary Liability Insurance
("FLI Coverage Section")

Notice: **Pursuant to Clause 1 of the General Terms and Conditions, the General Terms and Conditions are incorporated by reference into, made a part of, and are expressly applicable to this FLI Coverage Section, unless otherwise explicitly stated to the contrary in either the General Terms and Conditions or in this FLI Coverage Section.**

In consideration of the payment of the premium, and in reliance upon the statements made to the **Insurer** by **Application**, which forms a part of this policy, the **Insurer** agrees as follows:

1. INSURING AGREEMENTS

Subject to the other terms, conditions and limitations of this policy, this **FLI Coverage Section** affords the following coverage:

(a) Solely with respect to **Claims** first made against an **Insured** during the **Policy Period** or the **Discovery Period** (if applicable) and reported to the **Insurer** pursuant to the terms of this policy, this **FLI Coverage Section** shall pay the **Loss** of an **Insured** arising from a **Claim** against an **Insured** for any actual or alleged **Wrongful Act** by any such **Insured** (or by any employee for whom such **Insured** is legally responsible).

(b) Solely with respect to **CAP Penalties** and **Delinquent Filer Penalties** assessed against an **Insured**, and **Voluntary Fiduciary Correction Loss** incurred by an **Insured**, during the **Policy Period** or the **Discovery Period** (if applicable) and reported to the **Insurer** pursuant to the terms of this policy, this **FLI Coverage Section** shall:

(i) pay the **CAP Penalties** and **Delinquent Filer Penalties**; and

(ii) reimburse the **Voluntary Fiduciary Correction Loss**,

of an **Insured**, subject to the **Voluntary Compliance Loss Sublimit of Liability** set forth and defined under Clause 6. "LIMIT OF LIABILITY" of this **FLI Coverage Section**; provided that the **Insured** shall select a Panel Counsel Firm as provided in Clause 8 of this **FLI Coverage Section**.

The payment of any **Voluntary Compliance Loss** under this **FLI Coverage Section** shall not waive any of the **Insurer's** rights under this policy or at law, including in the event that a **Voluntary Compliance Loss** results in a **Claim**.

2. DEFENSE AGREEMENT

(a) **INSURER'S DUTY TO DEFEND**

Except as hereinafter stated, the **Insurer** shall have both the right and duty to defend any **Claim** against an **Insured** alleging a **Wrongful Act**, even if such **Claim** is groundless, false or fraudulent.

The **Insured** shall have the right to effectively associate with the **Insurer** in the defense of any **Claim**, including, but not limited to, negotiating a settlement, subject to the provisions of this Clause 2. The **Insurer** shall not, however, be obligated to defend any **Claim** after the **Policy Aggregate Limit of Liability** or any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this FLI Coverage Section has been exhausted.

(b) **INSURED'S OPTION TO ASSUME DEFENSE**

Notwithstanding the above, the **Insureds** shall have the right to assume the defense of any **Claim** made against them. This right shall be exercised in writing by the **Named**

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Entity on the behalf of all **Insureds** within sixty (60) days of the reporting of the **Claim** to the **Insurer** pursuant to Clause 6. of the **General Terms and Conditions**. Upon receipt of such written request, the **Insurer** shall tender the defense of the **Claim** to the **Insureds**. Once the defense has been so tendered, the **Insurer** cannot re-assume the defense of the **Claim**. The **Insurer** shall have the right to effectively associate with the **Insureds** in the defense of any **Claim**, including, but not limited to, negotiating a settlement. Provided that the **Insurer** shall be permitted to effectively associate with the **Insureds** in the defense of any **Claim**, including, but not limited, to negotiating a settlement of any **Claim**, the **Insurer**'s consent to settlements, stipulated judgments and **Defense Costs** shall not be unreasonably withheld.

(c) **GENERAL PROVISIONS** (applicable to both 2(a) and 2(b) above)

The **Insurer** shall advance **Defense Costs** prior to the final disposition of a **Claim**, subject to the other provisions of this **FLI Coverage Section**. Such advance payments by the **Insurer** shall be repaid to the **Insurer** by the **Insureds**, severally according to their respective interests, in the event and to the extent that the **Insureds** shall not be entitled to payment of such **Loss** under the terms and conditions of this **FLI Coverage Section**.

The **Insureds** shall not admit or assume any liability, enter into any settlement agreement, stipulate to any judgment, or incur any **Defense Costs** without the prior written consent of the **Insurer**. Only those settlements, stipulated judgments and **Defense Costs** which have been consented to in writing by the **Insurer** shall be recoverable as **Loss** under the terms of this **FLI Coverage Section**.

The **Insureds** shall give the **Insurer** full cooperation and such information as the Insurer may reasonably require.

Selection of counsel to defend the **Claim** made against the **Insureds** shall be governed by Clause 8 of this **FLI Coverage Section** (if applicable).

3. DEFINITIONS

(a) "**Application**" means each and every signed application, any attachments to such applications, other materials submitted therewith or incorporated therein, any other documents submitted in connection with the underwriting of this **FLI Coverage Section** or the underwriting of any other fiduciary liability policy (or equivalent policy) issued by the **Insurer**, or any of its affiliates, of which this **FLI Coverage Section** is a renewal or replacement of in whole or part or which it succeeds in time, any public documents filed by the **Named Entity** with any federal, state, local or foreign regulatory agency, and financial statements for all **Plans**, with investment portfolios.

The Definition of **Application** set forth in the **General Terms and Conditions** shall not apply to this **FLI Coverage Section**, which is subject to the above Definition only.

(b) "**Benefits**" means any obligation under a **Plan** to a participant or beneficiary under a **Plan** which is a payment of money or property, or the grant of a privilege, right, option or perquisite.

(c) "**Breach of Fiduciary Duty**" means a violation of the responsibilities, obligations or duties imposed upon **Insureds** by **ERISA**.

(d) "**Cafeteria Plan**" means a plan as defined in Section 125 of the Internal Revenue Code of 1986, as amended or a plan from which the participants may choose among two or more benefits consisting of cash and qualified benefits.

(e) "**CAP Penalties**" means fines, penalties, sanctions, voluntary correction fees, compliance fees or user fees assessed against or collected from an **Insured** by the Internal Revenue Service ("**IRS**") pursuant to a written agreement to correct an inadvertent **Plan** defect under an Employee Plans Compliance Resolution System, provided that such agreement to correct such **Plan** defect was entered into in writing by the **Insured** with the **IRS** during

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the **Policy Period** (or during the policy period of a policy issued by the **Insurer** of which this **FLI Coverage Section** is a continuous renewal).

(f) "**Claim**" means:

(i) a written demand for monetary, non-monetary or injunctive relief;

(ii) a civil, criminal or arbitration proceeding for monetary, non-monetary or injunctive relief which is commenced by:

(1) service of a complaint or similar pleading;

(2) return of an indictment, information or similar document (in the case of a criminal proceeding); or

(3) receipt or filing of a notice of charges;

(iii) a formal agency or regulatory adjudicative proceeding to which an **Insured** is subject; or

(iv) a fact-finding investigation by the U.S. Department of Labor, the Pension Benefit Guaranty Corporation or similar governmental agency which is located outside of the United States.

(g) "**Cleanup Costs**" means expenses, including, but not limited to, legal and professional fees incurred in testing for, monitoring, cleaning up, removing, containing, treating, neutralizing, detoxifying or assessing the effects of **Pollutants**.

(h) "**Consulting Fees**" means fees charged by a third party actuary, benefits consultant or accountant resulting solely from the correction of an actual or potential **Breach of Fiduciary Duty**, but excluding any fees, costs or expenses associated with: (i) a Plan audit; or (ii) identifying, finding or assessing such **Breach of Fiduciary Duty**.

(i) "**Defense Costs**" means reasonable and necessary fees, costs and expenses consented to by the **Insurer** (including premiums for any appeal bond, attachment bond or similar bond, but without any obligation to apply for or furnish any such bond) resulting solely from the investigation, adjustment, defense and appeal of a **Claim** against the **Insureds**, but excluding compensation of **Individual Insureds**. **Defense Costs** shall not include any fees, costs or expenses incurred prior to the time that a **Claim** is first made against an **Insured**.

(j) "**Defense Expenses**" means reasonable and necessary attorney's fees, costs or expenses consented to in writing by the **Insurer** resulting solely from the correction of an actual or potential **Breach of Fiduciary Duty**, but excluding any fees, costs and expenses associated with finding or assessing such **Breach of Fiduciary Duty** and any compensation of **Individual Insureds** or employees of an **Insured**.

(k) "**Delinquent Filer Penalties**" means penalties assessed by the U.S. Department of Labor ("**DOL**") or the **IRS** under a Delinquent Filer Voluntary Compliance Program for inadvertent failure to file Form 5500, provided that the failure to file such Form 5500 occurred during the **Policy Period** (or during the policy period of a policy issued by the **Insurer** of which this **FLI Coverage Section** is a continuous renewal).

(l) "**Dependent Care Assistance Program**" means a dependent care assistance program as defined in Section 129 of the Internal Revenue Code of 1986, as amended.

(m) "**Employee Benefit Law**" means **ERISA** or any similar common or statutory law of the United States of America, Canada or any state or other jurisdiction anywhere in the world to which a **Plan** is subject. Solely with respect to subparagraph 3(kk)(2) of the Definition of **Wrongful Act** in this **FLI Coverage Section**, **Employee Benefit Law** shall also include **HIPAA Privacy Regulations** and any laws concerning unemployment insurance, Social Security, government-mandated disability benefits or similar law. Except as provided in

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the previous sentence, **Employee Benefit Law** shall not include any law concerning workers' compensation, unemployment insurance, Social Security, government-mandated disability benefits or similar law.

(n) "**ERISA**" means the Employee Retirement Income Security Act of 1974 (including, but not limited to, amendments relating to the Consolidated Omnibus Budget Reconciliation Act of 1985, the Health Insurance Portability and Accountability Act of 1996, the Newborns' and Mothers' Health Protection Act of 1996, the Mental Health Parity Act of 1996, and the Women's Health and Cancer Rights Act of 1998), including any amendment or revision thereto.

(o) "**ESOP**" means any employee stock ownership plan as defined in **ERISA**, or any other **Plan** under which investments are made primarily in securities of or issued by (i) the **Company**, (ii) any acquired **Subsidiary**, or (iii) any parent of any acquired **Subsidiary**, or whose assets at any time within twelve (12) months prior to the inception date of this **FLI Coverage Section** were comprised of ten percent (10%) or more of securities of (i) the **Company**, (ii) any acquired **Subsidiary**, or (iii) any parent of any acquired **Subsidiary**.

(p) "**Fiduciary**" means a fiduciary as defined in an **Employee Benefit Law** (if applicable), with respect to a **Plan**, or a person or entity who exercises discretionary control as respects the management of a **Plan** or the disposition of its assets.

(q) "**Foreign Jurisdiction**" means any jurisdiction, other than the United States or any of its territories or possessions.

(r) "**Foreign Policy**" means the **Insurer's** or any other member company of Chartis, Inc.'s ("**Chartis**") standard fiduciary or pension trust liability policy (including all mandatory endorsements, if any) approved by **Chartis** to be sold within a **Foreign Jurisdiction**, that provides coverage substantially similar to the coverage afforded under this **FLI Coverage Section**. If more than one such **FLI Coverage Section** or policy exists, then **Foreign Policy** means the standard policy most recently registered in the local language of the **Foreign Jurisdiction**, or if no such policy has been registered, then the policy most recently registered in that **Foreign Jurisdiction**. The term **Foreign Policy** shall not include any directors and officers, partnership, managerial, comprehensive general liability, employment practices liability or professional liability coverage.

(s) "**Fringe Benefit**" means any plan or benefit described in Section 132 of the Internal Revenue Code of 1986, as amended.

(t) "**HIPAA Penalties**" means civil money penalties imposed upon an **Insured** for violation of **HIPAA Privacy Regulations**.

(u) "**HIPAA Privacy Regulations**" means the privacy provisions of the Health Insurance Portability and Accountability Act of 1996 and any amendments thereto.

(v) "**Indemnifiable Loss**" means **Loss** for which the **Company** has indemnified or is permitted or required to indemnify any **Individual Insured**.

(w) "**Individual Insured**" means any:

(i) past, present or future natural person director, officer, governor, general partner, management committee member, **Pension Oversight Committee Member**, member of the board of managers or employee of a **Company** or, if applicable, of a **Plan**, and as to all of the above in his or her capacity as a **Fiduciary**, administrator or trustee of a **Plan**; or

(ii) past, present or future natural person in a position equivalent to a position listed in subparagraph (i) of this Definition in the event that the **Company** is operating in a **Foreign Jurisdiction**.

(x) "**Insured**" means:

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(i) any **Individual Insured**;

(ii) any **Plan**;

(iii) the **Company**;

(iv) any **Pension Oversight Committee**; or

(v) any other person or entity in his, her or its capacity as a **Fiduciary**, administrator or trustee of a **Plan** and included in the Definition of **Insured** by specific written endorsement attached to this **FLI Coverage Section**.

(y) "**Loss**" means damages, judgments (including pre and post-judgment interest on a covered judgment), settlements and **Defense Costs**; provided, however, **Loss** shall not include:

(1) civil or criminal fines or penalties imposed by law, except:

(i) to the extent set forth in Insuring Agreement 1(b) of this **FLI Coverage Section** for **Voluntary Compliance Loss**,

(ii) **UK Fines and Penalties**,

(iii) **HIPAA Penalties**, subject to the HIPAA Penalties Sublimit of Liability set forth under Clause 6. "LIMIT OF LIABILITY" of **this FLI Coverage Section**,

(iv) the five percent (5%) or less civil penalty imposed upon an **Insured** under Section 502(i) of **ERISA**,

(v) the twenty percent (20%) or less penalty imposed upon an **Insured** under Section 502(l) of **ERISA**, with respect to covered settlements or judgments;

(2) taxes or tax penalties;

(3) any amount for which an **Insured** is not financially liable or which is without legal recourse to the **Insured**;

(4) **Benefits**, or that portion of any settlement or award in an amount equal to such **Benefits**, unless and to the extent that recovery of such **Benefits** is based upon a covered **Wrongful Act** and is payable as a personal obligation of an **Individual Insured**; provided however, that **Loss** shall include a monetary award in, or fund for settling, a **Claim** against any **Insured** to the extent it alleges a loss to a **Plan** or loss in the actual accounts of participants in a **Plan** by reason of a change in value of the investments held by that **Plan**, including, but not limited to, the securities of the **Named Entity**, regardless of whether the amounts sought in such **Claim** have been characterized by plaintiffs as "benefits" or held by a court to be "benefits"; or

(5) matters which may be deemed uninsurable under the law pursuant to which this policy shall be construed.

Defense Costs shall be provided for items specifically excluded from **Loss** pursuant to subparagraphs (y)(1) through (y)(6) above of this Definition, subject to the other terms, conditions and exclusions of this **FLI Coverage Section**.

Where permitted by law, **Loss** shall specifically include (subject to the policy's other terms, conditions and exclusions, including, but not limited to, exclusions 5(a) and 5(b) of this **FLI Coverage Section**), punitive or exemplary damages or the multiplied portion of multiplied damages imposed upon any **Insured**. The enforceability of this paragraph shall be governed by such applicable law which most favors coverage for punitive, exemplary and multiple damages.

Loss shall include **Voluntary Compliance Loss**.

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(z) "**Non-qualified Plan**" means any of the following plans for a select group of management or highly compensated directors, officers or employees: deferred compensation plan, supplemental executive retirement plan, top-hat plan or excess benefit plan.

(aa) "**Pension Oversight Committee**" means any pension oversight committee duly formed by a **Trustee Company** and duly appointed to act as a trustee of the **Plan** or acting as a constructive trustee of the **Plan**.

(bb) "**Pension Oversight Committee Member**" means any duly elected or appointed member of a **Pension Oversight Committee**.

(cc) "**Pension Plan**" means a pension plan as defined in any **Employee Benefit Law**.

(dd) "**Plan**" means automatically any plan, fund, trust or program (including, but not limited to, any plan, fund, trust or program considered or created by the **Named Entity** during the **Policy Period**, any IRA-based Plan, Welfare Plan, Cafeteria Plan, Dependent Care Assistance Program, Fringe Benefit, Non-qualified Plan, or qualified Pension Plan), established anywhere in the world, which was, is or shall be sponsored solely by the **Company**, or sponsored jointly by the **Company** and a labor organization, solely for the benefit of the employees or the directors and officers of the **Company**, subject to the provisions set forth below:

(1) if such Plan is a **Pension Plan**, other than an **ESOP** or **Pension Plan** described in subparagraphs (dd)(5) and (dd)6 below, then the **Named Entity** shall provide written notice of such **Plan** to the **Insurer** prior to the inception date of this **FLI Coverage Section**, unless such **Plan** was already covered under a policy issued by the **Insurer** of which this **FLI Coverage Section** is a continuous renewal;

(2) if such **Plan** was sold, spun-off or terminated prior to the inception date of this FLI Coverage **Section** the **Named Entity** shall have provided written notice of such sale, spin-off or termination to the **Insurer** prior to the inception date of this **FLI Coverage Section** and pay any required premium relating to such **Plan**, unless such sale, spin-off or termination had already been reported to the **Insurer** under a policy issued by the **Insurer** of which this **FLI Coverage Section** is a continuous renewal;

(3) if such **Plan** is sold, spun-off or terminated during the **Policy Period**, the **Named Entity** shall provide written notice of such sale, spin-off or termination to the **Insurer** prior to the end of the **Policy Period**;

(4) if such **Plan** is an **ESOP**, stock option plan or stock based compensation plan, this **FLI Coverage Section** shall only provide coverage for such plan upon written notice of such **Plan** to the **Insurer**, payment of any required premium, and such **Plan** has been added to the Definition of **Plan** by specific written endorsement attached to this policy;

(5) if such **Plan** is a **Pension Plan** (other than an **ESOP**) and:

(i) is acquired during the **Policy Period** as a result of the **Named Entity's** acquisition of a **Subsidiary** whose assets total less than twenty-five percent (25%) of the total consolidated assets of the **Named Entity** as of the inception date of this **FLI Coverage Section**; or

(ii) is acquired during the **Policy Period** and such **Plan's** assets total less than twenty-five percent (25%) of the total consolidated assets of all covered **Pension Plans** as of the inception date of this **FLI Coverage Section**;

then this **FLI Coverage Section** shall apply to such **Plan** (but solely with respect to any **Wrongful Act** occurring after the date of such acquisition). The **Named Entity** shall provide the **Insurer** with full particulars of such new **Plan** before the end of the **Policy Period**; or

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(6) if such **Plan** is a **Pension Plan** (other than an ESOP) and:

(i) is acquired during the **Policy Period** as a result of the **Named Entity's** acquisition of a **Subsidiary** whose assets total more than twenty-five percent (25%) of the total consolidated assets of the **Named Entity** as of the inception date of this **FLI Coverage Section**; or

(ii) is acquired during the **Policy Period** and such **Plan's** assets total more than twenty-five percent (25%) of the total consolidated assets of all covered **Pension Plans** as of the inception date of this **FLI Coverage Section**,

then, this **FLI Coverage Section** shall apply to such Plan (but solely with respect to any **Wrongful Act** occurring after the date of such acquisition), but only upon the condition that within ninety (90) days of its acquisition, the **Named Entity** shall have provided the **Insurer** with a completed **Application** for such new **Plan** and agreed to any additional premium or amendment of the provisions of this **FLI Coverage Section** required by the **Insurer** relating to such new **Plan**. This ninety (90) day reporting condition shall not apply if such new **Plan** does not constitute one of the five largest **Pension Plans** of the **Named Entity** and the failure to report such **Plan** within the ninety (90) day reporting period was due to inadvertent omission by the **Named Entity** and upon discovery of such **Plan**, the **Named Entity** shall notify the **Insurer** as soon as practicable, provide any information required by the **Insurer** relating to such **Plan** and pay any premium required by the **Insurer** relating to such **Plan**.

The Definition of **Plan** shall also include: the following government-mandated programs: unemployment insurance, Social Security or disability benefits, but solely with respect to a **Wrongful Act** defined in subparagraph (2) of the Definition of **Wrongful Act** in this **FLI Coverage Section**; and any other plan, fund or program which is included in the Definition of **Plan** by specific written endorsement attached to this **FLI Coverage Section**.

In no event, however, shall the definition of **Plan** include any multiemployer plan as defined in **Employee Benefit Law**.

(ee) "**Pollutants**" means, but is not limited to, any solid, liquid, gaseous, biological, radiological or thermal irritant or contaminant, including smoke, vapor, dust, fibers, mold, spores, fungi, germs, soot, fumes, acids, alkalis, chemicals and **Waste**. "**Waste**" includes, but is not limited to, materials to be recycled, reconditioned or reclaimed and nuclear materials.

(ff) "**UK Fines and Penalties**" means civil fines and penalties assessed against an **Insured** by either the Pensions Ombudsman appointed by the Secretary of State for Social Services in the United Kingdom, by the Occupational Pensions Regulatory Authority in the United Kingdom, by the Pensions Regulator in the United Kingdom or any successor body thereto, subject to the other terms, conditions and exclusions of this **FLI Coverage Section.**

(gg) "**Trustee Company**" means a corporate trustee company that is (1) established by a **Company** formed and operating in a **Foreign Jurisdiction**, or any predecessor of such **Company**, and (2) duly appointed to act as a trustee of a **Plan** in a **Foreign Jurisdiction** and sponsored solely by such **Company**.

(hh) "**Voluntary Compliance Loss**" means **CAP Penalties**, **Delinquent Filer Penalties** and **Voluntary Fiduciary Correction** Loss.

(ii) "**Voluntary Fiduciary Correction Loss**" means damages, **Defense Expenses** and **Consulting Fees** incurred in connection with the **DOL** Voluntary Fiduciary Correction Program as set forth in the Federal Register, resulting from an inadvertent **Breach of Fiduciary Duty** occurring during the **Policy Period** (or during the policy period of a policy

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issued by the **Insurer** of which this **FLI Coverage Section** is a continuous renewal), provided that such compliance with the **DOL**'s Voluntary Fiduciary Correction Program results in the **Insured** obtaining a "No Action" letter from the **DOL**; provided, however, **Voluntary Fiduciary Correction Loss** shall not include: (1) civil or criminal fines or penalties imposed by law; (2) punitive or exemplary damages; (3) the multiplied portion of multiplied damages; (4) taxes or tax penalties; (5) any amount for which an **Insured** is not financially liable or which is without legal recourse to the **Insured**; (6) **Benefits**, or that portion of damages equal to such **Benefits**; (7) matters of which the **Insured** had knowledge prior to the inception date of this **FLI Coverage Section** or the first policy issued by the **Insurer** to the **Named Entity** of which this **FLI Coverage Section** is a continuous renewal; or (8) matters which may be deemed uninsurable under the law pursuant to which this policy shall be construed.

(jj) "**Welfare Plan**" means a welfare plan as defined in **Employee Benefit Law**.

(kk) "**Wrongful Act**" means:

(1) a violation of any of the responsibilities, obligations or duties imposed upon **Fiduciaries** by **Employee Benefit Law** with respect to a **Plan**; or any matter claimed against an **Insured** solely by reason of his, her or its status as a **Fiduciary**, but only with respect to a **Plan**;

(2) any act, error or omission solely in the performance of one or more of the following administrative duties or activities, but only with respect to a **Plan**:

(i) counseling employees, participants and beneficiaries;

(ii) providing interpretations;

(iii) handling of records;

(iv) activities effecting enrollment, termination or cancellation of employees, participants and beneficiaries under the **Plan**; or

(v) complying with **HIPAA Privacy Regulations**;

or any matter claimed against an **Insured** solely by reason of his, her or its status as an administrator, but only with respect to a **Plan**; and

(3) as respects an **Individual Insured**, any matter claimed against him or her arising out of his or her service as a **Fiduciary** or administrator of any multiemployer plan as defined by **ERISA**, but only if such service is at the specific written request or direction of the **Company** and such multiemployer plan is added by specific written endorsement attached to this **FLI Coverage Section**, identified as a multiemployer plan and any required premium is paid. In no event shall coverage under this **FLI Coverage Section** extend to a **Claim** against a multiemployer plan itself, its contributing employer(s) or any other fiduciaries or administrators of such plan, other than an **Individual Insured**.

4. WORLDWIDE EXTENSION

For **Claims** made and maintained in a **Foreign Jurisdiction** for **Wrongful Acts** committed in such **Foreign Jurisdiction**, the **Insurer** shall apply to such **Claims** the provisions of the **Foreign Policy** in the **Foreign Jurisdiction** that are more favorable to such **Insured** in the **Foreign Jurisdiction**; provided, however, this paragraph shall apply only to provisions more favorable by virtue of insuring clauses, extensions, definitions, exclusions, pre-authorized securities or other defense counsel, discovery or extended reporting period, notice and authority, dispute resolution process or order of payments provisions, if any, of the **Foreign Policy** when compared to the same or similar clauses of this **FLI Coverage Section**. This paragraph shall not apply to excess provisions or policy provisions that address non-renewal, duty to defend, defense within or without limits, taxes, claims made and reported provisions or any other provision of this policy intended to govern coverage worldwide.

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All premiums, limits, retentions, **Loss** and other amounts under this **FLI Coverage Section** are expressed and payable in the currency of the United States of America. If judgment is rendered, settlement is denominated or other elements of **Loss** are stated or incurred in a currency other than United States of America dollars, payment of covered **Loss** due under this **FLI Coverage Section** (subject to the terms, conditions and limitations of this FLI **Coverage Section**) will be made either in such other currency (at the option of the **Insurer** and if agreeable to the **Named Entity**) or, in United States of America dollars, at the rate of exchange published in The Wall Street Journal on the date the **Insurer's** obligation to pay such **Loss** is established (or if not published on such date the next publication date of The Wall Street Journal).

5. EXCLUSIONS

The **Insurer** shall not be liable to make any payment for **Loss** in connection with a **Claim** made against an **Insured:**

(a) arising out of, based upon or attributable to the gaining of any profit or advantage to which any final adjudication establishes the **Insured** was not legally entitled;

(b) arising out of, based upon or attributable to the committing of any criminal or deliberate fraudulent act, or any knowing or willful violation of any statute, rule or law, including, but not limited to **Employee Benefit Law** by the **Insured** if any final adjudication establishes that such criminal or deliberate fraudulent act was committed;

(c) for discrimination in violation of any law; provided, however, this exclusion shall not apply to discrimination in violation of **Employee Benefit Law**;

(d) alleging, arising out of, based upon or attributable to the facts alleged, or to the same or related **Wrongful Act** alleged or contained, in any **Claim** which has been reported, or in any circumstances of which notice has been given, under any policy of which this **FLI Coverage Section** is a renewal or replacement of in whole or part or which it may succeed in time;

(e) alleging, arising out of, based upon or attributable to, as of the **Continuity Date**, any pending or prior: (1) litigation; or (2) administrative or regulatory proceeding or investigation of which an **Insured** had notice, or alleging or derived from the same or essentially the same facts as alleged in such pending or prior litigation or administrative or regulatory proceeding or investigation;

(f) for failure to fund a **Plan** in accordance with **Employee Benefit Law** or the Plan instrument, or the failure to collect contributions owed to the **Plan**; provided, however, this exclusion shall not apply to: (1) **Defense Costs**; or (2) the portion of **Loss** that is payable as a personal obligation of an **Individual Insured**;

(g) alleging, arising out of, based upon or attributable to any act or omission of an **Insured** in his, her or its capacity as a **Fiduciary** or administrator of any plan, fund or program, other than a **Plan** as defined in this **FLI Coverage Section**, or by reason of his, her or its status as a **Fiduciary** or administrator of such other plan, fund or program;

(h) for bodily injury, sickness, disease, death or emotional distress of any person, or damage to, loss of use of or destruction of any tangible property; provided, however, this exclusion shall not apply to **Defense Costs** incurred in the defense of a **Claim** for **Breach of Fiduciary Duty**;

(i) alleging, arising out of, based upon or attributable to any **Wrongful Act** as respects the **Plan** taking place at any time when the **Company** did not sponsor such **Plan** or when the **Individual Insured** was not a **Fiduciary**, administrator, trustee, **Pension Oversight Committee Member**, director, officer, governor, management committee member, member of the board of managers, general partner or employee of the **Company** or, if applicable, a **Plan**;

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(j) alleging, arising out of, based upon, attributable to, or in any way involving, directly or indirectly: (1) the actual, alleged or threatened discharge, dispersal, release or escape of **Pollutants**; or (2) any direction or request to test for, monitor, clean up, remove, contain, treat, detoxify or neutralize **Pollutants**; provided, however, this exclusion shall not apply to non-Indemnifiable **Loss** arising from a **Claim** alleging damage to a **Plan**, other than non-Indemnifiable **Loss** constituting **Cleanup Costs**;

(k) alleging, arising out of, based upon or attributable to any **Wrongful Act** as respects the **Plan** taking place at any time when the **Company** did not sponsor such **Plan** or when the **Individual Insured** was not a **Fiduciary**, administrator, trustee, director(s), officer(s) or employee of the **Company** or, if applicable, a **Plan**.

For the purpose of determining the applicability of the foregoing Exclusions, other than exclusions 5(d) and 5(e): (1) the facts pertaining to and knowledge possessed by any **Insured** shall not be imputed to any other **Individual Insured**; and (2) only facts pertaining to and knowledge possessed by any past, present or future chief executive officer, chief operating officer or chief financial officer (or equivalent positions) of the **Company** shall be imputed to the **Company**.

6. LIMIT OF LIABILITY

The following provision shall apply in addition to the provisions of Clause 4. LIMIT OF LIABILITY of the **General Terms and Conditions**:

VOLUNTARY COMPLIANCE LOSS SUBLIMIT OF LIABILITY

The maximum limit of the **Insurer's** liability for all **Voluntary Compliance Loss** occurring during the **Policy Period** or the **Discovery Period** (if applicable), in the aggregate, shall be the amount set forth in Item 7(e) of the Declarations ("**Voluntary Compliance Loss Sublimit of Liability**"). The **Voluntary Compliance Loss Sublimit of Liability** shall be part of, and not in addition to, the **Policy Aggregate Limit of Liability** or any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **FLI Coverage Section**, and shall in no way serve to increase the **Insurer's Policy Aggregate Limit of Liability** or any **Separate Limit of Liability** or **Shared Limit of Liability** as stated therein.

HIPAA PENALTIES SUBLIMIT OF LIABILITY

The maximum limit of the **Insurer's** liability for all **HIPAA Penalties**, in the aggregate, shall be the amount set forth in Item 7(f) of the Declarations ("**HIPAA Penalties Sublimit of Liability**"). The **HIPAA Penalties Sublimit of Liability** shall be part of, and not in addition to, the **Policy Aggregate Limit of Liability** and any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **FLI Coverage Section**, and shall in no way serve to increase the **Insurer's Policy Aggregate Limit of Liability** or any **Separate Limit of Liability** or **Shared Limit of Liability** as stated therein.

7. RETENTION CLAUSE

The following provision shall apply in addition to the provisions of Clause 5. RETENTION of the **General Terms and Conditions**:

The **Insurer** shall only be liable for the amount of **Loss** arising from a **Claim** which is in excess of the Retention amount stated in Item 3 of the Declarations, such Retention amount to be borne by the **Insured** and shall remain uninsured, with regard to (1) all **Indemnifiable Loss**; and (2) **Loss** of a **Company**. A single Retention amount shall apply to **Loss** arising from all **Claims** alleging the same **Wrongful Act** or related **Wrongful Acts**.

Notwithstanding the foregoing, no Retention is applicable to **Voluntary Compliance Loss** or **HIPAA Penalties**.

8. PRE-AUTHORIZED DEFENSE ATTORNEYS

This Clause 8 applies only to: (1) a **Claim** brought by any government entity; (2) a request for

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coverage for a **Voluntary Compliance Loss**; or (3) a **Claim** brought in the form of a class or representative action or which purports to be brought as a class or representative action.

Affixed as Appendix C hereto and made a part of this **FLI Coverage Section** is a list of Panel Counsel law firms ("**Panel Counsel Firm(s)**") from which a selection of legal counsel shall be made to conduct the defense of any **Claim** against an **Insured** to which this Clause 8 applies and pursuant to the terms set forth in this Clause.

In the event the **Insurer** is operating under a duty to defend pursuant to Clause 2(a) of this **FLI Coverage Section**, then the **Insurer** shall select a **Panel Counsel Firm** to defend the **Insureds**. Upon the written request of the **Named Entity**, the **Insurer** may consent to a different **Panel Counsel Firm** selected by the **Named Entity** to defend the **Insureds**, which consent shall not be unreasonably withheld.

In the event the **Insureds** have assumed the defense of the **Claim** pursuant to Clause 2(b) of this **FLI Coverage Section**, then the **Insureds** shall select a **Panel Counsel Firm** to defend the **Insured.** In addition, with the express prior written consent of the **Insurer**, which consent shall not be unreasonably withheld, the **Insured** may select a **Panel Counsel Firm** different from that selected by other **Insureds** if such selection is required due to an actual conflict of interest or is otherwise reasonably justifiable.

The selection of a **Panel Counsel Firm** from the attached list to defend the **Claim** against the **Insureds** shall not be restricted to the jurisdiction in which the **Claim** is brought.

The list of **Panel Counsel Firms** may be amended from time to time by the **Insurer**. However, no change shall be made to the specific list attached to this policy during the **Policy Period** without the consent of the **Named Entity.** At the request of the **Named Entity**, the **Insurer** may in its discretion add one or more law firms to the attached list of **Panel Counsel Firms** for the purposes of defending the **Claim** made against the **Insureds.** The list of **Panel Counsel Firms** may also be amended to add, at the sole discretion of the **Insurer**, a non-**Panel Counsel Firm** for the purpose of acting as "local counsel" to assist an existing **Panel Counsel Firm**, which **Panel Counsel Firm** will act as "lead counsel" in conducting the defense of the **Claim**, for **Claims** brought in a jurisdiction in which the chosen **Panel Counsel Firm** does not maintain an office.

9. WAIVER OF RECOURSE

Except for the **Insurer's** subrogation rights set forth in Clause 10 of the **General Terms and Conditions**, the **Insurer** shall have no right of recourse against an **Insured** unless required pursuant to any **Employee Benefit Law.**

It is further provided that in the event of any recovery under this Clause 9, any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **FLI Coverage Section** shall be restored to the extent of such recovery after subtracting any costs, expenses or reimbursements incurred by the **Insurer** in connection therewith.

10. ORDER OF PAYMENTS

In the event of **Loss** arising from a covered **Claim** for which payment is due under the provisions of this **FLI Coverage Section**, then the **Insurer** shall in all events:

(a) first, pay **Loss** for which coverage is provided under this **FLI Coverage Section** for any **Individual Insured**;

(b) second, only after payment of **Loss** has been made pursuant to Clause 10(a) above with respect to whatever remaining amount of any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **FLI Coverage Section** is available after such payment, pay the **Loss** of any covered **Plan**; and

(c) then, only after payment of **Loss** has been made pursuant to Clause 10(a) and 10(b) above, with respect to whatever remaining amount of any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **FLI Coverage Section** is available after such

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payment, shall payment for the **Company** be made for such other **Loss** for which coverage is provided under this **FLI Coverage Section**.

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APPENDIX C
EMPLOYEE BENEFIT PLAN FIDUCIARY LIABILITY
PANEL COUNSEL LIST

In consideration of the premium charged, it is understood and agreed as follows: The information in our Panel Counsel lists/appendices is now accessible through our online Panel Counsel Directory at http://www.chartisinsurance.com/panelcounseldirectory. To access the applicable online Panel Counsel Directory, please go to the website, click on the "Fiduciary Liability(ERISA and Non-ERISA)" link.

References in this policy to list of Panel Counsel law firms or related appendices are deemed amended to refer to the applicable Panel Counsel Directories at the website referenced above.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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ENDORSEMENT# 1

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

NUCLEAR ENERGY LIABILITY EXCLUSION ENDORSEMENT (ALL COVERAGE SECTIONS)

In consideration of the premium charged, it is hereby understood and agreed that the **Insurer** shall not be liable to make any payment for **Loss** in connection with any **Claim** made against any **Insured**:

A. alleging, arising out of, based upon, attributable to, or in any way involving, directly or indirectly, the **Hazardous Properties** of **Nuclear Material**, including but not limited to:

(1) **Nuclear Material** located at any **Nuclear Facility** owned by, or operated by or on behalf of, the **Company**, or discharged or dispersed therefrom; or

(2) **Nuclear Material** contained in spent fuel or waste which was or is at any time possessed, handled, used, processed, stored, transported or disposed of by or on behalf of the **Company**; or

(3) the furnishing by an **Insured** or the **Company** of services, materials, parts or equipment in connection with the planning, construction, maintenance, operation or use of any **Nuclear Facility**; or

(4) **Claims** for damage or other injury to the **Company** or its shareholders which allege, arise from, are based upon, are attributed to or in any way involve, directly or indirectly, the **Hazardous Properties** of **Nuclear Material**.

B. (1) which is insured under a nuclear energy liability policy issued by Nuclear Energy Liability Insurance Association, Mutual Atomic Energy Liability underwriters, or Nuclear Insurance Association of Canada, or would be insured under any such policy but for its termination or exhaustion of its limit of liability; or,

(2) with respect to which: (a) any person or organization is required to maintain financial protection pursuant to the Atomic Energy Act of 1954, or any law amendatory thereof, or (b) the **Insured** is, or had this policy not been issued would be, entitled to indemnity from Canada or the United States of America, or any agency thereof, under any agreement entered into by Canada or the United States of America, or any agency thereof, with any person or organization.

As used in this endorsement:

"**Hazardous Properties**" include radioactive, toxic or explosive properties.

"**Nuclear Facility**" means:

(a) any nuclear reactor;

(b) any equipment or device designed or used for

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END 001

ENDORSEMENT# 1 (continued)

(1) separating the isotopes of uranium or plutonium,
(2) processing or utilizing spent fuel, or
(3) handling, processing or packaging wastes;

(c) any equipment or device used for the processing, fabricating or alloying of special nuclear material if at any time the total amount of such material in the custody of the Insured at the premises where such equipment or device is located consists of or contains more than 25 grams of plutonium or uranium 233 or any combination thereof, or more than 250 grams of uranium 235; and

(d) any structure, basin, excavation, premises or place prepared or used for the storage or disposal of waste, and includes the site on which any of the foregoing is located, all operations conducted on such site and all premises used for such operations.

"**Nuclear Material**" means source material, special nuclear material or byproduct material.

"**Nuclear Reactor**" means any apparatus designed or used to sustain nuclear fission in a self- supporting chain reaction or to contain a critical mass of fissionable material.

"**Source Material**," "**Special Nuclear Material**," and "**Byproduct Material**" have the meanings given them in the Atomic Energy Act of 1954 or in any law amendatory thereof.

"**Spent Fuel**" means any fuel element or fuel component, solid or liquid, which has been used or exposed to radiation in a nuclear reactor.

"**Waste**" means any waste material (1) containing by product material and (2) resulting from the operation by any person or organization of any **Nuclear Facility** included within the definition of nuclear facility under paragraph (a) or (b) thereof.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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ENDORSEMENT# 2

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

CAPTIVE INSURANCE COMPANY EXCLUSION DELETED ENDORSEMENT
(D&O COVERAGE SECTION)

In consideration of the premium charged, it is hereby understood and agreed that in Clause 4. EXCLUSIONS, paragraph (p) of the **D&O Coverage Section** is deleted in its entirety

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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ENDORSEMENT# 3

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

COMMISSION EXCLUSION DELETED
(D&O COVERAGE SECTION)

In consideration of the premium charged, it is hereby understood and agreed that in Section 4. "EXCLUSIONS" of the D&O Coverage Section, paragraph (s) is deleted in its entirety.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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END 003

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ENDORSEMENT# 4

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

STATUTORY ENDORSEMENT COVERAGE
(D&O Coverage Section)

In consideration of the premium charged, and solely with respect to the coverage afforded by the **D&O Coverage Section** of this policy for any **Claims** with respect to any entity created, located or formed or incorporated in Canada, it is hereby understood and agreed that the coverage as is afforded by the **D&O Coverage Section** of this policy is extended to a "**Statutory Claim**" as defined below, subject to the terms, conditions and exclusions of this endorsement and policy.

INSURING AGREEMENTS

It is understood and agreed that for the purposes of this endorsement, Clause 1. **Insuring Agreement**, Coverage A of the **D&O Coverage Section** is deleted in its entirety and replaced with the following:

Coverage A: Directors and Officers Insurance

The **D&O Coverage Section** shall pay the **Loss** of each and every **Executive** of the **Company** arising from a **Statutory Claim** first made against the **Executives** during the **Policy Period** or the **Discovery Period** (if applicable) and reported to the **Insurer** pursuant to the terms of this policy for any actual or alleged **Wrongful Act** in their respective capacities as **Executive(s)** of the **Company**, except when and to the extent that the **Company** has indemnified the **Executive(s)**. The **Insurer** shall, in accordance with and subject to Clause7 of the **D&O Coverage Section**, advance **Defence Costs** of the **Statutory Claim** prior to its final disposition.

DEFINITIONS

It is further understood and agreed that solely with respect to the coverage afforded by this endorsement for a **Statutory Claim(s)**, Clause 2. **DEFINITIONS** of the **D&O Coverage Section** is amended as follows:

(a) "**Claim**" is deleted in its entirety and replaced with the following:

(1) any demand, action, proceeding or investigation by the Minister of National Revenue, against an **Executive** arising out of, based upon or attributable to the failure to deduct, withhold, or remit tax from a payment of salary or wages of an **Employee**;

(2) any demand, action, proceeding, or investigation by an **Employee** against a **Executive**.

(b) "**Employee**" is deleted in its entirety and replaced with the following:

"**Employee**" means a person in receipt of or entitled to wages for labour or services performed for the **Company**. **Employee** shall not include an independent contractor or an employee who is on probation.

(c) "**Executive**" is deleted in its entirety and replaced with the following:

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ENDORSEMENT# 4 (continued)

"**Executive**" means directors, officers, and *de facto* directors and officers of the Company.

(d) "**Loss**" is amended to include the following paragraphs:

(1) For the purposes of a **Statutory Claim** arising from the **Insured's** failure to deduct, withhold or remit tax, unemployment insurance contributions, or pension plan contributions from a payment of salary or wages of the **Company's Employees**, **Loss** shall mean:

(i.) taxes and related penalties and interest actually assessed against the Insured pursuant to the Income Tax Act, R.S.C. 1985 (5th Supp.);

(ii.) any amount including related penalties and interest assessed against the **Insured** pursuant to the Employment Insurance Act, S.C. 1996, c. 23;

(iii.) any amount including related penalties and interest assessed against the **Insured** pursuant to the Canada Pension Plan, R.S.C. 1985, c. C-8, and the Act Respecting the Ministère du Revenu, R.S.Q., c. M-31.

(2) For the purposes of a **Statutory Claim** arising from the Insured's failure to pay wages, vacation pay or debts for services rendered of the **Company's Employees** properly due and owing, **Loss** shall mean any amount constituting wages, vacation pay or debts for services rendered pursuant to the Canada Business Corporations Act, R.S.C. 1985, the Canada Labour Code, R.S.C. 1985, c. L-2, and the regulations promulgated thereunder and amendments thereto or any similar provisions of any provincial law.

(e) The following definition shall be added to the end thereof:

(aa) "**Statutory Claim**" means a **Claim** made against the **Insured** which alleges a violation of the Income Tax Act, R.S.C 1985, c. C-1 (5th supp.), the Canada Business Corporations Act, R.S.C. 1985, c. C-44, the Business Corporations Act, R.S.O. 1990, c. B-16, the Employment Insurance Act, R.S.C. 1985, c. U-1, or the Canada Pension Plan, R.S.C. 1985, c. C-8, the regulations promulgated thereunder and amendments thereto or any similar provisions of any provincial law, alleging, arising out of, based upon or attributable to:

(1) the failure to deduct, withhold or remit tax from a payment of salary or wages of the **Company's Employees**;

(2) the failure to deduct, withhold or remit unemployment insurance contributions from a payment of salary or wages of the **Company's Employees**;

(3) the failure to deduct, withhold or remit pension plan contributions from a payment of salary or wages of the **Company's Employees**;

(4) the failure to pay wages of the **Company's Employees** properly due and owing.

EXCLUSIONS

It is further understood and agreed that for the purposes of this endorsement, exclusion 4(e) of the **D&O Coverage Section** is deleted in its entirety and replaced with the following:

(e) "alleging, arising out of, based upon or attributable to any pending or prior litigation as of *September 1, 2005* , or alleging or derived from the same or essentially the same facts as alleged in such pending or prior litigation."

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ENDORSEMENT# 4 (continued)

SUBROGATION

It is further understood and agreed that for the purposes of this endorsement, Clause 10 of the General Terms and Conditions is deleted in its entirety and replaced with the following:

In no event shall the coverage afforded by this endorsement be extended to grant coverage to the **Company**.

In the event of any payment under this endorsement, the **Insurer** shall be subrogated to the extent of such payment to the **Insured's** rights of recovery thereof, and the **Insured** shall execute all papers required and shall do everything that may be necessary to secure such rights including the execution of such documents necessary to enable the **Insurer** to effectively bring suit in the name of the **Insured**.

It is agreed and accepted that the **Insured** expressly grants the **Insurer** the right of subrogation to bring suit against the **Company** for any payments that the **Insurer** has made under this endorsement.

It is further agreed and accepted that the **Company** will indemnify the **Insured** and save the **Insured** harmless from **Loss** alleging, arising out of, based upon or attributable to a **Statutory Claim**.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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END 004

ENDORSEMENT# 5

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

RELIANCE UPON APPLICATION MADE TO ANOTHER CARRIER ENDORSEMENT (D&O COVERAGE SECTION)

In consideration of the premium charged, it is hereby understood and agreed, solely with respect to coverage as may be provided under the **D&O Coverage Section**, as follows:

1. In granting under the **D&O Coverage Section**, the **Insurer** has relied upon the **Competitor's Application** and the statements, warranties and representations contained therein as being accurate and complete as of the **Date Signed**. The **Insureds** extend any warranties and representations in the **Competitor's Application** to the **Insurer** and further warrant and represent to the **Insurer** that the statements and representations made in the **Competitor's Application** were accurate and complete on the **Date Signed**. All such statements and representations shall be deemed to be material to the risk assumed by the **Insurer**, are the basis of this policy and are to be considered as incorporated into this policy.

2. "**Competitor's Application**" means the application of the **Named Applicant(s)** to the **Other Carrier** for the **Type of Coverage** reflected in the table below:

Named Applicant(s)	Other Carrier	Type of Coverage	Date Signed
Yukon Development Corporation	Chubb Insurance Copmany of Canada	DO	September 4, 2003

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END 005

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If such application form was submitted to the **Other Carrier** in connection with a renewal of coverage, then **"Competitor's Application"** shall also mean all previous policy application forms submitted to that **Other Carrier** for any policy of which this policy is a renewal, replacement or succeeds in time. **"Competitor's Application"** also means all the materials submitted with or incorporated by reference into any of the application forms referenced above.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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ENDORSEMENT# 6

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

SEVERABILITY OF THE APPLICATION ENDORSEMENT
(NON-RESCINDABLE - FULL INDIVIDUAL SEVERABILITY;
TOP 3 COMPANY POSITIONS IMPUTED TO COMPANY)
(D&O AND EPL COVERAGE SECTIONS)

In consideration of the premium charged, it is hereby understood and agreed that the policy is amended as follows:

1. Clause 10. "**REPRESENTATIONS AND SEVERABILITY**" of the **D&O Coverage Section** is deleted in its entirety and replaced with the following:

10. REPRESENTATIONS AND SEVERABILITY

In granting coverage under this **D&O Coverage Section**, it is agreed that the **Insurer** has relied upon the statements, warranties and representations contained in the **Application** for this **D&O Coverage Section** as being accurate and complete. All such statements and representations are the basis of this **D&O Coverage Section** and are to be considered as incorporated into this **D&O Coverage Section**.

With respect to any statements, warranties and representations contained in the **Application**, and solely with respect to the issue of whether coverage shall be afforded under this endorsement pursuant to subparagraphs (1), (2) and (3) below, no knowledge possessed by an **Individual Insured** shall be imputed to any other **Individual Insured**. However, in the event that any of the statements, warranties or representations is not accurately and completely disclosed in the **Application** and materially affects either the acceptance of the risk or the hazard assumed by the **Insurer**, no coverage shall be afforded for any **Claim** alleging, arising out of, based upon, attributable to or in consequence of the subject matter of any incomplete or inaccurate statements, warranties or representations under:

(1) Clause 1. **INSURING AGREEMENTS**, COVERAGE A, with respect to any **Individual Insured** who knew of such inaccurate or incomplete statements, warranties or representations;

(2) Clause 1. **INSURING AGREEMENTS**, Coverage B(ii), with respect to any **Company** to the extent it indemnifies any **Individual Insured** referenced in (1), above; and

(3) Clause 1. **INSURING AGREEMENTS**, Coverage B(i), with respect to any **Company** if any past or present chief executive officer, chief operating officer or chief financial officer of the **Company** knew of such inaccurate or incomplete statements, warranties or representations,

whether or not such **Individual Insured** knew that such facts were not accurately and completely disclosed in the **Application**.

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END 006

ENDORSEMENT# 6 (continued)

The **Insurer** shall not be entitled under any circumstances to rescind coverage under the Policy with respect to any **Insured**, but such coverage will be subject to all other terms, conditions and exclusions of the policy.

2. Clause 8. "**REPRESENTATIONS AND SEVERABILITY**" of the **EPL Coverage Section** is deleted in its entirety and replaced with the following:

8. **REPRESENTATIONS AND SEVERABILITY**

In granting coverage under this policy, it is agreed that the **Insurer** has relied upon the statements and representations contained in the **Application** for this **EPL Coverage Section** as being accurate and complete. All such statements and representations are the basis of this **EPL Coverage Section** and are to be considered as incorporated into this **EPL Coverage Section**.

With respect to any statements, warranties and representations contained in the Application, and solely with respect to the issue of whether coverage shall be afforded under this endorsement pursuant to subparagraphs (1), (2) and (3) below, no knowledge possessed by an **Individual Insured** shall be imputed to any other **Individual Insured**. However, in the event that any of the statements, warranties or representations is not accurately and completely disclosed in the **Application** and materially affects either the acceptance of the risk or the hazard assumed by the **Insurer**, no coverage shall be afforded for any **Claim** alleging, arising out of, based upon, attributable to or in consequence of subject matter of any incomplete or inaccurate statements, warranties or representations with respect to:

(1) any **Individual Insured** who knew as of the inception date of the **Policy Period** the facts that were not accurately and completely disclosed in the application;

(2) any **Company** to the extent it indemnifies any **Individual Insured** referenced in subparagraph (1) above; and

(3) any **Company** if any past or present chief executive officer, chief operating officer or chief financial officer of the **Company** knew of such inaccurate or incomplete statements, warranties or representations,

whether or not such **Individual Insured** knew that such facts were not accurately and completely disclosed in the **Application**.

The **Insurer** shall not be entitled under any circumstances to rescind coverage under the Policy with respect to any **Insured**, but such coverage will be subject to all other terms, conditions and exclusions of the policy.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

AUTHORIZED REPRESENTATIVE

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END 006

ENDORSEMENT# 7

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

CANADIAN CORPORATE TAX EXTENSION
(D&O Coverage Section)

In consideration of the premium charged, it is hereby understood and agreed that solely with respect to Coverage A under the **D&O Coverage Section**, and solely with respect to coverage as is afforded under the **D&O Coverage Section** for **Claims** made against any **Individual Insured**, as defined in Clause 2(s), subparagraph (i) (hereinafter "**Individual Insured**"), of a **Company** incorporated or formed in Canada and solely as respects Coverage A of this policy, the Definition of **Loss** in the D&O Coverage Section is amended by adding the following at the end thereof:

Notwithstanding the above, **Loss** shall include (subject to the other terms, conditions and exclusions of the policy):

(1) taxes actually assessed against an **Individual Insured** pursuant to section 227.1 of the Canadian Income Tax Act, section 323 of the Canadian Excise Tax Act or any comparable Canadian Provincial Retail Sales Tax legislation (hereinafter such section referred to as the "Sections"); and

(2) any related penalties and interest actually assessed against such **Individual Insured** pursuant to the Sections.

It is further understood and agreed that solely for the purposes of the coverage afforded by virtue of this endorsement the following additional provisions shall apply:

(a) The term "**Claim**" shall include any action, proceeding or investigation against an **Individual Insured** commenced by Revenue Canada or any Canadian provincial tax authority pursuant to the Sections that is commenced by a notice of investigation or similar document. **Loss** shall include **Defence Costs** incurred in connection with such a **Claim** subject to the other terms, conditions and exclusions of the policy.

(b) As a condition precedent to the rights of the **Individual Insured** under this endorsement, an event identified in the sections of the Canadian Income Tax Act listed below shall have occurred prior to the **Claim** being made against the Individual Insured:

Sec. 227.1(2) (a)- (c)

(c) The **Company** hereby agrees to indemnify and hold the **Insurer** harmless from any payment made to or on the behalf of an **Individual Insured** pursuant to the coverage granted by this endorsement.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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END 007

C0002 CAN (1/08)

ENDORSEMENT# 8

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

SIDE A POLLUTION COVERAGE ENDORSEMENT (GENERAL TERMS AND CONDITIONS)

In consideration of the premium charged, it is hereby understood and agreed that Item 3. COVERAGE SUMMARY of the policy Declarations, the section applicable to the D&O Coverage is hereby amended by adding the following subsection to the end thereof:

POLLUTION COVERAGE SUBLIMIT OF LIABILITY: $ 1,000,000 aggregate limit of the **Insurer's** liability for all **Non-Indemnifiable Loss** other than **Non-Indemnifiable Loss** constituting **Clean-up Costs** (including **Defence Costs**) in the aggregate arising from all **Claims** involving **Pollutants** combined (hereinafter " **Pollution Coverage Sublimit of Liability**"). This **Pollution Coverage Sublimit of Liability** shall be part of and not in addition to the **Policy Aggregate Limit of Liability** stated in the Item 7(a) of the Declarations and any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to this **D&O Coverage Section** as set forth in Item 3 of the Declarations.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

AUTHORIZED REPRESENTATIVE

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END 8

ENDORSEMENT# 9

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

CANCELLATION AMENDATORY
(GENERAL TERMS AND CONDITIONS AMENDMENT)

In consideration of the premium charged, it is hereby understood and agreed that Clause 7. **CANCELLATION CLAUSE** of the General Terms and Conditions is hereby amended by deleting the second paragraph and replacing it with the following:

7. CANCELLATION CLAUSE

This policy may be canceled by or on the behalf of the **Insurer** only in the event of non-payment of premium by the **Named Entity**. In the event of non-payment of premium by the **Named Entity**, the **Insurer** may cancel this policy by delivering to the **Named Entity** or by mailing to the **Named Entity**, by registered, certified or other first class mail, at the **Named Entity's** address as stated in Item 1 of the Declarations, written notice stating when, not less than thirty (30) days thereafter, the cancellation shall be effective. The mailing of such notice as aforesaid shall be sufficient proof of notice. The **Policy Period** terminates at the date and hour specified in such notice, or at the date and time of surrender. The **Insurer** shall have the right to the premium amount for the portion of the **Policy Period** during which the policy was in effect.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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END 009

C0054 CAN (3/09)

ENDORSEMENT# 10

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

INSURED V. INSURED EXCLUSION (CREDITORS COMMITTEE)
(D&O COVERAGE SECTION)

In consideration of the premium charged, it is hereby understood and agreed that in Clause 4. EXCLUSIONS of the **D&O Coverage Section**, paragraph (i) is deleted in its entirety and replaced as follows:

(i) which is brought by or on behalf of a **Company** or any **Individual Insured**, other than an **Employee** of a **Company**; or which is brought by any security holder of the **Company**, whether directly or derivatively, unless such security holder's **Claim** is instigated and continued totally independent of, and totally without the solicitation of, or assistance of, or active participation of, or intervention of any **Company** or any **Executive** of a **Company**; provided, however, this exclusion shall not apply to:

(i) any **Claim** brought by an **Individual Insured** in the form of a cross-claim or third-party claim for contribution or indemnity which is part of and results directly from a **Claim** that is covered by this policy;

(ii) in any bankruptcy proceeding by or against a **Company**, any **Claim** brought by the examiner, trustee, receiver, liquidator, rehabilitator or creditors' committee (or any assignee thereof) of such **Company**;

(iii) any **Claim** brought by any past **Executive** of a **Company** who has not served as a duly elected or appointed director, officer, trustee, governor, management committee member, member of the management board, General Counsel or Risk Manager (or equivalent position) of or consultant for a **Company** for at least four (4) years prior to such **Claim** being first made against any person; or

(iv) any **Claim** brought by an **Executive** of a **Company** formed and operating in a **Foreign Jurisdiction** against such **Company** or any **Executive** thereof, provided that such **Claim** is brought and maintained outside the United States, Canada or any other common law country (including any territories thereof);

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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END 010

99176 (5/08)

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ENDORSEMENT# 11

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

INSURED V. INSURED EXCLUSION AMENDED
(CARVE- BACK FOR SERVICE AS D&O OVER 3 YEARS PRIOR)
(D&O COVERAGE SECTION)

In consideration of the premium charged, it is hereby understood and agreed that in Clause 4. EXCLUSIONS of the **D&O Coverage Section**, subparagraph (iii) of paragraph (i) is deleted in its entirety and replaced with the following:

(iii) any **Claim** brought by any past **Executive** of a **Company** who has not served as a duly elected or appointed director, officer, trustee, governor, management committee member, member of the management board, General Counsel or Risk Manager (or equivalent position) of or consultant for a **Company** for at least three (3) years prior to such **Claim** being first made against any person; or

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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END 011

100696 (11/08)

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ENDORSEMENT# 12

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

EXTRADITION COVERAGE
(D&O COVERAGE SECTION)

In consideration of the premium charged, it is understood and agreed that, solely with respect to such coverage as is provided by the D&O Coverage Section, and solely where permitted by law, the **D&O Coverage Section** is amended as follows:

1. Clause 2. **DEFINITIONS**, paragraph (b)("**Claim**") is amended by appending the following to the end thereof:

   "**Claim**" also means any:

   (a) official request for **Extradition** of any **Individual Insured**; or

   (b) the execution of a warrant for the arrest of an **Individual Insured** where such execution is an element of **Extradition**.

2. Clause 2. **DEFINITIONS**, paragraph (k)("**Defense Costs**") is amended by appending the following to the end thereof:

   "**Defense Costs**" also means reasonable and necessary fees, costs and expenses incurred through legal counsel and consented to by the **Insurer** resulting from an **Individual Insured** lawfully:

   (a) opposing, challenging, resisting or defending against any request for or any effort to obtain the **Extradition** of that **Individual Insured**; or

   (b) appealing any order or other grant of **Extradition** of that **Individual Insured**.

3. Clause 2. **DEFINITIONS** is amended by appending the following to the end thereof:

   "**Extradition**" means any formal process by which an **Individual Insured** located in any country is surrendered to any other country for trial or otherwise to answer any criminal accusation.

4. Clause 9. **PRE-AUTHORIZED DEFENSE ATTORNEYS FOR SECURITIES CLAIMS** does not apply to **Defense Costs** solely relating to **Extradition** even if the underlying **Wrongful Acts** relate to a **Securities Claim.**

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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END 012

105118 (4/10)

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ENDORSEMENT# 13

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

INSURED V. INSURED EXCLUSION AMENDED
(SARBANES-OXLEY WHISTLEBLOWER)
(D&O COVERAGE SECTION)

In consideration of the premium charged, it is hereby understood and agreed that in Clause 4. EXCLUSIONS of the D&O Coverage Section, paragraph (i) is deleted in its entirety and replaced as follows:

(i) which is brought by or on behalf of a **Company** or any **Individual Insured**, other than an **Employee** of a **Company**; or which is brought by any security holder of the **Company**, whether directly or derivatively, unless such security holder's **Claim** is instigated and continued totally independent of, and totally without the solicitation of, or assistance of, or active participation of, or intervention of, any **Company** or any **Executive** of a **Company**; provided, however, this exclusion shall not apply to:

(i) any **Claim** brought by an **Individual Insured** in the form of a cross-claim or third-party claim for contribution or indemnity which is part of and results directly from a **Claim** which is covered by this policy;

(ii) in any bankruptcy proceeding by or against a **Company**, any **Claim** brought by the examiner, trustee, receiver, liquidator, or rehabilitator (or any assignee thereof) of such **Company**;

(iii) any **Claim** brought by any past **Executive** of a **Company** who has not served as a duly elected or appointed director, officer, trustee, governor, management committee member, member of the management board, General Counsel or Risk Manager (or equivalent position) of or consultant for a **Company** for at least four (4) years prior to such **Claim** being first made against any person;

(iv) any **Claim** brought by an **Executive** of a **Company** formed and operating in a **Foreign Jurisdiction** against such **Company** or any **Executive** thereof, provided that such **Claim** is brought and maintained outside the United States, Canada or any other common law country (including any territories thereof); or

(v) any **Executive** engaging in any protected "whistleblower" activity specified in 18 U.S.C. 1514A(a) or any other similar "whistleblower" protection provided under any state, local or foreign securities laws; provided, however, that this subsection (v) shall not apply where the actions of any **Executive** includes the filing of any proceeding or voluntarily testifying, voluntarily participating in or voluntarily assisting (other than de minimus assistance) in the filing or prosecution of any proceeding against an **Insured** relating to any violation of any rule or regulation of the Securities and Exchange Commission or any similar provision of any federal, state, local or foreign rule or law relating to

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END 013

ENDORSEMENT# 13 (continued)

fraud against shareholders, other than such actions in connection with a proceeding that is brought by the Securities and Exchange Commission, any similar state, local or foreign regulatory body that regulates securities, or any state, local or foreign law enforcement authority.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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END 013

105049 (4/10)

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ENDORSEMENT# 14

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

PREDETERMINED ALLOCATION FOR DEFENCE COSTS (D&O/EPL COVERAGE SECTIONS)

In consideration of the premium charged, it is hereby understood and agreed that the policy is amended as follows:

1. Clause 7. **DEFENCE COSTS, SETTLEMENTS, JUDGMENTS (INCLUDING THE ADVANCEMENT OF DEFENCE COSTS** of the **D&O Coverage Section** is hereby deleted in its entirety and replaced with the following:

   In the event that any **Claim** made involves both covered and uncovered allegations or matters, then the **Insureds**, the **Insurer** and the **Company** shall allocate **Defence Costs** relating to any such **Claim** in the manner set forth below.

   This endorsement relates to **Claims** which contain both covered and uncovered allegations or matters and accordingly, nothing in this endorsement shall be construed to provide coverage for **Loss** arising out of a **Claim** in which no matter is covered, or coverage for **Loss** (other than **Defence Costs**) for uncovered allegations or matters in **Claims** involving both covered and uncovered allegations or matters.

   Defence Costs incurred in connection with a **Claim** described in the first paragraph above shall be allocated as follows: 80% of such **Defence Costs** shall be allocated as **Loss** and 20% of such **Defence Costs** shall be allocated as not constituting **Loss** and not covered under the policy. The **Insurer's** liability for payment of the 80% of such **Defence Costs** shall be subject to all other terms, conditions and limitations of the policy and all endorsements thereto (whether any such endorsement precedes or follows this endorsement), including without limitation all terms and conditions of Clause 7 and Clause 9 of the policy. This **Defence Costs** allocation shall not apply to or create any presumption with respect to the allocation of any other **Loss** in connection with such a **Claim** or any other **Claim**.

2. Clause 6. **DEFENCE COSTS, SETTLEMENTS, JUDGMENTS (INCLUDING THE ADVANCEMENT OF DEFENCE COSTS** of the **Coverage Section** is hereby deleted in its entirety and replaced with the following:
   In the event that any **Claim** made involves both covered and uncovered allegations or matters, then the **Insureds**, the **Insurer** and the **Company** shall allocate **Defence Costs** relating to any such **Claim** in the manner set forth below.

   This endorsement relates to **Claims** which contain both covered and uncovered allegations or matters and accordingly, nothing in this endorsement shall be construed

END 14

ENDORSEMENT# 14 (Continued)

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

to provide coverage for **Loss** arising out of a **Claim** in which no matter is covered, or coverage for **Loss** (other than **Defence Costs**) for uncovered allegations or matters in **Claims** involving both covered and uncovered allegations or matters.

Defence Costs incurred in connection with a **Claim** described in the first paragraph above shall be allocated as follows: 80% of such **Defence Costs** shall be allocated as **Loss** and 20% of such **Defence Costs** shall be allocated as not constituting **Loss** and not covered under the policy. The **Insurer's** liability for payment of the 80% of such **Defence Costs** shall be subject to all other terms, conditions and limitations of the policy and all endorsements thereto (whether any such endorsement precedes or follows this endorsement), including without limitation all terms and conditions of Clause 6 and Clause 7 of the policy. This **Defence Costs** allocation shall not apply to or create any presumption with respect to the allocation of any other **Loss** in connection with such a **Claim** or any other **Claim**.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

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END 14

ENDORSEMENT# 15

This endorsement, effective September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

SIDE A EXCESS LIMIT OF LIABILITY ENDORSEMENT (EXCESS LIMIT APPLICABLE TO NON-INDEMNIFIABLE LOSS UNDER THE D&O COVERAGE SECTION)

In consideration of the premium charged, it is hereby understood and agreed that, solely with respect to coverage for **Loss** provided under the **D&O Coverage Section**, the policy is hereby amended as follows:

1. Item 7. of the Declarations is amended to include the following at the end thereof:

   (g) **SIDE A EXCESS LIMIT OF LIABILITY:** $1,000,000 , excess aggregate limit of liability for all **Non-Indemnifiable Loss** solely for **Executives** of a **Company** (including **Defence Costs**) under the **D&O Coverage Section** (herein the "**Side A Excess Limit of Liability**").

2. Clause 4. **LIMITS OF LIABILITY (FOR ALL LOSS IN THE AGGREGATE UNDER THIS POLICY AND UNDER EACH INDIVIDUAL COVERAGE SECTION - INCLUDING DEFENCE COSTS)** of the **General Terms And Conditions** is deleted in its entirety and replaced with the following:

   4. **LIMITS OF LIABILITY (FOR ALL LOSS IN THE AGGREGATE UNDER THIS POLICY AND UNDER EACH INDIVIDUAL COVERAGE SECTION - INCLUDING DEFENCE COSTS)**

      The **Policy Aggregate Limit of Liability** is the maximum limit of the **Insurer's** liability for all **Loss** (other than **Non-Indemnifiable Loss** covered under the **Side A Excess Limit of Liability**) under all **Coverage Sections** combined arising out of all **Claims** first made against the **Insureds** during the **Policy Period** or the **Discovery Period** (if applicable); provided, however, the **Policy Aggregate Limit of Liability** for the **Discovery Period** shall be part of, and not in addition to, the **Policy Aggregate Limit of Liability** for the **Policy Period**.

      If **Separate Limits of Liability** are stated in Item 3 of the Declarations, then each such **Separate Limit of Liability** shall be the maximum limit of the **Insurer's** liability for all **Loss** (other than **Non-Indemnifiable Loss** covered under the **Side A Excess Limit of Liability**) arising out of all **Claims** first made against the **Insureds** during the **Policy Period** or the **Discovery Period** (if applicable) with respect to the applicable **Coverage Section** as stated on the Declarations; provided, however, the **Separate Limit of Liability** for the **Discovery Period** shall be part of, and not in addition to, the **Separate Limit of Liability** for the **Policy Period**. Each **Separate Limit of Liability** shall be part of, and not in addition to, the **Policy Aggregate Limit of Liability** for all **Loss** under this policy and shall in no way serve to increase the **Insurer's Policy Aggregate Limit of Liability** as therein stated.

      If **Shared Limits of Liability** are stated in Item 3 of the Declarations, then each such **Shared Limit of Liability** shall be the maximum limit of the **Insurer's** liability for all **Loss** (other than **Non-Indemnifiable Loss** covered

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END

ENDORSEMENT# 15 (continued)

under the **Side A Excess Limit of Liability**) arising out of all **Claims** first made against the **Insureds** during the **Policy Period** or the **Discovery Period** (if applicable) with respect to all **Coverage Sections** for which such **Shared Limit of Liability** is applicable, as indicated on the Declarations; provided, however, with respect to all **Coverage Sections** that have a **Shared Limit of Liability**, the **Shared Limit of Liability** for the **Discovery Period** shall be part of, and not in addition to, the **Shared Limit of Liability** for the **Policy Period**. Each **Shared Limit of Liability** shall be part of, and not in addition to, the **Policy Aggregate Limit of Liability** for all **Loss** under this policy and shall in no way serve to increase the **Policy Aggregate Limit of Liability** as therein stated.

The **Side A Excess Limit of Liability** stated in Item 7(g) of the Declarations, as set forth by paragraph 1. of this endorsement above, is the aggregate limit of the **Insurer's** liability under the **D&O Coverage Section** excess of: (i) any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to the **D&O Coverage Section**; and (ii) any coverage for **Loss** (whether or not **Non-Indemnifiable Loss**) under any policy of insurance specifically written as excess over any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to the **D&O Coverage Section**, for all **Non-Indemnifiable Loss** under the **D&O Coverage Section** arising out of all **Claims** first made against an **Executive** of a **Company** during the **Policy Period** or the **Discovery Period** (if applicable). The **Side A Excess Limit of Liability** for the **Discovery Period** shall be part of, and not in addition to, the **Side A Excess Limit of Liability** for the **Policy Period**. The **Side A Excess Limit of Liability** shall be in addition to the **Policy Aggregate Limit of Liability** and any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to the **D&O Coverage Section**.

It is agreed that the **Insurer's** liability to pay **Non-Indemnifiable Loss** shall only attach to the **Side A Excess Limit of Liability** after:

(a) the full amount of any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to the **D&O Coverage Section** has been exhausted due to **Loss** paid thereunder; and

(b) any coverage for **Loss** (whether or not **Non-Indemnifiable Loss**) under any policy of insurance specifically written as excess over any **Separate Limit of Liability** or **Shared Limit of Liability** applicable to the **D&O Coverage Section** has been exhausted by reason of loss(es) paid thereunder.

The **Side A Excess Limit of Liability** provided by this endorsement shall "drop down" (continue in force as primary insurance) only in the event of (a) and (b) above and shall not drop down for any other reason.

Further, a **Claim** which is made subsequent to the **Policy Period** or **Discovery Period** (if applicable) which pursuant to Clause 6(b) or 6(c) of these **General Terms and Conditions** is considered made during the **Policy Period** or **Discovery Period**, shall also be subject to the **Policy Aggregate Limit of Liability** and subject to any applicable **Separate Limit of Liability**, **Shared Limit of Liability** or **Side A Excess Limit of Liability**.

Defence Costs are not payable by the **Insurer** in addition to the **Policy Aggregate Limit of Liability** or any applicable **Separate Limit of Liability**, **Shared Limit of Liability** or **Side A Excess Limit of Liability**. Defence Costs are part of **Loss** and as such are subject to the Policy Aggregate Limit of

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END 015

ENDORSEMENT# 15 (continued)

Liability for **Loss** and any applicable **Separate Limit of Liability**, **Shared Limit of Liability** or **Side A Excess Limit of Liability**. Amounts incurred for **Defence Costs** shall be applied against the Retention.

3. Solely for purposes of the coverage as afforded by this endorsement, "**Non-Indemnifiable Loss**" means **Loss** for which a **Company** has neither indemnified nor is permitted or required to indemnify an **Executive** of a **Company** pursuant to law or contract or the charter, bylaws, operating agreement or similar document of a **Company**.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

AUTHORIZED REPRESENTATIVE

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END 015

99563 CAN (7/08)

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ENDORSEMENT# 16

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

CANADIAN CRIME CODE 2.17.1 DEFENCE COSTS COVERAGE

1. In Clause 2. **DEFINITIONS** of the **D&O Coverage Section**, the definition of " **Loss**" is amended by adding the following at the end thereof:

   Loss shall also mean **Bill C-145 Defence Costs**, provided they arise out of a **Claim**.

2. Exclusion (l) of the **D&O Coverage Section** is deleted and replaced with the following:

   (l) for bodily injury, sickness, disease or death of any person, or damage to, loss of use of or destruction of any tangible property; provided, however, this exclusion shall not apply to **Securities Claims** or **Bill C-145 Defence Costs**;

As used in this endorsement, " **Bill C-145 Defence Costs**" means **Defence Costs** incurred by an **Individual Insured** that result solely from the investigation, adjustment, defence and/or appeal of a **Claim** against an **Organization** for violation of Section 217.1 in the Criminal Code of Canada or of any similar provision of any criminal code in any jurisdiction.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

AUTHORIZED REPRESENTATIVE

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END 16

ENDORSEMENT# *17*

This endorsement, effective *12:01 am September 1, 2011* forms a part of policy number *05-766-59-66*
issued to *YUKON DEVELOPMENT CORPORATION*

by *Chartis Insurance Company of Canada*

FORMS INDEX ENDORSEMENT

The contents of the Policy is comprised of the following forms:

FORM NUMBER	EDITION DATE	FORM TITLE
95862 CAN	09/07	PRIVATEEDGE PLUS - CANADA DEC
95726 CAN	09/07	PRIVATEEDGE PLUS - GENERAL TERMS & CONDITION
95727 CAN	09/07	D&O PrivateEdge Plus Coverage Section
95728 CAN	09/07	EPL PrivateEdge Plus Coverage Section
95729	09/08	FIDUCIARY LIABILITY INSURANCE ('FLI COVERAGE SECTION')
99544	07/08	EMPLOYEE BENEFIT PLAN FIDUCIARY LIABILITY PANEL COUNSEL
95737 CAN	09/07	NUCLEAR ENERGY LIABILITY EXCLUSION ENDORSEMENT (ALL COVERAGE SECTIONS)
95679	09/07	CAPTIVE INSURANCE COMPANY EXCLUSION DELETED ENDORSEMENT (D&O COVERAGE ENDORSEMENT)
98961	04/08	COMMISSION EXCLUSION DELETED (D&O COVERAGE SECTION)
C0004 CAN	01/08	STATUTORY ENDORSEMENT COVERAGE (D&O COVERAGE SECTION)
95806	09/07	RELIANCE UPON APPLICATION MADE TO ANOTHER CARRIER (D&O COVERAGE SECTION)
98966	04/08	SEVERABILITY OF THE APPLICATION ENDORSEMENT (NON-RESCINDABLE - FULL INDIVIDUAL SEVERABILITY; TOP 3 COMPANY POSITIONS IMPUTED TO COMPANY) (D&O AND EPL COVERAGE SECTIONS)
C0002 CAN	01/08	CANADIAN CORPORATE TAX EXTENSION (D&O COVERAGE SECTION)
		SIDE A POLLUTION COVERAGE ENDORSEMENT (GENERAL TERMS AND CONDITIONS)
C0054	03/09	CANCELLATION AMENDATORY (GENERAL TERMS AND CONDITIONS AMENDMENT)
99176	05/08	INSURED V. INSURED EXCLUSION (CREDITORS COMMITTEE) (D&O COVERAGE SECTION)
100696	11/08	INSURED V. INSURED EXCLUSION AMENDED (CARVE-BACK FOR SERVICE AS D&O OVER 3 YEARS PRIOR)(D&O COVERAGE SECTION)
105118	04/10	EXTRADITION COVERAGE (D&O COVERAGE SECTION)
105049	04/10	INSURED V. INSURED EXCLUSION (D&O)(WHISTLEBLOWER)

END 017

ENDORSEMENT# 17

This endorsement, effective 12:01 am September 1, 2011 forms a part of policy number 05-766-59-66
issued to YUKON DEVELOPMENT CORPORATION

by Chartis Insurance Company of Canada

FORMS INDEX ENDORSEMENT

The contents of the Policy is comprised of the following forms:

FORM NUMBER	EDITION DATE	FORM TITLE
		PREDETERMINED ALLOCATION FOR DEFENCE COSTS (D&O/EPL COVERAGE SECTIONS)
99563 CAN	07/08	SIDE A EXCESS LIMIT OF LIABILITY ENDORSEMENT (EXCESS LIMIT APPLICABLE TO NON-INDEMNIFIABLE LOSS UNDER THE D&O COVERAGE SECTION)
		CANADIAN CRIME CODE 2.17.1 DEFENCE COSTS COVERAGE
78859	10/01	FORMS INDEX ENDORSEMENT

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS REMAIN UNCHANGED.

AUTHORIZED REPRESENTATIVE

END 017

78859 (10/01)

Page 2 of 2

CUSTOMER ADVISORY
REGARDING THE ENFORCEMENT OF
ECONOMIC EMBARGOES AND TRADE SANCTIONS

Your rights as a policyholder and payments to you, any insured or claimant, for loss under this policy may be affected by the administration and enforcement of economic embargoes and trade sanctions applicable to you, any insured, claimant and/or to the insurer and their respective controlling entities (hereinafter "Trade Sanctions").

WHAT IS AN ECOMONIC EMBARGO AND/OR TRADE SANCTION

Trade Sanctions involve the imposition by a country of legal measures to restrict or prohibit trade, services or other economic activity with a target country, entity or individual. For example, the Parliament of Canada has enacted legislation authorizing the imposition of Trade Sanctions through the *United Nations Act,* the *Special Economic Measures Act* and some provisions of the *Export and Import Permits Act.*

Depending upon the identity, domicile, place of incorporation or nationality of the policyholder, insured, claimant, insurer, or the parent company and ultimate controlling entity of the policyholder, insured, claimant or insurer, or the country where the claim arises, Trade Sanctions of foreign countries, including the United States of America, may be applicable. The application of sanctions could necessitate the seizure or freezing of property, including but not limited to the payment of a claim.

Existing Trade Sanctions can be amended, and new Trade Sanctions can be imposed, at any time.

OBLIGATIONS PLACED ON US AS A RESULT OF TRADE SANCTIONS

If we determine that you or any insured, additional insured, loss payee, or claimant are on a prohibited list or are connected to a sanctioned country, entity or individual, or a prohibited activity, as designated by the relevant Trade Sanction, we may be required to comply with the requirements of the applicable Trade Sanction, which by way of example, may include blocking or "freezing" property and payment of any funds and the reporting of such occurrences to the relevant authorities within the prescribed time periods, if any.

POTENTIAL ACTIONS BY US

Depending upon the requirements of the relevant Trade Sanction:

1. We may be required to immediately cancel your coverage effective on the day that we determine that we have transacted business with an individual or entity associated with your policy on a prohibited list or connected to a sanctioned country as described in the relevant Trade Sanction.
2. If we cancel your coverage, you may not receive a return premium unless permitted pursuant to the relevant Trade Sanction. All blocked or frozen funds will be placed in an interest bearing blocked account established on the books of a financial institution.
3. We may not pay a claim, accept premium or exchange monies or assets of any kind to or with individuals, entities or companies (including a bank) on a prohibited list or connected to, or carrying on business in, a sanctioned country as designated by the relevant Trade Sanction. Furthermore, we may not defend or provide any other benefits under your policy to individuals, entities or companies on a prohibited list or connected to, or carrying on business in, a sanctioned country as designated by the relevant Trade Sanction.

This Trade Sanction Advisory is part of Chartis' comprehensive compliance program and is meant to serve as a reminder of the existing applicable legal requirements with respect to Trade Sanctions.

THE GUARANTEE COMPANY OF NORTH AMERICA

810 - 400 Burrard Street
Vancouver, BC V6C 3A6
Tel 604-687-7688
Fax 604-687-8861
www.gcna.com

NEW POLICY

INSURED

Name: YUKON DEVELOPMENT CORPORATION

BROKER

Name: AON REED STENHOUSE INC.

COPY

POLICY

No.: B17139
Type: CRIME SHIELD 3-D FORM A

Term:	SEPTEMBER 1, 2011 TO SEPTEMBER 1, 2012
Premium:	$3,390

21/09/2011 NS

NOREEN FUKUHARA
CORPORATE INSURANCE

ORIGINAL

Serving North America since 1872

THE GUARANTEE COMPANY OF NORTH AMERICA

GUARANTEE SHIELD

AMENDED DISCOVERY PROVISIONS

RIDER NO.: **1**
POLICY NO.: **B17139**

INSURED: **YUKON DEVELOPMENT CORPORATION**
(As more fully described in the attached Policy or amendments thereto)

IN CONSIDERATION OF THE PAYMENT OF THE PREMIUM, it is hereby understood and agreed that:

1. CONDITION 2 D is deleted in its entirety and replaced by the following:

   D If, prior to the cancellation or termination of this **Policy**, this **Policy** or any **Insuring Agreement** hereof is cancelled or terminated as to any **Insured**, the **Underwriter** shall have no liability for any **Loss** sustained by such **Insured** unless such **Loss** is **Discovered** within one hundred and twenty (120) days from the date of such cancellation or termination. Cancellation of this insurance hereunder as respects any **Employee** or **Partner** as provided in **Condition 19** herein shall apply to every **Insured**.

2. item (ii) of CONDITION 3A (ii) is deleted in its entirety and replaced by the following:

   (ii) during the period not later than one hundred and twenty (120) days from the end of the **Policy Period**.

3. item (ii) of CONDITION 9 A is deleted in its entirety and replaced by the following:

   (ii) give written notice thereof to the **Underwriter** at the earliest practicable moment, and in any event within the earlier of ninety (90) days after such **Discovery**, or one hundred and twenty (120) days after termination of coverage,

4. item (iv) of CONDITION 20 A is deleted in its entirety and replaced by the following:

   (iv) the expiration of one hundred and twenty (120) days after receipt by the first named **Insured** of written notice from the **Underwriter** to terminate the **Policy** for any other reason than the non-payment of premium or **Bankruptcy Event** which notice shall be sent to the first named **Insured's** last mailing address known to the **Underwriter**;

This Rider shall become effective as of 12:01 a.m. standard time on the 1st day of September, 2011.

All other terms and conditions of said **Policy** remain the same.

Executed at Vancouver, British Columbia
this 21st day of September, 2011.

THE GUARANTEE COMPANY OF NORTH AMERICA

Noreen Fukuhara, Attorney-in-fact

Mary da Costa, Attorney-in-fact



(herein called **Underwriter**)

CRIME SHIELD POLICY

COMPREHENSIVE DISHONESTY, DISAPPEARANCE AND DESTRUCTION

Policy No. B17139

DECLARATIONS

Item 1 Name of Insured (herein called **Insured**):

YUKON DEVELOPMENT CORPORATION
YUKON ENERGY CORPORATION

(and any Pension or Employee Benefit Plan sponsored and controlled by the Insured)

Principal Address:

#2 MILES CANYON ROAD, BOX 5920
WHITEHORSE, YUKON
Y1A 6S7

Item 2 **Policy Period**: Effective: 12:01 a.m. on **September 1, 2011**
Expiry: 12:01 a.m. on **the effective date of cancellation or termination of this Policy,** standard time at the Principal Address as to each of said dates.



Policy No. B17139

DECLARATIONS (continued)

Item 3 Insuring Agreements, Limits of Liability and Deductible Amounts

Insuring Agreements		**Limit of Liability** (Per Occurrence)	**Deductible Amount** (Per Occurrence)
1.	DISHONESTY:		
	☒ Form A – Limit per Occurrence, **OR** ☐ Form B – Limit per **Employee**		
	a) EMPLOYEE	**$**1,000,000.	**$**10,000.
	b) PARTNER	**$**Not Covered	**$**Not Covered
2.	LOSS INSIDE OR OUTSIDE THE PREMISES	**$**1,000,000.	$10,000.
3.	LOSS FROM ROBBERY AND SAFE BURGLARY	$1,000,000.	$10,000.
4.	MONEY ORDERS AND COUNTERFEIT PAPER CURRENCY	$1,000,000.	$10,000.
5.	FORGERY OR ALTERATION	$1,000,000.	$10,000.
6.	CREDIT CARD FORGERY	$50,000.	$Nil
7.	COMPUTER AND TRANSFER FRAUDS:		
	A COMPUTER FRAUD	$1,000,000.	$10,000.
	B COMPUTER VIRUS FRAUD – SPECIAL LIMIT	$1,000,000.	$10,000.
	C FUNDS TRANSFER FRAUD [CALL-BACK VERIFICATION REQUIRED FOR TRANSFERS GREATER THAN **$100,000.**]	$1,000,000.	$10,000.
	D VOICE COMPUTER TOLL FRAUD	$Not Covered	$Not Covered
8.	EXTORTION:		
	A THREATS TO PERSONS	$Not Covered	$Not Covered
	B THREATS TO PROPERTY	$Not Covered	$Not Covered
SUPPLEMENTAL COVERAGES			
9.	PENSION OR EMPLOYEE BENEFIT PLAN	$1,000,000.	$Nil
10.	CLIENT	$Not Covered	$Not Covered
11.	EXPENSES:		
	A RESTORATION EXPENSE	$Not Covered	$Not Covered
	B CLAIMS EXPENSE	$50,000.	$Nil



Policy No. B17139

DECLARATIONS (continued)

If "Not Covered" or "Nil" is inserted above opposite any specified Insuring Agreement or Coverage, such Insuring Agreement or Coverage and any other reference thereto in this **Policy** shall be deemed to be deleted therefrom.

Item 4 Riders forming part of this **Policy** when issued:

Rider(s) No. 1

Item 5 Upon delivery of this **Policy** to the **Insured** or its agent or broker, the **Insured** gives notice to the **Underwriter** terminating or cancelling, in whole or in part, prior bond(s) or policy(ies) no.(s) A57021, to the extent that this **Policy** replaces the said prior bond(s) or policy(ies), such termination or cancellation to be effective as of the time this **Policy** becomes effective.

Signed, sealed and dated this 21st day of September, 2011.

THE GUARANTEE COMPANY OF NORTH AMERICA

Noreen Fukuhara, Attorney-in-fact

Mary da Costa, Attorney-in-fact

In consideration of the payment of the premium, and subject to the **Declarations**, the **Insuring Agreements**, **Definitions**, **Exclusions** and **Conditions** and other terms of this **Policy**, the **Underwriter** agrees to pay for **Loss** sustained during the **Policy Period** or during the extended period to **Discover** a **Loss,** as follows:

INSURING AGREEMENTS

The **Underwriter** shall pay for **Loss** of **Property** (or as otherwise set out) sustained by an **Insured** resulting directly from:

1 **EMPLOYEE/PARTNER DISHONESTY**

One or more **Dishonest or Fraudulent Acts** committed by an **Employee** or by a **Partner**, acting alone or in collusion with others.

2 **LOSS INSIDE OR OUTSIDE THE PREMISES**

Theft, destruction or disappearance of **Money** and **Securities** within or from the **Premises or Financial Institution Premises,** or while **In Transit**.

3 **LOSS FROM ROBBERY AND SAFE BURGLARY**

A **Theft**, disappearance or destruction of, or damage to **Other Property** within or from the **Premises** or **Financial Institution Premises** from an actual or attempted **Robbery** or **Safe Burglary**.

B Damage to the **Premises** or its exterior, or damage to a locked safe, vault, cash register, cash box or cash drawer located inside the **Premises** from an actual or attempted **Theft, Safe Burglary** or **Robbery.** However, coverage shall apply only if the **Insured** is the owner of, or is legally liable for the **Premises** and/or the **Other Property** specifically referred to in this **Insuring Agreement**.

4 **MONEY ORDERS AND COUNTERFEIT PAPER CURRENCY**

The acceptance by the **Insured** in good faith, in the regular course of business, and in exchange for merchandise, **Money** or services, of any:

(i) bank, post office or express money order, issued or purporting to have been issued by any bank, post office or express company, if such money order is not paid upon presentation, or

(ii) counterfeit paper currency purporting to have been issued by Canada, the United States of America, or by any other country in which the **Insured** maintains a **Premises**.

5 **FORGERY OR ALTERATION**

Forgery or alteration of, on or in a **Financial Instrument**, made or drawn by or upon the **Insured**, or purporting to have been so made or drawn.

6 **CREDIT CARD FORGERY**

Forgery or alteration of, on or in any written instrument required in connection with any **Credit Card** issued either to the **Insured** or, at the request of the **Insured**, to any **Partner** or **Employee.** However, coverage shall apply only if the person or entity to whom the **Credit Card** was issued has fully complied with the provisions, conditions and other terms under which such **Credit Card** shall have been issued.

7 **COMPUTER AND TRANSFER FRAUDS**

A **COMPUTER FRAUD**

The use of a **Computer System** to cause a transfer of **Property** from inside the **Premises** or from inside a **Financial Institution Premises** to a person or place outside of either such **Premises**.

B **COMPUTER VIRUS FRAUD**

The **Insured** having, in good faith,

(i) transferred, paid or delivered any **Property**, or

(ii) established credit, debited any account or given any value,

as the direct result of the destruction or attempted destruction of the **Insured's Electronic Data** due to a **Computer Virus** while such **Electronic Data** are stored within the **Insured's** or a **Service Provider's Computer System**.

C **FUNDS TRANSFER FRAUD**

Any **Funds Transfer Fraud** by a **Third Party**.

D **VOICE COMPUTER TOLL FRAUD**

Any charges incurred by the **Insured** for telephone long-distance toll-calls as a direct result of the fraudulent use of either an **Account Code** or a **System Password** in connection with a **Voice Computer System,** but only where such **Voice Computer System** is owned or leased by the **Insured**, and installed on the **Premises**.

8 **EXTORTION**

A **THREATS TO PERSONS**

A threat communicated to the **Insured** to do bodily harm to:

(i) a director, **Employee** or **Partner** of the **Insured**,

(ii) a relative or invitee of any person indicated in (i) above,

who is, or allegedly is, being held captive when the captivity, or alleged captivity, takes place within Canada or the United States of America.

B **THREATS TO PROPERTY**

A threat communicated to the **Insured** to do damage to the **Premises** or to **Property** of the **Insured** located in Canada or the United States of America.

SUPPLEMENTAL COVERAGES

The **Underwriter** shall also pay for:

9 **PENSION OR EMPLOYEE BENEFIT PLAN**

Loss of **Property** which a **Pension or Employee Benefit Plan** shall sustain resulting directly from one or more **Dishonest or Fraudulent Acts** committed by a **Fiduciary**, acting alone or in collusion with others.

10 **CLIENT**

Loss of **Property** which any **Client** shall sustain resulting directly from one or more **Dishonest or Fraudulent Acts,** committed by an **Employee**, acting alone or in collusion with others, but not in collusion with the **Client's** employees.

11 **EXPENSES**

A **RESTORATION EXPENSE**

Restoration Expense caused solely by a **Computer Incident.**

B **CLAIMS EXPENSE**

Necessary and reasonable expenses, other than the **Insured's** internal costs (such as, but not limited to, any employee remuneration) paid by the **Insured** to prepare and file the proof of loss.

DEFINITIONS

Account Code means in connection with a **Voice Computer System**, a confidential and protected string of characters which identifies or authenticates a person and permits that person to gain access to the **Voice Computer System** for the purpose of making telephone long-distance toll-calls or utilizing voice mail box messaging capabilities or other authorized functional features.

Application Service Provider (ASP) means a business that provides computer-based services to customers over a network.

Authorized Representative means anyone, other than an **Employee**, **Partner**, director or trustee, acting with the actual or apparent authority of the **Insured**, and includes any person or entity that has the actual or apparent authority of the **Insured** to have care and custody of any **Property** outside the **Premises**.

Automated Mechanical Device means an unattended mechanical unit which disburses or which receives and gives credit for **Money** or **Securities**, or which makes loans, and includes an automated teller machine, a video lottery terminal, a gaming machine, a card-operated amusement device and a vending machine.

Bankruptcy Event means the making or the deemed making of an assignment into bankruptcy by the **Insured**, or the making of a bankruptcy order as against the **Insured**, or the appointment of a receiver, where such action is taken pursuant to the *Bankruptcy and Insolvency Act* (Canada), or any equivalent legislation in jurisdictions outside of Canada.

Client means a customer of the **Insured** to whom the **Insured** provides goods or services under a written contract or for a fee.

Counterfeit means an imitation of an actual valid original which is intended to deceive and to be taken as the original.

Computer Incident means:

(i) a **Loss** under either **Insuring Agreement 7 A** or **7 B**, but only where the amount of such **Loss** is in an amount in excess of any applicable **Deductible Amount**;

(ii) damage to or destruction of the **Insured's Computer Programs** or **Electronic Data** as a direct result of a **Computer Virus**, but only if the relevant **Electronic Data** are stored within the **Insured's** or a **Service Provider's Computer System; or**

(iii) damage to or destruction of the **Insured's Computer Programs** or **Electronic Data** as a direct result of any vandalism by a person, including an **Employee**, through that person's intrusion into the **Insured's Computer System.**

Computer Programs means related electronic instructions that direct the operations of a **Computer System** or connected devices to enable the receiving, processing, storage, retrieval, sending, creation and similar functions of the **Computer System** and connected devices to interact with **Electronic Data**.

Computer System means:

(i) personal computers, servers and mainframes with related peripheral components, including storage components and off-line media libraries, and including any similar equipment or facilities of any **Service Provider**, but only to the extent of the **Insured's** interest in such **Service Provider**;

(ii) operating systems and applications software;

(iii) terminal devices;

(iv) related communication devices and networks; and

(v) mobile communication devices with related peripheral components

by which **Electronic Data** are electronically collected, transmitted, processed, stored and retrieved.

Computer Virus means **Malware** which is deliberately and exclusively directed by an individual, including an **Employee** or a **Partner**, at the **Insured**, and which propagates itself through a **Computer System.**

Credit Card means an electronic card issued by a **Financial Institution**, retail store or other business containing unique identification or other verifiable security features to prevent fraud, used to facilitate repeated borrowing or purchasing goods or service without cash and to pay at a later date. However, it does not mean a debit card, stored value or pay safe card, convenience card, e-money or e-currency, or other electronic or digital cash card other than that expressly described in this definition.

Deductible Amount(s) means the deductible amount(s) listed for any particular **Insuring Agreement**(s) as set out in **Item 3** of the **Declarations**.

Designated Representative means in respect of the **Insured**, any elected or appointed director, officer or risk manager, or any senior manager, or any person who while in the **Insured's** employ, has or has had supervisory responsibilities over any **Employee** or **Partner** who is alleged to have committed any **Dishonest or Fraudulent Acts.**

Dishonest or Fraudulent Acts means any dishonest or fraudulent act or acts of an **Employee** or a **Partner**, committed alone or in collusion with others with the manifest intent to:

(i) cause the **Insured** to sustain a **Loss**; and

(ii) obtain financial benefit for any person or entity or for the **Employee** or **Partner**, other than salaries, commissions, fees, bonuses, promotions, awards, profit sharing, pensions or other employee benefits, obtained in the normal course of employment.

Discover, Discovers, Discovered, Discovery means the time when the **Insured**, or any **Partner** or **Designated Representative**:

(i) first becomes aware of facts which would cause a reasonable person to assume or to believe that a **Loss** of a type covered by this **Policy** has been or will be incurred, regardless of when the act or acts causing or contributing to such **Loss** occurred, even though the exact amount or details of such **Loss** may not then be known; or

(ii) receives notice or becomes aware of an actual or potential claim in which it is alleged or it is possible that the **Insured** is liable to a **Third Party** under circumstances which, if true, would constitute a **Loss** under this **Policy**.

Electronic Data means representations of information or concepts, in any form, stored in a **Computer System.**

Employee or **Employees** means:

(i) any natural person:

  (a) while in the regular service of the **Insured** in the ordinary course of its business, and for the first 60 days after termination of service, whether temporary, permanent, full-time, part-time or seasonal,

  (b) whom the **Insured** compensates directly by salary, wages, and/or commissions, and

  (c) whom the **Insured** has the right to direct and control while performing services for the **Insured**;

(ii) any natural person who is furnished temporarily to the **Insured** to:

  (a) substitute for a permanent employee (of a type described in (a) above), who is on leave, or

  (b) meet seasonal or short-term work-load requirements,

  whom the **Insured** has the right to direct and control while performing services for the **Insured;**

(iii) any natural person who satisfies (i) (a) and (i) (c) above and who is:

  (a) not compensated,

  (b) a member of a board of directors, board of trustees, board of managers, or equivalent management board of any **Pension or Employee Benefit Plan**, and

  (c) performing employee duties pursuant to a written contract to which any **Insured** is a party; and

(iv) any employee of an entity merged or consolidated with the **Insured** prior to the **Policy Period.**

If there is more than one **Insured** named in this **Policy**, an **Employee** (as defined above) of one **Insured** shall be considered to be an **Employee** of any other **Insured** provided that person is compensated by salary, wages and/or commissions by any one or more of the named **Insureds.**

However, **Employee** does not mean any:

(i) agent, broker, factor, commission merchant, consignee, independent contractor, **Authorized Representative**, or other agent or representative of the same general character, or any of their employees or agents; or

(ii) directors or trustees of the **Insured** except while performing acts within the scope of the usual duties of an **Employee**.

Fiduciary or **Fiduciaries** means a trustee, officer, **employee**, administrator or manager, and any of their employees, of any **Pension or Employee Benefit Plan** and any **Employee** or **Partner** while handling the **Property** of any **Pension or Employee Benefit Plan.**

However, a **Third Party** can be a **Fiduciary** only where such **Third Party** has insurance (other than any which may be provided under this **Policy**) in respect of, or provides indemnity for **Loss** of such **Property.**

Financial Institution means:

(i) a bank, trust company, credit union or other deposit-taking institution;

(ii) an insurance company; or

(iii) a stock brokerage, securities dealer firm, mutual fund company, or pension fund, securities fund, or liquid assets fund company or other investment institution,

at which the **Insured** maintains one or more accounts.

Financial Institution Premises means the interior portion of any building or the night depository chute or safe maintained or occupied by any **Financial Institution**.

Financial Instrument means a cheque, including a certified cheque, draft, promissory note, bill of exchange, or other written promise, order or direction to pay a sum certain in money, but does not include **Money**.

Forgery means the signing of the name of another person or organization with the intent to deceive; it does not mean a signature which consists in whole or in part of one's own name signed with or without authority, in any capacity, for any purpose. Mechanically or electronically reproduced signatures shall be treated the same as hand-written signatures.

Funds Transfer Fraud means fraudulent electronic, telegraphic, cable, teletype, facsimile or telephone instructions, or other fraudulent written instructions (other than those referred to in **Insuring Agreement 5**) issued to a **Financial Institution** without the **Insured's** knowledge or consent directing such Institution to transfer, pay or deliver **Money** or **Securities** from any account maintained by the **Insured** at such Institution to or for the benefit of a **Third Party**.

In Transit means outside the **Premises** and within the care and custody of:

(i) an **Employee;** or

(ii) an **Authorized Representative** but only where such **Authorized Representative** has insurance (other than any which may be provided under this **Policy**) in respect of, or provides indemnity for **Loss** of such **Property**.

Limit(s) of Liability means the limit(s) of liability listed for any particular **Insuring Agreement**(s) as set out in **Item 3** of the **Declarations**.

Loss and Losses means the actual direct financial loss sustained, and where applicable, the permanent reduction in value of any **Other Property** which is owned by the **Insured**, held by the **Insured** in any capacity or for which the **Insured** is legally liable.

Malware means any malicious and unauthorized software designed to infiltrate a **Computer System** without the **Insured's** informed consent and includes **Computer Viruses**, worms, Trojan Horses, spyware and other malicious and unwanted software.

Money means currency, coins, bank notes, bullion, travellers' cheques, register cheques, and money orders held for sale to the public.

Occurrence means:

(i) with respect to **Insuring Agreements 1, 9, 10,** and **11,** any **Loss** caused by or involving one or more **Employees, Partners**, or **Fiduciary(ies),** as the case may be, whether the result of a single act or series of related acts;

(ii) with respect to **Insuring Agreement 5,** any **Loss** caused by any person or in which that person is involved, whether the **Loss** involves one or more instruments;

(iii) with respect to all other **Insuring Agreements,** including **Insuring Agreements 7 A, 7 B,** and **7 D,** any **Loss** caused by:

(a) an act, or series of related acts, involving one or more persons;

(b) an act or series of acts involving a person or group of persons acting together, or

(c) an act or event, or a series of related acts or events, not involving any identifiable person,

(iv) with respect to **Insuring Agreement 7 A** and **7 B,** only, all acts or series of related acts occurring within a given 30 day period; or

(v) with respect to **Insuring Agreement 7 D** only, a **Single Loss.**

Other Property means any tangible property other than **Money** and **Securities** that has intrinsic value, but does not include any property excluded under this **Policy** and does not include intangible property such as **Electronic Data, Computer Programs**, intellectual property, trade secrets, or corporate opportunities.

Partner or **Partners** means a natural person who is a general partner or a limited partner of the **Insured** during the **Policy Period.**

Pension or Employee Benefit Plan means any employee benefit plan or pension benefit plan established solely for the benefit of **Employees** which is both sponsored and controlled by the **Insured,** and the existence of which is expressly disclosed to the **Underwriter** prior to **Discovery** of **Loss.**

Policy Period means the time span shown in **Item 2** of the **Declarations** commencing with the effective date of the **Policy** until its expiry date, and if there is no definite expiry date set out in the **Declarations,** then until such time as the **Policy** is cancelled or terminated in accordance with the terms herein.

Premises means the interior of that portion of any building which is occupied by the **Insured** in conducting its business.

Property means **Money, Securities** and **Other Property.**

Restoration Expense means necessary and reasonable expenses, other than the **Insured's** own internal costs (such as, but not limited to, any employee remuneration) paid by the **Insured** after **Discovery** of a **Computer Incident** to restore the operational capabilities of a **Computer Program** or of **Electronic Data** to the level that existed immediately prior to a **Computer Incident.**

Robbery means the **Theft** of **Property** from the care and custody of an **Employee, Partner,** or **Authorized Representative,** or from a **Watchperson,** by violence or threat of violence, committed in the presence and cognizance of such person.

Safe Burglary means:

(i) the **Theft** of **Property** from within a locked safe or vault located within the **Premises** or **Financial Institution Premises** by a person unlawfully entering the safe or vault as evidenced by marks of forcible entry upon its exterior; or

(ii) the **Theft** of a locked safe or vault from the **Premises** or **Financial Institution Premises.**

Securities means all negotiable and non-negotiable instruments or contracts representing either **Money** or **Other Property** and includes revenue and postage stamps in current use (whether actual stamps or unused value in a meter), tokens and tickets, and evidence of debt issued in connection with any creditor charge card, which card is not issued by the **Insured,** but does not include **Money.**

Service Provider means a natural person, partnership or corporation authorized by way of written agreement to perform data processing services on the **Insured's** behalf using a **Computer System,** and includes an **Application Service Provider.**

Single Loss means, in respect of **Insuring Agreement 7 D** only, a **Loss** resulting from telephone long-distance toll-call charges incurred over a period of not more than 30 days inclusive of the date on which the first such telephone long-distance toll-call charge was incurred.

Special Limit means a sub-limit that forms a part of, and is not in addition to, the **Limit of Liability** or amount payable under another **Insuring Agreement** sharing the **Loss.**

System Administration means, in connection with a **Voice Computer System**, the performance of security functions including, but not limited to, defining authorized persons to access a **Voice Computer System**, and modifying **Account Codes** or **System Passwords** in connection therewith; and invoking or revoking a **Voice Computer System** option which directs telephone call routing, or which changes telephone lines or voice over internet protocol (VoIP), or which performs any other similar activity allowed by a hardware-based or software-based **Voice Computer System**.

System Maintenance means in connection with a **Voice Computer System**, the performance of hardware and software installation, diagnostics and corrections and similar activities that are performed to establish or maintain the basic operational functionality of a **Voice Computer System** or components thereof.

System Password means in connection with a **Voice Computer System**, a confidential and protected string of characters which identifies or authenticates a person and permits that person to gain access to a **Voice Computer System** or any portion thereof for the purpose of performing **System Administration** or **System Maintenance** activities.

Theft means the unlawful taking of **Property** to the deprivation of the **Insured**.

Third Party means a person or entity, other than an **Insured**, a director, a trustee, an **Employee** or a **Partner**.

Unauthorized Instructions means instructions which are not actually or apparently authorized by the **Insured**.

Voice Computer System means a **Computer System** installed in one or more locations which functions as one or more of the following: a private branch exchange (PBX), a VoIP telephony router, a voice mail processor, an automated call attendant, or a system which provides similar capability, where such system is used for the direction or routing of telephone or voice calls in a voice communications network.

Watchperson means a person retained by the **Insured** specifically to safeguard or protect **Property** inside the **Premises** and who has no other duties.

EXCLUSIONS

THIS POLICY DOES NOT APPLY TO:

A **Loss** due to any **Dishonest or Fraudulent Act** committed by any **Insured, Partner, Employee, Fiduciary**, director, trustee or **Authorized Representative** of any **Insured**, whether acting alone or in collusion with others, while performing services for the **Insured** or otherwise, except when covered under **Insuring Agreements 1, 9, 10** or **11**;

B **Loss,** the proof of which, either as to its factual existence or as to its amount, is solely dependent upon an inventory computation or a profit and loss computation. However, where the **Insured** establishes wholly apart from such computation that it has sustained a **Loss,** it may offer its inventory records and actual physical count of inventory in support of the amount of **Loss** claimed;

C **Loss** due to war, whether or not declared, warlike action, insurrection, terrorism, rebellion or revolution, or any related act or incident;

D under **Insuring Agreements 2, 3, 6, 7** and **11 A, Loss** due to:

(i) the giving or surrendering of **Property** in any exchange or purchase,

(ii) accounting or arithmetical errors or omissions,

(iii) **Theft**, destruction or disappearance of manuscripts, books of account, records, microfilm, **Electronic Data**, or tapes, unless otherwise covered under **Insuring Agreement 11 A**, or

(iv) vandalism, unless otherwise covered under **Insuring Agreement 11 A**;

E under **Insuring Agreements 2, 3, 6 and 7, Loss** due to:

(i) any dishonest act used to induce an **Employee** or **Authorized Representative** to part voluntarily with title to or possession of any **Property**,

(ii) the transfer or the surrender of **Property** to a person or place outside the **Premises** or **Financial Institution Premises** on the basis of **Unauthorized Instructions**, unless otherwise covered under **Insuring Agreement 7**, or

(iii) the transfer or the surrender of **Property** to a person or place outside the **Premises** or **Financial Institution Premises**:

(a) as a result of a threat to do bodily harm to any person, or

(b) as a result of a threat to do damage to any **Property**;

F **Loss** due to or arising out of the use of any **Automated Mechanical Device** which is owned, leased or operated by the **Insured**, unless all amounts of **Money** and **Securities** disbursed from and received by the **Automated Mechanical Device** are recorded by a continuous recording instrument therein, and unless coverage for such **Loss** is specifically added by way of a rider to this **Policy**;

G **Loss** due to or arising out of nuclear reaction, nuclear radiation or radioactive contamination, or to any related act or incident;

H **Loss** due to damage to the **Premises** resulting from fire, however caused;

I any fees, costs or expenses incurred or paid by the **Insured** in prosecuting or defending any legal proceeding brought by or against the **Insured**, whether or not such proceeding results or would result in a **Loss** to the **Insured** that is covered by this **Policy**, except as may be specifically stated to the contrary in this **Policy**, or except to the extent expressly agreed to in writing by the **Underwriter**;

J indirect or consequential loss of any kind including, but not limited to:

(i) the **Insured's** inability to realize income including, but not limited to, interest and dividends that would or might have been realized had there been no **Loss**,

(ii) payment of damages of any type for which the **Insured** is or was legally liable, other than compensatory damages arising directly from a **Loss** covered under this **Policy**, or

(iii) payment of costs, fees or other expenses of any kind, except where covered under **Insuring Agreement 11**;

K **Loss** of **Property** due to the transfer or conversion by means of a computer to a person or place outside of the **Premises** or any **Financial Institution Premises** on the basis of **Unauthorized Instructions**, unless otherwise covered under any of **Insuring Agreements 7 A, 7 B** or **7 C**;

L **Loss** sustained by one **Insured** to the advantage of any other **Insured**.

M under **Insuring Agreements 2** and **3**, **Loss** due to the acts of any broker, factor, commission merchant, consignee, **Authorized Representative**, independent contractor or other agent, or other representative of the same general character, or any of their employees or agents;

N **Loss** of **Property** while in the mail or in the custody of a carrier for hire other than an armoured motor vehicle company;

O **Loss** due to any authorized or unauthorized trading of **Property** whether or not in the name of the **Insured** and whether or not in a genuine or fictitious account, provided however that this **Exclusion** shall not apply to **Insuring Agreement 1**;

P **Loss** of intangible property of any kind including, but not limited to, **Electronic Data**, **Computer Programs**, intellectual property, trade secrets or corporate opportunities.

CONDITIONS

1 **CONSOLIDATION - MERGER - ACQUISITION - CREATION OF NEW SUBSIDIARY**

A If through consolidation, merger, purchase or acquisition of another entity with assets valued at greater than 25% of the **Insured's** assets, any additional persons become **Employees**, or if the **Insured** acquires the use and control of any additional **Premises**:

(i) the **Insured** must within ninety (90) days of the date of such consolidation, merger, purchase or acquisition give written notice to and receive written consent from the **Underwriter** to extend coverage under this **Policy** to such addition, but

(ii) the **Underwriter** reserves the right to require payment of an additional premium for such consent.

B If, through the creation of any new organization (other than a **financial institution**) which the **Insured** owns, directly or indirectly, in a proportion greater than 25%, any additional persons become **Employees,** or if the **Insured** acquires the use and control of any additional **Premises**, then the insurance provided by this **Policy** shall also apply to such **Employees** and **Premises** automatically from the date of creation of the organization, without the requirement of notice to the **Underwriter**.

2 **JOINT INSURED**

A If more than one **Insured** is covered under this **Policy**, then the first named **Insured** in the **Declarations** shall act for itself and for every other **Insured** for all purposes of this **Policy**.

B The first named **Insured** in the **Declarations** is responsible for the payment of all premiums and shall be the payee for any returned premiums paid by the **Underwriter**.

C If any **Insured**, **Partner** or **Designated Representative**, not in collusion with a fraud, **Discovers** a **Loss** or has knowledge of any information relevant to this insurance, such **Discovery** or knowledge shall constitute **Discovery or knowledge** by every **Insured**.

D If, prior to the cancellation or termination of this **Policy,** this **Policy** or any **Insuring Agreement** hereof is cancelled or terminated as to any **Insured**, the **Underwriter** shall have no liability for any **Loss** sustained by such **Insured** unless such **Loss** is **Discovered** within sixty (60) days from the date of such cancellation or termination. Cancellation of this insurance hereunder as respects any **Employee** or **Partner** as provided in **Condition 19** herein shall apply to every **Insured**.

E Payment by the **Underwriter** to the first named **Insured** in the **Declarations** in respect of any **Loss** under this **Policy** shall fully release the **Underwriter** on account of such **Loss**. If the first named **Insured** ceases for any reason to be covered under this **Policy**, then the next named **Insured** shall thereafter be considered as the first named **Insured** for all purposes of this **Policy**.

F Where there is more than one **Insured**, the maximum liability of the **Underwriter** for any **Loss** or **Losses** sustained by any or all of them shall not exceed the amount for which the **Underwriter** would be liable if all losses were sustained by any one of them.

3 **LOSS SUSTAINED**

A **During Current Policy Period**

The **Underwriter** shall pay for any **Loss** sustained through acts committed or events occurring during the **Policy Period** shown in the **Declarations** and **Discovered**:

(i) during the **Policy Period**, or

(ii) during the period not later than sixty (60) days from the end of the **Policy Period**.

However the extended period to **Discover** a **Loss** set out in **3 A** (ii) above terminates immediately upon the effective date of any other insurance obtained by the **Insured** replacing in whole or in part the insurance afforded by this **Policy**, whether or not such other insurance provides coverage for **Loss** sustained prior to its effective date.

B **During Prior Insurance**

(i) If the **Insured**, or any predecessor in interest, sustained any **Loss** during the period of any prior insurance that the **Insured** or any predecessor in interest could have recovered under that insurance except that the time within which to **Discover** a **Loss** had expired, this **Policy** shall cover such **Loss**, provided:

(a) this **Policy** became effective at the time of cancellation or termination of the prior insurance, and

(b) the **Loss** would have been covered by this **Policy** had it been in effect when the acts or events causing the **Loss** were committed or occurred; and

(ii) the insurance under this **Condition** is part of, not in addition to, the applicable **Limits of Liability** applying to this **Policy** and is limited to the lesser of the amount recoverable under:

(a) this **Policy** as of its effective date, or

(b) the prior insurance had it remained in effect.

4 **TERRITORY**

Except as set out expressly elsewhere herein, this **Policy** covers **Losses** occurring anywhere in the world, at or in connection with **Premises** known to the **Underwriter**.

5 **LOSS CAUSED BY UNIDENTIFIABLE EMPLOYEES**

If a **Loss** is alleged to have been caused by the **Dishonest or Fraudulent Acts** of an **Employee** and the **Insured** is unable to identify and designate the specific **Employee** or **Employees** causing such **Loss**, the **Insured** shall nevertheless have the benefit of **Insuring Agreements 1** and **10**, subject to the other provisions of this **Policy**, provided that the evidence submitted by the **Insured** in the proof of loss proves that the **Loss** resulted directly from the **Dishonest or Fraudulent Act** of an **Employee**.

6 **OWNERSHIP OF PROPERTY; INTERESTS COVERED**

A Except as otherwise set out in this **Condition**:

(i) **Property** covered under this **Policy** is limited to **Property** that is owned by the **Insured**, held by the **Insured** in any capacity or for which the **Insured** was legally liable prior to the **Loss**,

(ii) this insurance is for the benefit of the **Insured** only. It provides no rights to any other person or organization,

(iii) no **Partner** who has committed or has been implicated in **Dishonest or Fraudulent Acts** covered hereunder, shall have any right to, or interest in, any payment made hereunder, and

(iv) in the event that a **Partner** is involved or implicated in any act which results in a **Loss**, then subject to the applicable **Limits of Liability** and terms of this **Policy**, the **Underwriter** shall be liable only for the amount by which such **Loss** exceeds the aggregate of the following:

(a) the applicable **Deductible Amount**,

(b) any amounts owing to such **Partner** by any **Insured**, and

(c) the value of such **Partner's** partnership interest in the **Insured** as determined at the applicable date of **Discovery**.

B In respect of **Insuring Agreement 10**, only:

(i) the **Property** covered under this **Policy** is limited to **Property** that is owned by the **Client**, held by the **Client** in any capacity or for which the **Client** was legally liable prior to the **Loss**,

(ii) this insurance is for the benefit of the **Client** and/or the **Insured** only. It provides no rights to any other person or organization, and

(iii) any payment to be made by the **Underwriter** in respect of a **Loss** shall be made payable jointly to the first named **Insured** and to the **Client** unless otherwise agreed in writing by the **Underwriter**, the **Insured** and the **Client**..

7 **BOOKS AND RECORDS**

The **Insured** shall keep records of all insured **Property** in such manner that the **Underwriter** can verify the amount of any **Loss**.

8 **CONCEALMENT, MISREPRESENTATION OR FRAUD**

This **Policy** is void in case of fraud by the **Insured** as it relates to this **Policy** at any time. It is also void if any **Insured**, at any time, intentionally conceals or misrepresents a material fact concerning:

(i) this **Policy**,

(ii) the **Property** covered under this **Policy**,

(iii) the interest of any **Insured** in the **Property** covered under the **Policy**, or

(iv) a claim under this **Policy**.

9 **DUTIES IN THE EVENT OF A LOSS**

A Upon **Discovery** of a **Loss**, the **Insured** shall:

(i) except for a **Loss** under **Insuring Agreements 1** and **5**, notify the police if the **Loss** is due to a violation of the law,

(ii) give written notice thereof to the **Underwriter** at the earliest practicable moment, and in any event within the earlier of ninety (90) days after such **Discovery**, or sixty (60) days after termination of coverage,

(iii) file a detailed proof of loss, duly sworn, with the **Underwriter** within four (4) months of such **Discovery**,

(iv) submit to examination under oath, if requested by the **Underwriter**, at such reasonable times and places as the **Underwriter** shall designate, and produce all pertinent records relating to any claim made under the **Policy**, and

(v) cooperate fully with the **Underwriter** in all matters pertaining to any **Loss** or claims with respect thereto and at all times act with the utmost of good faith towards the **Underwriter**.

B The proof of loss shall contain full particulars of the claimed **Loss** and all pertinent records relating to the **Loss**. Under **Insuring Agreement 5,** the proof of loss shall include the instrument which is the basis of claim for such **Loss**, or if it is impossible to file such instrument because the original no longer exists, it shall include instead the affidavit of the **Insured** or the applicable **Financial Institution** setting forth the amount and cause of **Loss**.

10 **SUBROGATION**

In the event of any payment under this **Policy**, the **Underwriter** shall be subrogated to all the **Insured's** rights of recovery against any person or organization and the **Insured** shall execute and deliver instruments and papers and do whatever else is necessary to secure such rights and to assign and transfer all such rights of recovery to the **Underwriter**. The **Insured** shall do nothing after **Discovery** of a **Loss** to prejudice such rights and shall extend its reasonable cooperation to the **Underwriter** in its recovery efforts to the extent requested or required.

11 **RECOVERIES**

A Any recoveries, less the cost of obtaining such recoveries, made after settlement of a **Loss** covered by this **Policy** shall be distributed in the following order:

(i) to the **Insured**, until the **Insured** is reimbursed for any **Loss** sustained that exceeds the applicable **Limit of Liability** and the applicable **Deductible Amount**, if any,

(ii) to the **Underwriter**, until the **Underwriter** is reimbursed for the settlement made, and

(iii) to the **Insured**, until the **Insured** is reimbursed for that part of the loss equal to the applicable **Deductible Amount**, if any.

B Recoveries do not include any recovery from insurance, suretyship, reinsurance, security or indemnity taken by or for the benefit of the **Underwriter**, or of original securities after duplicates of them have been issued.

12 **ACTION AGAINST UNDERWRITER**

A No legal action may be brought against the **Underwriter** involving any **Loss** claimed under this **Policy** unless, as a condition precedent thereto:

(i) the **Insured** has fully complied with all the terms of this **Policy**,

(ii) the period of ninety (90) days has elapsed from the date on which the required proof of loss was filed with the **Underwriter**, and

(iii) such action is commenced within two (2) years from the date of **Discovery** of the **Loss**.

B If any limitation is prohibited by law, such limitation is amended so as to equal the minimum period of limitation provided by law; and

C No suit or action by the **Insured** or by any other person claiming through the **Insured** or on the **Insured's** behalf shall lie against the **Underwriter** unless such suit or action is brought in a court of competent jurisdiction within Canada.

13 **VALUATION - PAYMENT - REPLACEMENT**

A Subject to the applicable **Limit of Liability**, and subject to this **Condition**, the **Underwriter** shall pay for:

(i) **Loss** of **Money** but only up to and including its face value,

(ii) **Loss** of **Securities**, but only up to and including the actual cash value thereof at the close of business on the day on which the **Loss** was **Discovered**. The **Underwriter** may, at its option:

(a) pay the value of such **Securities**, or replace them in kind, in which event the **Insured** must assign to the **Underwriter** all of its rights, title and interest in and to those **Securities**, or

(b) pay the cost of any Lost Instrument Bond required in connection with issuing duplicates of the **Securities**. However, the **Underwriter** shall be liable only for the payment of so much of the cost of such Bond as would be charged for a Bond having a penalty not exceeding the lesser of:

(1) the value of the **Securities** at the close of business on the day the **Loss** was **Discovered**, or

(2) the applicable **Limit of Liability**.

(iii) **Loss** of, or **Loss** from damage to **Other Property**, or **Loss** from damage to the **Premises** or its exterior on a replacement cost basis after deduction for depreciation. However, the **Underwriter** shall not pay more than the lesser of:

(a) the cost to replace the lost or damaged **Property** with **Property** of comparable material and quality and used for the same purpose, or

(b) the amount actually spent by the **Insured** necessary to repair or replace such **Property**.

B The **Underwriter** may, at its option, pay for **Loss** of **Property**:

(i) in the currency of the country in which the **Loss** occurred, or

(ii) in the Canadian dollar equivalent thereof determined at the rate of exchange as published by the Bank of Canada on the day the **Loss** was **Discovered**.

C The **Underwriter** may, with the consent of the **Insured**, settle any claim for **Loss** of **Property** with the owner thereof, if such **Property** is not owned by the **Insured**. Any **Property** for which the **Underwriter** has made indemnification shall become the **Property** of the **Underwriter**.

D If the **Underwriter** and the **Insured** cannot agree upon the actual cash value or such cost of repairs or replacement as set out herein, these shall be determined by arbitration.

14 **LIMITS OF LIABILITY**

A The **Underwriter's** maximum liability for a **Loss** in any one **Occurrence** shall not exceed the applicable **Limit of Liability**, regardless of the number of **Insureds** sustaining the **Loss**.

B Any payments made under **Insuring Agreement 11 B** shall be part of and not in addition to the applicable **Limit of Liability** for the particular covered **Loss**.

C Subject to **Special Conditions 1 D** if any **Loss** is covered under more than one **Insuring Agreement**, the **Underwriter** shall pay under the **Insuring Agreement** providing the greatest **Limit of Liability**, unless otherwise stated in this **Policy**. However, in the event that such **Limits of Liability** are the same, the **Underwriter** shall pay for **Loss** under only one **Insuring Agreement**, with the choice of such **Insuring Agreement** to be at the option of the first named **Insured.**

15 **NON-ACCUMULATION OF LIMITS OF INSURANCE**

Regardless of the number of years this **Policy** remains in force or the number of premiums paid or payable, the limit of the **Underwriter's** liability as specified in **Item 3** of the **Declarations** and in the applicable **Limits of Liability** and **Deductible Amounts** set out therein shall not be cumulative from year to year or period to period.

16 **DEDUCTIBLE**

A The **Underwriter** shall not pay for a **Loss** in any one **Occurrence** unless the amount of the **Loss** exceeds the applicable **Deductible Amount.** The **Underwriter** shall then pay the amount of **Loss** in excess of such **Deductible Amount** up to the applicable **Limit of Liability**.

B There shall be no **Deductible Amount** applicable to **Loss** covered under **Insuring Agreement 9**.

17 **CURRENCY**

The **Limits of Liability** and **Deductible Amounts** as stated in this **Policy** are in Canadian currency, unless stated otherwise.

18 **OTHER INSURANCE**

If other valid and collectible insurance is available to the **Insured** for a **Loss** otherwise covered under any **Insuring Agreement** in this **Policy**, the insurance under this **Policy** shall apply only as excess insurance and the **Underwriter** shall not be liable for any **Loss** until the amount of such other insurance is exhausted. However, this **Policy** shall not apply to the amount of **Loss** that is greater than the applicable **Limit of Liability**, regardless as to whether there is other insurance available.

19 **CANCELLATION AS TO ANY EMPLOYEE OR PARTNER**

A **Insuring Agreement 1** of this **Policy** shall be deemed cancelled as to any **Employee** or **Partner**:

(i) immediately upon **Discovery** by the **Insured**, or any **Partner** or **Designated Representative**, not in collusion with such **Employee** or **Partner**, of any **Dishonest or Fraudulent Acts** committed by that **Employee** or **Partner**, whether such act was committed before or after the date of employment by the **Insured** or the date of partnership, as the case may be.

(ii) upon the expiry of fifteen (15) days after receipt by the first named **Insured** of written notice from the **Underwriter** to terminate coverage in respect of such **Employee** or **Partner**, which notice shall be hand delivered or sent by registered mail to the first named **Insured's** last mailing address known to the **Underwriter**. If the **Underwriter** mails any notice of termination, receipt of such notice by the first named **Insured** shall be deemed to have occurred five (5) days after such mailing was delivered to the post office of the **Insured's** last mailing address.

B The **Underwriter** shall not pay for **Loss** caused by any **Employee** or **Partner**, whether such **Loss** was sustained by the **Insured** or any predecessor in interest to the **Insured**, for whom similar insurance has been cancelled and not reinstated unless the **Underwriter** specifically agrees in writing to include such **Employee** or **Partner** within the coverage of **Insuring Agreement** 1.

20 **CANCELLATION OF POLICY OR INSURING AGREEMENT**

A Subject to **Condition 3** herein, this **Policy,** or any **Insuring Agreement** if applicable, shall terminate immediately upon:

(i) receipt by the **Underwriter** of written notice of cancellation from the first named **Insured,**

(ii) the expiration of ten (10) days after receipt by the first named **Insured** of written notice from the **Underwriter** to terminate the **Policy** for non-payment of premium,

(iii) the expiration of ten (10) days after any **Bankruptcy Event**, provided however that in the event that more than one **Insured** is covered under this **Policy**, the termination shall apply only to those **Insureds** which are the subject of any **Bankruptcy Event**, or

(iv) the expiration of sixty (60) days after receipt by the first named **Insured** of written notice from the **Underwriter** to terminate the **Policy** for any other reason than the non-payment of premium or **Bankruptcy Event** which notice shall be sent to the first named **Insured's** last mailing address known to the **Underwriter**;

B If this Policy is cancelled, the **Underwriter** shall send the first named **Insured** any premium refund due. If the **Underwriter** cancels, the refund shall be pro rata. If the first named **Insured** cancels, the refund shall be made in accordance with the Underwriter's customary annual short rate table. Payment of any refund by the **Underwriter** shall not be a condition precedent to termination, but such payment shall be made as soon as practicable to the **Insured's** last mailing address known to the **Underwriter**.

C If the **Underwriter** mails any notice of termination, receipt of such notice by the first named **Insured** shall be deemed to have occurred after receipt at the post office of the Insured's last known mailing address known to the **Underwriter**, or as may be dictated otherwise by applicable statute.

21 **NO BENEFIT TO BAILEE**

The insurance afforded by this **Policy** shall not be, directly or indirectly, for the benefit of any carrier or other bailee for hire.

22 **ASSIGNMENT**

Other than to the extent set out in **Insuring Agreement 10,** the insurance coverage provided under this **Policy** is solely for the benefit of the **Insured** and shall not be for the benefit of any other person, organization or entity. The rights, duties and/or interests of the **Insured** under this **Policy** may not be transferred, assigned or modified without the **Underwriter's** written consent except in the case of the death of an individual named **Insured** (a natural person). In the event that such an **Insured** shall die, then the rights, duties and/or interests of such **Insured** shall be transferred to his or her legal representative, but only while acting within the scope of duties as legal representative. Until such representative is appointed, anyone having temporary custody of the **Insured's Property** shall have the same rights, duties and interests of the **Insured,** but only with respect to such **Property**.

23 **CHANGES**

This **Policy** contains all of the agreements between the **Underwriter** and the **Insured** concerning the insurance afforded. The first named **Insured** in the **Declarations** is authorized to make changes in the terms of the **Policy** but only with the written consent of the **Underwriter**. This **Policy's** terms can be amended or waived only by endorsement issued by the **Underwriter**, signed by an officer or Attorney-In-Fact of the **Underwriter** and made a part of this **Policy** by way of rider.

24 **LIBERALIZATION**

If the **Underwriter** adopts any revisions that broaden the coverage provided by the wording in this **Policy** without requiring an additional premium within forty-five (45) days prior to or during the **Policy Period**, then the broadened coverage shall immediately apply to this **Policy**.

SPECIAL CONDITIONS

1 **PENSION OR EMPLOYEE BENEFIT PLAN**

A If any **Pension or Employee Benefit Plan** (hereinafter called **Plan**) is insured jointly with any other entity under this **Policy**, the **Insured** or the particular **Plan** administrator must select a **Limit of Liability** for **Insuring Agreement 9** that is sufficient to provide a limit of insurance for each **Plan** that is at least equal to that required if each **Plan** were separately insured.

B If the first named **Insured** is an entity other than a **Pension or Employee Benefit Plan**, any payment made by the **Underwriter** in respect of a covered **Loss** under this **Policy** shall be held by that **Insured** for the use and benefit of such **Plan**.

C In the event that **Loss** is sustained in any one **Occurrence** by:

(i) two or more **Pension or Employee Benefit Plans**, or

(ii) at least one **Pension or Employee Benefit Plan**, and by an **Insured** other than a **Plan**,

then any amounts payable by the **Underwriter** shall be paid to the applicable **Insureds** or **Plans**, as the case may be, on a pro rata basis.

D Notwithstanding **Condition 14 C**, in the event that a **Loss** is sustained in any one **Occurrence** by at least one **Pension or Employee Benefit Plan**, and by an **Insured** other than a **Plan** (as set out in **Special Condition 1 C** (ii) above), then subject to the terms of this **Condition**, the **Underwriter** may pay for such **Loss** under two **Insuring Agreements**, if applicable. However, the maximum amount payable in this case shall be the greater of the applicable **Limit of Liability** under either but not both of such **Insuring Agreements**.

2 **FUNDS TRANSFER FRAUD**

It is a condition precedent for coverage under **Insuring Agreement 7 C** that:

(i) the **Insured** demonstrate to the satisfaction of the **Underwriter** that at the time the **Loss** was sustained, the **Insured** and the **Financial Institution** jointly had in place written policies and procedures to prevent and/or minimize losses from arising through any fraudulent electronic, telegraphic, cable, teletype, facsimile or telephone instructions, or arising through other fraudulent written instructions (other than those referred to in **Insuring Agreement 5**) from or ostensibly from the **Insured** to the **Financial Institution**; and

(ii) the **Insured** supply to the **Underwriter**, with the proof of loss, a copy of such written policies and procedures referred to in **2** (i) above, and demonstrate to the satisfaction of the **Underwriter** that such policies and procedures were followed and enforced internally at or by the **Insured** at all times leading up to **Discovery** of the **Loss**.

3 **VOICE COMPUTER TOLL FRAUD**

It is a condition precedent for coverage under **Insuring Agreement 7 D** that:

(i) the **Insured** demonstrate to the satisfaction of the **Underwriter** that at the time the **Loss** was sustained, the **Insured** had in place written policies and procedures to prevent persons from obtaining unauthorized access to the applicable **Voice Computer System** including the following:

(a) a **System Password** feature in connection with the **Voice Computer System,**

(b) a system by which the **System Password** was changed for each user at least once every thirty (30) days, and

(c) a call-disconnect feature in the **Voice Computer System** which automatically terminates a caller's access to the **Voice Computer System** after not more than three unsuccessful attempts to input an **Account Code** into the **Voice Computer System;** and

(ii) the **Insured** supply to the **Underwriter**, with the proof of loss, a copy of such written policies and procedures referred to in **Special Condition 3** (i) above, and the **Insured** demonstrate to the satisfaction of the **Underwriter** that the policies and procedures set out in **Special Condition 3** (i) above were followed and enforced internally at or by the **Insured** at all times leading up to **Discovery** of the **Loss**.

4 **RESTORATION EXPENSE**

The **Underwriter** shall make payment under **Insuring Agreement 11 A** only:

(i) in respect of **Computer Programs** or **Electronic Data** that are owned by the **Insured**, or for which the **Insured** is legally liable,

(ii) if at all times prior to **Discovery** of any **Computer Incident**, the **Insured** conducted daily back-ups of all of its **Electronic Data** and stored copies of such back-ups at an off-**Premises** storage facility, and

(iii) if the **Insured** is unable to reproduce such **Computer Programs** or **Electronic Data** from the copies of such back-ups.

5 **CLAIMS EXPENSE**

The **Underwriter** shall make payment under **Insuring Agreement 11 B** only where the applicable **Loss** is covered by this **Policy** and in an amount in excess of any **Deductible Amount** applicable to such covered **Loss** or **Restoration Expense**.

Payment under **Insuring Agreement 11 B** is limited to twenty-five percent (25%) of the **Loss** payable under the applicable **Insuring Agreement**, subject to any **Special Limit**.

For further clarity, payment under **Insuring Agreement 11 B** shall not apply to expenses incurred:

(i) for routine audits or examinations,

(ii) to correct, modernize, set up or prepare internal procedures, or to organize records, or

(iii) in any recovery effort or proceeding.

It is further understood and agreed that no **Deductible Amount** shall apply to **Insuring Agreement 11 B**.

6 **EXTORTION**

It is a condition precedent for coverage under **Insuring Agreement 8** that:

A prior to the surrender of any **Property**, the person receiving the threat made every reasonable effort under the circumstances to:

(i) determine positively that the threat was genuine;

(ii) report the extortionist's demand to the national police authority (Royal Canadian Mounted Police or foreign equivalent thereof), or the local law enforcement authority, and to comply with any recommendation or orders which such authority may have given; and

(iii) notify at least one other official of the **Insured** of any intention to surrender such **Property**, prior to such surrender;

B In the event that the **Insured** learns of any **Loss** or potential **Loss** under **Insuring Agreement 8**, the **Insured** shall give immediate notice thereof, with full particulars, to a claims manager or assistant claims manager of the **Underwriter**, and shall at all times provide to the **Underwriter** all co-operation and assistance in all matters pertaining to a **Loss** or potential **Loss** hereunder; and

C The **Insured** shall make all reasonable efforts not to disclose the existence of this coverage.

By acceptance of this **Policy**, the **Insured** agrees that it embodies all agreements existing between the **Insured** and the **Underwriter** or any of its agents relating to this insurance.

IN WITNESS WHEREOF, THE UNDERWRITER HAS CAUSED TIIIS POLICY TO BE EXECUTED ON THE DECLARATIONS PAGE

COMMONWEALTH

COMMONWEALTH INSURANCE COMPANY

(hereafter called the Insurer)

PO Box 49115 Bentall Tower Three, 595 Burrard Street, Suite 1500, Vancouver, BC, Canada V7X 1G4

COMPREHENSIVE GENERAL LIABILITY POLICY

POLICY NO. CRX 62108
(Replacing CRX 61733)

IN CONSIDERATION of the payment of the premium and subject to the Declarations, Insuring Agreements, Exclusions, Limits of Liability, Conditions and other terms of this Policy, HEREBY AGREES TO INSURE THE INSURED in the manner and to the extent herein set forth.

DECLARATIONS

COPY

NAMED INSURED:	YUKON ENERGY CORPORATION; YUKON DEVELOPMENT CORPORATION
MAILING ADDRESS:	PO Box 5920, Whitehorse, Yukon Y1A 6S7
POLICY PERIOD:	From: September 1, 2011 To: September 1, 2012 12:01 a.m. Standard Time at the mailing address stated hereon
LIMITS OF LIABILITY:	$ 5,000,000.00 Inclusive Each Occurrence $ 5,000,000.00 In the Aggregate with respect to Products and Completed Operations Liability
PREMIUM:	$ 46,750.00
ADJUSTMENT RATE:	$ Nil.
MINIMUM PREMIUM:	$ 37,400.00
SCHEDULE OF ENDORSEMENTS:	See Page 15
BROKER:	AON REED STENHOUSE INC., Vancouver, BC

In Witness Whereof, the Insurer through its representative duly authorized by it for this purpose has executed and signed this policy.

.....
COMMONWEALTH INSURANCE COMPANY

MM.62108/75075/F.13.yukon energy corporation (2023)/IPR
Issued: September 1, 2011

Commonwealth Insurance Company

INSURING AGREEMENTS

The Insurer agrees to pay on behalf of the Insured all sums which the Insured shall become legally obligated to pay as damages.

1. PERSONAL INJURY LIABILITY

   because of Personal Injury sustained by any person or persons during the Policy Period.

2. PROPERTY DAMAGE LIABILITY

   because of physical damage to or destruction of or loss of use of tangible property caused by an Occurrence during the Policy Period, hereinafter called Property Damage.

3. DEFENSE, SETTLEMENT, INVESTIGATION AND NEGOTIATION

   With respect to such insurance as is afforded by this Policy, the Insurer shall:

   (a) If claim is made or suit brought within Canada or the United States of America, their territories or possessions, defend any such claim or suit against the Insured, or against an indemnitee which the Insured is required to defend by the terms of a contract, but only to the same extent and on the same terms as if the indemnitee were the Insured under this Policy and then only if the following conditions are satisfied; (1) the claim or suit seeks damages for which the indemnitee is legally entitled to indemnification under the terms of the contract; (2) this Policy covers such damages and (3) the applicable limit of the Insurer's liability with respect to such damages has not been exhausted by payment of judgments or settlements, even if such claim or suit is groundless, false or fraudulent. The Insurer shall make such investigation, negotiation and settlement of any claim or suit as it deems expedient.

   If a claim is made or suit is brought elsewhere than within Canada or the United States of America, their territories or possessions, the Insurer shall have the right, but not the duty, to investigate and settle such claims and defend such suits. In any case in which the Insurer elects not to investigate, settle or defend, the Insured under the supervision of the Insurer, shall make or cause to be made such investigation and defense as is reasonably necessary, and subject to prior authorization by the Insurer, will effect to the extent possible such settlement or settlements as the Insurer and the Insured deem prudent. The Insurer shall reimburse the Insured as quickly as possible for the reasonable cost of such investigation, settlement or defense.

   (b) Pay all premiums on bonds to release attachments for an amount not in excess of the applicable limit of liability of this Policy, all premiums on appeal bonds required in any such defended suit, but without any obligation to apply for or furnish any such bonds.

   (c) Pay all expenses incurred by the Insured, all legal costs or any other costs taxed against the Insured in any such suit or appeal or judgment and all interest accruing before or after entry of judgment until the Insurer has paid or tendered or deposited in court such part of such judgment as does not exceed the limit of the Insurer's liability thereon.

   (d) Pay all expenses incurred by the Insured for such immediate medical, dental and surgical relief to others as shall be necessary at the time of an accident or occurrence.

Commonwealth Insurance Company

(e) Reimburse the Insured for all reasonable expenses, including loss of earnings which shall be subject to Two Hundred Dollars ($200.00) a day maximum per person, incurred at the Insurer's request.

and the amounts so incurred, except settlements of claims and suits, are payable by the Insurer in addition to the applicable limits of liability of this Policy.

EXCLUSIONS

This Policy DOES NOT apply to:

1. fines or penalties, for which the Insured is liable by reason of failure to comply with any statute, rule or regulation.

2. any obligation for which the Insured or any company as its Insurer may be held liable under any worker's compensation, unemployment compensation or disability benefits law; provided, however, that this exclusion does not apply to liability of others assumed by the Named Insured under contract or agreement.

3. with respect to Personal Injury coverage as defined in Definition 4 (b) to (f) inclusive,

   (a) to injury caused by the wilful violation of a penal statute or ordinance committed by or with the knowledge or consent of the Insured;

   (b) to acts committed in connection with advertising, by or in the interest of the Named Insured;

   (c) to injury arising out of any publication or utterance if the first injurious publication or utterance of the same or similar material by or on behalf of the Insured was made prior to the effective date of this insurance;

   (d) to injury arising out of a publication or utterance concerning any organization or business enterprise, or its products or services, made by or at the direction of any Insured with knowledge of the falsity thereof.

4. Personal Injury as defined under Definition 4 (a) caused intentionally by or at the direction of the Insured except when caused to protect persons or property; however, this exclusion shall not apply to any Insured who neither sanctioned, nor had knowledge of, nor was a party to the causing of such Personal Injury.

5. Personal Injury sustained by any person employed by the Insured in violation of the laws as to age.

6. Personal Injury (Definition 4[a]) or Property Damage arising out of the ownership, use or operation by or on behalf of the Insured of

   (a) any automobile, motorized snow vehicle, self-propelled land motor vehicle, trailer, semi-trailer, their equipment mounted on or attached thereto, with respect to which any motor vehicle liability policy is in effect or is required by law to be in effect.

   (b) any vehicle while being used in any speed or demolition contest or in any stunting activity or in practice or preparation for any such contest or activity.

(c) any watercraft over Five Hundred (500) tons gross registry, other than the Insured's liability for watercraft chartered by or on behalf of the Insured or used in connection with operations usual or incidental to the Insured's business where the Insured or any of his employees do not own or operate the watercraft.

It is further agreed that with respect to vessels in excess of Five Hundred (500) tons gross registry which are demised chartered, no liability shall attach hereunder which arises out of any form of agreement entered into by the Insured under which he assumes the sole negligence of the owner or operator of any watercraft or for damage to such watercraft unless the Insured would have been liable in the absence of such agreement.

(d) any aircraft.

(e) any premises for the purpose of any airport or aircraft landing strip and all operations which are necessary or incidental thereto.

(f) any air cushion vehicle.

but this exclusion SHALL NOT apply to Personal Injury, sickness, or disease, including death of any employee while acting in his capacity as such other than as a member of any air crew.

7. loss of use of tangible property which has not been physically injured or destroyed resulting from:

(a) a delay in or lack of performance by or on behalf of the Insured of any contract or agreement.

(b) the failure of the Insured's products or work performed by or on behalf of the Insured to meet the level of performance, quality, fitness or durability warranted or represented by the Insured.

but this exclusion DOES NOT apply to loss of use of other tangible property resulting from the sudden and accidental physical injury to or destruction of the Insured's products or work performed by or on behalf of the Insured after such products or work have been put to use by any person or organization.

8. damage to or destruction including loss of use of:

(a) property owned or occupied by or rented to the Insured;

(b) property held by the Insured for sale, property entrusted to the Insured for storage or safekeeping, property loaned to the Insured or personal property in the care, custody or control of the Insured;

(c) that particular part of any property:

(i) upon which operations are being performed by or on behalf of the Insured at the time of the damage thereto or destruction thereof, arising out of such operations, or

(ii) out of which any damage or destruction arises, or

(iii) the restoration, repair or replacement of which has been made or is necessary by reason of faulty workmanship thereon by or on behalf of the Insured;

Paragraphs (b) and (c) do not apply to liability under sidetrack agreements.

Subparagraphs (ii) and (iii) of Paragraph (c) do not apply to property damage included in the Completed Operations Hazard.

(d) property which is being transported by the Insured, including the loading or unloading thereof.

(e) with respect to the Products Hazard, that particular part of the Insured's products out of which an accident arises.

(f) with respect to the Completed Operations Hazard, that particular part of a work performed by the Insured out of which an accident arises due to faulty workmanship.

9. Personal Injury or Property Damage arising out of the rendering of or the failure to render professional services by the Insured's architect, engineer or surveyor, except such services as are an integral part of other work performed by or on behalf of the Insured or any associated or affiliated company or are incidental to the manufacture, installation, sale, handling or distribution of the Insured's products or the products of any associated or affiliated company.

10. Bodily Injury (Definition 4 [a]) arising out of the rendering of or the failure to render medical services by any doctor, physician and/or surgeon in the employ of the Insured, except that this exclusion SHALL NOT apply to the contingent liability of the Named Insured.

11. (a) "Personal Injury" or "Property Damage" arising out of the actual, alleged, or threatened discharge, emission, dispersal, release, escape, seepage, leakage or migration of pollutants

(i) at or from any premises, site, location, easement or right-of-way, which is or was at any time, owned by, rented to, loaned to or occupied by, any Insured;

(ii) at or from any premises, site or location which is or was at any time, used by or for any Insured or others for the handling, storage, disposal, processing or treatment of waste;

(iii) which are or were at any time transported, handled, stored, treated, disposed of, or processed as waste by or for an Insured or any person or organization for whom the Insured may be legally responsible; or

(iv) at or from any premises, site or location on which an Insured or any contractors or subcontractors working directly or indirectly on any Insured's behalf are performing operations:

A. if the pollutants are brought on or to the premises, site or location in connection with such operations by such Insured, contractor or subcontractor; or

B. if the operations are to test for, monitor, clean up, remove, contain, treat, detoxify, decontaminate, stabilize, remediate or neutralize, or in any way respond to, or assess the effect of pollutants.

Subparagraph (i) of paragraph (a) of this Exclusion DOES NOT apply to Personal Injury if sustained within a building and caused by smoke, fumes, vapor or soot from equipment used to heat that building.

Subparagraph (iv)A of paragraph (a) of this Exclusion DOES NOT apply to Personal Injury or Property Damage sustained within a building and caused by the release of gases, fumes or vapors from materials brought into that building in connection with operations being performed by the Insured or on the Insured's behalf by a contractor or subcontractor.

Subparagraphs (i) and (iv)A. of paragraph (a) of this Exclusion do not apply to "Personal Injury" or "Property Damage" caused by:

(i) heat, smoke or fumes from a hostile fire which becomes uncontrollable or breaks out from where it was intended to be; or

(ii) an unexpected and unintentional spill, discharge, emission, dispersal, seepage, leakage, migration, release or escape of pollutants provided such discharge, emission, dispersal, seepage, leakage, migration, release or escape of pollutants:

A. results in the injurious presence of pollutants in or upon land, the atmosphere, drainage or sewage system, watercourse or body of water; and

B. is detected within 120 hours after the commencement of the spill, discharge, emission, dispersal, seepage, leakage, migration, release or escape; and

C. is reported to the Insurer within 120 hours of being detected; and

D. does not occur in a quantity or with a quality that is routine or usual to the business of the Insured.

(b) Any loss, cost or expense or request for restitution arising out of any governmental direction, action or request that an Insured:

(i) test for, monitor, clean up, remove, contain, treat, detoxify, decontaminate, stabilize, remediate or neutralize or in any way respond to, or assess the effect of pollutants; or

(ii) restore, reclaim or rehabilitate any land, watercourse or body of water.

unless such loss, cost or expense is consequent upon "Personal Injury" or "Property Damage" covered by this Policy.

(c) Fines, penalties, punitive or exemplary damages arising out of the discharge, emission, dispersal, seepage, leakage, migration, release or escape of any pollutants.

"Pollutants" means any solid, liquid, gaseous, or thermal irritant or contaminant, including smoke, vapor, soot, fumes, acids, alkalis, chemicals and waste. "Waste" includes materials to be recycled, reconditioned or reclaimed.

Nothing contained in this Exclusion shall operate to provide any coverage with respect to clean up, removal, containment, treatment, detoxification or neutralization of pollutants situated on premises the Insured currently owns, rents or occupies or that the Insured formerly owned, rented or occupied.

12. Except with respect to occurrences taking place in Canada or the United States of America, its territories or possessions, to any liability of the Insured directly or indirectly occasioned by, happening through or in consequence of war, invasion, acts of foreign enemies, hostilities (whether war be declared or not), civil war, rebellion, revolution, insurrection or military or usurped power or confiscation or nationalization or requisition or destruction of or damage to property by or under the order of any government or public or local authority.

13. Damages or expenses incurred for the withdrawal, inspection, repair, replacement or loss of use of the Insured's products or work completed by or for the Insured or of any property of which such products or work form a part, if such products, work or property are withdrawn from the market or from use because of any known or suspected defect or deficiency therein.

14. It is agreed that this Policy DOES NOT apply:

(a) to liability imposed by or arising under the Nuclear Liability Act; nor

(b) to Personal Injury or Property Damage with respect to which an Insured under this Policy is also insured under a contract of nuclear energy liability insurance (whether the Insured is unnamed in such contract and whether or not it is legally enforceable by the Insured) issued by the Nuclear Insurance Association of Canada or any other insurer or group or pool of insurers or would be an Insured under any such policy but for its termination upon exhaustion of its limit of liability; nor

(c) to Personal Injury or Property Damage resulting directly or indirectly from the nuclear energy hazard arising from:

(i) the ownership, maintenance, operation or use of a nuclear facility by or on behalf of an Insured;

(ii) the furnishing by an Insured of services, materials, parts or equipment in connection with the planning, construction, maintenance, operation or use of any nuclear facility; and

(iii) the possession, consumption, use, handling, disposal or transportation of fissionable substances, or of other radioactive material (except radioactive isotopes, away from a nuclear facility, which have reached the final stage of fabrication so as to be usable for any scientific, medical, agricultural, commercial or industrial purpose) used, distributed, handled or sold by an Insured.

As used in this Policy:

(1) The term "nuclear energy hazard" means the radioactive, toxic, explosive, or other hazardous properties of radioactive material.

(2) The term "radioactive material" means uranium, thorium, plutonium, neptunium, their respective derivatives and compounds, radioactive isotopes of other elements and any other substances that the Atomic Energy Control Board may, by regulation, designate as being prescribed substances capable of releasing atomic energy, or as being requisite for the production, use or application of atomic energy;

(3) The term "nuclear facility" means:

(a) any apparatus designed or used to sustain nuclear fission in a self-supporting chain reaction or to contain a critical mass of plutonium, thorium and uranium or any one or more of them;

(b) any equipment or device designed or used for (i) separating the isotopes of plutonium, thorium and uranium or any one or more of them, (ii) processing or utilizing spent fuel, or (iii), processing or packaging waste;

(c) any equipment or device used for the processing, fabricating or alloying of plutonium, thorium or uranium enriched in the isotope uranium 233 or in the isotope uranium 235, or any one or more of them if at any time the total amount of such material in the custody of the Insured at the premises where such equipment or device is located consists of or contains more than 25 grams plutonium or uranium 233 or any combination thereof, or more than 250 grams of uranium 235;

(d) any structure, basin, excavation, premises or place prepared or used for the storage or disposal of waste radioactive material; and includes the site on which any of the foregoing is located, together with all operations conducted thereon and all premises used for such operations.

(4) The term "fissionable substance" means any prescribed substance that is, or from which can be obtained, a substance capable of releasing atomic energy by nuclear fission.

The insurance afforded with respect to liability assumed under contract is subject to the following additional exclusions:

15. Personal Injury or Property Damage for which the Insured has assumed liability under any contract, if such injury or damage occurred prior to the execution of the contract.

16. If the indemnitee of the Insured is an architect, engineer or surveyor, to the liability of the indemnitee, his agents or employees, arising out of:

(a) the preparation or approval of or the failure to prepare or approve maps, drawings, opinions, reports, surveys, change orders, designs or specifications, or

(b) the giving of or the failure to give directions or instructions by the indemnitee, his agents or employees, provided such giving or failure to give is the primary cause of the Personal Injury or Property Damage.

The insurance afforded to Additional Insureds required to be added to this Policy by contract is subject to this further exclusion:

17. Personal Injury or Property Damage arising out of the rendering of or the failure to render professional services by such insured, including:

    (a) the preparation or approval of maps, drawings, opinions, reports, surveys, change orders, designs or specifications, and

    (b) supervisory, inspection or engineering services.

DEFINITIONS

1. NAMED INSURED

   The Named Insured is as stated in the Declarations and includes all subsidiary companies owned or controlled by the Named Insured.

2. ADDITIONAL INSUREDS

   The unqualified word "Insured" includes the Named Insured and any other interest which may exist or be hereafter acquired or constituted, over which the Named Insured may exercise control, or for which the Named Insured is responsible for arranging insurance and also includes:

   (a) any present or former partner, officer, director, employee or shareholder with respect to acts performed on behalf of the Insured in that capacity and employees of others, however, only while such employees are subject to the Doctrine of "Borrowed Servant" or "Master Servant Relationship."

   (b) any owner, person, firm, organization, trustee, estate or governmental entity to whom or to which the Named Insured has contracted to effect insurance, by virtue of a contract or agreement or by the issuance or existence of a permit. But the insurance provided for such additional Insured is restricted to apply solely to liability arising out of operations performed under said contract and only to the extent required by such contract;

   It is understood and agreed however that the above extension (b) does not apply to subcontractors or contractors working on behalf of the Named Insured.

   (c) co-owners, joint venturers or partners having a nonoperating interest with the Insured in the operations insured hereunder.

   (d) all employee social clubs.

   This insurance DOES NOT apply to participants, other than the Insured, of any partnership or joint venture agreement unless liability is assumed by the Insured under any contract or agreement.

   The insurance provided for Additional Insureds shall apply only when the Named Insured so directs the Insurer in writing upon a claim being made against such Additional Insured.

3. OCCURRENCE

(a) With respect to Bodily Injury [Definition 4(a)] and Property Damage, the term "Occurrence" means an accident, happening or event, including continuous or repeated exposure to conditions, which results during the Policy Period in Bodily Injury or Property Damage neither expected nor intended from the standpoint of the Insured.

(b) With respect to Personal Injury [Definitions 4(b) to 4(f)], the term "Occurrence" means an act or offense committed in the conduct of the Insured's business during the Policy Period resulting in Personal Injury.

4. PERSONAL INJURY

The term "Personal Injury" wherever used in this Policy shall mean:

(a) Bodily injury, mental anguish, shock, sickness or disease, including death, care and loss of services at any time resulting therefrom, or

(b) False arrest, malicious prosecution, wilful or wrongful detention or imprisonment, or

(c) Libel, slander, defamation of character, or

(d) Invasion of privacy, right of privacy, wrongful eviction or wrongful entry, trespass, or

(e) Discrimination, except where it is a violation of a statute or regulation prohibiting insurance for such.

(f) Humiliation,

including any other legal action alleging the foregoing by any other name.

5. COMPLETED OPERATIONS HAZARD

"Completed Operations Hazard" includes Personal Injury or Property Damage arising out of operations, but only if the Personal Injury or Property Damage occurs after such operations have been completed or abandoned and occurs away from premises owned by or rented to the Insured. Operations include materials, parts or equipment furnished in connection therewith. Operations shall be deemed completed at the earliest of the following times:

(a) when all operations to be performed by or on behalf of the Insured under the contract have been completed;

(b) when all operations to be performed by or on behalf of the Insured at the site of the operations have been completed;

(c) when the portion of the work out of which the Personal Injury or Property Damage arises has been put to its intended use by any persons or organization other than another contractor or subcontractor engaged in performing operations for a principal as a part of the same project.

Operations which may require further service or maintenance work or correction, repair or replacement because of any defect or deficiency, but which are otherwise complete, shall be deemed completed. Such work shall be considered part of the completed operations hazard period and subject to the aggregate limit of liability applicable thereto.

The Completed Operations Hazard SHALL NOT include:

(a) operations in connection with the pick up and delivery of property;

(b) the existence of tools, uninstalled equipment or abandoned or unused materials.

6. PRODUCTS HAZARD

"Products Hazard" includes Personal Injury and Property Damage arising out of the Insured's Products but only if such Personal Injury or Property Damage occurs away from premises owned by or rented to the Insured and after physical possession of such products has been relinquished to others.

7. INSURED'S PRODUCTS

"Insured's Products" means goods or products, other than real property, manufactured, sold, handled or distributed by the Insured or by others trading under his name, including any container thereof (other than a vehicle), but shall not include a vending machine or any property other than such container, rented to or located for use of others, but not sold.

GENERAL CONDITIONS

1. LIMITS OF LIABILITY

The limit of the Insurer's liability under this Policy shall be the amount stated in the Declarations as "each Occurrence" for damages for any one Occurrence or series of Occurrences resulting from one cause, and subject to such limit the amount stated in the Declarations as "aggregate" for any number of Occurrences in any one policy period, if caused by the Products Hazard or Completed Operations Hazard as defined herein.

2. SEVERABILITY OF INSUREDS

Except for the Limits of Liability and specific obligations of the Named Insured under this Policy, this insurance shall apply separately to each Insured as to policy coverage, exclusions, terms and conditions in the same manner and to the same extent as though a separate policy had been issued to each Insured.

Any breach of a condition of this Policy by any Insured shall not affect the protection given by this Policy to any other Insured who is not or was not a party to such breach of condition.

3. NOTICE OF CLAIM OR SUIT

Upon the happening of an accident or Occurrence which may give rise to a claim hereunder, the Insured shall give notice thereof as soon as practicable after notice has been received by an officer of the Insured, to the Insurer.

Such notice shall contain all available information pertaining to such accident or Occurrence which is obtainable at the time.

If claim is made or suit is brought against the Insured, the Insured shall immediately forward to the Insurer every demand, notice, summons or other process received by the Insured or by the Insured's representative.

4. ASSISTANCE AND COOPERATION

The Insured shall cooperate with the Insurer and, upon the Insurer's request, assist in making settlements, in the conduct of suits and in enforcing any right of contribution or indemnity against any person or organization who may be liable to the Insured because of injury or damage with respect to which insurance is afforded under this Policy; and the Insured shall attend hearings and trials and assist in securing and giving evidence and obtaining the attendance of witnesses.

5. ASSUMPTION OF LIABILITY

The Insured shall not, except at his own cost, voluntarily make any payment, assume any obligation or incur any expenses other than for first aid to others at the time of accident.

6. ACTION AGAINST INSURER

No action shall lie against the Insurer unless, as a condition precedent thereto, there shall have been full compliance with all of the terms of this Policy, nor until the amount of the Insured's obligation to pay shall have been finally determined either by judgment against the Insured after actual trial or by written agreement of the Insured, the claimant and the Insurer. Every action or proceeding against the Insurer shall be commenced within one year next after the date of such judgment or written agreement and not afterwards. Nothing contained in this Policy shall give any person or organization any right to join the Insurer as a co-defendant in any action against the Insured to determine the Insured's liability.

Bankruptcy or insolvency of the Insured or of the Insured's estate shall not relieve the Insurer of any of its obligations hereunder.

7. INSPECTION

The Insurer shall be permitted to inspect the insured premises and operations at any reasonable time during the policy period and any extension thereof. The Insurer waives no right and undertakes no responsibility by reason of such inspection or the omission thereof.

8. OTHER INSURANCE

The Insurer shall not be liable if at the time of an accident or occurrence covered by this Policy there is any other insurance which would have attached if this insurance had not been effected, except that this insurance shall apply only as excess and in no event as contributing insurance and then only after all such other insurance has been exhausted.

The Insurer acknowledges the existence of any policies arranged to apply in excess of the insurance provided by this Policy and it is agreed that notwithstanding anything contained in this Condition the insurance provided by such excess policies shall be considered as excess and noncontributing insurance insofar as the insurance provided under this Policy is concerned and shall be held to attach and cover only after the insurance under this Policy has been exhausted.

9. SPECIAL STATUTORY PROVISIONS

If any condition of this Policy, relating to limitation of time for notice of accident or for instituting legal proceedings, is at variance with any specific statutory provision in the jurisdiction in which the accident occurs, such statutory provision shall be substituted for such condition.

10. SUBROGATION

In the event of any payment under this Policy, the Insurer shall be subrogated to the extent of such payment to all the Insured's rights of recovery against any third party, except where the amount of settlement exceeds the amount provided in aggregate by this Policy and any other valid and collectible insurance in which case the Insured shall be entitled to all recovery until such excess has been made good to the Insured. The Insured shall execute all papers required and shall do everything necessary within his power to secure such rights, but the Insurer shall have no right of subrogation against any Insured or subsidiary, allied or affiliated company owned or controlled by the Insured, nor against any person, firm or corporation in respect of which the Insured has assumed liability under any contract or agreement.

11. ADJUSTMENT OF PREMIUM

(a) The premium stated in the Declarations is a deposit premium for the hazards known to exist at the inception of the policy period.

At the end of the policy period, the earned premium shall be computed in accordance with the rates stated in the Declarations. If the earned premium thus computed exceeds the estimated advance premium paid, the Insured shall immediately pay the difference to the Insurer; if it is less the Insurer shall return to the Insured subject to the retention by the Insurer of the Minimum Premium stated in the Declarations.

(b) (i) If, through consolidation or merger with, or purchase of assets of, some other concern, or any major change in the Named Insured's operations as reported at inception, the Named Insured shall pay the Insurer an additional premium with respect thereto, computed in accordance with the Insurer's rules and rating plans.

(ii) If through the sale of any concern or a major reduction at the Named Insured's operations during the policy term, the Insurer will refund a pro rated amount of premium in accordance with the Insurer's rules and rating plans.

The Named Insured shall permit the Insurer to examine and audit the Named Insured's books and records at any time during the policy period (and any extension thereof and within one year after the termination of this Policy) as far as they relate to the premium basis or subject matter of this insurance. The Insurer assumes no responsibility and waives no rights by reason of such examination, audit or the omission thereof.

12. POLICY TERRITORY

This Policy applies to Personal Injury or Property Damage anywhere in the world.

13. AGENCY

It is understood and agreed that the First Named Insured stated in the Declarations who obtained this Policy and paid the premium therefore did so on his own behalf and as agent for the others insured hereby, including those referred to by general description. It is further acknowledged and agreed by the Insurer as evidenced by its acceptance of the premium paid that any person, firm or corporation coming within the description of an unnamed person insured by this Policy may ratify such agency at any time subsequent to the issuance of the policy for the purpose of entitlement to coverage granted by its terms for good consideration. This insurance shall not be invalidated should the interest of the First Named Insured stated in the Declarations or any one of them be other than sole or unconditional ownership.

14. NAMED INSURED

The First Named Insured stated in the Declarations shall be deemed the sole and irrevocable agent of each and every Insured under this Policy for the purpose of:

(a) giving to or receiving from the Insurers notice of cancellation;

(b) giving instructions to or agreeing with the Insurers for alterations of the Policy wording;

(c) making or receiving payments of premiums or adjustments of premium.

15. "IN REM"

An action "in rem" against a vessel owned by, leased to or chartered by the Insured shall be treated as if it were an action "in personam" against the Insured; provided, this insurance shall not apply if there is any other insurance available to the Insured under a protection and indemnity policy, whether such insurance is on a contributory, excess or escape basis or whether it is subject to a deductible or limitation of liability clause or any similar clause.

16. CANCELLATION

(a) This Policy may be cancelled by the First Named Insured stated in the Declarations by giving written notice to the Insurer stating when thereafter such cancellation is to become effective. Return premium shall be computed on the following basis:

(i) if the Premium shown in the Declarations is Flat and not adjustable, then on the customary short rate basis; or

(ii) if the Premium shown in the Declarations is subject to an adjustment rate, then the excess of the Deposit Premium over the actual amount of adjustable earned premium to the date of cancellation, subject in any event to the earned premium so calculated to be not less than what would be earned on a short rate basis;

and in any event subject to the retention by the Insurer in either case of the minimum premium stated in the Declarations.

(b) This Policy may be cancelled by the Insurer for nonpayment of premium by giving to the First Named Insured stated in the Declarations Fifteen (15) days notice of cancellation by registered mail, or Five (5) days written notice of cancellation personally delivered. Notice to the insurance department of the First Named Insured stated in the Declarations shall constitute notice to all Insureds.

(c) Except with respect to nonpayment of premium this Policy may be cancelled by the Insurer giving to the First Named Insured stated in the Declarations Sixty (60) days notice in writing of cancellation by registered mail and refunding the excess of paid premium beyond the pro rata earned premium for the expired time. Notice to the Insurance Department of the First Named Insured stated in the Declarations shall constitute notice to all Insureds.

Repayment of excess premium may be made by money, post office order, postal note or cheque and shall be forwarded to the Insured as soon as practicable after the giving or receiving of such notice of cancellation.

17. WAIVER

No notice to any agent or knowledge possessed by any agent or by any other person shall be held to effect a waiver or change in any part of this Policy; nor shall the terms of this Policy be waived or changed except by endorsement issued to form a part hereof signed by an authorized representative of the Insurer.

18. ASSIGNMENT

Assignment of interest under this Policy shall not bind the Insurer until their consent is endorsed hereon, except through change of title by succession, death or proceedings under any bankruptcy act.

MM.62108 (215)

SCHEDULE OF ENDORSEMENTS

ATTACHED TO AND FORMING PART OF THIS POLICY:

Endorsement	L-2:	Non-Owned Automobile Coverage
Endorsement	L-2A:	S.E.F. No. 94 - Legal Liability for Damage to Hired Automobiles
Endorsement	L-3:	All Risks Tenant's Legal Liability
Endorsement	L-4:	Employee Benefits Liability Insurance
Endorsement	L-5:	Medical Expense Insurance
Endorsement	L-7:	Forest and Prairie Protection Acts Expenses Insurance
Endorsement	L-9:	Advertisers' Liability
Endorsement	L-15:	All U.S. Exposure Exclusion
Endorsement	L-18:	Deductible (All Losses)
Endorsement	L-28:	Asbestos Exclusion
Endorsement	L-33:	Employment Practices Exclusion
Endorsement	L-37:	Data Exclusion
Endorsement	L-38:	Terrorism Exclusion
Endorsement	L-39:	Fungus, Mildew and Mould Exclusion
Endorsement	L-41:	Silica Exclusion
Endorsement	S-1:	Polychlorinated Biphenyl (PCB) Exclusion
Endorsement	S-2:	Limited Failure to Supply Extension
Endorsement	S-3:	Excluded Operations - Yukon Electrical Company Limited

MM.62108 (215)

ENDORSEMENT L-2

NON-OWNED AUTOMOBILE COVERAGE

INSURING AGREEMENT

In consideration of the payment of the premium and subject to the limits, terms, conditions, provisions, definitions and exclusions herein stated, the Insurer agrees to indemnify the Insured against the liability imposed by law upon the Insured for loss or damage arising from the use or operation of any automobile not owned in whole or in part by or licensed in the name of the Insured, and resulting from

BODILY INJURY TO OR THE DEATH OF ANY PERSON OR DAMAGE TO PROPERTY OF OTHERS NOT IN THE CARE, CUSTODY OR CONTROL OF THE INSURED.

Provided always the Insurer SHALL NOT be liable under this Policy:

(a) for any liability which arises from the use or operation of any automobile while personally driven by the Insured if the insured is an individual; or

*(b) for any liability imposed upon any person insured by this Policy:

(i) by any workmen's compensation law; or

(ii) by any law for bodily injury to or the death of the Insured or any partner, officer or employee of the Insured while engaged in the business of the Insured; or

* Not applicable in the Province of Ontario.

(c) for any liability assumed by any person insured by this Policy voluntarily under any contract or agreement except a written contract or agreement; or

(d) for loss or damage to property carried in or upon an automobile personally driven by any person insured by this Policy or to any property owned or rented by, or in the care, custody or control of any such person; or

(e) for any amount in excess of the limit stated in the Declarations, and expenditures provided for in the Additional Agreements of this Policy; subject always to the provisions of the section of the Insurance Act (Automobile Insurance Part) relating to the nuclear energy hazard.

ADDITIONAL AGREEMENTS OF INSURER

Where indemnity is provided by this Policy, the Insurer further agrees:

(1) Upon receipt of notice of loss or damage caused to persons or property to serve any person insured by this Policy by such investigation thereof, or by such negotiations with the claimant, or by such settlement of any resulting claims, as may be deemed expedient by the Insurer; and

(2) to defend in the name and on behalf of any person insured by this Policy and at the cost of the Insurer any civil action which may at any time be brought against such person on account of such loss or damage to persons or property; and

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(3) to pay all costs taxed against any person insured by this Policy in any civil action defended by the Insurer and any interest accruing after entry of judgment upon that part of the judgment which is within the limits of the Insurer's liability; and

(4) in case the injury be to a person, reimburse any person insured by this Policy for outlay for such medical aid as may be immediately necessary at the time of such injury; and

(5) be liable up to the minimum limit(s) prescribed for that province or territory of Canada in which the accident occurred, if that limit(s) is higher than the limit stated in the Declarations of this Policy; and

(6) not set up any defense to a claim that might not be set up if the policy were a motor vehicle liability policy issued in the province or territory of Canada in which the accident occurred.

AGREEMENTS OF INSURED

Where indemnity is provided by this Section, every person insured by this Policy

(a) by the acceptance of this Policy, constitutes and appoints the Insurer his irrevocable attorney to appear and defend in any province or territory of Canada in which action is brought against the Insured arising out of the use or operation of an automobile with respect to which insurance is provided hereunder;

(b) shall reimburse the Insurer upon demand, in the amount which the Insurer has paid by reason of the provisions of any statute relating to automobile insurance and which the Insurer would not otherwise be liable to pay under this Policy.

GENERAL PROVISIONS AND DEFINITIONS

1. ADDITIONAL INSUREDS

The Insurer agrees to indemnify in the same manner and to the same extent as if named herein as the Insured, every partner, officer or employee of the Insured who, with the consent of the owner thereof, personally drives (a) in the business of the Insured or incidental personal use in connection therewith, any automobile not owned in whole or in part by or licensed in the name of (i) the Insured, or (ii) such additional insured person, or (iii) any person or persons residing in the same dwelling premises as the Insured or such additional insured person, or (b) any automobile hired or leased in the name of the Insured or leased in the name of any partner, officer or employee of the Insured for use on the Insured's behalf including personal use in connection therewith except an automobile owned in whole or in part or licensed in the name of such additional insured person.

2. TERRITORY

This Policy applies only to the use or operation of automobiles within Canada or the United States of America or upon a vessel plying between ports of those countries.

3. HIRED AUTOMOBILES DEFINED

The term "Hired Automobiles" as used in this Policy means automobiles hired, leased or borrowed from others with or without drivers for periods not exceeding 30 days, used under control of the Insured in the business of the Insured but shall not include any automobile owned in whole or in part by or licensed in the name of the Insured or any partner, officer or employees of the Insured.

4. AUTOMOBILES OPERATED UNDER CONTRACT DEFINED

The term "Automobiles Operated under Contract" as used in this Policy shall mean automobiles operated in the business of the Insured where the complete supervision, direction and control of such automobiles remain with the owner thereof, but shall not include any automobile owned in whole or in part by or licensed in the name of the Insured or any partner, officer or employee of the Insured.

5. TWO OR MORE AUTOMOBILES

When two or more automobiles are insured hereunder the terms of this Policy shall apply separately to each, but a motor vehicle and a trailer or trailers attached thereto shall be held to be one automobile as respects the limits of liability stated in the Declarations.

The coverage provided by this Endorsement shall be subject to the Statutory Conditions (Conditions in Quebec) applicable in all Provinces of Canada.

MM.62108 (997.5-7)

ENDORSEMENT L-2A

S.E.F. No. 94

LEGAL LIABILITY FOR DAMAGE TO HIRED AUTOMOBILES ENDORSEMENT

The Insurer agrees to indemnify the Insured against the liability imposed by law upon the Insured or assumed by him under any contract or agreement for loss or damage arising from the care, custody or control of "Hired Automobiles" as defined on Endorsement L-2 and resulting from loss or damage thereto, caused by ALL PERILS.

DEDUCTIBLE CLAUSE

Each occurrence causing loss or damage covered herein, except loss or damage caused by fire or lightning or theft of the entire automobile, shall give rise to a separate claim in respect of which the Insurer's liability shall be limited to the amount of loss or damage in excess of the amount deductible, if any, stated herein.

TWO OR MORE AUTOMOBILES

A motor vehicle and one or more trailers or semi-trailers attached thereto shall be held to be separate automobiles with respect to the limit of liability, including deductible provision, if any, under this Insuring Agreement.

EXCLUSIONS

The Insurer SHALL NOT be liable:

(1) for loss or damage to any automobile while personally driven by the Insured if the Insured is an individual; or

(2) for loss or damage

(a) to tires or consisting of or caused by mechanical fracture or breakdown of any part of an automobile or by rusting, corrosion, wear and tear, freezing or explosion within the combustion chamber, unless the loss or damage is coincident with other loss or damage covered herein or is caused by fire, theft or malicious mischief; or

(b) to any automobile while being used without the consent of the owner thereof; or

(c) caused directly or indirectly by contamination by radioactive material; or

(d) to contents of trailers or to rugs or robes; or

(e) to tapes and equipment for use with a tape recorder when detached therefrom; or

(f) caused directly or indirectly by bombardment, invasion, civil war, insurrection, rebellion, revolution, military or usurped power, or by the operation of armed forces while engaged in hostilities whether war be declared or not; or

(g) for any amount in excess of the limit stated herein and expenditures provided for in the Additional Agreements of Endorsement L-2 to which this Endorsement is attached.

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ADDITIONAL AGREEMENTS

The Insurer further agrees to pay general average, salvage and fire department charges and custom duties of Canada or of the United States of America for which the Insured is legally liable.

LIMIT OF LIABILITY

$ 50,000.00 (Exclusive of interests and costs) any one accident.

DEDUCTIBLE AMOUNT

$ 2,500.00 per occurrence.

MM.62108 (997.8-9)

Commonwealth Insurance Company

ENDORSEMENT L-3

ALL RISKS TENANT'S LEGAL LIABILITY

Subject to the terms and provisions of the policy to which this Endorsement is attached, the Insurer agrees to pay on behalf of the Insured all sums which the Insured shall become legally obligated to pay as damages for injury to or destruction, including loss of use, of premises including building fixtures permanently attached thereto, rented to or occupied by the Insured and described and located as specified in the Schedule hereof, if such injury or destruction is caused by accident and arises out of direct physical loss or damage from any cause except as hereinafter provided.

LIMIT OF LIABILITY

The Limit of Liability stated opposite each item in the Schedule herein is the Limit of the Insurer's Liability in respect of that item for all damages arising out of any one accident during the policy Period.

The coverage provided by this Endorsement shall not increase the Limit of Liability shown in the Declarations.

SCHEDULE

LOCATION	LIMIT OF LIABILITY
Blanket – All Locations, excluding manufacturing and repair locations	$ 5,000,000.00

EXCLUSIONS

The insurance afforded by this Endorsement DOES NOT apply:

(a) to liability assumed by an Insured under contract except liability which would attach in the absence of such contract;

(b) to liability for gradual deterioration, ordinary wear and tear and mechanical or electrical breakdown or derangement; but not excluding resultant loss or damage.

DEDUCTIBLE

Each claim for loss or damage shall be adjusted separately and from the sum so determined the amount of One Thousand Dollars ($1,000.00) shall be deducted.

MM.62108 (997.13)

Commonwealth Insurance Company

ENDORSEMENT L-4

EMPLOYEE BENEFITS LIABILITY INSURANCE

THE COVERAGE PROVIDED BY THIS ENDORSEMENT IS ON A CLAIMS MADE BASIS.

By accepting this Endorsement, the Insured at the effective date of this Policy had no knowledge of or could not have reasonably foreseen any circumstances which might result in a claim hereunder.

1. Subject to the terms and provisions of the policy to which this Endorsement is attached, the Insurer agrees to pay on behalf of the Insured all sums which the Insured shall become legally obligated to pay any employee or former employee or the heirs, beneficiaries or legal representatives of either as damages arising from any act of negligence, error, mistake or omission of the Insured or others for whom the Insured is legally responsible in the administration of employee benefit programs of the Insured, provided any claim made to recover therefore is brought within the period this insurance is in effect.

2. The following definitions apply in connection with the insurance afforded by this Endorsement:

   (a) INSURED: The unqualified word "Insured" includes the Named Insured and also includes any executive officer, director or stockholder thereof while acting within the scope of his duties as such; any employee authorized to act in the administration of the Insured's employee benefit programs while so acting and, if the Named Insured is a partnership, any partner therein but only with respect to his liability as such.

   (b) EMPLOYEE BENEFIT PROGRAMS: The term "Employee Benefit Programs" shall mean group life insurance, group health insurance, profit sharing plans, pension plans, employee stock subscription plans, worker's compensation insurance, supplementary unemployment benefits, government unemployment compensation insurance, medical plans, dental plans, optical plans, social insurance and disability benefits insurance.

   (c) ADMINISTRATION: The unqualified word "Administration," wherever used, shall mean the following, provided the same are authorized by the Named Insured:

      (i) Counselling employees with respect to employee benefit programs;

      (ii) Interpretations relative to employee benefit programs;

      (iii) Record-keeping in connection with employee benefit programs;

      (iv) Enrollment, termination or cancellation of employees under employee benefit programs.

3. This insurance afforded by this Endorsement DOES NOT apply:

   (a) to any dishonest, fraudulent or criminal act or to libel, slander, discrimination or humiliation;

   (b) to bodily injury to, or sickness, disease or death, of any person, or to injury to or destruction of any tangible property, including the loss of use thereof;

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(c) to any claim for failure of performance of contract by any Insurer;

(d) to any claim based upon the Insured's deliberate failure to comply with any worker's compensation, unemployment compensation, government pension plans, social security or disability benefits law or any similar law;

(e) to any claim based upon:

(i) Failure of securities to perform as represented by an Insured;

(ii) Advice given by an Insured in connection with participation or nonparticipation in stock subscription plans;

(iii) Failure to comply with the requirements of the Pension Reform Act of 1974 (Employee Retirement Income Security Act of 1974) applicable in the United States of America.

4. The Limit of Liability as stated in the schedule hereof as applicable to "each claim" is the Limit of the Insurer's Liability for all damages incurred as a result of any one claim insured hereunder but each claim made shall be subject to the deductible amount set forth in the schedule and the Insurer shall be liable only for the difference between such deductible amount and the Limit of Liability for "each claim"; the Limit of such Liability stated in the schedule as "aggregate" is, subject to the above provision respecting each claim, the total Limit of the Insurer's Liability for all damages insured hereunder.

The payment of any deductible amount by the Insured shall not operate to reduce the aggregate Limit of the Insurer's Liability.

The aggregate Limit of Liability shall apply separately to each policy period this insurance is in force.

Any act or omission on the part of one or another of the Insureds under this Policy shall not prejudice the rights or interests of any other Insured. The insurance afforded by this Endorsement, subject to the Limits of Liability stated herein, shall apply to each Insured in the same manner and to the same extent as if a separate policy had been issued to each.

If, during the policy period, the Insured shall become aware of any event which may subsequently give rise to a claim against the Insured by reason of any negligent act, error or omission and shall during the policy period give written notice to the Insurer of such event, any claim which may subsequently be made against the Insured arising out of that negligent act, error or omission shall be deemed, for the purposes of this Endorsement, to have been made during the policy period.

SCHEDULE OF LIMITS:	$	5,000,000.00	any one claim
	$	5,000,000.00	in the aggregate
DEDUCTIBLE:	$	1,000.00	any one claim

MM.62108 (997.14-16)

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ENDORSEMENT L-5

MEDICAL EXPENSE INSURANCE

IT IS HEREBY UNDERSTOOD AND AGREED that this Policy is extended to pay all reasonable expenses incurred within one year of the date of accident, for necessary medical, surgical, ambulance, hospital, professional nursing and funeral services, to or for each person who sustains bodily injury, sickness or disease, caused by accident and arising out of (a) a condition in the Insured's premises, or (b) operations with respect to which the Insured is afforded coverage for Bodily Injury Liability under this Policy.

Provided however, that in addition to the other exclusions in this Policy, this insurance shall also exclude coverage for:-

(a) Bodily injury, sickness, disease or death sustained by any person practicing instructing or participating in any physical training, sport, athletic activity or contest.

(b) Bodily injury to or sickness, disease or death of:

(i) the Insured, any partner therein, or any tenant or other person regularly residing on the premises, or any employee of such Insured, tenant or other person while engaged in the employment thereof;

(ii) any other tenant of the premises, or any employee of such other tenant while engaged in the employment thereof, on that part of the premises rented to such other tenant;

(iii) any person if benefits therefor are payable under any worker's compensation law, disability benefits law or a similar law;

(iv) any person while engaged in maintenance, alteration, demolition or new construction operations for the Insured or for any lessee of the Insured or any lessor of the premises.

(c) Any expense for services rendered by the Insured, any employee thereof, or any person or organization under contract to the Insured to provide such services.

(d) Bodily injury included within the Products Hazard or Completed Operations Hazard.

Provided that:

1. The accident takes place during the policy period;
2. The expenses are incurred and reported to the Insurer within one year of the date of the accident;
3. The injured person(s) submit to examination at the expense of and by physicians of the Insurer's choice as often as the Insurer reasonably requires; and
4. It is a condition of this Endorsement that pursuant to any provincial hospital acts or statutes, that any hospital benefit payable under this endorsement shall be limited to reimbursement of the actual hospital expense incurred which is in excess of those hospital benefits for which provision has been made under any said act or statute; subject in any event to the maximum amounts payable as set out in this Endorsement.

IT IS FURTHER UNDERSTOOD AND AGREED that the limit for this coverage is as follows:

Per Person: $ 2,500.00 Per Accident: $ 25,000.00

which amount is part of, and not in addition to, the each occurrence Limit of Liability of this Policy.

MM.62108 (997.17-18)

Commonwealth Insurance Company

ENDORSEMENT L-7

FOREST AND PRAIRIE PROTECTION ACTS EXPENSES INSURANCE

IT IS HEREBY UNDERSTOOD AND AGREED THAT Insuring Agreement 2 - Property Damage Liability - is extended to include all sums for "Fire Fighting Expenses" which the Insured shall become obligated to pay by reason of liability imposed upon the Insured by law or statute pursuant to the relevant provisions of the Forest and Prairie Protection Acts of the Provinces of Canada.

Exclusions applicable to this coverage;

Coverage granted herein SHALL NOT extend to cover:

(a) any fire fighting expense of the Insured, its employees or agents;

(b) any fire fighting expense of a contractor or subcontractor engaged by the Insured at the time loss first occurs;

(c) any expense, fine or penalty, for which the Insured is liable by reason of failure to comply with any statute, permit, rule or regulation;

(d) liability assumed by the Insured under any contract or agreement, except liability of the Insured that would have existed in the absence of such contract or agreement;

(e) any action brought against any of the Insureds by any other Insured or Insureds under this Policy in respect to the recovery of fire fighting expenses;

(f) any fire fighting expense of others on behalf of the Insured where more specific coverage has been purchased and is available to the Insured.

The Limit of Liability stated in the Declarations as applicable to "each Occurrence" is the Limit of the Insurer's Liability hereunder for all sums on account of one Occurrence and in the aggregate for all sums in any one Policy Period. The Limit of Liability for this coverage shall be part of, and not in addition to, the Limit of Liability stated in the Declarations.

Each Occurrence shall be subject to a deductible of Two Thousand Five Hundred Dollars ($2,500.00).

MM.62108 (997.19)

Commonwealth Insurance Company

ENDORSEMENT L-9

ADVERTISERS' LIABILITY

Subject to the terms and provisions of the policy to which this Endorsement is attached, the Insurer agrees to pay on behalf of the Insured all sums which the Insured shall become obligated to pay by reason of the liability imposed by law, or assumed under contract as defined, herein, as the result of any final judgment or damages resulting from;

(a) libel, slander, defamation, disparagement, or

(b) any infringement of copyright or of title or of slogan, or

(c) piracy, plagiarism, or unfair competition or idea misappropriation under implied contract, or

(d) any invasion of rights of privacy,

committed or alleged to have been committed in any advertisement, internet activity, publicity article, broadcast or telecast and arising out of the Insured's advertising activities.

DEFINITIONS

Definition of Contract

The word "contract" wherever used in this Endorsement shall mean the liability assumed or agreed upon by the Insured with any party, including but not limited to, advertising agencies, broadcasting companies, publishers and other media for advertising, to hold said parties harmless from loss and/or expense resulting from claims for damages on account of violation, or alleged violation, of the rights of others, arising from the broadcasting, or telecasting, or the publication for the Insured of any advertising matter including, but not limited to, copy, portraits, pictures, or other material for use in connection therewith, furnished by the Insured.

Nothing in this endorsement shall be construed to cover any liability arising out of the negligence of said parties in their handling, use or publication of any advertising matter or material furnished by the Insured, regardless of such assumption or agreement by the Insured.

EXCLUSIONS

This insurance DOES NOT cover liability for:

1. Failure of performance of contract, but this shall not relate to claims for the unauthorized appropriation of ideas based upon the alleged breach of an implied contract.

2. Physical property damage or for damages which may be attributed to or are a direct or consequential result of bodily injury to or death of any person, whatever the cause of such injury or death.

3. Infringement of trade mark, service mark or trade name, nor shall this endorsement cover any claims or suits for unfair competition based upon infringement of trade mark, service mark, or trade name.

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4. Incorrect description of any article or commodity.

5. Mistake in advertised price.

6. Any claim, unless resulting from events occurring during the effective period of this endorsement. If such events shall have occurred or have been initiated prior to the effective date hereof and shall have been repeated or continued during the effective period, or shall be repeated or continued thereafter, then the Insurer's liability shall be limited to the proportion of the total claim or judgment which the number of events during the effective period, upon which the claim is based, bears to the total number of events upon which such claim is based.

LIMIT OF LIABILITY

The Insurer's liability for the indemnity provided by this Endorsement is limited to $5,000,000.00 excess of the first $5,000.00 of each claim for any advertisement, publicity article, broadcast or telecast or any combination thereof involving the same injurious material or act, regardless of the frequency of repetition thereof or the number or kind of media used, whether claim is made by one or more persons. The inclusion herein of more than one Insured shall not operate to increase the limit of the Insurer's liability.

MM.62108 (997.21-22)

ENDORSEMENT L-15

ALL U.S. EXPOSURE EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This Policy DOES NOT cover any operation of the Insured, including the Products Hazard and Completed Operations Hazard as defined in this Policy, performed by or on behalf of the Insured in or to the United States of America, its territories or possessions.

However, this Exclusion SHALL NOT apply in respect of Canadian Employees visiting in or travelling through the United States of America, its territories or possessions for the purpose of business meetings or contract negotiations.

MM.62108 (997.31)

Commonwealth Insurance Company

ENDORSEMENT L-18

DEDUCTIBLE

(All Losses)

In consideration of the premium charged, except as otherwise specified in other endorsements attached to this Policy, it is understood and agreed that the sum of Two Hundred and Fifty Thousand Dollars ($250,000.00) shall be deducted from the total amount of all claims, legal fees, defense costs and adjusting expenses combined in any one accident or occurrence, and the Insurer shall be liable only for the difference between such deductible amount and the Limit of the Insurer's Liability for each accident or occurrence as stated in this Policy.

The Insurer may pay any part or all of the deductible amount to effect settlement of any claim or suit and, upon notification of the action taken, the Named Insured shall promptly reimburse the Insurer for such part of the deductible amount as has been paid by the Insurer.

Nothing herein contained shall be held to vary, alter, waive or extend any of the statements, agreements, exclusions or conditions of the policy other than as stated above.

MM.62108 (997.34)

Commonwealth Insurance Company

ENDORSEMENT L-28

ASBESTOS EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This insurance DOES NOT apply to any liability for Property Damage, Personal Injury, sickness, disease, occupational disease, disability, shock, death, mental anguish and mental injury at any time arising out of the manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to asbestos, asbestos products, asbestos fibres or asbestos dust, or to any obligation of the Insured to indemnify any party because of damages arising out of such Property Damage, Personal Injury, sickness, disease, occupational disease, disability, shock, death, mental anguish or mental injury at any time as a result of the manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to asbestos, asbestos products, asbestos fibres or asbestos dust.

It is further understood and agreed that the Insurer is NOT obligated to defend any suit or claim against the Insured alleging Personal Injury or Property Damage and seeking damages, if such suit or claim arises from Personal Injury or Property Damage resulting from or contributed to, by any and all manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to asbestos, asbestos products, asbestos fibres or asbestos dust.

It is further understood and agreed that this Policy DOES NOT apply to any action or claim either for defense or payment of any damages compensatory, punitive or economic arising out of any Insured's failure to disclose the presence or presumed presence of asbestos in any properties owned or occupied by the Insured.

MM.62108 (997.44)

Commonwealth Insurance Company

ENDORSEMENT L-33

EMPLOYMENT PRACTICES EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

The coverage afforded by this Policy DOES NOT apply to "Personal Injury" arising out of any:

1. Refusal to employ;

2. Termination of employment;

3. Coercion, demotion, evaluation, reassignment, discipline, defamation, harassment, humiliation, discrimination or other employment related practices, policies, acts or omissions; or

4. Consequential "Personal Injury" arising out of 1 through 3 above.

This exclusion applies whether the Insured may be liable as an employer or in any other capacity, and to any obligation to share damages with or repay someone else who must pay damages because of the injury.

MM.62108 (997.51)

Commonwealth Insurance Company

ENDORSEMENT L-37

DATA EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This insurance DOES NOT apply to:

(a) Any liability for:

(i) erasure, destruction, corruption, misappropriation, misinterpretation of "Data"; or

(ii) erroneously creating, amending, entering, deleting or using "Data";

including any loss of use arising therefrom.

(b) Any liability arising out of the distribution or display of "Data", by means of an Internet Website, the Internet, an intranet, extranet, or similar device or system designed or intended for electronic communication of "Data".

"Data" means representations of information or concepts, in any form.

MM.62108 (997.55)

Commonwealth Insurance Company

ENDORSEMENT L-38

TERRORISM EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This Policy DOES NOT cover loss, damage, cost or expense of whatsoever nature caused by, resulting from or in connection with any act of terrorism. For the purpose of this exclusion, "Terrorism" shall mean any unlawful act of any person acting on behalf or in connection with any organization with activities directed towards the overthrowing or influencing of any government, de jure or de facto, by force or violence and/or to put the public, or any section of the public, in fear.

Such act must be declared to have been an act of terrorism by the appropriate law enforcement authority of the country or province or territory where the act or activity occurred. In the event of federal and/or state or provincial legislation becoming effective during the term of this Policy, which names a person, position or office as having the designated authority to make such a declaration of an act of terrorism, then such declaration of such named individual shall apply hereunder.

Unauthorized gaining of access to any information technology system shall only be considered to be an act of terrorism when so declared by the appropriate law enforcement authority.

MM.62108 (997.56)

Commonwealth Insurance Company

ENDORSEMENT L-39

FUNGUS, MILDEW AND MOULD EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This insurance DOES NOT apply to:

1. Any liability arising out of, resulting from, caused by, contributed to, or in any way related to the existence, inhalation or exposure to any "fungus/fungi" and/or "spore(s)";

2. Any legal fees, defense costs or other costs or expenses associated in any way, or arising out of the abatement, mitigation, remediation, containment, detoxification, neutralization, monitoring, removal, disposal, or any obligation to investigate or assess the presence or effects of any "fungus/fungi" or "spore(s)";

3. Any obligation to share with or repay any person, organization or entity, related in any way to items 1. and 2. above,

regardless of any other cause, event, material, product and/or building component that contributed concurrently or in any sequence to the injury or damage.

For purposes of this endorsement, the following definitions apply:

"Fungus/fungi" includes, but is not limited to, any form or type of mould, mildew, mushroom, yeast, or biocontaminant.

"Spore(s)" include, but is not limited to, any substance produced by, emanating from, or arising out of any "fungus/fungi".

MM.62108 (997.57)

Commonwealth Insurance Company

ENDORSEMENT L-41

SILICA EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

This insurance DOES NOT apply to any liability for Property Damage, Personal Injury, sickness, disease, occupational disease, disability, shock, death, mental anguish and mental injury at any time arising out of the manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to silica, silica products, silica fibres or silica dust, or to any obligation of the Insured to indemnify any party because of damages arising out of such Property Damage, Personal Injury, sickness, disease, occupational disease, disability, shock, death, mental anguish or mental injury at any time as a result of the manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to silica, silica products, silica fibres or silica dust.

It is further understood and agreed that the Insurer is NOT obligated to defend any suit or claim against the Insured alleging Personal Injury or Property Damage and seeking damages, if such suit or claim arises from Personal Injury or Property Damage resulting from or contributed to, by any and all manufacture of, mining of, use of, sales of, installation of, removal of, distribution of, or exposure to silica, silica products, silica fibres or silica dust.

It is further understood and agreed that this Policy DOES NOT apply to any action or claim either for defense or payment of any damages compensatory, punitive or economic arising out of any Insured's failure to disclose the presence or presumed presence of silica in any properties owned or occupied by the Insured.

MM.62108 (997)

Commonwealth Insurance Company

ENDORSEMENT S-1

POLYCHLORINATED BIPHENYL (PCB) EXCLUSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

The insurance provided by this Policy DOES NOT apply to claims arising out of Personal Injury or Property Damage caused by the discharge of, dispersal of, release of, escape of or exposure to Polychlorinated Biphenyl (PCB) with respect to the Insured's products or operations.

MM.62108 (217.52)

Commonwealth Insurance Company

ENDORSEMENT S-2

LIMITED FAILURE TO SUPPLY EXTENSION

IT IS HEREBY UNDERSTOOD AND AGREED that:-

The coverage afforded by this Policy DOES NOT apply to any liability for Personal Injury or Property Damage arising out of the failure to supply unless:

1. Such failure is caused by an Occurrence; and

2. The combined capacity of the Insured's installed production facilities and contractual supply arrangements is equal to or greater than One Hundred and Ten percent (110%) of the electricity demand immediately preceding such failure, on the Insured's electric system.

MM.62108

Commonwealth Insurance Company

ENDORSEMENT S-3

EXCLUDED OPERATIONS

IT IS HEREBY UNDERSTOOD AND AGREED that:-

The coverage afforded by this Policy DOES NOT apply to any claim arising out of the operations of Yukon Electrical Company Limited.

MM.62108

Commonwealth Insurance Company

TOPIC: **Diesel Contingency Fund (DCF)**

REFERENCE: **Appendix 3.2**

PREAMBLE:

The City requires more information on how the Diesel Contingency Fund will operate.

QUESTION:

a) Based on the description and parameters set out in Appendix 3.2, please provide numerical examples of Diesel Contingency Fund additions, withdrawals, opening and closing balances and secondary sales credits for the following conditions:

   i. 20% lower than average water flow.
   ii. 10% lower than average water flow.
   iii. Average water flow.
   iv. 10% higher than average water flow.
   v. 20% higher than average water flow.

b) Please provide a pro forma monthly report as described at page 3.2-3.

ANSWER:

(a)

The Diesel Contingency Fund (DCF) operation is affected by the variability in existing grid hydro generation, and not by the variability of water flow. Please see the response to YUB-YEC-1-30 (b) for numerical examples of the DCF operation for different grid hydro generation variations.

(b)

Please see Table 1 below for a pro-forma DCF monthly report. The table indicates a hypothetical snapshot of the DCF status as of October 2013, projecting an annual transfer totaling $0.240 million. A similar analysis would be re-run each month, to update

the projected annual transfer and how it has changed based on each new month of data. A final true up will be done at the end of the calendar year.

Table 1:

Diesel Contingency Fund Pro-Forma Monthly Report (2013)

		Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Actual	Sep Actual	Oct Actual	Nov Forecast	Dec Forecast	Total
	Hydro (MW.h)	41,527	36,581	37,028	31,388	31,899	29,925	31,770	30,710	33,216	35,203	39,806	40,870	419,921
	Diesel (MW.h)	1,501	1,357	3,670	688	300	132	212	212	112	112	1,901	1,901	12,098
	Wind (MW.h)	-	-	5	3	5	20	30	46	80	39	-	9	238
L1	Total YEC Supply (MW.h)	43,028	37,938	40,703	32,079	32,204	30,077	32,013	30,968	33,408	35,354	41,707	42,780	432,257
L2=L1-238	Actual Grid Load (Load less GRA Wind Generation) (MW.h)													432,019
L3	Grid Load Benchmark (MW.h) (Table 3.2-2)													430,000
L4	Diesel as % of Increased Load (MW.h)													56%
L5	Expected Base Diesel Generation (MW.h)													18,100
L6=(L2-L3)xL4	Expected Incremental Diesel Generation (MW.h)													1,131
L7=L5+L6	Total Expected Diesel Generation (MW.h)													19,231
L8=L7x59%	Expected Diesel Generation in Rates (MW.h)													11,342
L9	Actual Diesel Generation (MW.h)	1,501	1,357	3,670	688	300	132	212	212	112	112	1,901	1,901	12,098
L10=L9-L8	Diesel Generation to be Included in DCF (MW.h)													756
L11=L10x$0.3168	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)													$ 240

Note: Pro-forma monthly report assumes actual load and diesel generation for some 2013 months in the table for illustration purposes.

TOPIC: **Diesel Contingency Fund (DCF)**

REFERENCE: **Application page 3.2-2, lines 19-22**

YEC states:

> **On March 29, 2010, Yukon Energy filed its 2008 Diesel Contingency Fund Filing and noted the potential need to update methods of operation of the DCF. It was noted that the DCF operating rules would require attention in the future to address a number of new circumstances, including updating long-term average hydro generation values, fund triggers, and potentially a means to address secondary sales.**

PREAMBLE:

The City requires more information on the Diesel Contingency Fund.

QUESTION:

a) Please provide a copy of the filing of March 29, 2010 referenced above.

b) What changes does YEC propose in this application from the filing of March 29, 2010?

ANSWER:

(a)

Please refer to Attachment 1 of this response.

(b)

Proposed changes to the March 29, 2010 Diesel Contingency Fund Filing have been addressed in Tab 3, Attachment 3.2 to Appendix 3.2 of the Application.

YUKON ENERGY

YUKON ENERGY CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 6S7
(867) 393-5300

Our File: 2700-05-03

March 29, 2010

Yukon Utilities Board
P.O. Box 31728
Whitehorse, YT
Y1A 6L3

Attention: Mr. Bruce McClennan, Chair

Re: 2008 Diesel Contingency Fund Filing

In accordance with the negotiated settlement resulting from the 1996/97 Revenue Requirement and Rate Design Application, Yukon Energy is to file with the Board a report on the operation of the Diesel Contingency Fund for each year.

For the 2008 year, Yukon Energy was involved in a general review of its rates, which includes activities extending well beyond the 2008 year-end (the 2008/09 General Rate Application and follow up joint YEC/YECL Phase II Rate Application). These regulatory reviews include consideration of matters related to diesel generation forecasts and the potential need to update the methods of operation of the DCF. The Phase II Rate Application document has now been finalized and submitted to the Board for review. As part of that process, the utilities have not sought any changes to the DCF at this time.

No DCF report was filed at year-end 2008 pending YEC's and the Board's review of these matters. While the DCF operating rules will require attention in future to address a number of circumstances, including updating long-term average hydro generation values, fund "triggers", and potentially a means to address secondary sales, no changes are yet being proposed to the fund.

Consequently, in order to ensure a complete record for the Board's files, please find attached the schedules and tables related to the Diesel Contingency Fund for 2008:

1. Diesel Contingency Fund Continuity Schedule for 2008,
2. Diesel Contingency Fund Calculation Tables for 2008, and
3. As required by the DCF negotiated settlement, also attached is an internal memo regarding the 2009 forecast of available water.

Following is the general information on Diesel Contingency Fund operations for 2008:

- The opening balance of the Diesel Contingency Fund as at January 1, 2008 was $856,020.84.
- The Closing Balance of the Fund as at December 31, 2008 was $882,693.40.
- The net change in the Fund of $26,672.56 is attributable to interest of $29,389.43 net of account service fees of ($2,716.87). There was no other activity impacting the fund.
- Long term average annual non-diesel generation for purposes of this report remains unchanged as follows:
  - Whitehorse Rapids Hydro – 246 GWh
  - Aishihik Hydro – 105 GWh
  - Fish Lake Hydro – 10 GWh
  - Haeckel Hill – Wind Turbine – 0.3 GWh

- Actual diesel generation for 2008 was 1,214,174 kWh. Diesel was not on the margin for any month of the 2008 period.

- During December 2008 diesel generation exceeded the on the margin threshold of 250 MW.h/month used within the Diesel Contingency Fund as a determinant to indicate that all diesel generation during a month is presumably required only for baseload serving purposes. Upon review it is evident that the diesel generation was for unplanned maintenance or peaking purposes and not due to low water flow variances. As this generation does not meet the overall intent and purpose of the Diesel Contingency Fund it has been excluded from the December 2008 calculation so that there is no impact on the Diesel Contingency Fund for this generation.

- As per the attached memorandum written by Ron Gee, Resource Management Engineer, diesel consumption for generation or capacity requirements is not expected in 2009.

If there are any questions related to the filing of this report or management of the Diesel Contingency Fund please contact the undersigned.

Sincerely,



Ed Mollard, CGA
Chief Financial Officer

YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE

FOR THE YEAR			
2008	Opening balance		856,020.84
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M	-	-
	YECL Net withdrawals		-
	Interest Income/Service Fees		26,672.56
	Ending Balance		882,693.40

T:\Diesel Contingency Fund\2008\2008 DCF Schedule Summary of Continuity Schedules

2008 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2008
Continuity Schedule, Year Ending Dec. 31, 2008 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line#		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input	33,165,929	28,610,041	29,877,857	23,656,146	21,345,165	21,790,016	21,745,269	22,940,550	22,307,493	25,080,823	29,832,970	35,346,066	313,708,326
Wind	1a	Manual Input	0	0	25,100	0	174,790	55,760	70,500	18,900	0	0	101,390	6,450	452,890
Diesel	2	Manual Input	37,323	76,111	0	0	186,358	0	0	840	0	218,668	31,256	663,618	1,214,174
Total	3	Line 1 + Line 2	33,203,251	28,686,152	25,902,957	23,656,146	21,706,313	21,829,776	21,815,769	22,960,290	22,307,493	25,299,491	29,965,616	36,016,126	315,359,390
Forecast Generation - KWh															
Hydro	4	Manual Input	30,406,823	27,721,714	26,952,170	23,816,498	24,702,218	30,959,932	30,771,955	30,871,930	31,799,615	32,502,675	35,765,226	29,775,138	351,027,596.00
Wind	4a	Manual Input	30,000	26,000	28,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	309,000.00
Diesel	5	Manual Input	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,209	84,205,322.00
Total	6	Line 4 + Line 5	42,276,269	38,310,982	38,957,763	35,407,737	34,229,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,892,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	2,729,305	1,890,327	(117,213)	(177,352)	(3,206,263)	(9,145,156)	(8,971,187)	(7,932,380)	(9,517,122)	(7,461,853)	(850,886)	5,547,380	(37,242,380)
Diesel	8	Line 2 - Line 5	(11,802,123)	(10,485,157)	(11,937,593)	(11,564,239)	(9,315,963)	(1,203,010)	(1,346,054)	(1,349,672)	(1,442,675)	(3,393,097)	(7,963,975)	(11,187,590)	(82,991,148)
Total (favourable)	9	Line 3 - Line 6	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,282,052)	(10,959,797)	(10,844,950)	(8,824,841)	(5,640,210)	(120,233,528)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (Teryes, Duhoe)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	-
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,209	84,205,322.00
Total variance	12	Line 9	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,282,052)	(10,959,797)	(10,844,950)	(8,824,841)	(5,640,210)	(120,233,528.00)
	13	Line 11 + Line 12	2,766,628	1,936,438	(117,213)	(177,352)	(3,019,905)	(9,145,156)	(8,971,187)	(7,931,540)	(9,517,122)	(7,233,185)	(829,610)	5,210,998	(36,028,206.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,209	84,205,322.00
Actual diesel generation	15	Line 2	37,323	76,111	-	-	186,358	-	-	840	-	218,668	31,256	663,618	1,214,174.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	0.00	-
Standard efficiency (kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider (drawdown)	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29														-
Ending reserve balance	30	Line 26+27+28+29	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	Re-invested interest	3,297.79	2,870.19	2,843.68	2,821.04	2,428.57	2,383.06	2,347.38	2,172.91	2,378.75	2,399.90	1,925.31	1,881.01	29,399.43
Service fees	33	Investment Fees	(674.47)	0.00	0.00	(672.62)	0.00	0.00	(678.64)	0.00	0.00	(691.20)	0.00	0.00	(2,716.93)
Net interest earned	34	Line 32+33	2,623.32	2,870.19	2,843.68	1,848.42	2,428.57	2,383.06	1,668.74	2,172.91	2,378.75	1,648.70	1,925.31	1,881.01	26,672.56
Cumulative net interest earned	35		2,623.32	5,493.51	8,337.19	10,185.61	12,614.18	14,997.24	16,665.98	19,838.79	21,217.54	22,866.24	24,791.55	26,672.56	
Ending reserve balance including interest	36	Line 30+35	858,644.16	861,514.35	864,358.03	866,206.45	868,635.02	871,018.08	872,686.82	874,859.63	877,238.38	879,387.08	880,512.39	882,693.40	

T:\Diesel Contingency Fund\2008\2008 DCF Schedule Continuity Sched By Yr

3/26/2010

YUKON ENERGY

YUKON ENERGY CORPORATION
MEMORANDUM

DATE: May 5, 2008

TO: Melaine Fillion

FROM: Ronald Gee

RE: 2008 Forecast of Available Water on WAF Grid

The present sales forecast for 2008 on the Whitehorse-Aishihik-Faro (WAF) system is approximately 312.9 GWh's.

The Aishihik Lake reservoir is currently near its low for the year at an elevation of 914.27m. Inflows for 2008 are expected to be above average and therefore the forecasted peak elevation in October will reach the peak operating level of 915.1m. With the Carmacks to Stewart Crossing transmission line and Minto Mine spur expected to be in operation in 2008, the Aishihik Lake level will be brought up to near full supply level. The Aishihik system is expected to have full use of energy and capacity from the plant for the winter of 2008/09. Operationally, there is no scheduled maintenance of the Aishihik hydro units that would impact the winter generating capability of the hydro plant.

Marsh Lake reservoir is presently at 653.91m. The lake level will begin rising in the next week and is forecast to be completely full by the fall. Winter drawdown of the lake will begin in November and continue through to May 2009. Energy and capacity at Whitehorse Rapids will be constrained by the decreasing water flow in the Yukon River as the winter progresses. This decrease in generating capability is the normal operating situation for Whitehorse Rapids. Scheduled hydro maintenance is not expected to impact the winter generating capability of the Whitehorse Rapids Hydro Plant.

With the current sales forecast and the expectation of full hydro reservoirs in the fall, there is no forecast diesel generation for energy requirements expected in 2008.

Diesel generation in 2008 may occur for the following reasons: For maintenance purposes to ensure operational readiness, diesel peaking during periods of unseasonably cold temperatures and in the event of an unplanned hydro shut down. The total amount of diesel for the above purposes is not expected to exceed the thresholds specified in the calculation of the Diesel Contingency Fund. Attached is a forecast of the WAF generation levels for 2008.

\documents\memo\rg3132

Actual Data to May 3 / 08

AISH INFLOW 120 % OF LTA
2008 WAF FORECAST

WEEK ENDING	ACTUAL OR PROJ SYST GEN (GWH)	PROJ OR FORE SYST GEN AVG (MW)	ACTUAL OR FORE WHSE GEN AVERAGE (MW)	ACTUAL AISH INFLOW CMS.W	PROJ AISH OUTFLOW CMS	PROJECT AISH ELEV (m)	PROJ OR FORE AISH GEN AVG (MW)	ACTUAL OR FORE DIES GEN AVG (MW)
2008								
5-Jan	33.203251	43.886	25.768	3.221	8	914.824	18.118	0.000
12-Jan		44.193	24.621	3.169	8	914.793	19.570	0.002
19-Jan		42.098	23.761	4.305	8	914.767	18.336	0.000
26-Jan		43.625	23.952	0.761	8	914.727	19.673	0.000
2-Feb	29.686152	51.714	25.272	1.646	8	914.691	25.957	0.485
9-Feb		50.776	24.248	2.889	8	914.643	26.367	0.160
16-Feb		40.893	23.452	-0.850	8	914.579	17.425	0.016
23-Feb		35.832	23.105	0.126	8	914.539	12.728	0.000
1-Mar	26.902957	38.750	22.153	1.501	8	914.512	16.597	0.000
8-Mar		37.120	21.666	-3.643	8	914.465	15.455	0.000
15-Mar		35.866	20.902	2.359	8	914.443	14.964	0.000
22-Mar		35.808	20.665	3.517	8	914.426	15.143	0.000
29-Mar		35.109	20.800	0.537	8	914.397	14.309	0.000
5-Apr	25.382887	34.207	21.273	-4.190	8	914.349	12.934	0.000
12-Apr		33.606	20.760	0.608	8	914.321	12.846	0.000
19-Apr		33.277	19.553	4.681	8	914.310	13.724	0.000
26-Apr		31.252	19.922	-2.930	8	914.268	11.330	0.000
3-May	22.70213	30.351	19.131	9.205	8	914.276	11.220	0.000
10-May		30.514	18.314	13.215	6	914.306	12.200	0.000
17-May		30.514	18.314	14.540	6	914.341	12.200	0.000
24-May		30.514	19.914	16.283	5	914.387	10.600	0.000
31-May		30.514	19.914	21.686	5	914.455	10.600	0.000
7-Jun	20.879176	28.999	19.299	25.666	5	914.540	9.700	0.000
14-Jun		28.999	19.299	26.666	5	914.628	9.700	0.000
21-Jun		28.999	21.049	24.095	4	914.711	7.950	0.000
28-Jun		28.999	21.049	25.743	4	914.542	7.950	0.000
5-Jul	21.54486	28.970	25.401	24.154	4	914.625	3.569	0.000
12-Jul		28.958	25.389	24.837	4	914.675	3.569	0.000
19-Jul		28.958	25.389	27.676	4	914.730	3.569	0.000
26-Jul		28.958	25.389	24.308	4	914.813	3.569	0.000
2-Aug	21.435453	28.916	28.916	22.165	4	914.888	0.000	0.000
9-Aug		28.811	28.811	19.706	4	914.952	0.000	0.000
16-Aug		28.811	28.811	19.230	4	914.809	0.000	0.000
23-Aug		28.811	28.811	17.744	4	914.865	0.000	0.000
30-Aug		28.811	28.811	17.071	4	914.919	0.000	0.000
6-Sep	23.306207	31.861	28.292	16.672	4	914.971	3.569	0.000
13-Sep		32.370	28.801	15.053	4	915.016	3.569	0.000
20-Sep		32.370	25.051	12.654	6	915.043	7.319	0.000
27-Sep		32.370	25.051	11.586	6	915.066	7.319	0.000
4-Oct	27.945126	35.336	25.636	10.278	6	915.084	9.700	0.000
11-Oct		37.561	27.861	10.982	6	915.104	9.700	0.000
18-Oct		37.561	27.861	7.664	6	915.111	9.700	0.000
25-Oct		37.561	27.861	6.211	6	915.112	9.700	0.000
1-Nov	30.949948	38.336	28.636	4.585	6	915.106	9.700	0.000
8-Nov		42.986	24.036	4.432	12	915.075	18.950	0.000
15-Nov		42.986	24.036	4.579	12	915.045	18.950	0.000
22-Nov		42.986	24.036	5.037	12	915.016	18.950	0.000
29-Nov		42.986	24.036	4.890	12	914.987	18.950	0.000
6-Dec	33.357305	44.571	23.871	4.806	13	914.953	20.700	0.000
13-Dec		44.835	24.133	4.655	13	914.918	20.702	0.000
20-Dec		44.835	24.133	4.778	13	914.885	20.702	0.000
27-Dec		44.835	24.133	4.132	13	914.848	20.702	0.000

TOPIC: **CSTP Stage 2**

REFERENCE: **Application page 5-5, lines 9-12 and CW-YEC-5 (a) Table 1 (Mayo B)**

YEC states:

> **The project was energized on June 16, 2011.**
>
> **Project costs are not yet final. The present estimates of the final completion cots are approximately $41.9 million. The full $41.9 million is funded by the federal and Yukon government contributions and, accordingly, there is no impact to rate base and no impact on rates.**

PREAMBLE:

The City requires more information on this project.

QUESTION:

a) Please provide a detailed explanation of the variance in costs between the $41.9 million and the $40 million estimated cost noted at line 3 of page 5-5.

b) Please provide the original costs of this project approved by YEC's Board of Directors by component and the actual costs in the same detail with explanations for variances greater than ±5% between estimated and actual.

c) Please provide a copy of the response to YECL-YEC-1-8 REVISED from YEC's 2008/2009 Application.

d) Please explain why the cost of the project has not been finalized if the project has been in service since June 16, 2011.

e) Are the federal and Yukon government contributions final or are they subject to change based on final project costs?

f) Has this project and its associated contribution(s) been placed in rate base?

ANSWER:

(a) and **(b)**

Please see Table 1 below.

Table 1:
CSTP Stage 2 Board Approval Budget and Final Forecast Cost Variance

Project Component	**Board-Approved Budget ($ Millions)**	**Final Forecast Cost ($Millions)**	**Variance ($Millions)**	**%**
Planning	1,567	1,568	-1	0%
Survey	565	568	-3	0%
Clearing	2,112	2,095	17	1%
Line construction	11,676	11,804	-129	-1%
Substation construction	15,516	18,053	-2,537	-16%
Engineering	2,039	3,177	-1,138	-56%
Project management	1,635	2,473	-838	-51%
Owners' costs	1,006	1,911	-905	-90%
Overhead & Interest	580	304	276	48%
Pooled Contingencies & Variances	3,305		3,305	
Total	40,000	41,953	-1,953	-5%

Review of cost variances by project component is as follows:

- **Substation Construction** – Several factors contributed to the overage in this category.
    1. The Pelly Crossing substation was redesigned to be a more traditional design. This substation was originally designed to be a fairly simple skid-mounted configuration; however, due to long lead times, management was forced to re-design this substation. This re-design carried a higher overall cost than the initial budget ($0.506 million negative variance).

2. The balance of the cost increase relates to the substation at Stewart Crossing. In the original budget, management expected to locate the necessary equipment at the intersection with the Mayo to Dawson transmission line. Due to excessive civil works required to build at this site (the location is on the side of Ferry Hill), the decision was made to relocate most of the substation equipment to a level site south of Stewart Crossing. This required the design and construction of a new substation at the intersection, as well as changes to transmission line configuration and communications.

Overall, the budget for the Stewart Crossing substation was exceeded by about $2.5 million. There was about $0.500 million in savings at the Carmacks and Minto Landing substations and in commissioning.

- **Engineering** – Detailed design engineering costs are $1.008 million over gross budget (approximately 46% increase). Factors contributing to this overage are as follows:

Stewart Crossing substation relocation	$ 510,000
Scope changes	400,000
Pelly Crossing substation design	240,000
	$1,150,000

1. **Stewart Crossing substation relocation** – Due to excessive costs associated with location of the major substation at the junction of the Mayo-Dawson and CSTP lines (primarily due to very high civil costs), the decision was made to relocate the substation south of Stewart Crossing. This required re-design efforts on the transmission line, elimination of three circuit breakers from the design, changes to the cable tray system, a new civil site plan, changes to screw pile foundation (to limit construction costs) and conceptual and detailed engineering of a switching substation at the inter-tie.

2. **Scope changes** – Scope changes included the following major items:
   - Refinement of conceptual design from preliminary engineering ($0.160 million);
   - Re-engineering to reduce construction cost ($0.060 million);

- Relay programming ($0.032 million);
- Adjust drawings for equipment availability/configuration ($0.030 million).

3. **Pelly Crossing substation design** – The original engineering contract did not include provision for a substation at Pelly Crossing (at the time the contract was signed, management was investigating options).

- **Project Management** – This category covers two contracts: on-site project management responsibilities and project coordinator reporting to the President. The single most significant factor to the overage in this account is delay in completion of the line construction portion of the project (caused by inability of contractor to complete critical areas during winter freeze up); this contributed about $0.250 million in extra costs. Changes in substation scope as well as construction delays due to equipment delivery and commissioning challenges accounted for the balance of the variance.

- **Owners Costs** – Costs associated with internal labour and miscellaneous non-labour items (e.g. contract legal support, FN project agreement costs, ROW remediation, PR, etc). Variances have arisen from a variety of sources as follows:

Additional procurement support	$142,000
Construction support	125,000
Permitting costs	37,000
Additional geo-tech work on substations	60,000
Permafrost issues	60,000
YEC labour	300,000
	$724,000

- **Overhead & Interest** – During 2011, management determined that the historical allocation of overhead to capital projects is not in compliance with International Financial Reporting Standards (IFRS). Therefore, for the 2011 accounting year (first year of IFRS compliance), overheads were not charged to the project.

(c)

Please refer to Attachment 1 of this response.

(d)

The project costs are final subject to a potential claim by a contractor that YEC has denied, and completion of minor deficiencies work this year (such as right of way remediation).

(e)

Final reporting and audit procedures are in process, however, it is not expected that the project contributions will be affected by these activities.

(f)

This project and its associated contributions were included in rate base at the end of 2011.

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

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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

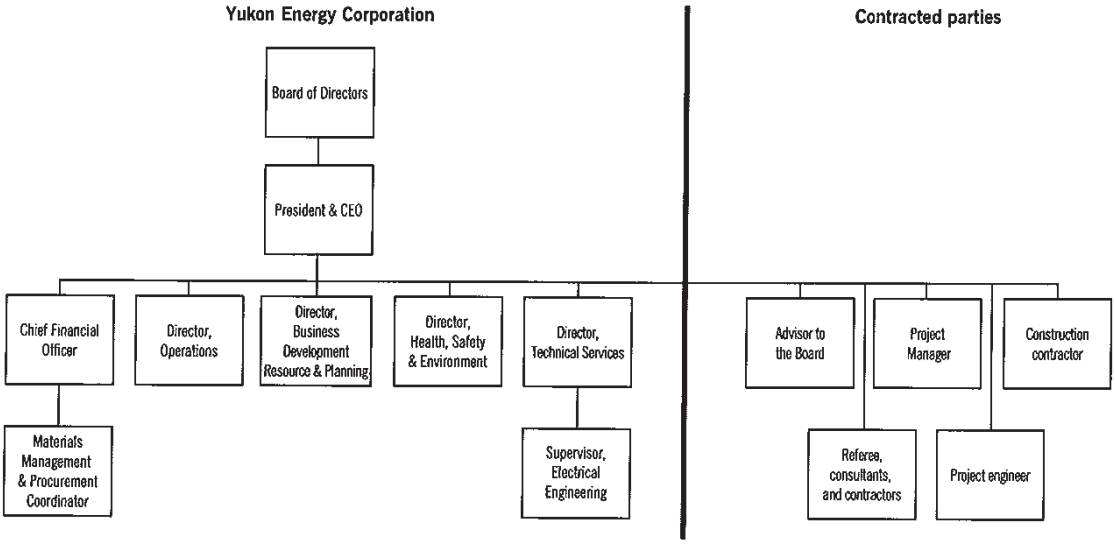
37. We expected to find a project brief with a statement of objectives that clearly defined roles, responsibilities, accountability, implementation approach, detailed budgets, and controls for this capital project. However, we did not find such a document. Instead, there were bits and pieces of information 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

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TOPIC: **Mayo B**

REFERENCE: **Application page 5-5, line 14 to page 5-6, line 22 and CW-YEC-5 (a) (Mayo B) Table 1 (see Attached)**

YEC states:

> **The project's completed cost is forecast at approximately $116.6 million (excluding the Mayo Lake project), or $1.9 million less than $118.5 million budget (excluding Mayo Lake project costs). The net rate base cost is forecast at $35 million, as project costs are forecast to be offset by federal and Yukon Government/YDC contributions of approximately $81.6 million.**

PREAMBLE:

The City requires more information on this project.

QUESTION:

a) Please provide a side-by-side comparison of the cost breakdown provided as CW-YEC-5 Table 1 in the Mayo B Facilities hearing (attached) and the 116.6 million actual costs, as stated above.

b) Please provide an explanation of any variance greater than ±5%.

c) When did the project enter service and when was it and its associated contribution(s) placed in rate base?

d) Please provide a table of generation output from Mayo B since entering service.

e) Please provide an analysis of the costs and benefits of the Mayo B project based on actual costs, contributions and forecast sales in the same format as YUB-YEC-25 Attachment 1 in the Mayo B hearing.

ANSWER:

(a) and **(b)**

Please see Table 1 below.

Table 1:
Mayo B Capital Cost Estimate Breakdown – February 2010 Forecast and Final Cost Estimate (2012/13 GRA) ($000)

		Feb-10	Final Cost	Variance		
Construction Contractor, Equipment & Detailed Engineering Costs		**Forecast**	**Estimate (GRA)**	**$**	**%**	
Construction Contract (Kiewit)						
Target Maximum Price		85.40	84.32	1.08	1.27%	
Turbine & Generator Supply		5.00	5.28	(0.28)	-5.62%	(a)
Detailed Engineering (KGS)		5.76	5.99	(0.23)	-3.94%	
Assigned to Substation		0.60	0.75	(0.15)	-25.00%	(b)
Owner Contingencies		1.25	0.40	0.85	68.00%	(c)
Sub-total		98.01	96.73	1.28	1.30%	
Owner Construction Costs						
Contract Administration (KGS)		3.82	4.70	(0.88)	-22.93%	(d)
Owner Admin		2.00	4.14	(2.14)	-107.20%	(e)
Land Acq		0.25	0.25	-	0.00%	
ES&G	0.50%	0.52	-	0.52	100.00%	(f)
Interest (AFUDC) (after 4Q-09)		1.00	0.48	0.52	52.30%	(g)
Contingency		1.38	-	1.38	100.00%	(h)
Sub total		8.97	9.57	(0.60)	-6.65%	
Pre-Construction & Other Permitting/Regulatory Planning Costs						
Feasibility Studies (to YESAB filing)		2.41	2.41	-	0.00%	
Post YESAB filing planning/engineering		8.81	7.65	1.16	13.21%	(i)
Mayo B Part III review		0.30	0.23	0.07	23.33%	(j)
Sub total		11.52	10.29	1.23	10.71%	
Total Mayo B Capital Costs		**118.50**	**116.59**	**1.91**	**1.61%**	

Notes:

(a) Spare parts purchased for the turbine and generator were not included in the original estimate.

(b) Increased allocation to Mayo A substation due to higher than forecast civil construction costs.

(c) $0.850 million of Owner's Contingency was required to be allocated as follows: $0.250 million for increased penstock diameter; $0.400 million for Quality Assurance (Q/A) activities in China; and $0.200 million for T&G spare parts.

(d) Increase in Contract Administration costs in relation to the following: $0.400 million for Q/A activities in China; $0.270 million for 2011 site activities; and $0.210 million for project extension into 2012.

(e) The original provision for Owner's Admin did not include the following expenses:

- $0.220 million for YEC Oversight (Labour reallocation in lieu of ES&G).
- $0.386 million for added diesel expense due to delays caused by tunnel leak.
- $0.300 million for performance testing and commissioning of units.

- $1.238 million for agreement with NND.

(f) Cost saving in ES&G expense compared to forecast due to a change in accounting policy to be IFRS compliant. This reduced ES&G expense for Mayo B (however, as indicated in (e) above IFRS changes increased Owner Admin by $0.220 million to address labour costs that would have been addressed in ES&G).

(g) Interest (AFUDC) cost saving due to securing favourable financing terms from YDC.

(h) Contingency for increased Owners Admin costs, Detail Engineering and substation.

(i) Cost saving in relation forecast land acquisition costs transferred from planning to construction (mainly preliminary engineering, financing and contingency).

(j) Cost saving as actual costs of Part 3 review were less than forecast.

(c)

As noted in Tab 5 of the Application (page 5-6), the Mayo B project was commissioned ahead of schedule in December 2011 and was deemed substantially complete. Further site work to address outstanding work is scheduled for summer of 2012.

The Mayo B project is considered to be in service at year end 2011 and project costs and contributions were transferred to rate base at that time.

(d)

Generation output from Mayo B since entering service is provided for each unit in Table 2 (Mayo B – Mayo B – MBH1) and Table 3 (MBH2) below.

Table 2:
Mayo B Generation Output (Mayo B – MBH1)

Month/Year	kWh Generated
November 2011	7,200
December 2011	869,900
January 2012	4,433,890
February 2012	2,882,101
March 2012	0
April 2012	2,098,242
May 2012	2,536,900
June 2012	1,590,054

Table 3:
Mayo B Generation Output (Mayo B – MBH2)

Month/Year	kWh Generated
November 2011	12,580
December 2011	601,730
January 2012	633,504
February 2012	478,388
March 2012	3,485,910
April 2012	814,072
May 2012	658,267
June 2012	961,093

(e)

Please see Attachment 1 and the attached Excel file. Items of note in Attachment 1 are as follows:

- The variables related to Mayo B (project cost, equity return, loads, debt rate) have been updated to be consistent with this GRA. The only exception is the diesel and hydro breakdown, which is based on 100% of long-term average hydro generation (versus the smaller percentages used in the GRA for setting rates).

- Depreciation and asset life is based on the updated KPMG depreciation report, using a composite average life of 89 years (reflecting the asset mix that makes up the Mayo B investment).

- Long-term average hydro generation is assumed for 2014 and thereafter based on updated polynomials and 100% of long-term average hydro generation. The updated polynomials include 28 years of hydrology – at the time of the Mayo B Part III hearing only 21 years of historical hydrology was being used.

- Loads are shown both with and without Victoria Gold. This is in contrast to the YUB-25 response from the Part III hearing, where the modeled prospective load of concern was Carmacks Copper.

- Scenarios are shown without Mayo Lake Hydro Enhancement Project, as this project is not yet approved; inclusion of the Mayo Lake Project would improve the LCOE estimates for each load case.

- Loads are also shown based on updated long-term load forecasts as provided in Appendix A of Overview of 20-Year Resource Plan (filed in response to YECL-YEC-1-18),extended as required, but excluding DSM/SSE as well as other possible new/future resource options (e.g., expanded wind, LNG, biomass, Marsh Lake, etc.).This reflects the economic analysis and decision-making which places Mayo B subsequent to Aishihik 3rd turbine in the overall Resource Planning decision making, but prior to these other resources.

- The calculations show both a "pure" LCOE based on project economics, and an LCOE which incorporates the near-term benefits of the Mayo B Flexible Financing instrument. Where the earlier YUB-YEC-1-25 analysis provided in the Mayo B Part 3 hearing coarsely included this financing concept based on the ideas then developed for the Note (most notable a 10-11 cent benchmark (2012$)), Attachment 1 reflects the actual Note as executed (per GRA Attachment 5.3).

- Grid loads are all reported net of Fish Lake (unlike YUB-25) so there is no need in Attachment 1 to adjust Fish Lake out of the load estimates.

- No secondary sales benefit is included as at current load levels it is at best very difficult to model the potential updated secondary sales benefit. While this is an underestimate (there will be years where Mayo B does provide some benefit via increased secondary sales) it is not considered to be material to the updated analysis.

Mayo B Cost of Energy - Summary ($000s)

Without New Mines

NPV O&M		7,184
NPV depr+return		33,566
less: NPV Secondary		-
NPV net		40,750
PV energy (MW.h)		685,720
real LCOE (2012$)	cents/kW.h	5.94
real LCOE (2012$) absent flexible financing		6.47

With Victoria Gold Mine

NPV O&M		7,184
NPV depr+return		34,489
less: NPV Secondary		-
NPV net		41,673
PV energy (MW.h)		760,873
real LCOE (2012$)	cents/kW.h	5.48
real LCOE (2012$) absent flexible financing		5.83

Note:

1. Analysis are done without Mayo Lake Hydro Enhancement Project.

Mayo B

(without Mayo Lake added storage, without new mines)

Annual Costs ($000)

Assumed YEC net ratebase cost: 35.00 million

Normal

Assumed cost of capital: Average 6.78% Debt 5.46%
(Real) 4.69% Equity 8.77%
life (yrs) 89 composite - based on new proposed depreciation rate Inflation 2.00%

			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
		year	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Loads																
Total Load (GW.h)			415.9	430.4	448.8	457.4	466.2	468.4	477.6	481.8	463.9	435.4	445.5	455.7	466.2	477.0
Non-Industrial loads (includes losses at 8.7%)			359.0	362.6	371.0	379.6	388.4	397.4	406.6	416.0	425.6	435.4	445.5	455.7	466.2	477.0
Industrial loads (includes losses at 8.7%)																
Minto			42.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	23.4					
Alexco			14.2	15.9	21.7	21.7	21.7	15.0	15.0	15.0	15.0					
WHCT				5.2	9.3	9.3	9.3	9.3	9.3	4.1						
Net Generation Contribution from Mayo B (MW.h)			20,700	22,300	24,327	25,148	26,016	26,252	27,303	27,836	25,788	22,850	23,996	24,991	26,023	27,227
PV over project average life		Net Gen (GW.h.)														
PV at	4.69%	685,720														
With Mayo B																
Existing Hydro			383.4	389.9	394.9	397.0	399.0	399.4	401.1	401.8	398.5	391.3	394.1	396.7	399.0	401.0
Mayo B - net benefit to system			20.7	22.3	24.3	25.1	26.0	26.3	27.3	27.8	25.8	22.9	24.0	25.0	26.0	27.2
Total Hydro with Mayo B			404.1	412.2	419.3	422.2	425.0	425.7	428.4	429.6	424.3	414.2	418.1	421.6	425.0	428.2
Diesel			11.8	18.2	29.5	35.2	41.2	42.7	49.2	52.2	39.6	21.2	27.4	34.1	41.2	48.8
Total Dispatchable Generation			415.9	430.4	448.8	457.4	466.2	468.4	477.6	481.8	463.9	435.4	445.5	455.7	466.2	477.0
No Mayo B																
Existing Hydro			383.4	389.9	394.9	397.0	399.0	399.4	401.1	401.8	398.5	391.3	394.1	396.7	399.0	401.0
Diesel			32.5	40.5	53.8	60.3	67.2	69.0	76.5	80.1	65.4	44.1	51.4	59.1	67.3	76.0
Total			415.9	430.4	448.8	457.4	466.2	468.4	477.6	481.8	463.9	435.4	445.5	455.7	466.2	477.0
Mayo B Diesel offset			20.7	22.3	24.3	25.1	26.0	26.3	27.3	27.8	25.8	22.9	24.0	25.0	26.0	27.2
Costs																
O&M costs ($000)		7,184	308	393	382	342	292	352	287	383	283	468	409	525	421	427
Depreciation ($000s)		6,172	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)			0	0	0	0	0	0	0	0	0	0	0	0	0	0
Start of yr rate base ($000)			35,000	34,607	34,213	33,820	33,427	33,034	32,640	32,247	31,854	31,461	31,067	30,674	30,281	29,888
Mid year rate base ($000)			34,803	34,410	34,017	33,624	33,230	32,837	32,444	32,051	31,657	31,264	30,871	30,478	30,084	29,691
Equity Return ($000)		16,026	1,221	1,207	1,193	1,180	1,166	1,152	1,138	1,124	1,111	1,097	1,083	1,069	1,055	1,042
Debt Return ($000)		14,967	1,140	1,127	1,114	1,102	1,089	1,076	1,063	1,050	1,037	1,024	1,011	998	986	973
Flexible Note forgiveness ($000)	-	3,599	(1,184.9)	(962.2)	(672.4)	(491.4)	(292.1)	(170.4)	-	-	-	(311.0)	-			
Total Return ($000)		27,394	1,176	1,372	1,635	1,790	1,962	2,057	2,201	2,174	2,148	1,810	2,094	2,068	2,041	2,014
Secondary volume enhanced																
Sec price																
Sec revenues		-														
Mayo B Total Costs - Net of Contributions ($000)		40,750	1,877	2,158	2,411	2,525	2,648	2,803	2,882	2,950	2,824	2,672	2,897	2,986	2,856	2,835
$/kW.h (net)			0.0907	0.0968	0.0991	0.1004	0.1018	0.1068	0.1055	0.1060	0.1095	0.1169	0.1207	0.1195	0.1097	0.1041
PV over life	$	40,750														
levelized $/kW.h (real)	$	0.0594														
Benefits																
Diesel Cost			$ 0.2868	$ 0.2868	$ 0.2925	$ 0.2984	$ 0.3044	$ 0.3104	$ 0.3167	$ 0.3230	$ 0.3294	$ 0.3360	$ 0.3428	$ 0.3496	$ 0.3566	$ 0.3637
Total cost to supply same load with diesel			$ 5,937	$ 6,396	$ 7,117	$ 7,504	$ 7,918	$ 8,150	$ 8,645	$ 8,991	$ 8,496	$ 7,678	$ 8,225	$ 8,737	$ 9,280	$ 9,903
Mayo B net costs (sav) to diesel			(4,059)	(4,238)	(4,706)	(4,979)	(5,270)	(5,347)	(5,764)	(6,040)	(5,672)	(5,007)	(5,328)	(5,751)	(6,424)	(7,069)
Total diesel cost without Mayo B			$ 9,323	$ 11,603	$ 15,752	$ 18,003	$ 20,451	$ 21,418	$ 24,226	$ 25,857	$ 21,555	$ 14,809	$ 17,612	$ 20,654	$ 23,982	$ 27,640

Mayo B

(without Mayo Lake added storage, without new mines)

Annual Costs ($000)

Assumed YEC net ratebase cost:

Assumed cost of capital:

			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
		year	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Loads																
Total Load (GW.h)			488.0	499.2	510.7	522.5	534.5	546.8	559.4	572.2	585.4	598.8	612.6	626.6	641.0	655.7
Non-Industrial loads (includes losses at 8.7%)			488.0	499.2	510.7	522.5	534.5	546.8	559.4	572.2	585.4	598.8	612.6	626.6	641.0	655.7
Industrial loads (includes losses at 8.7%)																
Minto																
Alexco																
WHCT																
Net Generation Contribution from Mayo B (MW.h)			28,669	30,327	32,070	33,636	34,598	34,435	34,470	34,640	34,925	35,304	35,755	36,255	36,785	37,322
PV over project average life		Net Gen (GW														
PV at	4.69%	685,720														
With Mayo B																
Existing Hydro			402.7	403.9	404.9	405.7	406.5	407.5	408.6	409.6	410.5	411.3	412.0	412.6	413.2	413.7
Mayo B - net benefit to system			28.7	30.3	32.1	33.6	34.6	34.4	34.5	34.6	34.9	35.3	35.8	36.3	36.8	37.3
Total Hydro with Mayo B			431.3	434.3	437.0	439.3	441.1	441.9	443.1	444.2	445.4	446.6	447.8	448.9	450.0	451.0
Diesel			56.7	65.0	73.7	83.2	93.5	104.9	116.3	128.0	140.0	152.2	164.8	177.7	191.0	204.7
Total Dispatchable Generation			488.0	499.2	510.7	522.5	534.5	546.8	559.4	572.2	585.4	598.8	612.6	626.6	641.0	655.7
No Mayo B																
Existing Hydro			402.7	403.9	404.9	405.7	406.5	407.5	408.6	409.6	410.5	411.3	412.0	412.6	413.2	413.7
Diesel			85.3	95.3	105.8	116.8	128.1	139.3	150.8	162.6	174.9	187.5	200.6	214.0	227.8	242.0
Total			488.0	499.2	510.7	522.5	534.5	546.8	559.4	572.2	585.4	598.8	612.6	626.6	641.0	655.7
Mayo B Diesel offset			28.7	30.3	32.1	33.6	34.6	34.4	34.5	34.6	34.9	35.3	35.8	36.3	36.8	37.3
Costs																
O&M costs ($000)		7,184	433	439	446	452	459	487	494	501	508	515	523	530	538	545
Depreciation ($000s)		6,172	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)			0	0	0	0	0	0	0	0	0	0	0	0	0	0
Start of yr rate base ($000)			29,494	29,101	28,708	28,315	27,921	27,528	27,135	26,742	26,348	25,955	25,562	25,169	24,775	24,382
Mid year rate base ($000)			29,298	28,904	28,511	28,118	27,725	27,331	26,938	26,545	26,152	25,758	25,365	24,972	24,579	24,185
Equity Return ($000)		16,026	1,028	1,014	1,000	986	973	959	945	931	917	904	890	876	862	848
Debt Return ($000)		14,967	960	947	934	921	908	895	882	870	857	844	831	818	805	792
Flexible Note forgiveness ($000)	-	3,599														
Total Return ($000)		27,394	1,988	1,961	1,934	1,908	1,881	1,854	1,827	1,801	1,774	1,747	1,721	1,694	1,667	1,641
Secondary volume enhanced																
Sec price																
Sec revenues		-														
Mayo B Total Costs - Net of Contributions ($000)		40,750	2,814	2,794	2,773	2,753	2,733	2,735	2,715	2,695	2,675	2,656	2,637	2,617	2,598	2,579
$/kW.h (net)			0.0982	0.0921	0.0865	0.0818	0.0790	0.0794	0.0788	0.0778	0.0766	0.0752	0.0737	0.0722	0.0706	0.0691
PV over life	$	40,750														
levelized $/kW.h (real)	$	0.0594														
Benefits																
Diesel Cost			$ 0.3710	$ 0.3784	$ 0.3860	$ 0.3937	$ 0.4016	$ 0.4096	$ 0.4178	$ 0.4262	$ 0.4347	$ 0.4434	$ 0.4523	$ 0.4613	$ 0.4705	$ 0.4799
Total cost to supply same load with diesel			$ 10,636	$ 11,476	$ 12,379	$ 13,243	$ 13,894	$ 14,105	$ 14,402	$ 14,762	$ 15,182	$ 15,653	$ 16,170	$ 16,725	$ 17,308	$ 17,912
Mayo B net costs (sav) to diesel			(7,822)	(8,683)	(9,606)	(10,490)	(11,161)	(11,371)	(11,687)	(12,067)	(12,506)	(12,997)	(13,534)	(14,107)	(14,710)	(15,332)
Total diesel cost without Mayo B			$ 31,661	$ 36,062	$ 40,846	$ 45,986	$ 51,425	$ 57,055	$ 62,993	$ 69,311	$ 76,024	$ 83,149	$ 90,704	$ 98,707	$ 107,176	$ 116,132

Mayo B

(without Mayo Lake added storage, without new mines)

Annual Costs ($000)

Assumed YEC net ratebase cost:

Assumed cost of capital:

			2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
		year	29	30	31	32	33	34	35	36	37	38	39	40	41	42
Loads																
Total Load (GW.h)			670.7	686.1	701.8	717.9	734.3	751.1	768.3	782.5	797.0	811.8	826.8	842.1	857.7	873.5
Non-Industrial loads (includes losses at 8.7%)			670.7	686.1	701.8	717.9	734.3	751.1	768.3	785.9	803.9	822.3	841.1	860.3	879.9	900.0
Industrial loads (includes losses at 8.7%)																
Minto																
Alexco																
WHCT																
Net Generation Contribution from Mayo B (MW.h)			37,846	38,341	38,792	39,189	39,525	39,802	40,029	40,189	40,344	40,515	40,732	41,029	41,100	41,100
PV over project average life		Net Gen (GW														
PV at	4.69%	685,720														
With Mayo B																
Existing Hydro			414.2	414.6	414.9	415.2	415.5	415.7	415.9	416.0	416.1	416.1	416.1	416.0	416.1	416.1
Mayo B - net benefit to system			37.8	38.3	38.8	39.2	39.5	39.8	40.0	40.2	40.3	40.5	40.7	41.0	41.1	41.1
Total Hydro with Mayo B			452.0	452.9	453.7	454.4	455.0	455.5	455.9	456.2	456.4	456.6	456.8	457.1	457.2	457.2
Diesel			218.7	233.2	248.1	263.5	279.3	295.6	312.4	326.3	340.6	355.1	369.9	385.0	400.5	416.3
Total Dispatchable Generation			670.7	686.1	701.8	717.9	734.3	751.1	768.3	782.5	797.0	811.8	826.8	842.1	857.7	873.5
No Mayo B																
Existing Hydro			414.2	414.6	414.9	415.2	415.5	415.7	415.9	416.0	416.1	416.1	416.1	416.0	416.1	416.1
Diesel			256.6	271.5	286.9	302.7	318.8	335.4	352.4	366.5	380.9	395.6	410.7	426.0	441.6	457.4
Total			670.7	686.1	701.8	717.9	734.3	751.1	768.3	782.5	797.0	811.8	826.8	842.1	857.7	873.5
Mayo B Diesel offset			37.8	38.3	38.8	39.2	39.5	39.8	40.0	40.2	40.3	40.5	40.7	41.0	41.1	41.1
Costs																
O&M costs ($000)		7,184	553	588	597	605	614	622	631	640	650	676	686	728	738	748
Depreciation ($000s)		6,172	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)			0	0												
Start of yr rate base ($000)			23,989	23,596	23,202	22,809	22,416	22,022	21,629	21,236	20,843	20,449	20,056	19,663	19,270	18,876
Mid year rate base ($000)			23,792	23,399	23,006	22,612	22,219	21,826	21,433	21,039	20,646	20,253	19,860	19,466	19,073	18,680
Equity Return ($000)		16,026	835	821	807	793	779	766	752	738	724	710	697	683	669	655
Debt Return ($000)		14,967	779	767	754	741	728	715	702	689	676	663	651	638	625	612
Flexible Note forgiveness ($000)	-	3,599														
Total Return ($000)		27,394	1,614	1,587	1,561	1,534	1,507	1,481	1,454	1,427	1,401	1,374	1,347	1,321	1,294	1,267
Secondary volume enhanced																
Sec price																
Sec revenues		-														
Mayo B Total Costs - Net of Contributions ($000)		40,750	2,561	2,569	2,550	2,532	2,514	2,496	2,479	2,461	2,444	2,443	2,426	2,442	2,425	2,409
$/kW.h (net)			0.0677	0.0670	0.0657	0.0646	0.0636	0.0627	0.0619	0.0612	0.0606	0.0603	0.0596	0.0595	0.0590	0.0586
PV over life		$ 40,750														
levelized $/kW.h (real)		$ 0.0594														
Benefits																
Diesel Cost			$ 0.4895	$ 0.4993	$ 0.5093	$ 0.5195	$ 0.5299	$ 0.5405	$ 0.5513	$ 0.5623	$ 0.5736	$ 0.5850	$ 0.5967	$ 0.6087	$ 0.6208	$ 0.6333
Total cost to supply same load with diesel			$ 18,527	$ 19,145	$ 19,757	$ 20,358	$ 20,944	$ 21,512	$ 22,068	$ 22,599	$ 23,140	$ 23,703	$ 24,306	$ 24,973	$ 25,517	$ 26,027
Mayo B net costs (sav) to diesel			(15,966)	(16,576)	(17,207)	(17,826)	(18,430)	(19,016)	(19,589)	(20,138)	(20,696)	(21,260)	(21,880)	(22,532)	(23,092)	(23,618)
Total diesel cost without Mayo B			$ 125,593	$ 135,583	$ 146,122	$ 157,236	$ 168,951	$ 181,293	$ 194,295	$ 206,110	$ 218,490	$ 231,465	$ 245,063	$ 259,320	$ 274,143	$ 289,674

Mayo B

(without Mayo Lake added storage, without new mines)

Annual Costs ($000)

Assumed YEC net ratebase cost:

Assumed cost of capital:

			2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067
		year	43	44	45	46	47	48	49	50	51	52	53	54	55	56
Loads																
Total Load (GW.h)			889.7	906.1	922.9	940.0	957.4	975.1	993.1	1011.5	1030.2	1049.3	1068.7	1088.5	1108.6	1129.1
Non-Industrial loads (includes losses at 8.7%)			920.6	941.6	963.1	985.1	1007.6	1030.6	1054.1	1078.1	1102.7	1127.8	1153.5	1179.8	1206.7	1234.2
Industrial loads (includes losses at 8.7%)																
Minto																
Alexco																
WHCT																
Net Generation Contribution from Mayo B (MW.h)			41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100
PV over project average life		Net Gen (GW														
PV at	4.69%	685,720														
With Mayo B																
Existing Hydro			416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1
Mayo B - net benefit to system			41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1
Total Hydro with Mayo B			457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2
Diesel			432.5	448.9	465.7	482.8	500.2	517.9	535.9	554.3	573.0	592.1	611.5	631.3	651.4	671.9
Total Dispatchable Generation			889.7	906.1	922.9	940.0	957.4	975.1	993.1	1011.5	1030.2	1049.3	1068.7	1088.5	1108.6	1129.1
No Mayo B																
Existing Hydro			416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1
Diesel			473.6	490.0	506.8	523.9	541.3	559.0	577.0	595.4	614.1	633.2	652.6	672.4	692.5	713.0
Total			889.7	906.1	922.9	940.0	957.4	975.1	993.1	1011.5	1030.2	1049.3	1068.7	1088.5	1108.6	1129.1
Mayo B Diesel offset			41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1
Costs																
O&M costs ($000)		7,184	759	770	780	792	803	815	826	878	890	903	916	929	942	956
Depreciation ($000s)		6,172	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)																
Start of yr rate base ($000)			18,483	18,090	17,697	17,303	16,910	16,517	16,124	15,730	15,337	14,944	14,551	14,157	13,764	13,371
Mid year rate base ($000)			18,287	17,893	17,500	17,107	16,713	16,320	15,927	15,534	15,140	14,747	14,354	13,961	13,567	13,174
Equity Return ($000)		16,026	641	628	614	600	586	573	559	545	531	517	504	490	476	462
Debt Return ($000)		14,967	599	586	573	560	548	535	522	509	496	483	470	457	444	432
Flexible Note forgiveness ($000)	-	3,599														
Total Return ($000)		27,394	1,241	1,214	1,187	1,161	1,134	1,107	1,080	1,054	1,027	1,000	974	947	920	894
Secondary volume enhanced																
Sec price																
Sec revenues		-														
Mayo B Total Costs - Net of Contributions ($000)		40,750	2,393	2,377	2,361	2,345	2,330	2,315	2,300	2,325	2,311	2,297	2,283	2,269	2,256	2,243
$/kW.h (net)			0.0582	0.0578	0.0574	0.0571	0.0567	0.0563	0.0560	0.0566	0.0562	0.0559	0.0555	0.0552	0.0549	0.0546
PV over life		$ 40,750														
levelized $/kW.h (real)		$ 0.0594														
Benefits																
Diesel Cost			$ 0.6459	$ 0.6588	$ 0.6720	$ 0.6855	$ 0.6992	$ 0.7132	$ 0.7274	$ 0.7420	$ 0.7568	$ 0.7719	$ 0.7874	$ 0.8031	$ 0.8192	$ 0.8356
Total cost to supply same load with diesel			$ 26,548	$ 27,079	$ 27,620	$ 28,173	$ 28,736	$ 29,311	$ 29,897	$ 30,495	$ 31,105	$ 31,727	$ 32,362	$ 33,009	$ 33,669	$ 34,342
Mayo B net costs (sav) to diesel			(24,155)	(24,702)	(25,259)	(25,827)	(26,406)	(26,996)	(27,597)	(28,170)	(28,794)	(29,430)	(30,079)	(30,740)	(31,413)	(32,100)
Total diesel cost without Mayo B			$ 305,906	$ 322,868	$ 340,591	$ 359,107	$ 378,447	$ 398,647	$ 419,742	$ 441,769	$ 464,767	$ 488,774	$ 513,834	$ 539,989	$ 567,285	$ 595,767

Mayo B

(without Mayo Lake added storage, without new mines)

Annual Costs ($000)

Assumed YEC net ratebase cost:

Assumed cost of capital:

			2068	2069	2070	2071	2072	2073	2074	2075	2076	2077
		year	57	58	59	60	61	62	63	64	65	66
Loads												
Total Load (GW.h)			1150.0	1171.3	1192.9	1215.0	1237.5	1260.4	1283.7	1307.4	1331.6	1356.3
Non-Industrial loads (includes losses at 8.7%)			1262.3	1291.0	1320.4	1350.4	1381.2	1412.6	1444.7	1477.6	1511.2	1545.6
Industrial loads (includes losses at 8.7%)												
Minto												
Alexco												
WHCT												
Net Generation Contribution from Mayo B (MW.h)			41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100	41,100
PV over project average life		Net Gen (GW										
PV at	4.69%	685,720										
With Mayo B												
Existing Hydro			416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1
Mayo B - net benefit to system			41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1
Total Hydro with Mayo B			457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2	457.2
Diesel			692.8	714.1	735.7	757.8	780.3	803.2	826.5	850.2	874.4	899.1
Total Dispatchable Generation			1150.0	1171.3	1192.9	1215.0	1237.5	1260.4	1283.7	1307.4	1331.6	1356.3
No Mayo B												
Existing Hydro			416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1
Diesel			733.9	755.2	776.8	798.9	821.4	844.3	867.6	891.3	915.5	940.2
Total			1150.0	1171.3	1192.9	1215.0	1237.5	1260.4	1283.7	1307.4	1331.6	1356.3
Mayo B Diesel offset			41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1	41.1
Costs												
O&M costs ($000)		7,184	970	984	998	1061	1076	1091	1134	1150	1166	1190
Depreciation ($000s)		6,172	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)												
Start of yr rate base ($000)			12,978	12,584	12,191	11,798	11,404	11,011	10,618	10,225	9,831	9,438
Mid year rate base ($000)			12,781	12,388	11,994	11,601	11,208	10,815	10,421	10,028	9,635	9,242
Equity Return ($000)		16,026	448	435	421	407	393	379	366	352	338	324
Debt Return ($000)		14,967	419	406	393	380	367	354	341	329	316	303
Flexible Note forgiveness ($000)	-	3,599										
Total Return ($000)		27,394	867	840	814	787	760	734	707	680	654	627
Secondary volume enhanced												
Sec price												
Sec revenues		-										
Mayo B Total Costs - Net of Contributions ($000)		40,750	2,230	2,217	2,205	2,241	2,230	2,218	2,234	2,224	2,213	2,210
$/kW.h (net)			0.0543	0.0539	0.0536	0.0545	0.0543	0.0540	0.0544	0.0541	0.0538	0.0538
PV over life	$	40,750										
levelized $/kW.h (real)	$	0.0594										
Benefits												
Diesel Cost			$ 0.8523	$ 0.8693	$ 0.8867	$ 0.9045	$ 0.9225	$ 0.9410	$ 0.9598	$ 0.9790	$ 0.9986	$ 1.0186
Total cost to supply same load with diesel			$ 35,029	$ 35,730	$ 36,444	$ 37,173	$ 37,917	$ 38,675	$ 39,449	$ 40,238	$ 41,042	$ 41,863
Mayo B net costs (sav) to diesel			(32,799)	(33,513)	(34,239)	(34,932)	(35,687)	(36,457)	(37,214)	(38,014)	(38,829)	(39,653)
Total diesel cost without Mayo B			$ 625,486	$ 656,490	$ 688,834	$ 722,571	$ 757,759	$ 794,457	$ 832,726	$ 872,631	$ 914,237	$ 957,614

Mayo B

(without Mayo Lake added storage, with Victoria Gold mine)

Annual Costs ($000)

Assumed YEC net ratebase cost: 35.00 million

Assumed cost of capital: Normal — Average 6.78% (Real 4.69%) — Debt 5.46% — Equity 8.77% — Inflation 2.00%

Average life (yrs): 89 composite - based on new proposed depreciation rate

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	year	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Loads															
Total Load (GW.h)		415.9	430.4	448.8	560.6	569.4	571.7	580.9	585.1	567.2	538.7	548.7	559.0	569.5	477.0
Non-Industrial loads (includes losses at 8.7%)		359.0	362.6	371.0	379.6	388.4	397.4	406.6	416.0	425.6	435.4	445.5	455.7	466.2	477.0
Industrial loads (includes losses at 8.7%)															
Minto		42.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	23.4					
Alexco		14.2	15.9	21.7	21.7	21.7	15.0	15.0	15.0	15.0					
WHCT			5.2	9.3	9.3	9.3	9.3	9.3	4.1						
Victoria Gold					103.3	103.3	103.3	103.3	103.3	103.3	103.3	103.3	103.3	103.3	
Net Generation Contribution from Mayo B (MW.h)		20,700	22,300	24,327	35,682	34,835	34,856	35,056	35,028	35,065	33,625	33,812	33,824	34,207	27,227
PV over project average life	Net Gen (GW.h.)														
PV at 4.69%	760,873														
With Mayo B															
Existing Hydro		383.4	389.9	394.9	409.7	410.4	410.5	411.1	410.9	408.1	406.7	407.5	408.2	409.1	401.0
Mayo B - net benefit to system		20.7	22.3	24.3	35.7	34.8	34.9	35.1	35.0	35.1	33.6	33.8	33.8	34.2	27.2
Total Hydro with Mayo B		404.1	412.2	419.3	445.4	445.2	445.3	446.1	446.0	443.2	440.3	441.3	442.0	443.3	428.2
Diesel		11.8	18.2	29.5	115.2	124.2	126.4	134.7	139.1	124.0	98.3	107.4	116.9	126.2	48.8
Total Dispatchable Generation		415.9	430.4	448.8	560.6	569.4	571.7	580.9	585.1	567.2	538.7	548.7	559.0	569.5	477.0
No Mayo B															
Existing Hydro		383.4	389.9	394.9	409.7	410.4	410.5	411.1	410.9	408.1	406.7	407.5	408.2	409.1	401.0
Diesel		32.5	40.5	53.8	150.9	159.0	161.2	169.8	174.2	159.1	132.0	141.2	150.8	160.4	76.0
Total		415.9	430.4	448.8	560.6	569.4	571.7	580.9	585.1	567.2	538.7	548.7	559.0	569.5	477.0
Mayo B Diesel offset		20.7	22.3	24.3	35.7	34.8	34.9	35.1	35.0	35.1	33.6	33.8	33.8	34.2	27.2
Costs															
O&M costs ($000)	7,184	308	393	382	342	292	352	287	383	283	468	409	525	421	427
Depreciation ($000s)	6,172	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Start of yr rate base ($000)		35,000	34,607	34,213	33,820	33,427	33,034	32,640	32,247	31,854	31,461	31,067	30,674	30,281	29,888
Mid year rate base ($000)		34,803	34,410	34,017	33,624	33,230	32,837	32,444	32,051	31,657	31,264	30,871	30,478	30,084	29,691
Equity Return ($000)	16,026	1,221	1,207	1,193	1,180	1,166	1,152	1,138	1,124	1,111	1,097	1,083	1,069	1,055	1,042
Debt Return ($000)	14,967	1,140	1,127	1,114	1,102	1,089	1,076	1,063	1,050	1,037	1,024	1,011	998	986	973
Flexible Note forgiveness ($000)	- 2,676	(1,184.9)	(962.2)	(672.4)	-	-	-	-	-	-	-	-			
Total Return ($000)	28,317	1,176	1,372	1,635	2,281	2,254	2,228	2,201	2,174	2,148	2,121	2,094	2,068	2,041	2,014
Secondary volume enhanced															
Sec price															
Sec revenues	-														
Mayo B Total Costs - Net of Contributions ($000)	41,673	1,877	2,158	2,411	3,017	2,940	2,973	2,882	2,950	2,824	2,983	2,897	2,986	2,856	2,835
$/kW.h (net)		0.0907	0.0968	0.0991	0.0845	0.0844	0.0853	0.0822	0.0842	0.0805	0.0887	0.0857	0.0883	0.0835	0.1041
PV over life	$ 41,673														
levelized $/kW.h (real)	$ 0.0548														
Benefits															
Diesel Cost		$ 0.2868	$ 0.2868	$ 0.2925	$ 0.2984	$ 0.3044	$ 0.3104	$ 0.3167	$ 0.3230	$ 0.3294	$ 0.3360	$ 0.3428	$ 0.3496	$ 0.3566	$ 0.3637
Total cost to supply same load with diesel		$ 5,937	$ 6,396	$ 7,117	$ 10,647	$ 10,602	$ 10,821	$ 11,100	$ 11,314	$ 11,552	$ 11,299	$ 11,589	$ 11,825	$ 12,198	$ 9,903
Mayo B net costs (sav) to diesel		(4,059)	(4,238)	(4,706)	(7,631)	(7,662)	(7,848)	(8,219)	(8,363)	(8,728)	(8,316)	(8,693)	(8,840)	(9,343)	(7,069)
Total diesel cost without Mayo B		$ 9,323	$ 11,603	$ 15,752	$ 45,032	$ 48,406	$ 50,049	$ 53,768	$ 56,254	$ 52,402	$ 44,347	$ 48,408	$ 52,711	$ 57,216	$ 27,640

Mayo B

(without Mayo Lake added storage, with Victoria Gold mine)

Annual Costs ($000)

Assumed YEC net ratebase cost:

Assumed cost of capital:

			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
		year	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Loads																
Total Load (GW.h)			488.0	499.2	510.7	522.5	534.5	546.8	559.4	572.2	585.4	598.8	612.6	626.6	641.0	655.7
Non-Industrial loads (includes losses at 8.7%)			488.0	499.2	510.7	522.5	534.5	546.8	559.4	572.2	585.4	598.8	612.6	626.6	641.0	655.7
Industrial loads (includes losses at 8.7%)																
Minto																
Alexco																
WHCT																
Victoria Gold																
Net Generation Contribution from Mayo B (MW.h)			28,669	30,327	32,070	33,636	34,598	34,435	34,470	34,640	34,925	35,304	35,755	36,255	36,785	37,322
PV over project average life		Net Gen (GW														
PV at	4.69%	760,873														
With Mayo B																
Existing Hydro			402.7	403.9	404.9	405.7	406.5	407.5	408.6	409.6	410.5	411.3	412.0	412.6	413.2	413.7
Mayo B - net benefit to system			28.7	30.3	32.1	33.6	34.6	34.4	34.5	34.6	34.9	35.3	35.8	36.3	36.8	37.3
Total Hydro with Mayo B			431.3	434.3	437.0	439.3	441.1	441.9	443.1	444.2	445.4	446.6	447.8	448.9	450.0	451.0
Diesel			56.7	65.0	73.7	83.2	93.5	104.9	116.3	128.0	140.0	152.2	164.8	177.7	191.0	204.7
Total Dispatchable Generation			488.0	499.2	510.7	522.5	534.5	546.8	559.4	572.2	585.4	598.8	612.6	626.6	641.0	655.7
No Mayo B																
Existing Hydro			402.7	403.9	404.9	405.7	406.5	407.5	408.6	409.6	410.5	411.3	412.0	412.6	413.2	413.7
Diesel			85.3	95.3	105.8	116.8	128.1	139.3	150.8	162.6	174.9	187.5	200.6	214.0	227.8	242.0
Total			488.0	499.2	510.7	522.5	534.5	546.8	559.4	572.2	585.4	598.8	612.6	626.6	641.0	655.7
Mayo B Diesel offset			28.7	30.3	32.1	33.6	34.6	34.4	34.5	34.6	34.9	35.3	35.8	36.3	36.8	37.3
Costs																
O&M costs ($000)		7,184	433	439	446	452	459	487	494	501	508	515	523	530	538	545
Depreciation ($000s)		6,172	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)			0	0	0	0	0	0	0	0	0	0	0	0	0	0
Start of yr rate base ($000)			29,494	29,101	28,708	28,315	27,921	27,528	27,135	26,742	26,348	25,955	25,562	25,169	24,775	24,382
Mid year rate base ($000)			29,298	28,904	28,511	28,118	27,725	27,331	26,938	26,545	26,152	25,758	25,365	24,972	24,579	24,185
Equity Return ($000)		16,026	1,028	1,014	1,000	986	973	959	945	931	917	904	890	876	862	848
Debt Return ($000)		14,967	960	947	934	921	908	895	882	870	857	844	831	818	805	792
Flexible Note forgiveness ($000)	-	2,676														
Total Return ($000)		28,317	1,988	1,961	1,934	1,908	1,881	1,854	1,827	1,801	1,774	1,747	1,721	1,694	1,667	1,641
Secondary volume enhanced																
Sec price																
Sec revenues		-														
Mayo B Total Costs - Net of Contributions ($000)		41,673	2,814	2,794	2,773	2,753	2,733	2,735	2,715	2,695	2,675	2,656	2,637	2,617	2,598	2,579
$/kW.h (net)			0.0982	0.0921	0.0865	0.0818	0.0790	0.0794	0.0788	0.0778	0.0766	0.0752	0.0737	0.0722	0.0706	0.0691
PV over life	$	41,673														
levelized $/kW.h (real)	$	0.0548														
Benefits																
Diesel Cost			$ 0.3710	$ 0.3784	$ 0.3860	$ 0.3937	$ 0.4016	$ 0.4096	$ 0.4178	$ 0.4262	$ 0.4347	$ 0.4434	$ 0.4523	$ 0.4613	$ 0.4705	$ 0.4799
Total cost to supply same load with diesel			$ 10,636	$ 11,476	$ 12,379	$ 13,243	$ 13,894	$ 14,105	$ 14,402	$ 14,762	$ 15,182	$ 15,653	$ 16,170	$ 16,725	$ 17,308	$ 17,912
Mayo B net costs (sav) to diesel			(7,822)	(8,683)	(9,606)	(10,490)	(11,161)	(11,371)	(11,687)	(12,067)	(12,506)	(12,997)	(13,534)	(14,107)	(14,710)	(15,332)
Total diesel cost without Mayo B			$ 31,661	$ 36,062	$ 40,846	$ 45,986	$ 51,425	$ 57,055	$ 62,993	$ 69,311	$ 76,024	$ 83,149	$ 90,704	$ 98,707	$ 107,176	$ 116,132

Mayo B

(without Mayo Lake added storage, with Victoria Gold mine)

Annual Costs ($000)

Assumed YEC net ratebase cost:

Assumed cost of capital:

			2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
	year		29	30	31	32	33	34	35	36	37	38	39	40	41	42
Loads																
Total Load (GW.h)			670.7	686.1	701.8	717.9	734.3	751.1	768.3	785.9	803.9	822.3	841.1	860.3	879.9	900.0
Non-Industrial loads (includes losses at 8.7%)			670.7	686.1	701.8	717.9	734.3	751.1	768.3	785.9	803.9	822.3	841.1	860.3	879.9	900.0
Industrial loads (includes losses at 8.7%)																
Minto																
Alexco																
WHCT																
Victoria Gold																
Net Generation Contribution from Mayo B (MW.h)			37,846	38,341	38,792	39,189	39,525	39,802	40,029	40,225	40,420	40,660	41,006	44,300	44,300	44,300
PV over project average life		Net Gen (GW														
PV at	4.69%	760,873														
With Mayo B																
Existing Hydro			414.2	414.6	414.9	415.2	415.5	415.7	415.9	416.0	416.1	416.1	416.1	416.1	416.1	416.1
Mayo B - net benefit to system			37.8	38.3	38.8	39.2	39.5	39.8	40.0	40.2	40.4	40.7	41.0	44.3	44.3	44.3
Total Hydro with Mayo B			452.0	452.9	453.7	454.4	455.0	455.5	455.9	456.3	456.5	456.8	457.1	460.4	460.4	460.4
Diesel			218.7	233.2	248.1	263.5	279.3	295.6	312.4	329.7	347.4	365.5	384.0	399.9	419.5	439.6
Total Dispatchable Generation			670.7	686.1	701.8	717.9	734.3	751.1	768.3	785.9	803.9	822.3	841.1	860.3	879.9	900.0
No Mayo B																
Existing Hydro			414.2	414.6	414.9	415.2	415.5	415.7	415.9	416.0	416.1	416.1	416.1	416.1	416.1	416.1
Diesel			256.6	271.5	286.9	302.7	318.8	335.4	352.4	369.9	387.8	406.1	425.0	444.2	463.8	483.9
Total			670.7	686.1	701.8	717.9	734.3	751.1	768.3	785.9	803.9	822.3	841.1	860.3	879.9	900.0
Mayo B Diesel offset			37.8	38.3	38.8	39.2	39.5	39.8	40.0	40.2	40.4	40.7	41.0	44.3	44.3	44.3
Costs																
O&M costs ($000)		7,184	553	588	597	605	614	622	631	640	650	676	686	728	738	748
Depreciation ($000s)		6,172	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)			0	0												
Start of yr rate base ($000)			23,989	23,596	23,202	22,809	22,416	22,022	21,629	21,236	20,843	20,449	20,056	19,663	19,270	18,876
Mid year rate base ($000)			23,792	23,399	23,006	22,612	22,219	21,826	21,433	21,039	20,646	20,253	19,860	19,466	19,073	18,680
Equity Return ($000)		16,026	835	821	807	793	779	766	752	738	724	710	697	683	669	655
Debt Return ($000)		14,967	779	767	754	741	728	715	702	689	676	663	651	638	625	612
Flexible Note forgiveness ($000)	-	2,676														
Total Return ($000)		28,317	1,614	1,587	1,561	1,534	1,507	1,481	1,454	1,427	1,401	1,374	1,347	1,321	1,294	1,267
Secondary volume enhanced																
Sec price																
Sec revenues		-														
Mayo B Total Costs - Net of Contributions ($000)		41,673	2,561	2,569	2,550	2,532	2,514	2,496	2,479	2,461	2,444	2,443	2,426	2,442	2,425	2,409
$/kW.h (net)			0.0677	0.0670	0.0657	0.0646	0.0636	0.0627	0.0619	0.0612	0.0605	0.0601	0.0592	0.0551	0.0547	0.0544
PV over life	$	41,673														
levelized $/kW.h (real)	$	0.0548														
Benefits																
Diesel Cost			$ 0.4895	$ 0.4993	$ 0.5093	$ 0.5195	$ 0.5299	$ 0.5405	$ 0.5513	$ 0.5623	$ 0.5736	$ 0.5850	$ 0.5967	$ 0.6087	$ 0.6208	$ 0.6333
Total cost to supply same load with diesel			$ 18,527	$ 19,145	$ 19,757	$ 20,358	$ 20,944	$ 21,512	$ 22,068	$ 22,619	$ 23,184	$ 23,788	$ 24,470	$ 26,964	$ 27,504	$ 28,054
Mayo B net costs (sav) to diesel			(15,966)	(16,576)	(17,207)	(17,826)	(18,430)	(19,016)	(19,589)	(20,158)	(20,740)	(21,345)	(22,044)	(24,522)	(25,078)	(25,645)
Total diesel cost without Mayo B			$ 125,593	$ 135,583	$ 146,122	$ 157,236	$ 168,951	$ 181,293	$ 194,295	$ 207,989	$ 222,413	$ 237,609	$ 253,624	$ 270,366	$ 287,977	$ 306,465

Mayo B

(without Mayo Lake added storage, with Victoria Gold mine)

Annual Costs ($000)

Assumed YEC net ratebase cost:

Assumed cost of capital:

			2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067
	year		43	44	45	46	47	48	49	50	51	52	53	54	55	56
Loads																
Total Load (GW.h)			920.6	941.6	963.1	985.1	1007.6	1030.6	1054.1	1078.1	1102.7	1127.8	1153.5	1179.8	1206.7	1234.2
Non-Industrial loads (includes losses at 8.7%)			920.6	941.6	963.1	985.1	1007.6	1030.6	1054.1	1078.1	1102.7	1127.8	1153.5	1179.8	1206.7	1234.2
Industrial loads (includes losses at 8.7%)																
Minto																
Alexco																
WHCT																
Victoria Gold																
Net Generation Contribution from Mayo B (MW.h)			44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300
PV over project average life		Net Gen (GW														
PV at	4.69%	760,873														
With Mayo B																
Existing Hydro			416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1
Mayo B - net benefit to system			44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3
Total Hydro with Mayo B			460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4
Diesel			460.2	481.2	502.7	524.7	547.2	570.2	593.7	617.7	642.3	667.4	693.1	719.4	746.3	773.8
Total Dispatchable Generation			920.6	941.6	963.1	985.1	1007.6	1030.6	1054.1	1078.1	1102.7	1127.8	1153.5	1179.8	1206.7	1234.2
No Mayo B																
Existing Hydro			416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1
Diesel			504.5	525.5	547.0	569.0	591.5	614.5	638.0	662.0	686.6	711.7	737.4	763.7	790.6	818.1
Total			920.6	941.6	963.1	985.1	1007.6	1030.6	1054.1	1078.1	1102.7	1127.8	1153.5	1179.8	1206.7	1234.2
Mayo B Diesel offset			44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3
Costs																
O&M costs ($000)		7,184	759	770	780	792	803	815	826	878	890	903	916	929	942	956
Depreciation ($000s)		6,172	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)																
Start of yr rate base ($000)			18,483	18,090	17,697	17,303	16,910	16,517	16,124	15,730	15,337	14,944	14,551	14,157	13,764	13,371
Mid year rate base ($000)			18,287	17,893	17,500	17,107	16,713	16,320	15,927	15,534	15,140	14,747	14,354	13,961	13,567	13,174
Equity Return ($000)		16,026	641	628	614	600	586	573	559	545	531	517	504	490	476	462
Debt Return ($000)		14,967	599	586	573	560	548	535	522	509	496	483	470	457	444	432
Flexible Note forgiveness ($000)	-	2,676														
Total Return ($000)		28,317	1,241	1,214	1,187	1,161	1,134	1,107	1,080	1,054	1,027	1,000	974	947	920	894
Secondary volume enhanced																
Sec price																
Sec revenues		-														
Mayo B Total Costs - Net of Contributions ($000)		41,673	2,393	2,377	2,361	2,345	2,330	2,315	2,300	2,325	2,311	2,297	2,283	2,269	2,256	2,243
$/kW.h (net)			0.0540	0.0536	0.0533	0.0529	0.0526	0.0523	0.0519	0.0525	0.0522	0.0518	0.0515	0.0512	0.0509	0.0506
PV over life	$	41,673														
levelized $/kW.h (real)	$	0.0548														
Benefits																
Diesel Cost			$ 0.6459	$ 0.6588	$ 0.6720	$ 0.6855	$ 0.6992	$ 0.7132	$ 0.7274	$ 0.7420	$ 0.7568	$ 0.7719	$ 0.7874	$ 0.8031	$ 0.8192	$ 0.8356
Total cost to supply same load with diesel			$ 28,615	$ 29,187	$ 29,771	$ 30,366	$ 30,974	$ 31,593	$ 32,225	$ 32,869	$ 33,527	$ 34,197	$ 34,881	$ 35,579	$ 36,290	$ 37,016
Mayo B net costs (sav) to diesel			(26,222)	(26,810)	(27,410)	(28,021)	(28,643)	(29,278)	(29,925)	(30,544)	(31,216)	(31,901)	(32,598)	(33,310)	(34,035)	(34,774)
Total diesel cost without Mayo B			$ 325,872	$ 346,238	$ 367,607	$ 390,026	$ 413,542	$ 438,204	$ 464,066	$ 491,181	$ 519,606	$ 549,400	$ 580,626	$ 613,347	$ 647,632	$ 683,550

Mayo B

(without Mayo Lake added storage, with Victoria Gold mine)

Annual Costs ($000)

Assumed YEC net ratebase cost:

Assumed cost of capital:

			2068	2069	2070	2071	2072	2073	2074	2075	2076	2077
		year	57	58	59	60	61	62	63	64	65	66
Loads												
Total Load (GW.h)			1262.3	1291.0	1320.4	1350.4	1381.2	1412.6	1444.7	1477.6	1511.2	1545.6
Non-Industrial loads (includes losses at 8.7%)			1262.3	1291.0	1320.4	1350.4	1381.2	1412.6	1444.7	1477.6	1511.2	1545.6
Industrial loads (includes losses at 8.7%)												
Minto												
Alexco												
WHCT												
Victoria Gold												
Net Generation Contribution from Mayo B (MW.h)			44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300	44,300
PV over project average life		Net Gen (GW										
PV at	4.69%	760,873										
With Mayo B												
Existing Hydro			416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1
Mayo B - net benefit to system			44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3
Total Hydro with Mayo B			460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4	460.4
Diesel			801.9	830.6	860.0	890.0	920.8	952.2	984.3	1017.2	1050.8	1085.2
Total Dispatchable Generation			1262.3	1291.0	1320.4	1350.4	1381.2	1412.6	1444.7	1477.6	1511.2	1545.6
No Mayo B												
Existing Hydro			416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1	416.1
Diesel			846.2	874.9	904.3	934.3	965.1	996.5	1028.6	1061.5	1095.1	1129.5
Total			1262.3	1291.0	1320.4	1350.4	1381.2	1412.6	1444.7	1477.6	1511.2	1545.6
Mayo B Diesel offset			44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3	44.3
Costs												
O&M costs ($000)		7,184	970	984	998	1061	1076	1091	1134	1150	1166	1190
Depreciation ($000s)		6,172	393	393	393	393	393	393	393	393	393	393
Carbon Credits ($000)												
Start of yr rate base ($000)			12,978	12,584	12,191	11,798	11,404	11,011	10,618	10,225	9,831	9,438
Mid year rate base ($000)			12,781	12,388	11,994	11,601	11,208	10,815	10,421	10,028	9,635	9,242
Equity Return ($000)		16,026	448	435	421	407	393	379	366	352	338	324
Debt Return ($000)		14,967	419	406	393	380	367	354	341	329	316	303
Flexible Note forgiveness ($000)	-	2,676										
Total Return ($000)		28,317	867	840	814	787	760	734	707	680	654	627
Secondary volume enhanced												
Sec price												
Sec revenues		-										
Mayo B Total Costs - Net of Contributions ($000)		41,673	2,230	2,217	2,205	2,241	2,230	2,218	2,234	2,224	2,213	2,210
$/kW.h (net)			0.0503	0.0501	0.0498	0.0506	0.0503	0.0501	0.0504	0.0502	0.0500	0.0499
PV over life	$	41,673										
levelized $/kW.h (real)	$	0.0548										
Benefits												
Diesel Cost			$ 0.8523	$ 0.8693	$ 0.8867	$ 0.9045	$ 0.9225	$ 0.9410	$ 0.9598	$ 0.9790	$ 0.9986	$ 1.0186
Total cost to supply same load with diesel			$ 37,757	$ 38,512	$ 39,282	$ 40,068	$ 40,869	$ 41,686	$ 42,520	$ 43,370	$ 44,238	$ 45,123
Mayo B net costs (sav) to diesel			(35,527)	(36,294)	(37,077)	(37,826)	(38,639)	(39,468)	(40,286)	(41,147)	(42,025)	(42,913)
Total diesel cost without Mayo B			$ 721,175	$ 760,584	$ 801,857	$ 845,077	$ 890,332	$ 937,712	$ 987,314	$ 1,039,236	$ 1,093,581	$ 1,150,458

Schedule 1 of Mayo B Promissory Note

	Year	Maximum Grid Load (GWh)	Minimum Grid Load (GWh)	Range
1	2012	515	415	100
2	2013	508	413	95
3	2014	501	411	90
4	2015	494	409	85
5	2016	487	407	80
6	2017	480	405	75
7	2018	473	403	70
8	2019	466	401	65
9	2020	459	399	60
10	2021	452	397	55
11	2022	445	395	50
12	2023	438	393	45
13	2024	431	391	40
14	2025	424	389	35
15	2026	417	387	30
16	2027	410	385	25
17	2028	408	383	25
18	2029	406	381	25
19	2030	404	379	25
20	2031	402	377	25
21	2032	400	375	25
22	2033	400	375	25
23	2034	400	375	25
24	2035	400	375	25
25	2036	400	375	25
26	2037	400	375	25
27	2038	400	375	25
28	2039	400	375	25
29	2040	400	375	25
30	2041	400	375	25
31	2042	400	375	25
32	2043	400	375	25
33	2044	400	375	25
34	2045	400	375	25
35	2046	400	375	25
36	2047	400	375	25
37	2048	400	375	25
38	2049	400	375	25
39	2050	400	375	25
40	2051	400	375	25

Base Case

Year	Load (GW.h)	Interest Rate	Mayo B FTN Opening balance ($000)	FTN Interest Expense ($000)	Full Interest Expense ($000)	Flexible Note forgiveness ($000)
2012	415.9	0.05%	21,900	10.9	1,195.7	(1,184.9)
2013	430.4	1.00%	21,563	215.1	1,177.3	(962.2)
2014	448.8	2.29%	21,226	486.5	1,158.9	(672.4)
2015	457.4	3.11%	20,889	649.2	1,140.6	(491.4)
2016	466.2	4.04%	20,552	830.0	1,122.2	(292.1)
2017	468.4	4.62%	20,215	933.4	1,103.8	(170.4)
2018	477.6	5.46%	19,878	1,085.4	1,085.4	-
2019	481.8	5.46%	19,542	1,067.0	1,067.0	-
2020	463.9	5.46%	19,205	1,048.6	1,048.6	-
2021	435.4	3.81%	18,868	719.2	1,030.2	(311.0)
2022	445.5	5.46%	18,531	1,011.8	1,011.8	-
2023	455.7	5.46%	18,194	993.4	993.4	-

Base Case with Victoria Gold

Load (GW.h)	Interest Rate	Mayo B FTN Opening balance ($000)	FTN Interest Expense ($000)	Full Interest Expense ($000)	Flexible Note forgiveness ($000)
415.9	0.05%	21,900	10.9	1,195.7	(1,184.9)
430.4	1.00%	21,563	215.1	1,177.3	(962.2)
448.8	2.29%	21,226	486.5	1,158.9	(672.4)
560.6	5.46%	20,889	1,140.6	1,140.6	-
569.4	5.46%	20,552	1,122.2	1,122.2	-
571.7	5.46%	20,215	1,103.8	1,103.8	-
580.9	5.46%	19,878	1,085.4	1,085.4	-
585.1	5.46%	19,542	1,067.0	1,067.0	-
567.2	5.46%	19,205	1,048.6	1,048.6	-
538.7	5.46%	18,868	1,030.2	1,030.2	-
548.7	5.46%	18,531	1,011.8	1,011.8	-
559.0	5.46%	18,194	993.4	993.4	-

TOPIC: **Aishihik Third Turbine Construction**

REFERENCE: **Application page 5-5, line 23 to page 5-9, line 21**

PREAMBLE:

The City requires more information on this project.

QUESTION:

a) What peaking capacity and "long-term average hydro energy supply" has been added to the system by this project (page 5-6, lines 25-26)?

b) Please provide the NPV analysis of the benefits of this project mentioned in footnote 3, page 5-7.

c) Please provide the analysis that led YEC to conclude in August 2010 that this project was still beneficial (page 5-8, lines 16-19).

d) Please provide the original costs of this project as of August 2010 by component and the actual costs in the same detail with explanations for variances greater than ±5% between estimated and actual.

e) Please provide the output of this project by month since December 2011 (page 5-9, line 10).

f) Has this project and its associated contribution(s) been placed in rate base? If yes, please advise when this project and its associated contribution(s) have been placed in rate base?

ANSWER:

(a)

Peaking capacity is approximately 7 MW. Under the N-1 capacity planning criteria, none of the capacity at Aishihik is included in reliable grid peaking capacity.

Diesel displacement under long term average hydro availability is expected to exceed 4 GWh/year over a wide range of grid loads (i.e., 450 GWh/year and higher) with no Mayo B (i.e., the Aishihik Project was committed prior to Mayo B being committed).

(b)

Please see Exhibit B-9 filed during the 2007 Carmacks Stewart Transmission Line Part 3 hearing provided as Attachment 1 to this response.

(c)

In August 2010, a feasibility review was undertaken that determined that at a revised project cost of $12.813 million, the Aishihik Third Turbine project was still economically feasible and would have a Net Present Value of $9.77 million and a payback period of 7.9 years (with a generation cost of $0.170/ kWh as compared to $ 0.30/kWh for diesel generation).

The specific analysis supporting that conclusion that was presented to the Yukon Energy Board is provided below.

Assumptions:

Net Unit Cost of Diesel Generation (Incl. O&M):	$0.30 / kWh ($300 / MWh)
AH3 Added Generation:	5.4 GWh / Yr (5.4 GWh)
Capital Interest Rate (i):	7.09%
AH Third Turbine Project Cost:	$ 12,813,044
Amortization Period (n):	65 Yrs

Calculations:

Definitions:

Capital Recovery Factor (CRF) is defined as the ratio of a constant yearly cost / benefit to the present value of that cost / benefit, amortized over a known period of time (n) at a capital interest rate (i):

$$\text{Capital Recovery Factor (CRF)} = \frac{\quad}{\quad}$$

Series Present Worth Factor (SPWF) is the ratio of present value of a constant yearly cost / benefit to that annual cost / benefit over a known period of time (n) and an interest rate (i). It is the inverse of the Capital Recovery Factor:

$$\text{Series Present Worth Factor (SPWF)} = \frac{\quad}{\quad}$$

Equivalent Annual Cost (EAC) of AH3

= Project Cost x Capital Recovery Factor

$$= \$12{,}813{,}044 \times \frac{\quad}{\quad}$$

= $919,153 / yr

Cost of AH3 Generation ($ / kWh)

= EAC(Project) / Annual Added Generation
= $919,153 / [5,400,000 kWh /Yr]
= $0.170 / kWh

Annual Benefit From AH3

= Value of Displaced Diesel Generation Per Year
= (5,400,000 kWh/Yr) x $ 0.30 / kWh
= $1,620,000 / Yr

Present Worth of Yearly Diesel Savings

= Annual Benefit for AH3 x Series Present Worth Factor

$$= \$\ 1{,}620{,}000 / \text{yr} \times \frac{\quad}{\quad}$$

= $1,620,000 x 13.940
= $22,582,800

Net Present Value of 3rd Turbine

= Present Worth (Yearly Diesel Savings) – Project Cost
= $22,582,800 – $12,813,044
= $9,769,756

Payback Period

= Project Cost / Net Annual Savings
= $12,813,044 / $1,620,000
= 7.9 Yrs

(d)

Table 1 below provides the costs by component of this project by component at time of Construction Approval (August 2010) and Final Cost Estimates (2012/13 GRA).

Table 1:
Aishihik Third Turbine Comparison of Construction Cost Estimates (August 2010) and Final Cost Estimates (2012/13 GRA)

	Construction Approval Estimate (Aug 2010)	Final Cost Estimate (2012/13 GRA)	Difference ($)	Difference (%)
Building	$1,000	$0	-$1,000	-100.00%
Rock Excavation	$1,177,054	$1,132,765	-$44,289	-3.76%
Generating Hall	$627,962	$773,270	$145,308	23.14%
Turbine Generator	$3,989,731	$4,056,114	$66,383	1.66%
Supply Electro-Mechanical	$400,000	$713,994	$313,994	78.50%
Penstock Installation	$696,228	$884,079	$187,851	26.98%
Turbine Generator Installation	$574,977	$569,360	-$5,617	-0.98%
Auxiliary System Installation	$828,204	$821,815	-$6,389	-0.77%
Electrical Installation Generating Hall	$333,327	$322,673	-$10,654	-3.20%
Electrical Installation Generating Control Room	$608,413	$589,037	-$19,376	-3.18%
Testing and Commissioning	$79,812	$114,735	$34,923	43.76%
Diesel Fuel	$653,000	$636,759	-$16,241	-2.49%
Mobilization	$185,336	$386,152	$200,816	108.35%
Estimated Construction Field Cost:	**$10,155,044**	**$11,000,752**	**$845,708**	**8.33%**
Contingency:	$750,000	$0	-$750,000	-100.00%
Preliminary Design:	$700,000	$762,955	$62,955	8.99%
Detail Design:	$400,000	$609,702	$209,702	52.43%
Construction Management:	$425,000	$350,264	-$74,736	-17.58%
YEC Cost (Owner's Cost):	$250,000	$843,580	$593,580	237.43%
Construction Financing Cost:	$133,000	$249,486	$116,486	87.58%
CAPITAL COST:	$12,813,044	$13,816,739	$1,003,695	7.83%
Yukon Government Contribution	$5,000,000	$5,000,000	$0	0.00%
TOTAL CAPITAL COST: (with contribution)	**$7,813,044**	**$8,816,739**	**$1,003,695**	**12.85%**

Explanations for variances greater than ±5% between the Construction Approval Estimate (August 2010) and the Final Cost Estimate (2012/13 GRA) are as follows:

- **Building:** The difference here was due to YEC deciding to charge all the small building costs into Supply Electro-Mechanical and not to utilize this cost code. This is the cause for this component reduction in cost by minus 100%.

- **Generating Hall:** Additional Penstock piping costs due to final design and site requirements, in conjunction with additional generator and associated equipment location alignments caused this component cost to increase.

- **Supply Electro - Mechanical:** Complications with the Draft Tube and Knife Gate installations, in conjunction with Governor and Controls work by external consultants and YEC personnel caused this component cost to increase.

- **Penstock Installation:** Additional Penstock Thrust Block costs due to final design and site requirements caused this component cost to increase.

- **Testing and Commissioning:** Additional resources of YEC personnel and external contractors caused this component costs to increase.

- **Mobilization:** The extended maintenance of the work camp and additional contractors caused this component to increase.

- **Contingency:** This component was used to balance other components.

- **Preliminary Design:** Additional preliminary design was require by AECOM and YEC personnel to complete the Generating Hall and Supply-Electro-Mechanical components.

- **Detail Design:** Additional design work by AECOM and YEC personnel was required to finalize the Supply Electro-Mechanical and Penstock work.

- **Construction Management/ YEC Cost (Owner's Cost):** Due to issues related to cost estimating and construction management, YEC's personnel increased involvement in all of the later phases and work on this project such as; Construction Management, Design, Testing and Commissioning, Penstock Installation, Supply Electro- Mechanical, and Generating Hall resulting in a net increase in cost for this component.

- **Construction Financing Cost:** Overall the project took longer than planned or scheduled and YEC incurred additional costs in this component.

(e)

Output of this project by month since December 2011 is provided in Table 1 below.

Table 1:
Aishihik Third Turbine Generation by Month (kWh)

Month/Year	kWh Generated
December 2011	1,510,000
January 2012	3,428,072
February 2012	3,088,919
March 2012	3,078,009
April 2012	1,437,934
May 2012	1,070,432
June 2012	605,064

(f)

This project came into service December 2011 and its costs and associated contributions were placed into rate base at year end 2011.

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

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	-	787	4	(783)	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	1,366	-	96	96	(1,272)
2022	7,299	1,899	(5,400)	3.9	1,385	464	-	(464)	3.48	133	1,518	1,361	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 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	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	1,508	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	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	-	1,762	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	(1,308)
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%											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 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	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	-	-	-	3.8	-	-	-	-	3.48	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	3.8	-	22	22	-	3.48	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	3.8	-	91	91	-	3.48	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	3.8	-	775	775	-	3.48	-	-	-	-	-	-	-	-	-	-
2010	27,320	21,920	(5,400)	3.8	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)	3.8	1,385	-	-	-	3.48	-	1,385	1,014	97	not assessed	1,111	-	79	79	(1,032)
2012	38,170	32,770	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,034	99	not assessed	1,133	-	80	80	(1,053)
2013	43,914	38,514	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,054	101	not assessed	1,156	-	82	82	(1,074)
2014	49,593	44,193	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,076	103	not assessed	1,179	-	84	84	(1,095)
2015	55,378	49,978	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,097	105	not assessed	1,202	-	85	85	(1,117)
2016	61,270	55,870	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,119	107	not assessed	1,226	-	87	87	(1,139)
2017	30,643	25,243	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,141	110	not assessed	1,251	-	89	89	(1,162)
2018	-	-	-	3.8	-	3,293	575	(2,719)	3.48	781	781	657	56	not assessed	713	-	91	91	(623)
2019	-	-	-	3.8	-	4,202	780	(3,422)	3.48	983	983	843	72	not assessed	916	-	92	92	(823)
2020	-	-	-	3.8	-	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)	3.8	619	4,126	1,415	(2,711)	3.48	779	1,398	1,247	113	not assessed	1,360	-	96	96	(1,264)
2022	8,980	3,590	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,260	121	not assessed	1,381	-	98	98	(1,283)
2023	15,688	10,288	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,285	123	not assessed	1,409	-	100	100	(1,309)
2024	22,510	17,110	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,311	126	not assessed	1,437	-	102	102	(1,335)
2025	29,458	24,058	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,337	128	not assessed	1,466	-	104	104	(1,362)
2026	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,364	131	not assessed	1,495	-	106	106	(1,389)
2027	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,391	134	not assessed	1,525	-	108	108	(1,417)
2028	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,419	136	not assessed	1,555	-	110	110	(1,445)
2029	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,448	139	not assessed	1,587	-	113	113	(1,474)
2030	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,477	142	not assessed	1,618	-	115	115	(1,503)
2031	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,506	145	not assessed	1,651	-	117	117	(1,534)
2032	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,536	147	not assessed	1,684	-	119	119	(1,564)
2033	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,567	150	not assessed	1,717	-	122	122	(1,595)
2034	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,598	153	not assessed	1,752	-	124	124	(1,627)
2035	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,630	157	not assessed	1,787	-	127	127	(1,660)
2036	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,663	160	not assessed	1,822	-	129	129	(1,693)
2037	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,698	163	not assessed	1,859	-	132	132	(1,727)
2038	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,730	166	not assessed	1,896	-	135	135	(1,762)
2039	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,765	169	not assessed	1,934	-	137	137	(1,797)
2040	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,800	173	not assessed	1,973	-	140	140	(1,833)
2041	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,836	176	not assessed	2,012	-	143	143	(1,869)
2042	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,873	180	not assessed	2,052	-	146	146	(1,907)
2043	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,910	183	not assessed	2,093	-	149	149	(1,945)
2044	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,948	187	not assessed	2,135	-	152	152	(1,984)
2045	-	-	(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	1,987	191	not assessed	2,178	-	155	155	(2,023)
2046			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,027	195	not assessed	2,222	-	158	158	(2,064)
2047			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,068	198	not assessed	2,266	-	161	161	(2,105)
2048			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,109	202	not assessed	2,311	-	164	164	(2,147)
2049			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,151	207	not assessed	2,358	-	167	167	(2,190)
2050			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,194	211	not assessed	2,405	-	171	171	(2,234)
2051			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,238	215	not assessed	2,453	-	174	174	(2,279)
2052			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,283	219	not assessed	2,502	-	178	178	(2,324)
2053			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,328	224	not assessed	2,552	-	181	181	(2,371)
2054			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,375	228	not assessed	2,603	-	185	185	(2,418)
2055			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,422	233	not assessed	2,655	-	188	188	(2,467)
2056			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,471	237	not assessed	2,708	-	192	192	(2,516)
2057			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,520	242	not assessed	2,762	-	196	196	(2,566)
2058			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,571	247	not assessed	2,817	-	200	200	(2,618)
2059			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,622	252	not assessed	2,874	-	204	204	(2,670)
2060			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,675	257	not assessed	2,931	-	208	208	(2,723)
2061			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,728	262	not assessed	2,990	-	212	212	(2,778)
2062			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,783	267	not assessed	3,050	-	216	216	(2,833)
2063			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,838	272	not assessed	3,111	-	221	221	(2,890)
2064			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,895	278	not assessed	3,173	-	225	225	(2,948)
2065			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	2,953	283	not assessed	3,236	-	230	230	(3,007)
2066			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	3,012	289	not assessed	3,301	-	234	234	(3,067)
2067			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	3,072	295	not assessed	3,367	-	239	239	(3,128)
2068			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	3,134	301	not assessed	3,435	-	244	244	(3,191)
2069			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	3,196	307	not assessed	3,503	-	249	249	(3,255)
2070			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	3,260	313	not assessed	3,573	-	254	254	(3,320)
2071			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	3,325	319	not assessed	3,645	-	259	259	(3,386)
2072			(5,400)	3.8	1,385	-	-	-	3.48	-	1,385	3,392	326	not assessed	3,718	-	264	264	(3,454)
2073			(5,400)	3.8	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	51,786	46,386	(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	-	7,388	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 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	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)

TOPIC: **Mayo Hydro – Substation Enhancements**

REFERENCE: **Application page 5-11, lines 5-8**

YEC states:

> **The spending profile over the three year period is projected to total $10.15 million:**
>
> - **$0.163 million in 2010;**
> - **$3.647 million in 2011(net of $0.750 million cost assigned to Mayo B Project); and**
> - **$6.342 million in 2012.**

PREAMBLE:

The City requires more information on this project.

QUESTION:

a) What part of the project listed at page 5-10, line 23 to page 5-11, line 4 was assigned to Mayo B and why?

b) Please provide a continuity of Construction Work in Progress (CWIP), Allowance for Funds Used During Construction (AFUDC) and additions to rate base for this project.

ANSWER:

(a)

As noted in footnote 6 at page 5-10, the Mayo B Part 3 Application (filed December 2009), noted that due to the range of non-Mayo B material planning considerations and requirements associated with this substation, engineering and construction for the substation was being addressed separately from the Mayo B Project. The Mayo B capital cost budget at that time included a set assignment of $0.600 million towards the substation project to cover costs for a least cost Mayo B connection option involving a

simple single tap to the bus with appropriate disconnects for isolation. This cost increased to $0.750 million in the GRA forecast.

Please see also response to LE-YEC-1-22 and CW-YEC-1-29 for discussion regarding rationale for this specific assignment of costs to Mayo B.

(b)

For a continuity table of costs associated with the project please see Table 5.2 in the Application. It is unclear what further information is being requested.

TOPIC: **Aishihik Generation Station Redundancy**

REFERENCE: **Application page 5-16, lines 1-12**

YEC states:

> **In August 2009, based on AECOM preliminary estimates Yukon Energy set its preliminary budget at $2.9 million. However, when the construction contract was tendered, the bid prices came in materially higher than AECOM's preliminary estimates. The tender process was cancelled and direct discussions were held with individual contractors to determine if the project scope could be refined to reduce the cost of the project. This was not possible and as a result of these discussions the estimate had to be materially increased.**
>
> **Some of the material challenges that caused difficulties in AECOM estimating the costs included necessary changes to the building location and design, additional grading and related costs for a retaining wall (to address contaminated soil and soil integrity), and changes in base metal prices which increased the cost of cables and cable tray. Further, due to the complexity and importance of electrical work additional Yukon Energy resources had to be committed to the project to advise, plan and lead the work.**
>
> **With all relevant cost information now compiled, the forecast project cost estimate is now $6.356 million.**

PREAMBLE:

The City requires more information on this project.

QUESTION:

a) Please provide the original business case for this project and a breakdown of the original estimated cost if the original business case does not provide it. If the business case has a different estimated cost than the 2009 estimate of

$2.9 million quoted above, please provide a detailed explanation of the changes in costs.

b) Please provide a detailed history of the estimated costs of this project showing how each factor in the quote above increased costs from $2.9 million to $6.356 million.

c) Please provide a continuity schedule of expenditures, AFUDC and additions to rate base from 2009 to 2013 for this project.

ANSWER:

(a) and **(b)**

The project justification was provided to the YEC Board in August 2009.

Please see response to LE-YEC-1-18. The Aishihik Redundancy project was undertaken to rectify a serious system reliability issue relating to redundancy identified as a result of a major system outage.

A detailed cost breakdown of the Original Budget estimates (April 2009), Construction Approval estimates (with tendered costs as of August 2010), and Final Cost Estimates (2012/13 GRA) is provided in Table 1 below.

Original Budget Cost Estimates noted in Table 1 below were not based on tendered costs. Differences between Original Budget (April 2009) and August 2010 were due primarily to adjustments needed to the estimates provided by AECOM. As indicated in the Application, after the tender process in February 2010, AECOM acknowledged that they had significantly underestimated the costs of the project and that the bids more accurately reflected the magnitude of the costs. As a result of the high bids the tender was cancelled and AECOM and YEC had discussions with two separate contractors to refine project scope and achieve lower costs. However, these discussions did not materially alter the then estimated project costs.

Table 1 below indicates the estimated costs at the time a decision was made to proceed with the project based on these tendered costs. Note that the component breakdown below totals to $6.108 million as at the end of 2011 (and not $6.365 million total for the project included in Application Table 5.2). An additional $0.257 million is forecast to be required in 2012; this amount is estimated to address project wrap-up activities and outstanding items such as gauges, performance testing, minor deficiencies' corrections, and other matters. This additional spending provides for the Final Cost Estimate of $6.365 million included in the 2012/2013 GRA.

Table 1:
Aishihik Redundancy Project Original Budget Estimate, Construction Approval Budget Estimate to Completion and Final Cost Estimate to End of 2011

	Original Budget (Apr 2009)	Construction Approval (Aug 2010)	Final Cost Estimate (2012/13 GRA)
Building	$333,300	$708,785	$848,914
Supply Electro-Mechanical	$1,060,000	$1,868,648	$1,990,377
Electrical Installation in Generating	$353,400	$948,203	$900,245
Electrical Installation Generating Control Room	$305,900	$0	$250,660
Testing and Commissioning	$131,750	$58,827	$330,907
Mobilization	$88,000	$23,558	$125,983
Diesel Fuel	$0	$0	$190,343
Estimated Construction Field Cost:	**$2,272,350**	**$3,608,021**	**$4,637,429**
Contingency:	$300,000	$300,000	$0
Detail Design:	$144,000	$419,270	$591,667
Construction Management:	$77,000	$207,334	$306,323
YEC Cost (Owner's Cost):	$0	$0	$493,736
Construction Financing Cost:	$110,000	$45,000	$78,732
TOTAL CAPITAL COST:	**$2,903,350**	**$4,579,625**	**$6,107,887**

A detailed history of cost changes from August 2010 (when tendered costs were provided) to Actuals 2012 is provided below. All cost increases prior to August 2010 were caused by the project re-evaluation which took place due to the tender price increases from Contractors:

- **Building:** The building was originally designed to be at ground level which would have provided no internal access to YEC personnel to the building or substation. Therefore it was decided to install the building at the same level as the substation and the existing Control Room. This decision in conjunction with the contaminated soil on site is the cause of cost increases with this component.

- **Supply Electro-Mechanical:** Increases in the complexity and restriction in the substation work area in conjunction with the building switchgear power cable work caused this component to increase in cost.

- **Electrical Installation in Generating:** Cost decreases with this component are offset by increased costs in the Electrical Installation in Generating Control Room costs.

- **Electrical Installation in Generating Control Room:** Cost increases with this component are due to the increased costs for Power Cables and Cable Tray in conjunction with their installation is the cause of cost increases with this component.

- **Testing and Commissioning:** Cost increases with this component are due to YEC personnel and additional contractor resources being required to work with the contractor to maintain the project schedule.

- **Mobilization:** The extended maintenance of the work camp and additional contractors caused this component to increase in cost.

- **Diesel Fuel:** This project was the primary cause for a portion of the June and October 2011 scheduled plant shut downs and as such a component of diesel cost was allocated here.

- **Contingency:** This component was used to balance other components.

- **Detail Design:** The increase in this component is due to YEC personnel having to be involved with work in this area of this project as the external engineering was becoming too costly.

- **Construction Management/ YEC Cost (Owner's Cost):** Due to issues related to cost estimating and construction management, YEC increased involvement in most areas of this project as the contractor was falling behind on the schedule.

- **Construction Financing Cost:** Overall the project took longer than planned or scheduled and YEC incurred additional costs in this component.

(c)

For a continuity table of costs associated with the project please see Table 5.2 in the Application. It is unclear what further information is being requested.

TOPIC: **GRA Phase 1 Revenue Requirement Review – $1.1 million**

REFERENCE: **Application page 5-47, line 18-20**

YEC states:

> **This spending addresses the costs of preparing and filing a 2012/2013 Phase I GRA, as well as a full regulatory review. Any joint YEC/YECL cost of service and rate design filing is to be undertaken at a future date to be determined, and is not included in this projected cost.**

PREAMBLE:

The City requires more information concerning this project and its associated costs.

QUESTION:

a) Please provide a detailed breakdown and description of the costs included in the "GRA Phase 1 Revenue Requirement Review" project and the year(s) in which the expenditures occurred or are forecast to occur.

b) Has YEC obtained approval of these costs yet? If not, is YEC seeking approval of these costs in these proceedings or in the related costs proceeding?

c) Has YEC included this project in Appendices 5.4 or 5.5?

ANSWER:

(a) and **(b)**

Yukon Energy has not obtained approval for these costs.

As in prior GRA proceedings, Yukon Energy has included a "placeholder" expense related to estimated costs for the current GRA (Phase I) Application, anticipated to be incurred in 2012 for preparation and review of the Application and reimbursement of

related intervenor and YUB costs, to be amortized over the 2 test years (2012 and 2013).

The intensity and duration of the regulatory process cannot be determined at this time. Accordingly, Yukon Energy is seeking approval to adjust the above amount to reflect the full actual amounts incurred or ordered to be reimbursed at the time of the final compliance filing 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.

Hearing related costs will be subject to Board review pursuant to a hearing cost awards process to occur after a final Board Order on the current application is issued. As in prior proceedings, the total cost will include Yukon Energy costs to prepare and defend the Application, as well as Board costs and such intervenor costs as approved by the Board.

(c)

Appendix 5.4 and Appendix 5.5 address projects under $ 1 million. The GRA costs are not included in either appendix (as they are not under $1 million) and are instead discussed as a major deferred project (i.e., greater $1 million) in Tab 5, section 5.3.1.10 of the Application.

TOPIC: **Rate Case**

REFERENCE: **Application page 5-49, lines 10-14**

YEC states:

> **Rate Case (from 2009 to 2011 of $1.02 million (excluding GRA reviews), and with an additional $0.23 million in 2012) – spending in the test years is focused on the preparation of the 2011 Resource Plan Update required to facilitate decision making on major infrastructure projects by providing new an additional information on load forecasts, generation and transmission options as well as an assessment of alternatives.**

PREAMBLE:

The City requires more information concerning this project and its associated costs.

QUESTION:

a) How do these costs differ from the costs discussed at page 5-47, line 18-20?

b) Please provide a detailed breakdown and description of the 1.02 million of spending between 2009 and 2011.

c) What will the "additional $0.23 million in 2012" be spent on in 2012?

d) Has YEC included this project in Appendices 5.4 or 5.5?

ANSWER:

(a)

The costs discussed on page 5-49, lines 10-14 include studies on Reserve for Injuries and Damages, Brushing and Vegetations Management, and 2011 Resource Plan Update. They exclude any costs related to preparation, filing and review of a 2012/13 Phase I GRA, which is discussed on page 5-47, lines 18-20.

Both groups of costs represent rate case costs however, they are discussed separately consistent with the Application structure, which groups major projects (over $1 million) and projects between $100 thousand and $1 million separately.

(b)

Please see Table 1 below for the requested information.

Table 1:
Breakdown and Description of $1.02 Million Spending for the Projects Between $100 Thousand and $1 Million under Rate Case

	$000
Reserve for Injuries & Damages - Study	43
Brushing & ROW Vegetation Management	173
Resource Plan Update	809
Total	1,025

(c)

The additional $0.23 million in 2012 reflects the spending in the test years, which is focused on the preparation of the 2011 Resource Plan Update as discussed page 5-49, lines 10-14 of the Application.

(d)

Yes. Please see Resource Plan Update on page 5.5-9 of Appendix 5.5 to the GRA Application.

TOPIC: **Planning Policy**

REFERENCE: **Appendix 5.1**

PREAMBLE:

The City wishes to evaluate YEC's proposed Planning Policy.

QUESTION:

a) Please provide YEC's current planning policy. When was this policy developed?

b) What would be the amount of deferred project costs amortized in 2012 and 2013 under the current planning policy? What is the change in amortization under the proposed planning policy?

c) What is the Reasonable Assurance test and what are the parameters that YEC applies?

d) Have all the studies in Tables 5.1 to 5.7 passed the Reasonable Assurance Test? If not, which studies have not?

e) Which studies in Tables 5.1 to 5.7 are associated with projects that are feasible and will provide service to customers at a future date?

f) Please explain the choice of a five-year amortization period for projects that do not meet the Reasonable Assurance Test.

g) Please explain the choice of a ten-year amortization period for project costs that are abandoned after meeting the Reasonable Assurance Test.

h) Section 4.0 of Appendix 5.1 discusses a "Transition Policy for 2012 & 2013 Test Years". How does this policy result in intergenerational equity for customers?

ANSWER:

(a)

See Attachment 1 to this response. This planning cost accounting policy was developed in 1992 and filed with the YUB as part of IR response BD-YEC/YECL-124 during the 1993/94 General Rate Application.

(b)

Without the new policy, including the reasonable assurance test, the feasibility project amortization expense would be approximately $1.2 million in 2012 (compared to $1.6 million in GRA Application) and $1.4 million (compared to $2.7 million in the GRA Application) in 2013. This assumes any project would not be closed-out if there is any spending forecast in the following year. For example, the expenditures for Geothermal, Wind, Waste to Energy, Marsh Lake, Gladstone and Large Hydro projects would not have been closed-out and would instead just stay in WIP by end of 2013. Under this scenario the WIP balances for Planning Studies by the end of 2013 would be $15.6 million.

(c)

Please see the Planning Cost Accounting Policy provided as Attachment 5.1 to the Application.

Reasonable assurance is generally consistent with Yukon Energy's commitment to proceed with a specific project. This would be consistent with the following specific types of activities:

- A decision by YEC to define a specific project location, approach, technology;
- Prepare and file a YESAB Project Proposal;
- Enter into substantive negotiations with First Nations or other project partners;
- Preparation of engineering designs and tender materials; and

- Arrangement of project financing where needed.

Recent experience with CSTP and Mayo B has indicated “Commitment to Proceed” or “Reasonable Assurance” at time of a decision to prepare a YESAB filing.

(d) and **(e)**

The feasibility studies shown in Table 5.3 to 5.7 have generally not passed the Reasonable Assurance Test nor become a capital project. For some studies this is because the project is not oriented to become a specific capital project (e.g., the Hydro Storage and Generation Pre-Feasibility, which was a scan of multiple possible hydro sites).

Those that have passed the Reasonable Assurance Test no longer show up in Table 5.2 through 5.7 after the date of this decision, as at that time they are reclassified as a capital project. Examples of this include Mayo B, and Mayo Lake, and in the test years LNG.

(f), **(g)** and **(h)**

Please see response to YUB-YEC-1-39.

YUKON ENERGY CORPORATION

ACCOUNTING POLICY FOR PLANNING AND STUDY COSTS

General

Planning and study costs include, but are not limited to, the following:

- Generation planning;
- Pre-feasibility and feasibility;
- Environmental;
- Water management;
- Fisheries;
- Reconnaissance;
- Survey and investigation; and
- Water license renewal studies.

Accounting Policy

1. Planning and study costs which are pure research in nature shall be recorded as an expense of the period in which they are incurred. It should be noted that costs of this type, if any, are not expected to be significant.

2. Planning and study costs related to ongoing operations shall be recorded as an expense of the period in which they are incurred.

3. When the expected outcome of planning and study costs is to enhance the service potential or extend the useful life of an existing asset or to add new assets to the system, the related costs shall be capitalized to, and amortized on the same basis as, the related project.

   If the project does not proceed, the capitalized development costs shall be amortized on a straight-line basis over five years, commencing with the next rate application period following the decision not to proceed with the project.

4. Planning and study costs related to water license renewals shall be amortized over the term of the existing license plus the expected term of the renewed license.

Application

Management should use its best judgement in determining which of the above categories each specific study applies to.

ACTG-POLICY/92/12/10

TOPIC: **Demand Side Management Accounting**

REFERENCE: **Appendix 5.2**

PREAMBLE:

The City wishes to evaluate YEC's proposed Demand Side Management Accounting Policy.

QUESTION:

a) How does YEC's proposed Demand Side Management Accounting Policy ensure that the costs of developing a DSM project are matched to the benefits of the same project?

b) Please explain the choice of a ten-year amortization period for projects that "Management has indicated its intention to proceed with the program."

c) Please provide examples of "Research related activities not associated with a specific program".

d) How will YEC dispose of costs associated with a specific project which management decides not to proceed with?

e) Does YEC have a test for DSM projects similar to the Reasonable Assurance test?

f) Are there any projects or research underway currently in YEC that fall under this policy? Please identify and indicate how the costs and any associated revenues will be accounted for.

ANSWER:

(a) and **(b)**

YEC adopted the 10 year approach for program spending to achieve consistency and simplicity. While this does not precisely match amortization to benefits, it is clear and

understandable, and in many cases the duration of DSM benefits can be difficult to precisely determine in any event. Please also see response to YUB-YEC-1-38(e).

(c)

Examples of research-related activities would be work by YEC staff to scan the DSM programs of other utilities to identify best-practices.

(d)

These costs will be expensed.

(e)

In effect, yes. It is described in the DSM policy as programs where “Management has indicated its intention to proceed with the program”.

(f)

DSM activities underway at the present time are described in LE-YEC-1-24 and YUB-YEC-1-46. All spending and activities on DSM “fall under this policy”, with costs occurring both under Table 5.6 and 5.7 (for deferred costs amortized over 10 years) and in Tab 3 (for O&M related costs that are expensed each year).

TOPIC: **Directive # 3 Demand Side Management**

REFERENCE: **Application Tab 6, pages 6-3 to 6-7**

PREAMBLE:

The City wishes to evaluate YEC's proposed Demand Side Management Program in response to Directive # 3.

QUESTION:

a) At page 6-6, lines 20-23, YEC states: "a policy document will be completed in early Q2 2012 and it is anticipated that before the end of 2012 Yukon Energy in collaboration with others will have determined the specific DSM programs to be implemented in the near-term. The policy document and any further updates regarding DSM programming will be filed with the Board once available." As it is now late in Q2 2012, has the policy document been completed? Please provide if completed. If not completed, please advise why not and when the policy document will become available.

b) Footnote 5 on page 6-7 states with respect to YEC's LED Streetlight project: "YEC pilot project undertaken with input from ESC. Yukon Electrical has also undertaken its own pilot program." Has YEC coordinated its LED Streetlight project with that of YECL to share results and avoid duplication?

ANSWER:

(a)

Work to develop a DSM program has taken longer than anticipated. The Conservation Potential Review, which provided necessary baseline data, added several months to the process. It is anticipated that the DSM Plan will be available in fall 2012.

(b)

YEC has worked closely with YECL to share information from both 2011 LED pilot projects. Noting information gaps in both pilots, YEC and YECL have partnered to conduct a joint follow up pilot in 2012/2013.

Further to this partnership, YEC will be working closely with YECL's sister company in Yellowknife to share information regarding an upcoming LED change-out. This does not include commitments or partnerships regarding funds, data etc.

TOPIC: **Directive # 8 Reserve for Injuries and Damages**

REFERENCE: **Application Tab 6, pages 6-9 to 6-11**

YEC quotes Directive 8:

> **The Board concludes that a policy outlining the criteria for charging items to the Reserve [for Injuries and Damages] is needed. The Board directs YEC to undertake a risk management study (Study) of other utilities. The Study should examine and provide results that among other things:**
>
> - **Maximizes the benefits of trade offs between the deductible amounts proposed to be used on property insurance, the additional costs of making claims on its existing insurance and the size of uninsured claims; and**
>
> - **Outlines the criteria used to include an item in the Reserve, i.e. materiality threshold, probability of the event occurring, etc.**

PREAMBLE:

The City wishes to evaluate YEC's response to Directive # 8.

QUESTION:

a) What are the deductible amounts on YEC's existing property and liability insurance? Please provide any supporting documents.

b) What are the additional costs of making claims on YEC's existing property and liability insurance? Please provide any study or studies undertaken.

c) How does YEC maximize the tradeoff between making insurance claims and the charges to the Reserve for Injuries and damages? Please provide any study or studies undertaken or cross-reference to Appendices 12.4 and 12.5.

ANSWER:

(a)

Please see table below for the deductible amounts on YEC's existing property and liability insurance.

Policy Description	Amount	Notes
Property	$100,000	1
Commercial General	$250,000	1
Umbrella	$10,000	
Excess	N/A	
Directors & Officers	$50,000	1
Crime	$1,000	

Note 1 - General policy deductible is quoted; certain loss events attract different deductible. See policies attached to CW-YEC-1-23(h) for the specifics of each policy.

(b)

Additional costs of making claims are generally limited to internal labour costs to assemble documentation and correspond with the insurer for the purpose of defending the claim. Studies have not been undertaken and cannot be provided in this regard.

(c)

The use of the RFID allows the utility to take a fairly high deductible under the annual insurance policies. To mitigate the risk from a loss, the Company maintains assets to a high standard such that the Company has a favorable loss history.

TOPIC: **Financial Schedules**

REFERENCE: **Application Tab 7**

PREAMBLE:

The City wishes to analyze YEC's regulatory schedules in detail.

QUESTION:

a) Please provide the regulatory schedules in Tab 7 in Excel format with all formulae and internal links intact.

ANSWER:

(a)

Please see Attachment 1 to this response.

Please note that Schedule 11 has been revised per CW-YEC-1-38 (a) to show YDC's refinanced long-term debts separately with its corresponding year-end balances and annual interest expenses for 2009 and 2010, i.e. before refinancing. This will not affect total long-term debt balances and any other numbers in the 2012/13 GRA Application.

Yukon Energy Corporation
Computation of Rate Base
($000s)

Schedule 1
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	**Property, Plant and Equipment**									
2	Year end balance	S.3 L.5	286,660	297,261	378,170	473,017	496,938	496,938	520,650	520,650
	Deduct:									
3	Accumulated depreciation (note 1)	S.3 L.10	89,221	89,353	95,584	103,288	115,017	111,706	127,419	120,694
4	Construction-in-progress	S.3 L.11	8,686	20,898	91,851	7,892	6,199	6,199	19,798	19,798
5	Disallowed assets	S.3 L.12	200	200	200	200	200	200	200	200
6	Miscellaneous reserves	S.3 L.13	7,814	7,373	6,782	6,366	6,001	6,140	5,636	5,914
7	Total deductions		105,921	117,824	194,417	117,745	127,417	124,245	153,053	146,606
	Add:									
8	Deferred study costs (note 2)	S.3 L.15	22,451	12,374	17,328	22,115	26,760	27,178	25,466	27,207
9	Less: Studies in Progress	S.3 L.16	(14,526)	(4,584)	(10,543)	(8,965)	(2,169)	(2,169)	-	-
10	Other deferred costs	S.3 L.17	121	-	-	-	-	-	-	-
11	Accum. Disallowed depreciation	S.3 L.18	78	78	82	86	90	90	94	94
12	Total additions		8,124	7,868	6,867	13,236	24,681	25,099	25,560	27,301
	Net plant in Service									
13	Current year-end balance	S.3 L.20	188,863	187,306	190,621	368,508	394,202	397,792	393,158	401,346
14	Previous year-end balance		191,305	186,710	187,306	190,621	368,508	368,508	394,202	397,792
15	Total		380,168	374,016	377,926	559,128	762,710	766,300	787,360	799,138
16	Mid-year balance		190,084	187,008	188,963	279,564	381,355	383,150	393,680	399,569
18	Mid-year rate case expense		1,026	966	915	1,570	3,281	3,006	4,736	3,911
19	Working capital	S.2 L.8	3,192	3,594	3,822	4,150	4,014	4,118	4,218	4,280
20	**Gross Rate Base**		194,302	191,568	193,700	285,284	388,650	390,274	402,634	407,760
	Deduct:									
	Contributions for extensions									
21	Current year-end balance		55,366	57,408	140,896	176,220	182,343	182,343	191,243	191,243
22	Contributions in WIP		5,000	6,932	90,238	120	2,000	2,000	10,500	10,500
23	Current year-end balance in-service		50,366	50,476	50,658	176,100	180,343	180,343	180,743	180,743
24	Accumulated amortization of contributions		4,376	5,179	7,025	9,200	13,733	12,736	18,315	16,305
25	Net current year-end balance in-service		45,990	45,297	43,633	166,900	166,610	167,607	162,428	164,438
26	Previous year-end balance		46,680	45,077	45,297	43,633	166,900	166,900	166,610	167,607
27	Total		92,670	90,374	88,930	210,533	333,511	334,507	329,039	332,046
28	Mid-year balance		46,335	45,187	44,465	105,267	166,755	167,254	164,519	166,023
29	**Net Rate Base**	S.5 L.1	147,967	146,381	149,235	180,017	221,895	223,020	238,115	241,738

Note 1: Including Reserve for Future Removal and Site Restoration
Note 2: Planning and Study costs, Relicencing, Dam Safety costs and Deferred Overhauls. Net of contributions.

Yukon Energy Corporation
Computation of Allowance for Working Capital
($000s)

Schedule 2
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Operating and maintenance	S.5 L.5	13,403	14,765	15,219	18,377	17,681	19,241	19,779	21,026
2	Taxes other than income	S.5 L.6	256	288	291	297	312	312	326	326
3	Non-allowable expenses		(85)	(159)	(133)	(333)	(85)	(85)	(85)	(85)
4	Cash operating expenses		13,575	14,894	15,377	18,341	17,907	19,468	20,021	21,267
5	27/365 in 2009 GRA		1,004	1,102	1,137	1,357	1,325	1,440	1,481	1,573
6	Inventory (three year average)		2,279	2,574	2,644	2,731	2,770	2,770	2,830	2,830
7	GST Impact on working capital	S.2A L.11	(91)	(81)	41	62	(80)	(92)	(93)	(123)
8	Working capital	S.1 L.19	3,192	3,594	3,822	4,150	4,014	4,118	4,218	4,280

Yukon Energy Corporation
Effect of GST on Working Capital
($000s)

Schedule 2A
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Expenses subject to GST		25,921	30,134	95,658	111,287	41,519	43,079	38,801	40,047
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		1,296	1,507	4,783	5,564	2,076	2,154	1,940	2,002
4	Day Factor		14	14	14	14	14	14	14	14
5	Recoverable portion of GST impact		50	58	183	213	80	83	74	77
6	Revenue subject to GST		31,997	31,708	32,376	34,294	36,402	39,857	37,956	45,641
7	GST blended rate (2009 GRA)		4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%
8	GST payable		1,465	1,452	1,483	1,571	1,667	1,825	1,738	2,090
9	Day factor		35	35	35	35	35	35	35	35
10	Payable portion of GST impact		141	139	142	151	160	175	167	200
11	Net impact of GST on working capital	S.2 L.7	(91)	(81)	41	62	(80)	(92)	(93)	(123)

Yukon Energy Corporation

Continuity Schedule of Property, Plant and Equipment ($000s)

Schedule 3
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	**Property, Plant and Equipment**									
2	Balance at beginning of year		277,842	275,268	297,261	378,170	473,017	473,017	496,938	496,938
3	Net Increases to PPE (Table 5.1)		9,078	22,824	81,827	95,000	23,921	23,921	23,713	23,713
4	Retirements, disposals and adjustments (note 1)		(260)	(831)	(918)	(153)	-	-	-	-
5	Balance at end of year	S.1 L.2	286,660	297,261	378,170	473,017	496,938	496,938	520,650	520,650
6	**Accumulated depreciation (including Future Removal Reserve)**									
7	Balance at beginning of year		82,955	83,107	89,353	95,584	103,288	103,288	115,017	111,706
8	Depreciation expense	S.6 L.7	6,526	7,214	7,369	7,902	11,730	8,418	12,402	8,989
9	Retirements, disposals and adjustments (note 1)		(260)	(969)	(1,137)	(199)	-	-	-	-
10	Balance at end of year		89,221	89,353	95,584	103,288	115,017	111,706	127,419	120,694
	Deduct:									
11	Construction-in-progress	S.1 L.4	8,686	20,898	91,851	7,892	6,199	6,199	19,798	19,798
12	Disallowed assets	S.1 L.5	200	200	200	200	200	200	200	200
13	Miscellaneous reserves (note 2)	S.1 L.6	7,814	7,373	6,782	6,366	6,001	6,140	5,636	5,914
14	Total		16,700	28,471	98,833	14,457	12,400	12,539	25,634	25,912
	Add:									
15	Deferred study costs (note 3)	S.1 L.8	22,451	12,374	17,328	22,115	26,760	27,178	25,466	27,207
16	Less: Studies in Progress	S.1 L.9	(14,526)	(4,584)	(10,543)	(8,965)	(2,169)	(2,169)	-	-
17	Other deferred costs	S.1 L.10	121	-	-	-	-	-	-	-
18	Accum. Disallowed depreciation	S.1 L.11	78	78	82	86	90	90	94	94
19	Total		8,124	7,868	6,867	13,236	24,681	25,099	25,560	27,301
20	Net Property, Plant and Equipment	S.1 L.13	188,863	187,306	190,621	368,508	394,202	397,792	393,158	401,346

Note 1: Largely relate to retirements and disposals, as well as charges against the Reserve for Future Removal and Restoration
Note 2: Includes Fire Insurance Reserve, Deferred Dewatering Revenues and the Reserve for Injuries and Damages
Note 3: Planning and Study costs, Relicencing, Dam Safety costs and Deferred Overhauls. Net of contributions.

Yukon Energy Corporation
Cost of Capital Calculation
2009 Approved and 2009-2010 Actual
($000s)

Schedule 4A
April 2012

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
	2009 Approved						
1	Long-Term debt	S.11 L.18	92,092	60.0%	88,781	6.15%	5,463
2	Common Stock	S.7 L. 8	61,385	40.0%	59,188	8.49%	5,025
3	Total	S.5 L.3	153,477	100.0%	147,969	7.09%	10,488
	2009 Actual						
4	Long-Term debt	S.11 L.18	91,289	60.0%	87,897	6.22%	5,464
5	Common Stock	S.7 L. 8	60,740	40.0%	58,483	7.92%	4,631
6	Total	S.5 L.3	152,029	100.0%	146,381	6.90%	10,095
	2010 Actual						
7	Long-Term debt	S.11 L.18	89,516	58.6%	87,400	6.38%	5,575
8	Common Stock	S.7 L. 8	63,332	41.4%	61,835	7.45%	4,610
9	Total	S.5 L.3	152,848	100.0%	149,235	6.82%	10,185

Yukon Energy Corporation
Cost of Capital Calculation
2011 Actual and 2012 Forecast
($000s)

Schedule 4B
April 2012

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
	2011 Preliminary Actual						
1	Long-Term debt	S.11 L.18	106,222	58.8%	105,825	3.61%	3,818
2	Common Stock	S.7 L. 8	74,471	41.2%	74,192	6.59%	4,886
3	Total	S.5 L.3	180,693	100.0%	180,017	4.84%	8,704
	Forecast for 2012 - Existing						
4	Long-Term debt	S.11 L.18	133,177	64.3%	142,655	3.40%	4,844
5	Common Stock	S.7 L. 8	73,975	35.7%	79,240	4.38%	3,470
6	Total	S.5 L.3	207,153	100.0%	221,895	3.75%	8,313
	Proposed 2012 - GRA						
7	Long-Term debt	S.11 L.18	133,821	64.3%	143,329	3.38%	4,843
8	Common Stock	S.7 L. 8	74,405	35.7%	79,691	8.77%	6,988
9	Total	S.5 L.3	208,226	100.0%	223,020	5.31%	11,832

Yukon Energy Corporation
Cost of Capital Calculation
2013 Forecast
($000s)

Schedule 4C
April 2012

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
	Forecast for 2013 - Existing						
1	Long-Term debt	S.11 L.18	142,807	68.5%	163,176	3.91%	6,380
2	Common Stock	S.7 L. 8	65,585	31.5%	74,939	-0.97%	-730
3	Total	S.5 L.3	208,392	100.0%	238,115	2.37%	5,650
	Proposed 2013 - GRA						
4	Long-Term debt	S.11 L.18	144,993	68.4%	165,305	3.90%	6,440
5	Common Stock	S.7 L. 8	67,042	31.6%	76,433	8.77%	6,703
6	Total	S.5 L.3	212,035	100.0%	241,738	5.44%	13,143

Yukon Energy Corporation
Utility Revenue Requirement
($000s)

Schedule 5
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Net rate base	S.1 L.30	147,967	146,381	149,235	180,017	221,895	223,020	238,115	241,738
2	Average Rate of return on rate base		7.09%	6.90%	6.82%	4.84%	3.75%	5.31%	2.37%	5.44%
3	Utility income	S.8 L.1	10,488	10,095	10,185	8,704	8,313	11,832	5,650	13,143
4	Utility expenses									
5	Operating and maintenance (note 1)	S.6 L.3	13,403	14,765	15,219	18,377	17,681	19,241	19,779	21,026
6	Taxes other than income	S.6 L.4	256	288	291	297	312	312	326	326
7	Amortization of deferred costs	S.6 L.5	1,707	1,735	1,407	1,447	3,065	3,198	5,632	4,859
8	Reserve for Injuries and Damages	S.6 L.6	100	100	100	100	100	231	100	231
9	Depreciation	S.6 L.7	6,526	7,214	7,369	7,902	11,730	8,418	12,402	8,989
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(1,361)	(2,166)	(2,116)	(2,445)	(4,803)	(3,798)	(4,852)	(3,831)
11	Disallowed depreciation		(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
12	Donations		(85)	(94)	(75)	(85)	(85)	(85)	(85)	(85)
13	Disallowed Expenses (note 2)			(224)						
14	Total utility expenses		20,544	21,614	22,191	25,590	27,996	27,513	33,299	31,511
15	Revenue Requirement	S.6 L.1	31,031	31,708	32,376	34,294	36,309	39,344	38,949	44,654

Note 1: Includes fuel expenses and purchased power.
Note 2: 2009 disallowed expenses with respect to 2008/2009 GRA Cost Awards Filing (YUB 2009-11). Other disallowed expenses are included in Regulatory gain/losses (Schedule 6, Line 13).

Yukon Energy Corporation
Statement of Earnings
($000s)

Schedule 6
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Revenues (note 1)	S.5 L.17	31,031	31,708	32,376	34,294	36,402	39,857	37,956	45,641
2	**Operating expenses**									
3	Operating and maintenance	S.10 L.15	13,403	14,765	15,219	18,377	17,681	19,241	19,779	21,026
4	Taxes other than income	S.5 L.6	256	288	291	297	312	312	326	326
5	Amortize deferred costs	S.5 L.7	1,707	1,735	1,407	1,447	3,065	3,198	5,632	4,859
6	Reserve for Injuries and Damages	S.5 L.8	100	100	100	100	100	231	100	231
7	Depreciation	S.3 L.8	6,526	7,214	7,369	7,902	11,730	8,418	12,402	8,989
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(1,361)	(2,166)	(2,116)	(2,445)	(4,803)	(3,798)	(4,852)	(3,831)
9	Total		20,632	21,936	22,270	25,679	28,085	27,602	33,388	31,600
10	**Operating income**		10,399	9,773	10,106	8,615	8,317	12,255	4,569	14,041
11	**Other income**									
12	Allowed for Funds Used	S.8 L.2	798	392	514	555	500	500	500	500
13	Miscellaneous (note 2)	S.8 L.3	(155)	1,099	1,163	61	(49)	(49)	(23)	(23)
14	Total		643	1,491	1,677	616	451	451	477	477
15	**Other expenses**									
16	Interest expense	S.8 L.4	5,665	6,893	7,006	4,278	4,522	4,522	5,584	5,648
17	Total		5,665	6,893	7,006	4,278	4,522	4,522	5,584	5,648
18	**Net earnings**	S.8 L.8	5,378	4,370	4,777	4,954	4,246	8,184	- 538	8,870

Note 1: Includes revenues from sales, non-operating revenues and other revenues. 2009 revenues also include the Faro Dewatering transfer.
Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

Yukon Energy Corporation
Statement of Retained Earnings
($000s)

Schedule 7
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Balance at beginning of year		22,048	21,536	21,943	26,720	29,621	29,621	11,129	11,988
	Add:									
2	Net earnings	S.6 L.18	5,378	4,370	4,777	4,954	4,246	8,184	(538)	8,870
3			27,426	25,906	26,720	31,674	4,246	8,184	10,593	20,859
	Less:									
4	Common Dividends/(Injection) (note 1)		4,704	3,963	-	2,053	(6,883)	(3,804)	(2,247)	5,964
5	Balance at end of year		22,722	21,943	26,720	29,621	11,129	11,988	12,840	14,895
	Shareholder's Equity									
6	Common shares		39,000	39,000	39,000	53,600	53,600	53,600	53,600	53,600
7	Retained earnings		22,722	21,943	26,720	29,621	11,129	11,988	12,840	14,895
8	Total		61,722	60,943	65,720	83,221	64,729	65,588	66,440	68,495

Note:
1. YDC equity injection required in order to maintain 60/40 debt to equity ratio.

Yukon Energy Corporation
Reconciliation of Utility Income to Net Earnings
($000s)

Schedule 8
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Utility Income (Return on Rate Base)	S.5 L.3	10,488	10,095	10,185	8,704	8,313	11,832	5,650	13,143
	Add:									
2	Allowance for funds used	S.6 L.13	798	392	514	555	500	500	500	500
3	Other income (expenses)	S.6 L.14	(155)	1,099	1,163	61	(49)	(49)	(23)	(23)
			11,131	11,585	11,862	9,320	8,764	12,282	6,127	13,620
	Less:									
4	Interest - long-term	S.6 L.17	5,665	6,893	7,006	4,278	4,522	4,522	5,584	5,648
5	Donations	S.5 L.12	85	94	75	85	85	85	85	85
6	Disallowed costs	S.5 L.13	-	224	-	-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	4	4	4	4	4	4	4	4
			5,754	7,215	7,085	4,367	4,611	4,611	5,673	5,737
8	Net earnings	S.6 L.18	5,378	4,370	4,777	4,953	4,153	7,671	455	7,883
9	Adjustments to Net earnings (note 1)			(241)						
10	Net earnings per financial statements			4,129	4,777					

Note 1:
1. Adjustments to the net earnings reflect the impact of YUB 2009-8 ($0.375 million secondary sales revenues: decrease in 2009 and increase in 2008; $0.026 million transfer from deferred Dewatering revenues: decrease in 2009 and increase in 2008; $0.4 million rate case amortization expense: decrease in 2009 and increase in 2008; $0.05 million RFID: decrease in 2009 and increase in 2008; $0.192 million fuel cost: decrease in 2009 and increase in 2008)

Yukon Energy Corporation

Summary of Customers, Energy Sales and Revenues
($000s)

Schedule 9
April 2012

Line No.	Description	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Proposed 2012	Proposed 2013
1	**Residential**						
2	Customers	1,432	1,457	1,472	1,515	1,526	1,536
3	Sales in MWh	11,183	11,676	11,386	12,710	12,325	12,408
4	MWh sales per customer	8	8	8	8	8	8
5	Revenue ($000s)	1,335	1,386	1,359	1,694	1,803	1,815
6	Cents per KWh	11.94	11.87	11.94	13.33	14.63	14.63
7	**General Service**						
8	Customers	457	442	455	464	460	467
9	Sales in MWh	19,543	19,672	22,719	21,305	21,693	22,620
10	MWh sales per customer	43	45	50	46	47	48
11	Revenue ($000s)	2,637	2,696	2,942	3,218	3,582	3,735
12	Cents per KWh	13.49	13.70	12.95	15.10	16.51	16.51
13	**Industrial**						
14	Sales in MWh	29,023	29,355	30,255	43,259	52,309	62,364
15	Revenue ($000s)	3,203	3,190	3,311	4,599	6,179	7,383
16	Cents per KWh	11	11	11	11	12	11.84
17	**Street lights**						
18	Sales in MWh	278	496	283	283	279	279
19	Revenue ($000s)	71	60	74	82	88	88
20	Cents per KWh	25.63	12.07	26.26	29.02	31.55	31.55
21	**Space lights**						
22	Sales in MWh	15	26	14	14	15	15
23	Revenue ($000s)	3	3	3	3	4	4
24	Cents per KWh	21.54	12.03	21.73	23.96	26.76	26.76
25	**Total Company - Firm Retail and Industrial**						
26	Customers	1,889	1,899	1,927	1,979	1,986	2,003
27	Sales in MWh	60,042	61,225	64,658	77,571	86,621	97,685
28	Revenue ($000s)	7,249	7,335	7,689	9,596	11,656	13,025
29	Cents per KWh	12.07	11.98	11.89	12.37	13.46	13.33
30	**Wholesale sales**						
31	Sales in MWh	267,747	267,229	276,345	290,541	296,000	298,228
32	Revenue ($000s)	18,314	18,279	18,902	21,940	24,562	24,747
33	Cents per KWh	6.84	6.84	6.84	7.55	8.30	8.30
34	**Total Company - Firm**						
35	Sales in MWh	327,789	328,455	341,003	368,112	382,621	395,913
36	Revenue ($000s)	25,563	25,613	26,591	31,535	36,218	37,772
37	Cents per KWh	7.80	7.80	7.80	8.57	9.47	9.54
38	**Secondary**						
39	Sales in MWh	7,584	17,384	10,489	552	0	0
40	Revenue ($000s)	470	1,066	644	46	0	0
41	Cents per KWh	6.20	6.13	6.14	8.30		
42	**Total Company**						
43	Sales in MWh	335,373	345,839	351,492	368,665	382,621	395,913
44	Revenue ($000s)	26,033	26,679	27,234	31,581	36,218	37,772
45	Cents per KWh	7.76	7.71	7.75	8.57	9.47	9.54
46	Rider J	4,518	4,493	4,944	2,466		
47	Post-GRA Reconcil Req'd	355	355				
48	GRA Increase Req'd					3,455	7,685
49	Total Sales of Power	30,906	31,527	32,178	34,047	39,673	45,457
50	Other Revenues	125	181	198	247	184	184
51	Total Revenues	31,031	31,708	32,376	34,294	39,857	45,641

Yukon Energy Corporation
Summary of Operating and Maintenance Expenses
($000s)

Schedule 10
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	**Utility operations**									
2	Production		2,977	3,759	4,179	4,472	4,452	4,452	4,494	4,494
3	Transmission and distribution		1,793	1,868	1,383	1,767	1,970	1,970	2,112	2,112
4	General		952	1,145	1,194	1,336	1,339	1,339	1,405	1,405
5	Administration and general		6,148	6,453	6,418	7,197	8,357	8,357	8,923	8,923
6	Insurance		952	787	787	774	835	835	895	895
7	Sub-total		12,822	14,012	13,962	15,547	16,953	16,953	17,828	17,828
8	Donations		85	94	75	85	85	85	85	85
9	Sub-total		85	94	75	85	85	85	85	85
10	O&M not including fuel and									
11	purchased power		12,907	14,106	14,037	15,632	17,038	17,038	17,913	17,913
12	Fuel		443	622	1,145	2,708	602	2,163	1,826	3,073
13	Purchased power		54	36	38	38	40	40	40	40
14	Sub-total		497	658	1,183	2,746	642	2,203	1,866	3,113
15	Total operating and maintenance	S.6 L.3	13,403	14,764	15,220	18,377	17,681	19,241	19,779	21,026
	Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:									
16	*Reserve for Injuries and Damages*		*100*	*100*	*100*	*100*	*100*	*231*	*100*	*231*
17	*Property Taxes*		*256*	*288*	*291*	*297*	*312*	*312*	*326*	*326*
18	*less: Donations*		*-85*	*-94*	*-75*	*-85*	*-85*	*-85*	*-85*	*-85*
19	*O&M per Table 3.3 (Tab 3)*		*13,178*	*14,401*	*14,353*	*15,943*	*17,365*	*17,496*	*18,254*	*18,385*

Note: 2009 actuals reflect the impact of YUB Order 2009-8 (Note 1, Schedule 8).

Yukon Energy Corporation
Summary of Cost of Long - Term Debt
($000s)

Schedule 11
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
	General Purpose Long-Term Debt Balance									
1	Canada Flexible Term Note		25,126	25,111	24,111					
2	TD Canada Trust		6,471	6,471	5,724	4,891	3,938	3,938	2,945	2,945
3	YDC Loan					78,891	75,891	75,891	72,891	72,891
4	Mayo B Flexible Term Note					21,900	21,563	21,563	21,226	21,226
5	New YDC Loan					19,148	18,510	18,510	17,871	17,871
6	New YDC Loan						21,623	22,911	20,902	22,147
7	New YDC Loan								8,254	10,093
8	YDC Loan #12 (5.88%)		22,493	22,493	20,887					
9	YDC Loan #13 (6.03%)		3,649	3,649	3,649					
10	YDC Loan #14 (5.40%)		2,841	2,839	2,839					
11	YDC Mayo-Dawson Note (6.55%)		15,157	15,157	14,707					
12	YDC Loan #15 (5.34%)		3,585	3,583	3,583					
13	YDC Loan #16 (5.28%)		4,251	4,251	4,251					
14	YDC Loan #17 (5.28%)		4,304	3,901	3,901					
15	YDC Loan #18 (5.28%)		4,704	3,963	3,963					
16	Current year-end balance		92,581	91,418	87,614	124,830	141,525	142,813	144,090	147,174
17	Previous year-end balance		91,602	91,159	91,418	87,614	124,830	124,830	141,525	142,813
18	Mid Year		92,092	91,289	89,516	106,222	133,177	133,821	142,807	144,993
	Interest Costs									
19	Canada Flexible Term Note		1,726	1,742	1,758					
20	TD Canada Trust		535	535	479	371	180	180	140	140
21	YDC Loan					3,461	3,371	3,371	3,225	3,225
22	Mayo B Flexible Term Note						11	11	212	212
23	New YDC Loan						960	960	925	925
24	New YDC Loan								1,081	1,146
25	New YDC Loan									
26	YDC Loan #12 (5.88%)		1,393	1,382	1,277					
27	YDC Loan #13 (6.03%)		220	220	220					
28	YDC Loan #14 (5.40%)		153	153	153					
29	YDC Mayo-Dawson Note (6.55%)		1,022	1,022	993					
30	YDC Loan #15 (5.34%)		191	191	191					
31	YDC Loan #16 (5.28%)		224	224	224					
32	YDC Loan #17 (5.28%)		200	206	206					
33	YDC Loan #18 (5.28%)				209					
34	Minto Diesel		155							
35	**Total Cost of Interest**		5,820	5,675	5,710	3,833	4,522	4,522	5,584	5,648
36	Mid-Year Cost of Debt		6.15%	6.22%	6.38%	3.61%	3.40%	3.38%	3.91%	3.90%

TOPIC: Forecast Cost of Debt

REFERENCE: Application Tab 7, Schedule 11, page 7-15

YEC provides the following table:

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
	General Purpose Long-Term Debt Balance									
1	Canada Flexible Term Note		25,126	25,111	24,111					
2	TD Canada Trust		6,471	6,471	5,724	4,891	3,938	3,938	2,945	2,945
3	YDC Loan			59,836	57,779	78,891	75,891	75,891	72,891	72,891
4	Mayo B Flexible Term Note					21,900	21,563	21,563	21,226	21,226
5	New YDC Loan					19,148	18,510	18,510	17,871	17,871
6	New YDC Loan						21,623	22,911	20,902	22,147
7	New YDC Loan								8,254	10,093
8	YDC Loan #12 (5.88%)		22,493							
9	YDC Loan #13 (6.03%)		3,649							
10	YDC Loan #14 (5.40%)		2,841							
11	YDC Mayo-Dawson Note (6.55%)		15,157							
12	YDC Loan #15 (5.34%)		3,585							
13	YDC Loan #16 (5.28%)		4,251							
14	YDC Loan #17 (5.28%)		4,304							
15	YDC Loan #18 (5.28%)		4,704							
16	Current year-end balance		92,581	91,418	87,614	124,830	141,525	142,813	144,090	147,174
17	Previous year-end balance		91,602	91,159	91,418	87,614	124,830	124,830	141,525	142,813
18	Mid Year		92,092	91,288	89,516	106,222	133,177	133,821	142,807	144,993
	Interest Costs									
19	Canada Flexible Term Note		1,726	1,742	1,758					
20	TD Canada Trust		535	535	479	371	180	180	140	140
21	YDC Loan			3,398	3,473	3,461	3,371	3,371	3,225	3,225
22	Mayo B Flexible Term Note						11	11	212	212
23	New YDC Loan						960	960	925	925
24	New YDC Loan								1,081	1,146
25	New YDC Loan									
26	YDC Loan #12 (5.88%)		1,393							
27	YDC Loan #13 (6.03%)		220							
28	YDC Loan #14 (5.40%)		153							
29	YDC Mayo-Dawson Note (6.55%)		1,022							
30	YDC Loan #15 (5.34%)		191							
31	YDC Loan #16 (5.28%)		224							
32	YDC Loan #17 (5.28%)		200							
33	YDC Loan #18 (5.28%)									
34	Minto Diesel		155							
35	**Total Cost of Interest**		5,820	5,675	5,710	3,833	4,522	4,522	5,584	5,648
36	Mid-Year Cost of Debt		6.15%	6.22%	6.38%	3.61%	3.40%	3.38%	3.91%	3.90%

PREAMBLE:

The City wishes to examine YEC's debt costs.

QUESTION:

a) Have YDC Loans #12 through #18 (lines 8-15) been merged into one loan (line 3) by the YDC? If yes, what is the rate of the consolidated loan? If not, please redo Schedule 11 showing each debt issue separately with its corresponding year-end balance and yearly cost of interest.

b) Has the Canada Flexible Term Note (line 1) been merged into the YDC loan (line 3) for 2012 and beyond? If yes, please explain.

c) Why are different amounts shown for existing 2012 and forecast 2012 YDC New Loan?

d) Why are different amounts shown for existing 2013 and forecast 2013 YDC New Loan?

e) What is the timing of the forecast new loans from YDC and how have YEC and YDC forecast the cost of these new issues?

ANSWER:

(a) and **(b)**

In January 2011 Canada Flex Term Note with outstanding balance of $24.111 million (Schedule 11, line 1) and Yukon Development Corporation's (YDC) Flexible Promissory Note for Mayo-Dawson with outstanding balance of $14.707 million (Schedule 11, line 11), YDC's term note with outstanding balance of $20.887 million (Schedule 11, line 8) and YDC's unsecured advances with outstanding balance of $22.186 million (Schedule 11, lines 9,10,12-15) were refinanced through YDC's $81.891 million new long-term debt. The interest rate for this $81.891 million long-term debt is 4.25% and it is estimated to reduce the interest payments by approximately $1.6 million in 2011 and by approximately $1.5 million in both test years.

Please see Table 1 below for the revised Schedule 11 that shows YDC's refinanced long-term debts with corresponding year end balances and interest expenses separately for 2009 and 2010.

Table 1:
Yukon Energy Corporation
Summary of Costs of Long-term Debt
($000s)

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
	General Purpose Long-Term Debt Balance									
1	Canada Flexible Term Note		25,126	25,111	24,111					
2	TD Canada Trust		6,471	6,471	5,724	4,891	3,938	3,938	2,945	2,945
3	YDC Loan					78,891	75,891	75,891	72,891	72,891
4	Mayo B Flexible Term Note					21,900	21,563	21,563	21,226	21,226
5	New YDC Loan					19,148	18,510	18,510	17,871	17,871
6	New YDC Loan						21,623	22,911	20,902	22,147
7	New YDC Loan								8,254	10,093
8	YDC Loan #12 (5.88%)		22,493	22,493	20,887					
9	YDC Loan #13 (6.03%)		3,649	3,649	3,649					
10	YDC Loan #14 (5.40%)		2,841	2,839	2,839					
11	YDC Mayo-Dawson Note (6.55%)		15,157	15,157	14,707					
12	YDC Loan #15 (5.34%)		3,585	3,583	3,583					
13	YDC Loan #16 (5.28%)		4,251	4,251	4,251					
14	YDC Loan #17 (5.28%)[1]		4,304	3,901	3,901					
15	YDC Loan #18 (5.28%)		4,704	3,963	3,963					
16	Current year-end balance		92,581	91,418	87,614	124,830	141,525	142,813	144,090	147,174
17	Previous year-end balance		91,602	91,159	91,418	87,614	124,830	124,830	141,525	142,813
18	Mid Year		92,092	91,289	89,516	106,222	133,177	133,821	142,807	144,993
	Interest Costs									
19	Canada Flexible Term Note		1,726	1,742	1,758					
20	TD Canada Trust		535	535	479	371	180	180	140	140
21	YDC Loan					3,461	3,371	3,371	3,225	3,225
22	Mayo B Flexible Term Note						11	11	212	212
23	New YDC Loan						960	960	925	925
24	New YDC Loan								1,081	1,146
25	New YDC Loan									
26	YDC Loan #12 (5.88%)		1,393	1,382	1,277					
27	YDC Loan #13 (6.03%)		220	220	220					
28	YDC Loan #14 (5.40%)		153	153	153					
29	YDC Mayo-Dawson Note (6.55%)		1,022	1,022	993					
30	YDC Loan #15 (5.34%)		191	191	191					
31	YDC Loan #16 (5.28%)		224	224	224					
32	YDC Loan #17 (5.28%)[1]		200	206	206					
33	YDC Loan #18 (5.28%)				209					
34	Minto Diesel		155							
35	**Total Cost of Interest**		5,820	5,675	5,710	3,833	4,522	4,522	5,584	5,648
36	Mid-Year Cost of Debt		6.15%	6.22%	6.38%	3.61%	3.40%	3.38%	3.91%	3.90%

Note:
1. The interest rate of 5.28% is for column "2009 Approved", 2009-2010 actual interest rate is 4.65%.

(c) and **(d)**

The new long-term debts for the test years are required to maintain 60% debt and 40% equity ratio based on year end balances of the YEC's rate base. The new long-term debt requirement forecasts under "Proposed 2012" and "Proposed 2013" are calculated based on 2012/13 GRA Application proposed changes, which includes proposed rate increases, proposed Planning Study Policy as well as a placeholder regulatory cost of

$1.1 million for Phase I GRA review. The new long-term debt requirement forecasts under “Existing 2012” and “Existing 2013” are calculated based on existing rates, and do not consider any changes in Planning Study Policy and regulatory cost assumptions. These two scenarios (with GRA versus without GRA) result in slightly different rate base values, and consequently slightly different borrowing requirements to reach 60% of rate base.

(e)

Forecast new loans are assumed to be issued in the respective forecast years in order to maintain 60% debt and 40% equity ratio based on year-end ratebase. Financing cost of these new debts is estimated at 5% annual interest rate assuming the new-long term debt is secured in the end of the forecast year.

It is important to note that while the new debt is titled as “YDC Loan”, YDC finances YEC’s new long-term debt only if such funds are available from YDC. If no such funds are available from YDC to finance 2012 and 2013 forecast long-term debts, then YEC will seek funding through the financial markets.

TOPIC: **Risk**

REFERENCE: **Application page 8-1, lines 11-14 and Schedule 4B, page 7-7**

YEC states:

> **In past General Rate Applications (GRA), including the 1996/97 GRA, Yukon Energy's allowed return on equity (ROE) has been set by the Board based on being 0.5% below the ROE awarded for Yukon Electrical (YECL), notwithstanding that Yukon Energy as a generation utility would typically be understood to face considerably higher risk levels than Yukon Electrical with its focus on distribution.**

PREAMBLE:

The City wishes to understand YEC's discussion of risk.

QUESTION:

a) Please provide supporting materials or precedents for YEC's submission that "Yukon Energy as a generation utility would typically be understood to face considerably higher risk levels than Yukon Electrical with its focus on distribution."

b) Is YEC a transmission utility as well as a generation utility? If yes, please provide any materials or precedents that would aid the Board in evaluating the risks of a transmission utility relative to generation and distribution utility.

c) Is YEC a distribution utility as well as a generation utility?

d) In Schedule 4B, YEC forecasts a 40% equity ratio. Is this equity ratio commensurate with YEC's perceived risk of itself as a generation-only utility?

ANSWER:

(a) through **(c)**

YEC's method for developing a proposed ROE has been designed to minimize the regulatory burden and expense for Yukon ratepayers associated with preparing and testing ROE evidence at each rate hearing.

YEC is a vertically integrated utility with generation, transmission and distribution functions. As a result, YEC has a wider range of operating risks than a utility that provides primarily distribution-related functions.

(d)

YEC is not a "generation-only" utility, but a vertically integrated utility providing generation, transmission and distribution functions.

As stated in YEC's 2005 Revenue Requirement and Related Matters in YUB-YEC-1-39.4:

"The establishment of an appropriate mix of debt and equity for Yukon Energy is based on a past assessment (a 1990 RBC Dominion Securities review) that indicated the utility can maintain no lower than 40% equity to maintain what would be viewed by the markets as an investment-grade rating. Any increase in equity ratio for Yukon Energy has routinely been viewed by the company, intervenors and the YUB as resulting in a higher overall revenue requirement."

TOPIC: **Return on Equity**

REFERENCE: **Application page 8-2, lines 16-24**

YEC states:

> **Since 2009, there has been a material shift in how return on equity is determined in British Columbia. In effect, the Terasen ROE decision (Order G-158-09) eliminated the automatic adjustment mechanism and ordered Terasen Gas Inc[3] to complete a study of alternative formulae for an automatic adjustment mechanism and report results to the BCUC by December 31, 2010[4]. However, the BCUC determined that the 2009 approved ROE for Terasen (9.5%) may continue to be used as the Benchmark ROE in establishing the ROE for rate-setting purposes for other BC utilities[5]. BC utilities continue to reference this benchmark and apply utility-specific risk premiums as approved by the BCUC. The BCUC has recently initiated a generic cost of capital proceeding; however, an up-to-date low risk benchmark is not expected before the end of 2012[6].**

PREAMBLE:

The City wishes to understand the BCUC's determinations.

QUESTION:

a) Please provide Order G-158-09.

b) Has Terasen completed its study of alternative ROE formulae? If yes, please provide.

c) What are the "other utilities" referenced in footnote 5? What equity ratios did the BCUC allow these utilities listed in footnote 6? What were the utilities' actual equity ratios since Order G-158-09?

d) What utility-specific risk premiums has the BCUC applied to the utilities listed in footnote 6 since Order G-158-09?

ANSWER:

(a)

Please see Attachment 1 of this response.

(b)

Terasen Utilities filed their study on ROE alternative formulae with the British Columbia Utilities Commission on December 8, 2010. The report is posted as Exhibit A2-2 as part of the record in the BCUC Generic Cost of Capital Proceeding and can be found at the following link: http://www.bcuc.com/ApplicationView.aspx?ApplicationId=338.

(c)

In BCUC Order G-158-09, 'other utilities' refers to "Fortis BC and any other utility in British Columbia that uses the Benchmark ROE to set rates"[1]. Utilities reviewed by Yukon Energy in addition to FortisBC Energy Inc. [formerly Terasen Gas Inc.] include:

- FortisBC Inc.;
- FortisBC Energy (Vancouver Island) Inc. [formerly Terasen Gas (Vancouver Island) Inc]; and
- FortisBC Energy (and FortisBC Energy (Whistler) Inc. [formerly Terasen Gas (Whistler) Inc].

With respect to the equity ratios allowed by the BCUC for these utilities, YEC can provide the following information:

- FortisBC Inc.'s allowed equity ratio of 40 percent was reviewed and confirmed during the BCUC's review of FortisBC Inc's 2012-2013 Revenue Requirements and Review of the 2012 Integrated System Plan proceeding (Order G-199-11).

[1] See Order G-158-09, pg. 3.

FortisBC Inc.'s ROE and equity ratio are subject to review during the Generic Cost of Capital Hearing scheduled for later in 2012[2].

- An equity ratio of 40 percent for FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. was last approved in Order G-158-09[3].

With respect to the actual equity ratios of these utilities, Yukon Energy did not review the actual equity ratios of these utilities in developing its ROE proposal for the 2012-2013 General Rate Application. Therefore, Yukon Energy cannot provide the requested information.

(d)

YEC can provide the following information on risk premium adjustments set by the Commission:

- FortisBC Inc.'s ROE is based on the benchmark utility's allowed return and a risk premium of 40 basis points as per Order G-199-11.

- In Order G-158-09, the BCUC determined that Terason Gas Inc (now Fortis BC Energy Inc.) should continue to be used as a benchmark for all utilities that calculate return on equity using the benchmarking method. Upon review, the following risk premium adjustments were determined in Order G-158-09:
  - Terasen Gas (Vancouver Island) Inc.'s risk premium was reduced from 70 basis points down to 50 basis points.
  - The risk premium for Terason Gas (Whistler) Inc. remained at 50 basis points on the benchmark.

[2] On November 28, 2011, the Commission issued a letter expressing its intent to conduct a Generic Cost of Capital Hearing focused on capital structure and ROE, which would apply to all utilities. The Commission concluded that it would be appropriate to maintain the previously approved ROE of 9.9% and capital structure (40% equity) pending determinations made in the Generic Cost of Capital Hearing (see Appendix B to Order G-199-11).

[3] In the 2012-2013 Revenue Requirements proceeding, the FortisBC Utilities requested a delay in filing of ROE and capital structure evidence until after amalgamation. In response to BCUC information request BCUC 1.10.8-2, FortisBC Utilities expressed its intent to file evidence with respect to ROE for the amalgamated entity in the Amalgamation and Rate Design Phase 'A' application; proceedings scheduled to be completed Fall 2012. In the interim, respective ROE and equity ratios would remain in place.

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-158-09

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by
Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and
Terasen Gas (Whistler) Inc. ("TGW") (collectively the "Terasen Utilities")
for Return on Equity and Capital Structure

BEFORE: A.J. Pullman, Panel Chair
D.A. Cote, Commissioner
M.R. Harle, Commissioner

December 16, 2009

O R D E R

WHEREAS:

A. By letter dated May 15, 2009, the Terasen Utilities filed with the British Columbia Utilities Commission (the "Commission") pursuant to sections 59 and 60 of the *Utilities Commission Act* (the "*Act*"), an application for Return on Equity and Capital Structure (the "Application"); and

B. TGI applied for an increased Return on Equity ("ROE") for rate-setting purposes, and that the so determined ROE for TGI be used in establishing the ROE of TGVI and TGW used for rate-setting. The Application requests that the revised ROE be effective from July 1, 2009. In addition TGI applied for an increase of the equity ratio in its Capital Structure to 40 percent effective January 1, 2010. Terasen Utilities further requested that the Commission set their current rates as interim, effective July 1, 2009, until such time as permanent rates were established; and

C. By Order G-53-09 dated May 21, 2009, the Commission established a Procedural Conference to take place on June 9, 2009 to hear submissions regarding the regulatory process for the review of the Application; and

D. Further to the Procedural Conference, the Commission issued Order G-70-09 dated June 9, 2009 which established a Regulatory Timetable for an Oral Hearing Process as well as a schedule for written argument to hear submissions from the Parties on the subject of the request for interim rates; and

E. By Order G-78-09 dated June 24, 2009, the Commission ordered, with Reasons for Decision attached as Appendix A to the Order, that the current rates of TGI and TGW be set as interim effective July 1, 2009 and that the changes to the allowed ROE from this proceeding be treated as changes to TGVI's cost of service, effective July 1, 2009; and

F. The Oral Hearing took place from September 28, 2009 to October 1, 2009. The following Intervenors took an active role in the proceedings, filed written argument or took part in the Oral Phase of Argument; the British Columbia Old Age Pensioners' Organization *et al.* ("BCOAPO"), the Commercial Energy Consumers of British Columbia ("CEC"), FortisBC Inc. ("FortisBC"), Pacific Natural Gas Ltd. ("PNG"), the Joint Industry Electricity Steering Committee ("JIESC") and the Industrial Customer Group ("ICG"); and

G. The schedule of written Argument provided for Final Submissions to be filed as follows: i) Terasen Utilities, FortisBC and PNG on or before October 20, 2009; ii) Intervenors on or before November 6, 2009; and iii) Reply from Terasen Utilities, FortisBC and PNG on or before November 13, 2009; and

H. An Oral Phase of Argument was held on November 24, 2009; and

I. The Commission Panel has considered the Application, the evidence, and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. The appropriate equity ratio for TGI is 40 percent effective January 1, 2010.

2. TGI is to file within 30 days a document setting out how and when it will implement the change to its capital structure in compliance with the ring-fencing conditions approved by Commission Order G-49-07.

3. A return on equity for TGI of 9.50 percent for rate-setting purposes is approved effective July 1, 2009.

4. The TGI ROE approved in paragraph 3 of this Order is to be used as the Benchmark ROE in establishing the return on equity of TGVI and TGW used for rate-setting purposes and the allowed return on equity for TGVI and TGW is effective July 1, 2009.

5. TGVI's request to continue to set its allowed return on equity with reference to the Benchmark ROE by adding a utility specific risk premium of 70 basis points is denied. TGVI is allowed a utility specific risk premium of 50 basis points above the Benchmark ROE.

6. TGW's request to continue to set its allowed return on equity with reference to the Benchmark ROE by adding a utility specific risk premium of 50 basis points is approved.

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-158-09

7. TGVI and TGW are to file in their respective next revenue requirement applications evidence on the equity component that best reflects their respective long-term business risks.

8. The TGI ROE approved in paragraph 3 of this Order can continue to serve as the Benchmark ROE for FortisBC and any other utility in British Columbia that uses a Benchmark ROE to set rates.

9. The automatic adjustment mechanism is eliminated.

10. TGI is to complete its study of alternative formulae to an automatic adjustment mechanism and report to the Commission on the study results by December 31, 2010.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of December, 2009

BY ORDER

Original signed by:

A.J. Pullman
Panel Chair and Commissioner

TOPIC: **Return on Equity**

REFERENCE: **Application page 8-3, lines 15-20**

YEC states:

> **Yukon Energy has reviewed recent ROE decisions from other jurisdictions. Based on this review, the Application proposes to use the most recent low risk utility benchmark ROE established in Canada set by the Alberta Utilities Commission (AUC) in December 2011 (Decision 2011-474[8]) in order to determine a fair ROE for the test years. This would modify the benchmarking approach used since 1998 by referencing the Alberta Utilities Commission generic ROE rather than the BCUC generic ROE before applying the previously approved utility-specific risk premium of 52 basis points[9].**

PREAMBLE:

The City wishes to understand YEC's use of the Alberta benchmark

QUESTION:

a) Please provide a table of the benchmark ROEs, associated allowed equity ratios for each utility regulated by that jurisdiction and any adjustment mechanism for each jurisdiction examined by YEC.

b) What were the resultant ROEs for each jurisdiction examined in a) for the 2009-2012 period and 2013, if available?

c) Please provide YEC's reasons for choosing the AUC's benchmark ROE over other jurisdictions reviewed.

d) Please summarize the method employed by the AUC in Decision 2011-474 to determine a fair return to a utility.

e) Did the AUC, in Decision 2011-474, employ utility-specific risk premiums to the utilities under its jurisdiction? If yes, what utility-specific risk premiums were applied to each utility?

f) Did the AUC determine or provide an adjustment mechanism for a 2013 benchmark return on equity in Decision 2011-474?

ANSWER:

(a)

See Table 1 for 2011-2012 approved ROEs and equity ratios for AUC-regulated utilities.

Table 1:
2011-2012 Approved ROE and Equity Ratios for Jurisdictions Reviewed by Yukon Energy

	Most Recent ROE & Equity Ratio				2009-2013 Approved ROE				
Jurisdiction / Utility	**Year of Decision**	**Benchmark ROE**	**Utility-specific Risk Premium**	**Approved Equity Ratio**	**2009**	**2010**	**2011**	**2012**	**2013**
British Columbia Utilities Commission									
FortisBC Energy Inc.	2009	9.50%	-	40%	9.50%	9.50%	9.50%	9.50%	-
FortisBC Inc.	2011		0.40%	40%	9.90%	9.90%	9.90%	9.90%	-
FortisBC Energy (Vancouver Island) Inc.	2009		0.50%	40%	10.00%	10.00%	10.00%	10.00%	-
FortisBC Energy (Whistler) Inc.	2009		0.50%	40%	10.00%	10.00%	10.00%	10.00%	-
Alberta Utilities Commission									
Generic return on equity	2011	8.75%	-	37-45	9.00%	9.00%	8.75%	8.75%	8.75%
ATCO Electric TFO	2011		-	37	9.00%	9.00%	8.75%	8.75%	8.75%
AltaLink	2011		-	37	9.00%	9.00%	8.75%	8.75%	8.75%
ENMAX TFO	2011		-	37	9.00%	9.00%	8.75%	8.75%	8.75%
EPCOR TFO	2011		-	37	9.00%	9.00%	8.75%	8.75%	8.75%
RED Deer TFO	2011		-	37	9.00%	9.00%	8.75%	8.75%	8.75%
Lethbridge TFO	2011		-	37	9.00%	9.00%	8.75%	8.75%	8.75%
TransAlta	2011		-	36	9.00%	9.00%	8.75%	8.75%	8.75%
ATCO Pipelines	2011		-	45	9.00%	9.00%	8.75%	8.75%	8.75%
ATCO Pipelines	2011		-	38	9.00%	9.00%	8.75%	8.75%	8.75%
ATCO Electric DISCO	2011		-	39	9.00%	9.00%	8.75%	8.75%	8.75%
ENMAX DISCO	2011		-	41	9.00%	9.00%	8.75%	8.75%	8.75%
EPCOR DISCO	2011		-	41	9.00%	9.00%	8.75%	8.75%	8.75%
ATCO Gas	2011		-	39	9.00%	9.00%	8.75%	8.75%	8.75%
FortisAlberta	2011		-	41	9.00%	9.00%	8.75%	8.75%	8.75%
AltaGas	2011		-	43	9.00%	9.00%	8.75%	8.75%	8.75%
National Energy Board									
Discontinued RH-2-94 formula	2011	8.08%	-	-	8.57%	8.52%	8.08%	7.58%	-
Northland Utilities Ltd.									
NUL (YK)	2011		-	43.5	9.10%	9.10%	9.30%	9.30%	9.30%
NUL (NWT)	2011		-	44	9.10%	9.10%	9.30%	9.30%	9.30%
Ontario Energy Board									
Formulaic benchmark approach	2011	9.42%	-	-	8.57%	8.57%	9.43%	9.42%	-

Note

note 1 FortisBC Energy Inc. as per British Columbia Utilities Commission Order G-158-09; dated December 16, 2009

note 2 FortisBC Inc. as per British Columbia Utilities Commission Order G-199-11; dated November 3, 2011.

note 3 FortisBC Energy (Vancouver Island) Inc. as per British Columbia Utilities Commission Order G-158-09; dated December 16, 2009.

note 4 FortisBC Energy (Whistler) Inc as per British Columbia Utilities Commission Order G-158-09; dated December 16, 2009.

note 5 Alberta Utilities Commission per AUC Decision 2011-474; dated December 8, 2011.

note 6 National Energy Board per Rate of Return on Common Equity (ROE) per Discontinued RH-2-94 Formula annual publication. The NEB will continue to provide a ROE using the discounted RH-2-94 formulaic approach for the convenience of parties until 2014.

note 7 NUL (YK) as per NWT Public Utilities Board Decision 13-2011; dated August 26, 2011

note 8 NUL (NWT) as per NWT Public Utilities Board Decision 17-2011; dated November 14, 2011

note 9 Ontario Energy Board publishes the determined cost of capital parameters annually. The 2012 ROE was set at 9.42% in a letter dated November 10, 2011 (effective January 1, 2012) and later revised the ROE to 9.12% in a letter dated March 2, 2012 (effective May 1, 2012).

The following adjustment mechanisms were set by jurisdictions reviewed by YEC in Table 2.

Table 2:
Adjustment Mechanisms by Jurisdiction

Jurisdiction	Adjustment Mechanism(s)
Alberta Utilities Commission	The AUC established a generic rate of return on equity that is applied to all utilities. The AUC approved a risk-free ROE of 8.75% for 2011 and 2012, and on an interim basis for 2013[1]. Adjustments are made to capital structures to account for differences in risk among individual utilities (see Table 1).
British Columbia Utilities Commission	The BCUC first determines an allowed ROE for a benchmark utility (Terasen Gas Inc.). Approved ROEs for utilities with higher business risks calculated based on an adjustment (or adder) to the benchmark utility ROE. The following adjustments were made to utilities reviewed by YEC: • FortisBC Inc. - apply 40 basis point adder to the benchmark ROE[2]. • FortisBC Energy (VI) Inc.[3] - apply 50 basis point adder to the benchmark ROE. • Fortis Energy (W) Inc.[4] - apply 50 basis point adder to the benchmark ROE.
National Energy Board	The NEB publishes a benchmark return on common equity on an annual basis, using the discontinued RH-2-94 formulaic approach. The NEB states in its 2012 Rate of Return on Common Equity per Discontinued RH-2-94 Formula update that the Board would continue to *"publish the ROE results pursuant to the discontinued RH-2-94 Formula for calendar years until 2014 unless parties ask the Board to extend this practice further."*[5,6] On December 2, 2011, the NEB published a 2012 return on equity of 7.58% per its discontinued RH-2-94 Formula[7].

[1] As per Decision 2011-474, Alberta Utilities Board 2011 Generic Cost of Capital; dated December 8, 2011.
[2] As per Order G-199-11; British Columbia Utilities Commission; dated.
[3] As per Order G-158-09; British Columbia Utilities Commission; dated.
[4] Ibid.
[5] As per 2012 Rate of Return on Common Equity per Discontinued RH-2-94 Formula update; National Energy Board; dated December 2, 2011.
[6] In 2009, some settlements between pipeline companies and shippers referenced the ROE generated by the RH-2-94 Decision. The NEB will continue to publish a benchmark ROE using the discontinued formula until 2014, and possibly longer if requested.
[7] In Decision RH-1-2008, the NEB moved away from using the RH-2-94 formulaic approach and adopted a market-based approach for Trans Quebec & Maritimes Pipeline Inc., based on an After Tax Weighted Average Cost of Capital approach.

Jurisdiction	Adjustment Mechanism(s)
NWT Public Utilities Board	YEC focused its review on Northland Utilities Ltd (Yellowknife) and Northland Utilities Ltd. (NWT). Northland Utilities Limited (NUL) filed a General Rate Application to the Northwest Territories Public Utilities Board (PUB) on April 21, 2011 for both its Yellowknife and Northwest Territories divisions for the test years 2011 through to 2013. Northland requested that the Board set the ROE for each of the test years 2011-2013 at the percentage determined on a generic basis for all Alberta utilities for 2011, as determined in the 2011 Alberta Generic Cost of Capital Proceeding, plus a risk premium of 0.5%. In Decision 13-2011, NUL (YK) negotiated a return on equity of 9.3% for each of the 2011-2013 test years with interveners, which was approved by the Board[8]. NUL (NWT) reached a revised negotiated settlement on November 14, 2011 and was also awarded a ROE of 9.3%[9]. The utilities negotiated equity ratios of 43.5% and 44%, respectively, for each of the 2011-2013 test years.
Ontario Energy Board	The OEB continues to use a formulaic approach that was refined in 2009 to determine a fair ROE, similar to the BCUC approach. The updated cost of capital parameter for 2012 was set at 9.42% beginning January 1, 2012, but was later revised to 9.12% in a letter dated March 2, 2012[10].

(b)

Approved ROEs for the 2009-2013 period for jurisdictions reviewed by YEC are listed in Table 1 above.

(c)

During the YECL 2008/09 GRA, the BCUC method to return on equity was proposed to and ultimately accepted by the Board. In Order 2009-2, three jurisdictions were considered for use as potential benchmark ROEs – BCUC, NEB and the AUC. The

[8] As per Decision 13-2011; NWT Public Utilities Board; dated August 26, 2011.
[9] As per Decision 17-2011; NWT Public Utilities Board; dated November 14, 2011.
[10] The OEB publishes its cost of capital parameters annually. The 2012 ROE was set at 9.42% in a letter dated November 10, 2011 (effective January 1, 2012) and later revised the ROE to 9.12% in a letter dated March 2, 2012 (effective May 1, 2012).

Board concluded that the BCUC benchmark ROE was *"the most appropriate as it has been the most recently reviewed and is generally accepted by the parties.* [11]*"*
The AUC's 2011-2012 8.75% generic rate of return on equity has been proposed as a benchmark for Yukon Energy (over the previously used BCUC benchmark ROE) because at this time it is the most recently reviewed (dating from December 2011). BCUC last set their benchmark ROE in 2009, which may not reflect current market conditions. BCUC has recently initiated a generic cost of capital proceeding; however, an up to date low risk benchmark is not expected before the end of 2012.

(d)

As stated in AUC Decision 2011-474:

"*To satisfy the fair return standard, the Commission is required to determine a fair return on equity for the utilities. The Commission was again presented with a significant body of evidence on the tests to be considered when determining the fair ROE, a number of opinions on the proper methodology to be employed for many of the tests and, as a result, a wide range of proposed ROEs. Briefly, the record of the proceeding included evidence to support ROE estimates based on:*

- *Changes in the financial environment since the 2009 proceeding;*
- *The capital asset pricing model (CAPM);*
- *The discounted cash flow model (DCF) which was applied to proxy utilities as well as to the equity market overall;*
- *Other evidence on comparable investments;*
- *ROE awards by other Canadian regulators;*
- *Market price-to-book values;*
- *Returns on high grade bonds;*

[11] As per Order 2009-2, pg. 29; Yukon Utilities Board; dated February 12, 2009.

- *The return expectations from pension and investment managers; and*

- *The impact of growth on the required ROE"*[12].

In its decision the Board also wrote:

"Having considered and weighed all of the evidence and assessed it in the context of the lingering credit market volatility, and recognizing that there has been a reduction in the risk free rate of some 60 basis since 2009 by the close of the record of this proceeding, the Commission finds that some reduction in the ROE awarded in Decision 2009-216 is warranted. Accepting that some of the reduction in the risk free rate may be offset by an increase in the market equity risk premium, the Commission considers that a generic ROE of 8.75 per cent is reasonable for 2011."[13]

(e)

No. Decision 2011-474 set a ROE of 8.75% uniformly for all utilities. As stated by the Board, *"Consistent with the approach taken in the previous GCOC decision, the Commission will account for the differences in risk among the individual utilities by adjusting their capital structures"*[14].

(f)

No. As per Decision 2011-474, *"In addition, the Commission is setting the allowed ROE for 2013 at 8.75 per cent on an interim basis. The Commission will initiate a proceeding in due course to establish a final allowed ROE for 2013 and to revisit the matter of a return to a formula for setting the allowed ROE on a go forward basis"*[15].

[12] As per Decision 2011-474, pg. 4; Alberta Utilities Board 2011 Generic Cost of Capital; dated December 8, 2011 (also stated in AUC Decision 2009-2016).
[13] As per Decision 2011-474, pg. 27; Alberta Utilities Board 2011 Generic Cost of Capital; dated December 8, 2011.
[14] As per Decision 2011-474, pg. 31; Alberta Utilities Board 2011 Generic Cost of Capital; dated December 8, 2011.
[15] As per Decision 2011-474, pg. 31; Alberta Utilities Board 2011 Generic Cost of Capital; dated December 8, 2011.

TOPIC: **KPMG Depreciation Study**

REFERENCE: **Tab 10 Depreciation Study**

PREAMBLE:

Important background information appears to be missing from this study.

QUESTION:

a) Please provide complete supporting information that led KPMG to its recommendations on depreciation rates. This should include, but is not limited to:

   i. Service life analysis;
   ii. Calculated annual accrual rates;
   iii. Composite remaining life calculations;
   iv. Calculated depreciation reserves; and
   v. Salvage analysis.

b) Has KPMG netted out costs of removal from the salvage values in the Results by Account (pages 10-16 and 10-17)? Which accounts did KPMG include costs of removal and how much was included in each account?

ANSWER:

(a) and **(b)**

Please see the complete narrative report provided as Attachment 1 to YECL-YEC-1-55(a).

The net salvage analysis was excluded from the scope of the study undertaken by KPMG, and no costs of removal or salvage are included in the Results by Account. This is because Order 2005-12 directed that no further future removal costs or salvage should flow through depreciation rates, at least until YEC's Reserve for Future Removal and Site Restoration reaches $2 million. See also response to YECL-YEC-1-58.

TOPIC: **General Liability and Commercial Property Retention Analysis and Actuarial Valuation**

REFERENCE: **Appendix 12.4 and 12.5**

PREAMBLE:

CW wishes to better understand the conclusions of these studies.

QUESTION:

a) Please provide a glossary of the technical terms used in these studies. This glossary should include but not be limited to:

   i. Inherent Uncertainty;
   ii. Extraordinary Future Emergence;
   iii. Expected retained losses at various retention levels;
   iv. Technical premium;
   v. Retained RFID Loss;
   vi. Technical Premium Insured Layer; and
   vii. Insured layer.

b) Please provide the same background data as supplied to AON on past losses charged to the RFID and the property and liability insurance policies.

c) What was the materiality threshold that was applied to the past losses set out in b)? If the change to the materiality threshold proposed in Appendix 3.1 is approved, how would the recommendations of AEON in Appendices 12.4 and 12.5 change? Please explain in detail with numerical examples showing the changes.

ANSWER:

(a)

See below for glossary of terms:

i. **Inherent Uncertainty** - The financial impact of future contingent events is inherently uncertain. Although our estimates represent reasonable provisions based on the application of appropriate techniques to the available data, we cannot guarantee the actual future payments will not differ from our estimates.

ii. **Extraordinary Future Emergence** - The emergence of future losses could be extraordinarily large compared with the assumption based on which we calculate the ultimate losses.

iii. **Expected retained losses at various retention levels** - The expected losses RFID would retain at different retention levels (RFID limit).

iv. **Technical premium** - The technical premium is the sum a prudent underwriter would require, all things being equal, to meet forecasted losses with a reasonable degree of confidence, plus direct and indirect expenses related to policy issuance and claims administration and an acceptable profit margin.

v. **Retained RFID Loss** - The total annual losses would be retained by the RFID.

vi. **Insured Layer** - The segment of losses for which the insurer would be responsible. For example, the property policy deductible (namely RFID limit) is $100,000 and the policy limit is $250,000,000. Therefore, the insured layer is $100,000 to $250,000,000.

vii. **Technical premium of Insured Layer** - The premium the prudent insurer would charge for the losses in the insured layer. It is equal to losses in insured layer divided by permissible loss ratio.

(b)

The loss data provided to AON for the purpose of the study is the actual schedule of losses charged to the RFID – see CW-YEC-1-43(b) Attachment 1. The consultant was further provided with historical records of insured values from 2003 to 2010 – see CW-YEC-1-43(b) Attachment 2.

(c)

Based on the actuarial methods explained in the report, the adjustment to the RFID threshold to $10,000 would reduce the annual charge to approximately $190,000 or about $5,000 less than the recommendation in the report.

YUKON ENERGY CORPORATION-RESERVE FOR INJURIES AND DAMAGES
ACCOUNT 20.240001 & 240002

DR 963098.800007-CR 20.240001.100			1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Opening Balance	**Summarized**	**Status**	-215,697.90	-128,619.86	(11,543.99)	(43,643.99)	(91,795.57)	57,965.43	620,720.93	745,764.36	315,513.84	290,509.84	345,610.41	679,383.71	796,581.59	(33,188.68)	499,902.96	463,202.41	556,295.36	110,875.57
Cust mcrwave rpr							235.00													
Rev cust mcrwave rpr							(235.00)													
Rev cust mcrwave rpr (twice in error)							(235.00)													
Ins deductible-J00053 S150 T10 Failure	Ins Ded						100,000.00													
Ins deductible- Whse Fire J98007	Ins Ded						100,000.00													
Post closing entry							(296,000.00)													
Rvs post closing entry s/b 29500							296,000.00													
98DCF adj see WDF DCF files je 911	Wh Rapid Fire							369,623.85												
98DCF adj see WDF DCF files je 1019	FF							58,182.00												
98DCF adj see WDF DCF files (30 day waiting period) je 1019	Wh Rapid Fire							(852.92)												
98DCF adj see WDF DCF files (30 day waiting period) je 1019	Wh Rapid Fire							(36,533.19)												
J00084 S150 T10 Failure 2nd Occurance to rvse	Line Failure							34,675.19												
J98009 L170 Forest fire Faro	FF							77,652.22												
J98011 Forest fire Little Fox Lk	FF							42,476.36												
TF C0115 new truck replacement je 808	Asset Replace							33,253.97												
Truck proceeds je 808	Asset Replace							(27,412.17)												
Reverse Trcuck proceeds je 849 money rec'd jan 99	Asset Replace							27,412.17												
S/B post clsg adj 1998 Diesel burned during fire waiting period	Wh Rapid Fire							34,282.02												
Loss on vehicle #T 34 - Oct 98	Asset Replace								4,220.90											
TF J00053 S150 T10 Failure 1997 balance	Line Failure								46,449.69											
TF J00084 S150 T10 Failure 2nd occurance 1997 balance	Line Failure								16,704.13											
TF M99021 Frazil Ice	Weather Related								32,806.06											
TF M99017 - Wind Damage	Weather Related								5,882.29											
TF M99018 - Wind Damage	Weather Related								27,359.92											
TF M99019 - Wind Damage	Weather Related								41,624.52											
Record Impact-Fire Serttlement	####JE									(503,052.95)										
Reallocate JE 1019(1998) O&M/Fuel-not reserve	Wh Rapid Fire									36,533.19										
Yukon Explosives-Replacement climbing equip	Wh Rapid Fire									2,760.73										
Fuel for generator at Fox Lake fire	FF									353.59										
TF J00105 Frazil Ice Nov 2000	Weather Related									83,159.00										
Payment of Deductable to Kendall Adj for Fire Fighing cost	Feds sued YEC/insurance co paid										25,000.00									
Royal & Sun Alliance-deductible re w/o unit 44	Deductible											1,000.00								
A1 Auto Body	Veh Accident											1,251.75								
Irving Collision	Veh Accident											904.79								
Olson Construction	Wind-Fence repair											145.00								
Olson Construction	Vandalism-Fence repair											2,160.00								
M02002	Dawson House Repair											5,456.17								
M02003	WD2 Oil Containment											20,271.37								
M02008	2002 FRAZIL ICE											72,054.90								
J02001	UNIT 44 BUCKET TRUCK											1,860.59								
A1 Auto Body	Auto Repairs												2,026.84							
Norcan Leasing	Replace windshield-=Lease Auto												1,033.00							
Norcan Leasing	Lease Auto Repair												529.43							
Norcan Leasing	Lease Auto Repair												1,564.69							
UAB Buzzeo Loss Adj--Bank Rec Item	Auto Repair												1,000.00							
Norcan Leasing	lease Auto-Winshield Repair												475.46							
J03002 WH3 Turbine	Repair												357,406.51							
J01006 Veh Vandalism	Repair												15,996.35							
Norcan Leasing	Repair Rental Unit												3,745.02							
Norcan Leasing	Body Work Unit 50													2,804.96						
Insurance Settlement	Unit 50													(2,804.96)						
Service Truck Fire Loss	Unit 61													16,904.19						
WW2 Ring Gear Repair	TF J04008													150,297.69						
Computer Stolen	Computer Theft														3,974.00					
Third Party Vehicle Damage - Mayo	Kris Pavlovich														1,000.00					
Service Truck Fire Loss	Unit 61														1,169.32					
TF J05001 Dwsn Hse H20 Dmge	TF J05001														5,725.50					
Repair marsh lk dam	Marsh Lake Dam Repair														1,773.45					
YUB Board Order 2005-12 transfer from Reg Liability	YUB 2005-12														(743,412.54)					
TF J05002 - Takhini Substation Break-In	Takhini Substn Break-In															15,274.73				
TF J05006 - Kulan Break In	Kulan Break In															32,347.16				
TF J05007 - L171 Lighning Arrestor Failure	L171 Lightning Arr Failure															10,848.83				
R06001 - L171 Insulator Failure	L171 Insulator Failure															35,348.19				
R06002 - Whitehorse Hydrant Leak	Whitehorse Hydrant Leak															35,620.20				
R06003 - Unit 63 Vehicle Theft	Unit 63 Theft															1,739.72				
J06002 - WH1 Hub and Blade Overhaul	WH1 Overhaul															302,098.36				
J06001 - Aishihik Cable Repair	Aishihik Cable Repair															199,814.45				
R07001 - L174 Broken Pole	L174 Broken Pole																39,073.24			
R07002 - Water Damage at MLCS	Marsh Lake Water Damage																17,261.02			
R07003 - Kulan Warehouse Water Damage	Kulan Water Damage																6,965.19			
R08001-L172 Insulator Failure	L172 Insulator Failure																	40,430.98		
R08002- Rock Creek Crossing	Rock Creek Crossing																	11,243.68		
R08003-Polaris Ranger & Trailer Rplcm	Polaris Ranger & Trailer Rplcm																	8,813.99		
R08004-Outage Damages- Oct.2008	Outage Damages Longweek Oct.08																	24,879.76		
	YEC Knocked over Street Light																	1,041.90		
	Repair Flood Cost Damage																	15,062.70		
R06002 - Whitehorse Hydrant Leak																				
R08004-Outage Damages- Oct.2008																				
R08005-Aishihik Sub Cable Failure																				
R09001-Premature VFD Failure																			26,931.00	
R09002- Lost Tool Kit																			1,627.34	
R09003- Aishihik Service Building Crane Cable Replacement																			60,141.03	
R09004-Aishihik Pole Fire																			23,636.77	
R09005-Vehicle Rollover Deductible																			5,000.00	
R10001 - WH4 Rotor Crack Repair																				
R10002 - MH1 Slip Ring Repair																				
R10003 - Aishihil Station Transformer																				
R10004 - Mayo Customer Damage																				
Trail Blazer																				
R11002 - S150 Cable & PT Repairs																				
R11001 - Repair WD6 Premature Failure																				
R10001 - WH4 Rotor Crack Repair																				
Lewes Control Gate fire																				
Cumulative Additions			118,578.04	149,175.87	-	1,852.42	199,765.00	612,759.50	175,047.51	(380,246.44)	25,000.00	105,104.57	383,777.30	167,201.88	13,642.27	633,091.64	63,299.45	101,473.01	117,336.14	-
TOTAL COST			-215,697.90	-128,619.86	(11,543.99)	(43,643.99)	107,969.43	670,724.93	795,768.44	365,517.92	340,513.84	395,614.41	729,387.71	846,585.59	66,811.32	599,902.96	563,202.41	564,675.42	673,631.50	
WIP 240002																				
R06002 - Whitehorse Hydrant Leak																		15,900.00		
R08004-Outage Damages- Oct.2008																		1,368.00	244.07	
R08005-Aishihik Sub Cable Failure																		24,351.94		
Faro Dewater Transfer																			(413,000.00)	
Annual provisions			-31,500.00	-32,100.00	(32,100.00)	(50,004.00)	(50,004.00)	(50,004.00)	(50,004.08)	(50,004.08)	(50,004.00)	(50,004.00)	(50,004.00)	(50,004.00)	(100,000.00)	(100,000.00)	(100,000.00)	(50,000.00)	(150,000.00)	
NET BALANCE			**-128,619.86**	**-11,543.99**	**(43,643.99)**	**(91,795.57)**	**57,965.43**	**620,720.93**	**745,764.36**	**315,513.84**	**290,509.84**	**345,610.41**	**679,383.71**	**796,581.59**	**(33,188.68)**	**499,902.96**	**463,202.41**	**556,295.36**	**110,875.57**	-
BAL FWD								**58**	**621**	**746**	**316**	**291**	**346**	**679**	**797**	**(33)**	**500**	**463**	**556**	
Annual Provision								**(50)**	**(50)**	**(50)**	**(50)**	**(50)**	**(50)**	**(50)**	**(100)**	**(100)**	**(100)**	**(50)**	**(150)**	
Board Order 2005-12 Transfer from Reg Liab															**(743)**				**(413)**	
Faro Dewater Transfer																				
Additions(000's)																				
FIRE INS SETTLE IMPACT 2000										**(503)**										
Asset Replacement								**33**	**67**	**3**		**33**	**384**	**167**	**14**	**587**	**46**	**36**	**2**	
Line Failures								**35**		**-**						**46**		**92**	**111**	
Frazil Ice									**33**	**84**		**72**								
Wind Storm / Flooding								**178**	**75**								**17**	**15**		
Whitehorse Rapids Generation Interupt								**367**	**-**	**37**										
Insurance Deductible											**25**								**5**	
Closing Balance								**621**	**746**	**316**	**291**	**346**	**679**	**797**	**(33)**	**500**	**463**	**556**	**111**	-

Yukon Energy Corporation Replacement Cost Insurable Values

Effective May 2003
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Whitehorse, Y.T.						
Hydro Powerhouse 1, 2 & 3		13,684.5	29,916.4			43,600.8
Diesel Powerhouse 1, 2 & 3		2,290.3	28,512.2			30,802.5
Yard and outside	1	110,464.4	15,052.4			125,516.8
McIntyre Substation		103.5	10.0			113.5
Sluice Gate Diesel Generator Building		17.9	82.0			99.9
Powerhouse 4		13,535.3	26,276.0			39,811.3
Substation Across River		60.9	0.0			60.9
Fish Hatchery		262.0	182.5			444.5
Fish Ladder/Viewing Centre		2,472.4	0.0			2,472.4
Valuable Papers				329.1		329.1
File Storage Trailer		94.0	12.5			106.5
Double-Wide Office Trailer		78.0	26.0			104.0
Single-Wide Office Trailer		73.0	27.0			100.0
Administration Office		2,485.0	1,034.5			
Kulan warehouse		173.0	128.5		1,700.0	2,001.5
Cold Storage Building		143.2	25.0		250.0	
Control Building- S150		105.5	66.9			
Marsh Lake Control Structure		12,432.1	0.0			
Misc Substation equipment		0.0	4,145.0			
Sub-Total		158,474.9	105,496.9	329.1	1,950.0	266,250.9
Wind Turbines						
Vestas		2,060.0	0.0	0.0	0.0	2,060.0
Bonus		885.0	-	-	-	885.0
Sub-Total		2,945.0	0.0	0.0	0.0	2,945.0
Total Whitehorse		161,419.9	105,496.9	329.1	1,950.0	269,195.9

Yukon Energy Corporation Replacement Cost Insurable Values

Effective May 2003
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Aishihik, Y.T.						
Roads & Bridges		2,686.0	-	-	-	2,686.0
Service Building		1,476.7	2,067.2			3,543.9
Aishihik Substation			3,318.0			3,318.0
Takhini Substation		56.5	6,617.0			6,673.5
Access Shaft		8,158.1	238.4			8,396.5
Garage and Carpentry Shop		34.3	4.0			38.3
Residence		190.0	20.0			210.0
Storage Shed		15.5	0.0			15.5
Intake Structure		3,133.0				3,133.0
By-Pass Tunnel		1,511.0				1,511.0
Tail Race Tunnel		17,214.0				17,214.0
Tail Race Improvements		6,004.0				6,004.0
Pressure Tunnel		10,944.0				10,944.0
Penstocks		2,891.0				2,891.0
Hydro Powerhouse		6,964.6	19,708.3			26,672.8
Surge Chamber/DR Tube Gallery		2,532.8	30.4			2,563.2
Control Building Canyon Lake		287.5	11.5			299.0
Sub-Total		64,099.0	32,014.7	0.0	0.0	96,113.7
Dam Structures						
Aishihik Lake Control Structure		6,065.0	-	-	-	6,065.0
Power Canal		21,000.0	-	-	-	21,000.0
Sekulman River Improvements		1,885.0	-	-	-	1,885.0
Canyon Lake Control Structure		3,130.0	-	-	-	3,130.0
Sub-Total		32,080.0	0.0	0.0	0.0	32,080.0
Total Aishihik		96,179.0	32,014.7	0.0	0.0	128,193.7

Yukon Energy Corporation Replacement Cost Insurable Values

Effective May 2003
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Faro, Y.T.						
Diesel Powerhouse - FD1		680.8	5,952.2			6,633.1
Power House #2 - FD7		373.3	3,179.8			3,553.1
Yard/Diesel Plants - FD2, 3, 4, 6 only			1,630.0			1,630.0
Substation		27.9	124.2			152.0
Anvil Substation			4,342.0			4,342.0
Warehouse		143.3	1,940.0			2,083.3
Electrical Structure		0.0	598.1			598.1
Fuel Storage System			754.0			754.0
Transmission and Distribution Inventory					126.0	126.0
Fuel Building		20.7	14.0			34.7
Total Faro		1,246.1	18,534.3	0.0	126.0	19,906.3
Mayo Y.T.						
Hydro Powerhouse		5,226.8	15,657.5			20,884.2
Intake Structure		1,164.0				1,164.0
Tunnel, Penstocks & Surge Tank		7,079.0				7,079.0
Substation			1,781.0			1,781.0
Office/Warehouse		152.1	0.0			152.1
Powerhouse Armco Steel Building		65.0	0.0			65.0
Mayo-Dawson substation		2,250.0	0.0	0.0	0.0	2,250.0
Road and Land Improvements		3,606.0				
Transmission and Distribution Inventory					110.0	110.0
Total Mayo		19,542.9	17,438.5	0.0	110.0	37,091.4
Mayo Townsite						
Warehouse/Diesel Yard		120.7	9.5			130.2
Office/Warehouse Downtown		434.2	63.5			497.7
Diesel Supplies Shed-Diesel Yard		18.9	738.5		271.0	
Diesel Generators and Accessory Equipment			2,846.4			
Total Mayo Townsite		573.8	73.0	0.0	0.0	646.8

Yukon Energy Corporation Replacement Cost Insurable Values

Effective May 2003
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Mayo Dam Structures						
Mayo Lake Dam		7,048.0	-	-	-	7,048.0
Wareham Dam		19,150.0	-	-	-	19,150.0
River Improvements - Tail Race		564.0	-	-	-	564.0
Total Mayo Dam Structures		26,762.0	0.0	0.0	0.0	26,762.0
Dawson City, YT						
Diesel Powerhouse		622.4	5,138.1			5,760.4
Garage/Office		403.0	55.0			458.0
Fuel storage		-	1,560.0			1,560.0
Mayo to Dawson substation		2,250.0	0.0	0.0	190.0	2,440.0
Residence: 833-6th Avenue		136.0	0.0			
Garage: 1136-5th Avenue		28.6	0.0			
Residence: 1136-5th Avenue		101.7	0.0			
Residence: 626-6th Avenue		205.0	0.0			
Residence: 817-6th Avenue		191.0	0.0			
Total Dawson City		3,937.6	6,753.1	0.0	190.0	10,880.7
GRAND TOTAL		**309,661.3**	**180,310.4**	**329.1**	**2,376.0**	**492,676.8**

Footnote explanations

1 Stated value includes value of dam, intake structures, penstocks, power canals and other waterway improvements

This Summary of Values is issued for information purposes only, and does not form a part of the policy. However, we do certify that the values shown reflect our best and most current valuation,and acknowledge that these values form the basis upon which the policy is to be issued.

Signature

Date

Title

Please sign & return

Yukon Energy Corporation Replacement Cost Insurable Values

Effective May 2004
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Whitehorse, Y.T.						
Hydro Powerhouse 1, 2 & 3		13,684.5	29,916.4			43,600.8
Diesel Powerhouse 1, 2 & 3		2,290.3	28,512.2			30,802.5
Yard and outside	1	110,464.4	15,052.4			125,516.8
McIntyre Substation		103.5	10.0			113.5
Sluice Gate Diesel Generator Building		17.9	82.0			99.9
Powerhouse 4		13,535.3	26,276.0			39,811.3
Substation Across River		60.9	0.0			60.9
Fish Hatchery		262.0	182.5			444.5
Fish Ladder/Viewing Centre		2,472.4	0.0			2,472.4
Valuable Papers				329.1		329.1
File Storage Trailer		94.0	12.5			106.5
Double-Wide Office Trailer		78.0	26.0			104.0
Single-Wide Office Trailer		73.0	27.0			100.0
Administration Office		2,485.0	1,034.5			
Kulan warehouse		173.0	128.5		1,700.0	2,001.5
Cold Storage Building		143.2	25.0		250.0	
Control Building- S150		105.5	66.9			
Marsh Lake Control Structure		12,432.1	0.0			
Misc Substation equipment		0.0	4,145.0			
Sub-Total		158,474.9	105,496.9	329.1	1,950.0	266,250.9
Wind Turbines						
Vestas		2,060.0	0.0	0.0	0.0	2,060.0
Bonus		885.0	-	-	-	885.0
Sub-Total		2,945.0	0.0	0.0	0.0	2,945.0
Total Whitehorse		161,419.9	105,496.9	329.1	1,950.0	269,195.9

Yukon Energy Corporation Replacement Cost Insurable Values

Effective May 2004
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Aishihik, Y.T.						
Roads & Bridges		2,686.0	-	-	-	2,686.0
Service Building		1,476.7	2,067.2			3,543.9
Aishihik Substation			3,318.0			3,318.0
Takhini Substation		56.5	6,617.0			6,673.5
Access Shaft		8,158.1	238.4			8,396.5
Garage and Carpentry Shop		34.3	4.0			38.3
Residence		190.0	20.0			210.0
Storage Shed		15.5	0.0			15.5
Intake Structure		3,133.0				3,133.0
By-Pass Tunnel		1,511.0				1,511.0
Tail Race Tunnel		17,214.0				17,214.0
Tail Race Improvements		6,004.0				6,004.0
Pressure Tunnel		10,944.0				10,944.0
Penstocks		2,891.0				2,891.0
Hydro Powerhouse		6,964.6	19,708.3			26,672.8
Surge Chamber/DR Tube Gallery		2,532.8	30.4			2,563.2
Control Building Canyon Lake		287.5	11.5			299.0
Sub-Total		64,099.0	32,014.7	0.0	0.0	96,113.7
Dam Structures						
Aishihik Lake Control Structure		6,065.0	-	-	-	6,065.0
Power Canal		21,000.0	-	-	-	21,000.0
Sekulman River Improvements		1,885.0	-	-	-	1,885.0
Aishihik Lake Boat Launch		600.0	-	-	-	600.0
Canyon Lake Control Structure		3,130.0	-	-	-	3,130.0
Sub-Total		32,680.0	0.0	0.0	0.0	32,680.0
Total Aishihik		96,779.0	32,014.7	0.0	0.0	128,793.7

Yukon Energy Corporation Replacement Cost Insurable Values

Effective May 2004
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Faro, Y.T.						
Diesel Powerhouse - FD1		680.8	5,952.2			6,633.1
Power House #2 - FD7		373.3	3,179.8			3,553.1
Yard/Diesel Plants - FD2, 3, 4, 6 only			1,630.0			1,630.0
Substation		27.9	124.2			152.0
Anvil Substation			4,342.0			4,342.0
Warehouse		143.3	1,940.0			2,083.3
Electrical Structure		0.0	598.1			598.1
Fuel Storage System			754.0			754.0
Transmission and Distribution Inventory					126.0	126.0
Fuel Building		20.7	14.0			34.7
Total Faro		1,246.1	18,534.3	0.0	126.0	19,906.3
Mayo Y.T.						
Hydro Powerhouse		5,226.8	15,657.5			20,884.2
Intake Structure		1,164.0				1,164.0
Tunnel, Penstocks & Surge Tank		7,079.0				7,079.0
Substation			1,781.0			1,781.0
Office/Warehouse		152.1	0.0			152.1
Powerhouse Armco Steel Building		65.0	0.0			65.0
Mayo-Dawson substation		2,250.0	0.0	0.0	0.0	2,250.0
Road and Land Improvements		3,606.0				
Transmission and Distribution Inventory					110.0	110.0
Total Mayo		19,542.9	17,438.5	0.0	110.0	37,091.4

Yukon Energy Corporation Replacement Cost Insurable Values

Effective May 2004
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Mayo Townsite						
Warehouse/Diesel Yard		120.7	9.5			130.2
Office/Warehouse Downtown		434.2	63.5			497.7
Diesel Supplies Shed-Diesel Yard		18.9	738.5		271.0	
Diesel Generators and Accessory Equipment			2,846.4			
Total Mayo Townsite		573.8	73.0	0.0	0.0	646.8
Mayo Dam Structures						
Mayo Lake Dam		7,048.0	-	-	-	7,048.0
Wareham Dam		19,150.0	-	-	-	19,150.0
River Improvements - Tail Race		564.0	-	-	-	564.0
Total Mayo Dam Structures		26,762.0	0.0	0.0	0.0	26,762.0
Dawson City, YT						
Diesel Powerhouse		622.4	5,138.1			5,760.4
Garage/Office		403.0	55.0			458.0
Fuel storage		-	1,560.0			1,560.0
Mayo to Dawson substation		2,250.0	0.0	0.0	190.0	2,440.0
Residence: 833-6th Avenue		136.0	0.0			
Garage: 1136-5th Avenue		28.6	0.0			
Residence: 1136-5th Avenue		101.7	0.0			
Residence: 626-6th Avenue		205.0	0.0			
Residence: 817-6th Avenue		191.0	0.0			
Total Dawson City		3,937.6	6,753.1	0.0	190.0	10,880.7

Yukon Energy Corporation Replacement Cost Insurable Values

Effective May 2004
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Transmission & Distribution Power Line Assets						
138 Kv 520 kms						
69 Kv 274 kms						
25-34.5 Kv 195 kms						
below 25Kv 300 kms		0.0	67,500.0	0.0	0.0	67,500.0
Yukon Development Corporation						
Office furniture and equipment			250.0			250.0
			250.0			250.0
Energy Solutions Centre Inc						
Office furniture and equipment			250.0			250.0
			250.0			250.0
GRAND TOTAL		**310,261.3**	**248,310.4**	**329.1**	**2,376.0**	**561,276.8**

Footnote explanations

1 Stated value includes value of dam, intake structures, penstocks, power canals and other waterway improvements

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Signature

Date

Title

Please sign & return

Yukon Energy Corporation Replacement Cost Insurable Values

2005
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Whitehorse, Y.T.						
Hydro Powerhouse 1, 2 & 3		13,684.5	29,916.4			43,600.8
Diesel Powerhouse 1, 2 & 3		2,290.3	28,512.2			30,802.5
Yard and outside	1	110,464.4	15,052.4			125,516.8
McIntyre Substation		103.5	10.0			113.5
Sluice Gate Diesel Generator Building		17.9	82.0			99.9
Powerhouse 4		13,535.3	26,276.0			39,811.3
Substation Across River		60.9	0.0			60.9
Fish Hatchery		262.0	182.5			444.5
Fish Ladder/Viewing Centre		2,472.4	0.0			2,472.4
Valuable Papers				329.1		329.1
File Storage Trailer		94.0	12.5			106.5
Double-Wide Office Trailer		78.0	26.0			104.0
Single-Wide Office Trailer		73.0	27.0			100.0
Administration Office		2,485.0	1,034.5			
Kulan warehouse		173.0	128.5		1,700.0	2,001.5
Cold Storage Building		143.2	25.0		250.0	
Control Building- S150		105.5	66.9			
Marsh Lake Control Structure		12,432.1	0.0			
Misc Substation equipment		0.0	4,145.0			
Sub-Total		158,474.9	105,496.9	329.1	1,950.0	266,250.9
Wind Turbines						
Vestas		2,060.0	0.0	0.0	0.0	2,060.0
Bonus		885.0	-	-	-	885.0
Sub-Total		2,945.0	0.0	0.0	0.0	2,945.0
Total Whitehorse		161,419.9	105,496.9	329.1	1,950.0	269,195.9

Yukon Energy Corporation Replacement Cost Insurable Values

2005
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Aishihik, Y.T.						
Roads & Bridges		2,686.0	-	-	-	2,686.0
Service Building		1,476.7	2,067.2			3,543.9
Aishihik Substation			3,318.0			3,318.0
Takhini Substation		56.5	6,617.0			6,673.5
Access Shaft		8,158.1	238.4			8,396.5
Garage and Carpentry Shop		34.3	4.0			38.3
Residence		190.0	20.0			210.0
Storage Shed		15.5	0.0			15.5
Intake Structure		3,133.0				3,133.0
By-Pass Tunnel		1,511.0				1,511.0
Tail Race Tunnel		17,214.0				17,214.0
Tail Race Improvements		6,004.0				6,004.0
Pressure Tunnel		10,944.0				10,944.0
Penstocks		2,891.0				2,891.0
Hydro Powerhouse		6,964.6	19,708.3			26,672.8
Surge Chamber/DR Tube Gallery		2,532.8	30.4			2,563.2
Control Building Canyon Lake		287.5	11.5			299.0
Sub-Total		64,099.0	32,014.7	0.0	0.0	96,113.7
Dam Structures						
Aishihik Lake Control Structure		6,065.0	-	-	-	6,065.0
Power Canal		21,000.0	-	-	-	21,000.0
Sekulman River Improvements		1,885.0	-	-	-	1,885.0
Aishihik Lake Boat Launch		600.0	-	-	-	600.0
Canyon Lake Control Structure		3,130.0	-	-	-	3,130.0
Sub-Total		32,680.0	0.0	0.0	0.0	32,680.0
Total Aishihik		96,779.0	32,014.7	0.0	0.0	128,793.7

Yukon Energy Corporation Replacement Cost Insurable Values

2005
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Faro, Y.T.						
Diesel Powerhouse - FD1		680.8	5,952.2			6,633.1
Power House #2 - FD7		373.3	3,179.8			3,553.1
Yard/Diesel Plants - FD2, 3, 4, 6 only			1,630.0			1,630.0
Substation		27.9	124.2			152.0
Anvil Substation			4,342.0			4,342.0
Warehouse		143.3	1,940.0			2,083.3
Electrical Structure		0.0	598.1			598.1
Fuel Storage System			754.0			754.0
Transmission and Distribution Inventory					126.0	126.0
Fuel Building		20.7	14.0			34.7
Total Faro		1,246.1	18,534.3	0.0	126.0	19,906.3
Mayo Y.T.						
Hydro Powerhouse		5,226.8	15,657.5			20,884.2
Intake Structure		1,164.0				1,164.0
Tunnel, Penstocks & Surge Tank		7,079.0				7,079.0
Substation			1,781.0			1,781.0
Office/Warehouse		152.1	0.0			152.1
Powerhouse Armco Steel Building		65.0	0.0			65.0
Mayo-Dawson substation		2,250.0	0.0	0.0	0.0	2,250.0
Road and Land Improvements		3,606.0				
Transmission and Distribution Inventory					110.0	110.0
Total Mayo		19,542.9	17,438.5	0.0	110.0	37,091.4
Mayo Townsite						
Warehouse/Diesel Yard		120.7	9.5			130.2
Office/Warehouse Downtown		434.2	63.5			497.7
Diesel Supplies Shed-Diesel Yard		18.9	738.5		271.0	
Diesel Generators and Accessory Equipment			2,846.4			
Total Mayo Townsite		573.8	73.0	0.0	0.0	646.8

Yukon Energy Corporation Replacement Cost Insurable Values

2005
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Mayo Dam Structures						
Mayo Lake Dam		7,048.0	-	-	-	7,048.0
Wareham Dam		19,150.0	-	-	-	19,150.0
River Improvements - Tail Race		564.0	-	-	-	564.0
Total Mayo Dam Structures		26,762.0	0.0	0.0	0.0	26,762.0
Dawson City, YT						
Diesel Powerhouse		622.4	5,138.1			5,760.4
Garage/Office		403.0	55.0			458.0
Fuel storage		-	1,560.0			1,560.0
Mayo to Dawson substation		2,250.0	0.0	0.0	190.0	2,440.0
Residence: 833-6th Avenue		136.0	0.0			
Garage: 1136-5th Avenue		28.6	0.0			
Residence: 1136-5th Avenue		101.7	0.0			
Residence: 626-6th Avenue		205.0	0.0			
Residence: 817-6th Avenue		191.0	0.0			
Total Dawson City		3,937.6	6,753.1	0.0	190.0	10,880.7
Transmission & Distribution Power Line Assets						
138 Kv 520 kms						
69 Kv 274 kms						
25-34.5 Kv 195 kms						
below 25Kv 300 kms		0.0	67,500.0	0.0	0.0	67,500.0

Yukon Energy Corporation Replacement Cost Insurable Values

2005
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Yukon Development Corporation						
Office furniture and equipment			250.0			250.0
			250.0			250.0
Energy Solutions Centre Inc						
Office furniture and equipment			250.0			250.0
			250.0			250.0
GRAND TOTAL		**310,261.3**	**248,310.4**	**329.1**	**2,376.0**	**561,276.8**

Footnote explanations

1 Stated value includes value of dam, intake structures, penstocks, power canals and other waterway improvements

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Signature

Date

Title

Please sign & return

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2005
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Whitehorse, Y.T.						
Hydro Powerhouse 1, 2 & 3		13,821.3	29,497.5			43,318.9
Diesel Powerhouse 1, 2 & 3		2,313.2	28,113.0			30,426.3
Yard and outside	1	111,569.0	14,841.7			126,410.7
McIntyre Substation		104.6	9.9			114.4
Sluice Gate Diesel Generator Building		18.1	80.8			98.9
Powerhouse 4		13,670.7	25,908.2			39,578.8
Substation Across River		61.5	0.0			61.5
Fish Hatchery		264.6	179.9			444.6
Fish Ladder/Viewing Centre		2,497.1	0.0			2,497.1
Valuable Papers		0.0	0.0	329.1		329.1
File Storage Trailer		94.9	12.3			107.3
Double-Wide Office Trailer		78.8	25.6			104.4
Single-Wide Office Trailer		73.7	26.6			100.4
Administration Office		2,509.9	1,020.0			3,529.9
Kulan warehouse		174.7	126.7		1,700.0	2,001.4
Cold Storage Building		144.6	24.7		250.0	419.3
Control Building- S150		106.6	66.0			172.6
Marsh Lake Control Structure		12,556.4	0.0			12,556.4
Misc Substation equipment		0.0	4,087.0			4,087.0
Sub-Total		160,059.7	104,019.9	329.1	1,950.0	266,358.7
Wind Turbines						
Vestas		2,080.6	0.0	0.0	0.0	2,080.6
Bonus		893.9	0.0	0.0	0.0	893.9
Sub-Total		2,974.5	0.0	0.0	0.0	2,974.5
Total Whitehorse		163,034.1	104,019.9	329.1	1,950.0	269,333.2

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2005
$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Aishihik, Y.T.						
Roads & Bridges		2,712.9				2,712.9
Service Building		1,491.4	2,038.3			3,529.7
Aishihik Substation			3,271.5			3,271.5
Takhini Substation		57.1	6,524.4			6,581.5
Access Shaft		8,239.7	235.0			8,474.7
Garage and Carpentry Shop		34.7	3.9			38.6
Residence		191.9	19.7			211.6
Storage Shed		15.7	0.0			15.7
Intake Structure		3,164.3				3,164.3
By-Pass Tunnel		1,526.1				1,526.1
Tail Race Tunnel		17,386.1				17,386.1
Tail Race Improvements		6,064.0				6,064.0
Pressure Tunnel		11,053.4				11,053.4
Penstocks		2,919.9				2,919.9
Hydro Powerhouse		7,034.2	19,432.4			26,466.6
Surge Chamber/DR Tube Gallery		2,558.2	29.9			2,588.1
Control Building Canyon Lake		290.4	11.3			301.7
Sub-Total		64,740.0	31,566.5	0.0	0.0	96,306.5
Dam Structures						
Aishihik Lake Control Structure		6,125.7	-	-	-	6,125.7
Power Canal		21,210.0	-	-	-	21,210.0
Sekulman River Improvements		1,903.9	-	-	-	1,903.9
Aishihik Lake Boat Launch		606.0	-	-	-	606.0
Canyon Lake Control Structure		3,161.3	-	-	-	3,161.3
Sub-Total		33,006.8	0.0	0.0	0.0	33,006.8
Total Aishihik		97,746.8	31,566.5	0.0	0.0	129,313.3

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2005

$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Faro, Y.T.						
Diesel Powerhouse - FD1		687.6	5,868.9			6,556.5
Power House #2 - FD7		377.1	3,135.3			3,512.3
Yard/Diesel Plants - FD2, 3, 4, 6 only			1,607.2			1,607.2
Substation		28.1	122.4			150.6
Anvil Substation			4,281.2			4,281.2
Warehouse		144.8	1,912.8			2,057.6
Electrical Structure		0.0	589.7			589.7
Fuel Storage System			743.4			743.4
Transmission and Distribution Inventory					126.0	126.0
Fuel Building		20.9	13.8			34.7
Total Faro		1,258.5	18,274.8	0.0	126.0	19,659.3
						0.0
Mayo Y.T.						0.0
Hydro Powerhouse		5,279.0	15,438.2			20,717.3
Intake Structure		1,175.6				1,175.6
Tunnel, Penstocks & Surge Tank		7,149.8				7,149.8
Substation			1,756.1			1,756.1
Office/Warehouse		153.7	0.0			153.7
Powerhouse Armco Steel Building		65.7	0.0			65.7
Mayo-Dawson substation		2,272.5	0.0	0.0	0.0	2,272.5
Road and Land Improvements		3,642.1				3,642.1
Transmission and Distribution Inventory					110.0	110.0
Total Mayo		19,738.3	17,194.3	0.0	110.0	37,042.7

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2005

$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Mayo Townsite						
Warehouse/Diesel Yard		121.9	9.4			131.3
Office/Warehouse Downtown		438.5	62.6			501.1
Diesel Supplies Shed-Diesel Yard		19.1	728.2		271.0	1,018.3
Diesel Generators and Accessory Equipment			2,806.5			2,806.5
Total Mayo Townsite		579.5	3,606.7	0.0	271.0	4,457.2
Mayo Dam Structures						
Mayo Lake Dam		7,118.5				7,118.5
Wareham Dam		19,341.5				19,341.5
River Improvements - Tail Race		569.6				569.6
Total Mayo Dam Structures		27,029.6	0.0	0.0	0.0	27,029.6
Dawson City, YT						
Diesel Powerhouse		628.6	5,066.1			5,694.7
Garage/Office		407.0	54.2			461.3
Fuel storage			1,538.2			1,538.2
Mayo to Dawson substation		2,272.5	0.0	0.0	190.0	2,462.5
Residence: 833-6th Avenue		137.3	0.0			
Garage: 1136-5th Avenue		28.9	0.0			
Residence: 1136-5th Avenue		102.7	0.0			
Residence: 626-6th Avenue		207.1	0.0			
Residence: 817-6th Avenue		192.9	0.0			
Total Dawson City		3,977.0	6,658.5	0.0	190.0	10,825.5

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2005

$=000's

Location	Footnote	Buildings	Machinery & Equipment	Contents	Inventory	Total
Transmission & Distribution Power Line Assets						
138 Kv 520 kms						
69 Kv 274 kms						
25-34.5 Kv 195 kms						
below 25Kv 300 kms		0.0	67,500.0	0.0	0.0	67,500.0
Yukon Development Corporation						
Office furniture and equipment			246.5			246.5
			246.5			246.5
2004 Additions		3,307.8				3,307.8
2005 Additions		5,380.0				5,380.0
GRAND TOTAL		**322,051.7**	**249,067.2**	**329.1**	**2,647.0**	**574,095.0**

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Signature

Date

Title

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2007

$=000's

Location		Buildings	Machinery & Equipment	Contents	Inventory	Total
Whitehorse, Y.T.						
Hydro Powerhouse 1, 2 & 3		15,657.1	29,261.6			44,918.7
Diesel Powerhouse 1, 2 & 3		2,620.5	27,888.1			30,508.6
Yard and outside	1	126,388.0	14,722.9			141,110.9
McIntyre Substation		118.4	9.8			128.2
Sluice Gate Diesel Generator Building		20.5	80.2			100.6
Powerhouse 4		15,486.4	25,700.9			41,187.3
Substation Across River		69.6	0.0			69.6
Fish Hatchery		299.8	178.5			478.3
Fish Ladder/Viewing Centre		2,828.7	0.0			2,828.7
Valuable Papers		0.0	0.0	329.1		329.1
File Storage Trailer		106.5	12.2			118.7
Double-Wide Office Trailer		88.4	25.4			113.8
Single-Wide Office Trailer		82.7	26.4			109.1
Administration Office		2,815.1	1,011.9			3,827.0
Kulan warehouse		196.0	125.7		1,700.0	2,021.7
Cold Storage Building		162.2	24.5		250.0	436.6
Control Building- S150		119.6	65.5			185.0
Marsh Lake Control Structure		14,224.2	0.0			14,224.2
Misc Substation equipment			4,054.3			4,054.3
Sub-Total		181,283.7	103,187.8	329.1	1,950.0	286,750.5
Wind Turbines						
Vestas		2,357.0		0.0	0.0	2,357.0
Bonus		1,012.6		0.0	0.0	1,012.6
Sub-Total		3,369.5		0.0	0.0	3,369.5
Total Whitehorse		184,653.2	103,187.8	329.1	1,950.0	290,120.0

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2007

$=000's

Location	Buildings	Machinery & Equipment	Contents	Inventory	Total
Aishihik, Y.T.					
Roads & Bridges	3,073.2				3,073.2
Service Building	1,672.8	2,021.9			3,694.8
Aishihik Substation		3,245.4			3,245.4
Takhini Substation	64.7	6,472.2			6,536.8
Access Shaft	9,334.1	233.2			9,567.3
Garage and Carpentry Shop	39.3	3.9			43.2
Residence	215.2	19.6			234.8
Storage Shed	17.6	0.0			17.6
Intake Structure	3,584.6				3,584.6
By-Pass Tunnel	1,728.8				1,728.8
Tail Race Tunnel	19,695.4				19,695.4
Tail Race Improvements	6,869.5				6,869.5
Pressure Tunnel	12,521.6				12,521.6
Penstocks	3,307.7				3,307.7
Hydro Powerhouse	7,968.5	19,276.9			27,245.4
Surge Chamber/DR Tube Gallery	2,897.9	29.7			2,927.7
Control Building Canyon Lake	329.0	11.2			340.2
Sub-Total	73,320.0	31,314.0	0.0	0.0	104,633.9
Dam Structures					
Aishihik Lake Control Structure	6,939.3		0.0	0.0	6,939.3
Power Canal	24,027.2		0.0	0.0	24,027.2
Sekulman River Improvements	2,156.7		0.0	0.0	2,156.7
Aishihik Lake Boat Launch	686.5		-	-	686.5
Canyon Lake Control Structure	3,581.2		0.0	0.0	3,581.2
Sub-Total	37,390.9		0.0	0.0	37,390.9
Total Aishihik	110,710.8	31,314.0	0.0	0.0	142,024.8

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2007

$=000's

Location	Buildings	Machinery & Equipment	Contents	Inventory	Total
Faro, Y.T.					
Diesel Powerhouse - FD1	779.0	5,821.9			6,600.9
Power House #2 - FD7	427.1	3,110.2			3,537.3
Yard/Diesel Plants - FD2, 3, 4, 6 only	0.0	1,594.3	0.0	0.0	1,594.3
Substation	31.9	121.5		0.0	153.3
Anvil Substation	0.0	4,247.0			4,247.0
Warehouse	164.0	1,897.5			2,061.5
Electrical Structure	0.0	585.0			585.0
Fuel Storage System	0.0	737.5			737.5
Transmission and Distribution Inventory	0.0	0.0		126.0	126.0
Fuel Building	23.7	13.7			37.4
Total Faro	1,425.7	18,128.6	0.0	126.0	19,680.3
					0.0
Mayo Y.T.					
Hydro Powerhouse	5,980.2	15,314.7			21,295.0
Intake Structure	1,331.8				1,331.8
Tunnel, Penstocks & Surge Tank	8,099.4				8,099.4
Substation		1,742.0			1,742.0
Office/Warehouse	172.4				172.4
Powerhouse Armco Steel Building	74.4				74.4
Mayo-Dawson substation	2,574.3		0.0	0.0	2,574.3
Road and Land Improvements	4,125.8				4,125.8
Transmission and Distribution Inventory				110.0	110.0
Total Mayo	22,358.3	17,056.8	0.0	110.0	39,525.1

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2007

$=000's

Location	Buildings	Machinery & Equipment	Contents	Inventory	Total
Mayo Townsite					
Warehouse/Diesel Yard	138.1	9.3			147.4
Office/Warehouse Downtown	491.8	62.1			553.9
Diesel Supplies Shed-Diesel Yard	21.6	722.3		271.0	1,015.0
Diesel Generators and Accessory Equipment		2,784.1			2,784.1
Total Mayo Townsite	651.6	3,577.8	0.0	271.0	4,500.4
Mayo Dam Structures					
Mayo Lake Dam	8,064.0				8,064.0
Wareham Dam	21,910.5				21,910.5
River Improvements - Tail Race	645.3				645.3
Total Mayo Dam Structures	30,619.8		0.0	0.0	30,619.8
Dawson City, YT					
Diesel Powerhouse	712.1	5,025.6			5,737.7
Garage/Office	456.5	53.8			510.3
Fuel storage		1,525.9			1,525.9
Mayo to Dawson substation	2,574.3		0.0	190.0	2,764.3
Residence: 833-6th Avenue	154.0				154.0
Garage: 1136-5th Avenue	32.7				32.7
Residence: 1136-5th Avenue	115.2				115.2
Residence: 626-6th Avenue	232.2				232.2
Residence: 817-6th Avenue	216.4				216.4
Total Dawson City	4,493.5	6,605.2	0.0	190.0	11,288.8
Yukon Development Corporation					
Office furniture and equipment		244.5			244.5
		244.5			244.5

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2007

$=000's

Location	Buildings	Machinery & Equipment	Contents	Inventory	Total
2004 Additions	3,747.1				3,747.1
2005 Additions	5,681.3				5,681.3
2006 Additions	4,804.6				4,804.6
GRAND TOTAL	**369,145.9**	**180,114.7**	**329.1**	**2,647.0**	**552,236.6**

1 Stated value includes value of dam, intake structures, penstocks, power canals and other waterway improvements

Transmission & Distribution Power Line Assets

138 Kv 520 kms					
69 Kv 274 kms					
25-34.5 Kv 195 kms					
below 25Kv 300 kms		67,500.0	0.0	0.0	67,500.0

This Summary of Values is issued for information purposes only, and does not form a part of the policy. However, we do certify that the values shown reflect our best and most current valuation,and acknowledge that these values form the basis upon which the policy is to be issued.

Signature

Date

Title

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2008

$=000's

Location		Building	Machinery & Equipment	Contents	Inventory	Total
Whitehorse, Y.T.						
Hydro Powerhouse 1, 2 & 3		18,802.5	34,761.4			53,563.95
Diesel Powerhouse 1, 2 & 3		3,146.9	33,129.9			36,276.78
Yard and outside	1	151,778.3	17,490.2			169,268.51
McIntyre Substation		142.2	11.6			153.85
Sluice Gate Diesel Generator Building		24.6	95.2			119.83
Powerhouse 4		18,597.5	30,531.5			49,129.09
Substation Across River		83.6	0.0			83.63
Fish Hatchery		360.0	212.1			572.05
Fish Ladder/Viewing Centre		3,397.0	0.0			3,397.02
Valuable Papers		0.0	0.0	329.1		329.05
File Storage Trailer		126.9	14.5			141.38
Double-Wide Office Trailer		105.3	30.2			135.47
Single-Wide Office Trailer		98.5	31.4			129.88
Administration Office		3,353.5	1,202.0			4,555.50
Kulan warehouse		233.5	149.3		1,700.0	2,082.77
Cold Storage Building		193.2	29.0		250.0	472.26
Control Building- S150		142.4	77.8			220.20
Marsh Lake Control Structure		17,081.7	0.0			17,081.73
Misc Substation equipment			4,816.3			4,816.30
Sub-Total		217,667.7	122,582.5	329.1	1,950.0	342,529.26
Wind Turbines						
Vestas		2,830.4		0.0	0.0	2,830.45
Bonus		1,216.0		0.0	0.0	1,215.99
Sub-Total		4,046.4		0.0	0.0	4,046.44
Total Whitehorse		221,714.1	122,582.5	329.1	1,950.0	346,575.69

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2008

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Aishihik, Y.T.					
Roads & Bridges	3,690.6	0.0			3,690.57
Service Building	1,992.7	2,402.0			4,394.71
Aishihik Substation		3,855.4			3,855.36
Takhini Substation	77.7	7,688.6			7,766.32
Access Shaft	11,209.2	277.0			11,486.22
Garage and Carpentry Shop	47.2	4.6			51.81
Residence	256.4	23.2			279.64
Storage Shed	20.9	0.0			20.92
Intake Structure	4,304.7	0.0			4,304.75
By-Pass Tunnel	2,076.1	0.0			2,076.12
Tail Race Tunnel	23,652.1	0.0			23,652.08
Tail Race Improvements	8,249.5	0.0			8,249.51
Pressure Tunnel	15,037.1	0.0			15,037.08
Penstocks	3,972.2	0.0			3,972.24
Hydro Powerhouse	9,569.3	22,900.1			32,469.44
Surge Chamber/DR Tube Gallery	3,480.1	35.3			3,515.41
Control Building Canyon Lake	395.1	13.3			408.39
Sub-Total	88,031.0	37,199.6	0.0	0.0	125,230.57
Dam Structures					
Aishihik Lake Control Structure	8,333.3		0.0	0.0	8,333.32
Power Canal	28,854.1		0.0	0.0	28,854.05
Sekulman River Improvements	2,590.0		0.0	0.0	2,589.99
Aishihik Lake Boat Launch	824.4		-	-	824.40
Canyon Lake Control Structure	4,300.6		0.0	0.0	4,300.63
Sub-Total	44,902.4		0.0	0.0	44,902.40
Total Aishihik	132,933.4	37,199.6	0.0	0.0	170,133.0

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2008

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Faro, Y.T.					
Diesel Powerhouse - FD1	935.5	6,916.2			7,851.69
Power House #2 - FD7	513.0	3,694.8			4,207.72
Yard/Diesel Plants - FD2, 3, 4, 6 only	0.0	1,894.0	0.0	0.0	1,893.99
Substation	38.3	144.3		0.0	182.56
Anvil Substation	0.0	5,045.2			5,045.20
Warehouse	196.9	2,254.2			2,451.13
Electrical Structure	0.0	695.0			694.96
Fuel Storage System	0.0	876.1			876.11
Transmission and Distribution Inventory	0.0	0.0		126.0	126.00
Fuel Building	28.4	16.3			44.71
Total Faro	1,712.1	21,536.0	0.0	126.0	23,374.07
Mayo Y.T.					
Hydro Powerhouse	7,181.6	18,193.2			25,374.83
Intake Structure	1,599.3	0.0			1,599.34
Tunnel, Penstocks & Surge Tank	9,726.6	0.0			9,726.56
Substation	0.0	2,069.4			2,069.44
Office/Warehouse	205.3	0.0			205.32
Powerhouse Armco Steel Building	89.3				89.31
Mayo-Dawson substation	3,091.5		0.0	0.0	3,091.51
Road and Land Improvements	4,954.7				4,954.65
Transmission and Distribution Inventory				110.0	110.00
Total Mayo	26,848.3	20,262.7	0.0	110.0	47,221.0
Mayo Townsite					
Warehouse/Diesel Yard	165.8	11.1			176.91
Office/Warehouse Downtown	585.9	73.8			659.67
Diesel Supplies Shed-Diesel Yard	26.0	858.1		271.0	1,155.09
Diesel Generators and Accessory Equipment		3,307.3			3,307.34
Total Mayo Townsite	777.7	4,250.3	0.0	271.0	5,299.0

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2008

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Mayo Dam Structures					
Mayo Lake Dam	9,684.0				9,683.97
Wareham Dam	26,312.1				26,312.15
River Improvements - Tail Race	774.9				774.94
Total Mayo Dam Structures	36,771.1		0.0	0.0	36,771.1
Dawson City, YT					
Diesel Powerhouse	855.1	5,970.2			6,825.30
Garage/Office	543.8	63.9			607.75
Fuel storage	0.0	1,812.6			1,812.65
Mayo to Dawson substation	3,091.5		0.0	190.0	3,281.51
Residence: 833-6th Avenue	183.5				183.50
Garage: 1136-5th Avenue	38.9				38.88
Residence: 1136-5th Avenue	137.3				137.26
Residence: 817-6th Avenue	257.8				257.75
Total Dawson City	5,107.9	7,846.7	0.0	190.0	13,144.6
Yukon Development Corporation					

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2008

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
2004 Additions	4,499.9				4,499.86
2005 Additions	6,822.6				6,822.60
2006 Additions	5,769.8				5,769.81
2007 Additions	6,356.5				6,356.48
2008 Additions	12,826.0				12,826.00
GRAND TOTAL	**462,139.2**	**213,677.9**	**329.1**	**2,647.0**	**678,793.1**

1 Stated value includes value of dam, intake structures, penstocks, power canals and other waterway improvements

Transmission & Distribution Power Line Assets

138 Kv 520 kms					
69 Kv 274 kms					
25-34.5 Kv 195 kms					
below 25Kv 300 kms		109,841.0	0.0	0.0	109,841.03

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Signature

Date

Title

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2009

$=000's

Location		Building	Machinery & Equipment	Contents	Inventory	Total
Whitehorse, Y.T.						
Hydro Powerhouse 1, 2 & 3		17,862.4	32,710.5			50,572.9
Diesel Powerhouse 1, 2 & 3		2,989.6	31,175.2			34,164.8
Yard and outside	1	144,189.4	16,458.3			160,647.7
McIntyre Substation		135.1	10.9			146.1
Sluice Gate Diesel Generator Building		23.4	89.6			113.0
Powerhouse 4		17,667.7	28,730.2			46,397.9
Substation Across River		79.4	0.0			79.4
Fish Hatchery		342.0	199.5			541.5
Fish Ladder/Viewing Centre		3,227.2	0.0			3,227.2
Valuable Papers		0.0	0.0	329.1		329.1
File Storage Trailer		118.5	13.7			132.1
Double-Wide Office Trailer		98.3	28.4			126.7
Single-Wide Office Trailer		92.0	29.5			121.5
Administration Office		3,132.1	1,131.1			4,263.3
Kulan warehouse		218.1	140.5		1,700.0	2,058.6
Cold Storage Building		180.5	27.3		250.0	457.8
Control Building- S150		133.0	73.2			206.2
Marsh Lake Control Structure		16,227.6	0.0			16,227.6
Misc Substation equipment			4,532.1			4,532.1
Sub-Total		206,716.2	115,350.2	329.1	1,950.0	324,345.45
Wind Turbines						
Vestas		2,688.9		0.0	0.0	2,688.9
Bonus		1,155.2		0.0	0.0	1,155.2
Sub-Total		3,844.12		0.0	0.0	3,844.12
Total Whitehorse		210,560.3	115,350.2	329.1	1,950.0	328,189.57

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2009

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Aishihik, Y.T.					
Roads & Bridges	3,506.0	0.0			3,506.0
Service Building	1,861.2	2,260.3			4,121.5
Aishihik Substation		3,627.9			3,627.9
Takhini Substation	73.8	7,235.0			7,308.8
Access Shaft	10,648.8	260.6			10,909.4
Garage and Carpentry Shop	44.8	4.4			49.2
Residence	239.5	21.9			261.3
Storage Shed	19.5	0.0			19.5
Intake Structure	4,089.5	0.0			4,089.5
By-Pass Tunnel	1,972.3	0.0			1,972.3
Tail Race Tunnel	22,469.5	0.0			22,469.5
Tail Race Improvements	7,837.0	0.0			7,837.0
Pressure Tunnel	14,285.2	0.0			14,285.2
Penstocks	3,773.6	0.0			3,773.6
Hydro Powerhouse	9,090.8	21,549.0			30,639.9
Surge Chamber/DR Tube Gallery	3,306.1	33.2			3,339.3
Control Building Canyon Lake	375.3	12.5			387.9
Sub-Total	83,593.1	35,004.8	0.0	0.0	118,597.92
Dam Structures					
Aishihik Lake Control Structure	7,916.7		0.0	0.0	7,916.7
Power Canal	27,411.3		0.0	0.0	27,411.3
Sekulman River Improvements	2,460.5		0.0	0.0	2,460.5
Aishihik Lake Boat Launch	783.2		-	-	783.2
Canyon Lake Control Structure	4,085.6		0.0	0.0	4,085.6
Sub-Total	42,657.3		0.0	0.0	42,657.3
Total Aishihik	126,250.4	35,004.8	0.0	0.0	161,255.2

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2009

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Faro, Y.T.					
Diesel Powerhouse - FD1	888.7	6,508.2			7,396.9
Power House #2 - FD7	487.3	3,476.8			3,964.1
Yard/Diesel Plants - FD2, 3, 4, 6 only	0.0	1,782.2	0.0	0.0	1,782.2
Substation	36.4	135.8		0.0	172.1
Anvil Substation	0.0	4,747.5			4,747.5
Warehouse	187.1	2,121.2			2,308.3
Electrical Structure	0.0	654.0			654.0
Fuel Storage System	0.0	824.4			824.4
Transmission and Distribution Inventory	0.0	0.0		126.0	126.0
Fuel Building	27.0	15.3			42.3
Total Faro	1,626.5	20,265.4	0.0	126.0	22,017.8
Mayo Y.T.					
Hydro Powerhouse	6,822.5	17,119.8			23,942.4
Intake Structure	1,519.4	0.0			1,519.4
Tunnel, Penstocks & Surge Tank	9,240.2	0.0			9,240.2
Substation	0.0	1,947.3			1,947.3
Office/Warehouse	191.8				191.8
Powerhouse Armco Steel Building	84.8				84.8
Mayo-Dawson substation	2,936.9		0.0	0.0	2,936.9
Road and Land Improvements	4,706.9				4,706.9
Transmission and Distribution Inventory				110.0	110.0
Total Mayo	25,502.6	19,067.2	0.0	110.0	44,679.8

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2009
$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Mayo Townsite					
Warehouse/Diesel Yard	157.6	10.4			168.0
Office/Warehouse Downtown	547.2	69.4			616.6
Diesel Supplies Shed-Diesel Yard	24.7	807.5		271.0	1,103.2
Diesel Generators and Accessory Equipment		3,112.2			3,112.2
Total Mayo Townsite	729.4	3,999.5	0.0	271.0	5,000.0
Mayo Dam Structures					
Mayo Lake Dam	9,199.8				9,199.8
Wareham Dam	24,996.5				24,996.5
River Improvements - Tail Race	736.2				736.2
Total Mayo Dam Structures	34,932.5		0.0	0.0	34,932.5
Dawson City, YT					
Diesel Powerhouse	812.4	5,617.9			6,430.3
Garage/Office	507.9	60.1			568.1
Fuel storage		1,705.7			1,705.7
Mayo to Dawson substation	2,936.9		0.0	190.0	3,126.9
Residence: 833-6th Avenue	171.4				171.4
Garage: 1136-5th Avenue	36.3				36.3
Residence: 1136-5th Avenue	128.2				128.2
Residence: 817-6th Avenue	240.7				240.7
Total Dawson City	4,833.9	7,383.8	0.0	190.0	12,407.7

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2009

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Yukon Development Corporation					
2004 Additions	4,274.9				4,274.9
2005 Additions	6,481.5				6,481.5
2006 Additions	5,481.3				5,481.3
2007 Additions	6,038.7				6,038.7
2008 Additions	12,184.7				12,184.7
2009 Additions	6,093.5				6,093.5
GRAND TOTAL	**444,990.1**	**201,070.9**	**329.1**	**2,647.0**	**649,037.0**

1 Stated value includes value of dam, intake structures, penstocks, power canals and other waterway improvements

Transmission & Distribution Power Line Assets					
138 Kv 520 kms					
69 Kv 274 kms					
25-34.5 Kv 195 kms					
below 25Kv 300 kms		103,360.4	0.0	0.0	103,360.4

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Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2010

$=000's

Location		Building	Machinery & Equipment	Contents	Inventory	Total
Whitehorse, Y.T.						
Hydro Powerhouse 1, 2 & 3		17,808.8	32,579.7			50,388.5
Diesel Powerhouse 1, 2 & 3		2,980.6	31,050.5			34,031.1
Yard and outside	1	143,756.8	16,392.4			160,149.3
McIntyre Substation		134.7	10.9			145.6
Sluice Gate Diesel Generator Building		23.3	89.3			112.6
Powerhouse 4		17,614.7	28,615.3			46,229.9
Substation Across River		79.2	0.0			79.2
Fish Hatchery		341.0	198.7			539.7
Fish Ladder/Viewing Centre		3,217.5	0.0			3,217.5
Valuable Papers		0.0	0.0	329.1		329.1
File Storage Trailer		117.8	13.6			131.4
Double-Wide Office Trailer		97.7	28.3			126.0
Single-Wide Office Trailer		91.5	29.4			120.9
Administration Office		3,113.3	1,126.6			4,239.9
Kulan warehouse		216.7	139.9		1,700.0	2,056.7
Cold Storage Building		179.4	27.2		250.0	456.6
Control Building- S150		132.2	72.9			205.1
Marsh Lake Control Structure		16,179.0	0.0			16,179.0
Misc Substation equipment			4,514.0			4,514.0
Sub-Total		206,084.2	114,888.8	329.1	1,950.0	323,252.0
Wind Turbines						
Vestas		2,680.9		0.0	0.0	2,680.9
Bonus		1,151.7		0.0	0.0	1,151.7
Sub-Total		3,832.6	0.0	0.0	0.0	3,832.6
Total Whitehorse		209,916.7	114,888.8	329.1	1,950.0	327,084.6

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2010

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Aishihik, Y.T.					
Roads & Bridges	3,495.5	0.0			3,495.5
Service Building	1,850.0	2,251.2			4,101.3
Aishihik Substation		3,613.4			3,613.4
Takhini Substation	73.6	7,206.1			7,279.6
Access Shaft	10,616.8	259.6			10,876.4
Garage and Carpentry Shop	44.7	4.4			49.0
Residence	238.0	21.8			259.8
Storage Shed	19.4	0.0			19.4
Intake Structure	4,077.2	0.0			4,077.2
By-Pass Tunnel	1,966.4	0.0			1,966.4
Tail Race Tunnel	22,402.1	0.0			22,402.1
Tail Race Improvements	7,813.5	0.0			7,813.5
Pressure Tunnel	14,242.4	0.0			14,242.4
Penstocks	3,762.3	0.0			3,762.3
Hydro Powerhouse	9,063.6	21,462.8			30,526.4
Surge Chamber/DR Tube Gallery	3,296.2	33.1			3,329.3
Control Building Canyon Lake	374.2	12.5			386.7
Sub-Total	83,336.0	34,864.8	0.0	0.0	118,200.8
Dam Structures					
Aishihik Lake Control Structure	7,892.9		0.0	0.0	7,892.9
Power Canal	27,329.1		0.0	0.0	27,329.1
Sekulman River Improvements	2,453.1		0.0	0.0	2,453.1
Aishihik Lake Boat Launch	780.8		-	-	780.8
Canyon Lake Control Structure	4,073.3		0.0	0.0	4,073.3
Sub-Total	42,529.3	0.0	0.0	0.0	42,529.3
Total Aishihik	125,865.3	34,864.8	0.0	0.0	160,730.1

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2010

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Faro, Y.T.					
Diesel Powerhouse - FD1	886.0	6,482.1			7,368.2
Power House #2 - FD7	485.8	3,462.9			3,948.7
Yard/Diesel Plants - FD2, 3, 4, 6 only	0.0	1,775.1	0.0	0.0	1,775.1
Substation	36.2	135.2		0.0	171.5
Anvil Substation	0.0	4,728.5			4,728.5
Warehouse	186.5	2,112.7			2,299.2
Electrical Structure	0.0	651.3			651.3
Fuel Storage System	0.0	821.1			821.1
Transmission and Distribution Inventory	0.0	0.0		126.0	126.0
Fuel Building	26.9	15.2			42.2
Total Faro	1,621.6	20,184.3	0.0	126.0	21,931.9
Mayo Y.T.					
Hydro Powerhouse	6,802.0	17,051.4			23,853.4
Intake Structure	1,514.8	0.0			1,514.8
Tunnel, Penstocks & Surge Tank	9,212.5	0.0			9,212.5
Substation	0.0	1,939.6			1,939.6
Office/Warehouse	190.6				190.6
Powerhouse Armco Steel Building	84.6				84.6
Mayo-Dawson substation	2,928.1		0.0	0.0	2,928.1
Road and Land Improvements	4,692.8				4,692.8
Transmission and Distribution Inventory				110.0	110.0
Total Mayo	25,425.5	18,990.9	0.0	110.0	44,526.4

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2010

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Mayo Townsite					
Warehouse/Diesel Yard	157.1	10.4			167.4
Office/Warehouse Downtown	543.9	69.2			613.1
Diesel Supplies Shed-Diesel Yard	24.6	804.3		271.0	1,099.9
Diesel Generators and Accessory Equipment		3,099.8			3,099.8
Total Mayo Townsite	725.6	3,983.5	0.0	271.0	4,980.1
Mayo Dam Structures					
Mayo Lake Dam	9,172.2				9,172.2
Wareham Dam	24,921.6				24,921.6
River Improvements - Tail Race	734.0				734.0
Total Mayo Dam Structures	34,827.7	0.0	0.0	0.0	34,827.7
Dawson City, YT					
Diesel Powerhouse	809.9	5,595.5			6,405.4
Garage/Office	504.9	59.9			564.8
Fuel storage		1,698.9			1,698.9
Mayo to Dawson substation	2,928.1		0.0	190.0	3,118.1
Residence: 833-6th Avenue	170.4				170.4
Garage: 1136-5th Avenue	36.1				36.1
Residence: 1136-5th Avenue	127.4				127.4
Residence: 817-6th Avenue	239.3				239.3
Total Dawson City	4,816.1	7,354.2	0.0	190.0	12,360.4

Yukon Energy Corporation Replacement Cost Insurable Values

Effective December 2010

$=000's

Location	Building	Machinery & Equipment	Contents	Inventory	Total
Yukon Development Corporation					
2004 Additions	4,262.0				4,262.0
2005 Additions	6,462.0				6,462.0
2006 Additions	5,464.9				5,464.9
2007 Additions	6,020.5				6,020.5
2008 Additions	12,148.1				12,148.1
2009 Additions	6,093.5				6,093.5
2010 Additions	24,492.9				24,492.9
GRAND TOTAL	**443,649.7**	**200,266.6**	**329.1**	**2,647.0**	**671,385.2**

1Stated value includes value of dam, intake structures, penstocks, power canals and other waterway improvements

Transmission & Distribution Power Line Assets

138 Kv 520 kms 69 Kv 274 kms 25-34.5 Kv 195 kms below 25Kv 300 kms		102,947.0	0.0	0.0	102,947.0

This Summary of Values is issued for information purposes only, and does not form a part of the policy. However, we do certify that the values shown reflect our best and most current valuation,and acknowledge that these values form the basis upon which the policy is to be issued.

Signature

Date

Title

TOPIC: **Map of System**

REFERENCE: **General**

PREAMBLE:

CW wishes to better understand YEC's proposed capital additions and system operation.

QUESTION:

a) Please provide a current 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)

A current map of Yukon power facilities is provided as Attachment 1 to this response.

Figure 1: Generation Capacity in Yukon 2011 Current & Committed

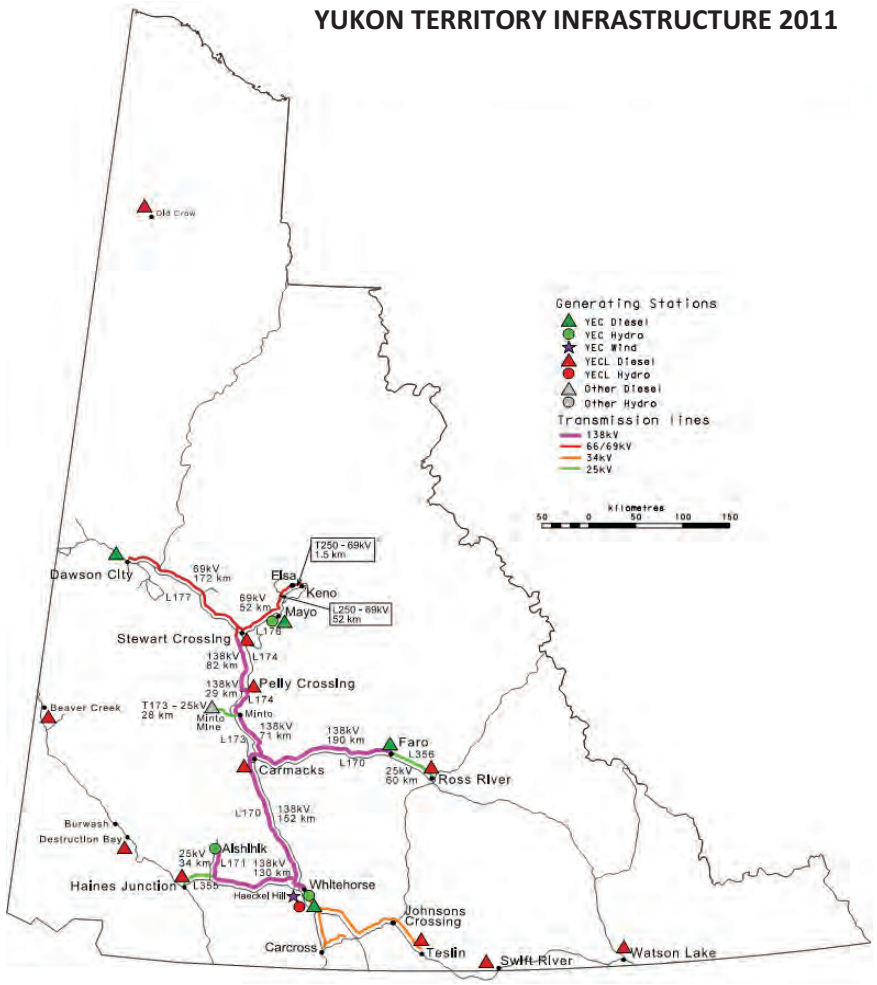
Yukon Energy Generation Assets
(in MW installed & current rating)

Hydro Facilities			
	Whitehorse	WAF	40.0
	Aishihik	WAF	37.0 *
	Mayo	MD	15.4 **
	Total Hydro		**92.4**
Wind Facilities			
	Haeckel Hill	WAF	**0.8**
Diesel Facilities			
	Whitehorse	WAF	22.5
	Faro	WAF	8.9
	Dawson	MD	4.0
	Mayo	MD	1.7
	Mobile Diesel		1.6
	Total Diesel		**38.6**
TOTAL YUKON ENERGY			**131.8**

YECL Generation Assets
(in MW installed)

Hydro Facilities			
	Fish Lake	WAF	1.3
Base Load Diesel Facilities			
	Old Crow	Isolated	1.1
	Beaver Creek	Isolated	1.0
	Destruction Bay	Isolated	0.9
	Swift River	Isolated	0.2
	Watson Lake	Watson Lake	5.3
Back-up Diesel Facilities			
	Carmacks	WAF	1.6
	Pelly Crossing	WAF	1.0
	Teslin	WAF	1.5
	Haines Junction	WAF	1.8
	Stewart Crossing	MD	0.4
	Ross River	WAF	1.0
	Mobile		1.1
	Total Diesel		**16.7**
TOTAL YECL			**18.0**
TOTAL YUKON			**149.9 (YEC + YECL)**

* Ashihik 3rd Turbine (7MW) committed in 2011
** Mayo B (10 MW) committed by end of 2011



Leading Edge
(LE)

TOPIC:

REFERENCE: Page 1-1

PREAMBLE:

Yukon Energy is seeking its first increase in retail rates since the 1998-1999 period."

QUESTION:

a) Please provide the rate schedules (including all riders) that outline all charges applicable to each of residential non-government and general service non-government customers resulting from the 1998-1999 adjustments.

b) Please provide the rate schedules (including all riders) that outline all charges applicable to residential non-government and general service non-government customers resulting from the 2008-2009 GRA Phase II YUB decisions.

c) What were Yukon Energy's total sales in 1999?

d) What were Yukon Energy's total revenues in 1999?

e) What were Yukon Energy's total sales in 2011?

f) What were Yukon Energy's total revenues in 2011?

g) Does Yukon Energy not consider Rider F which as at May 1, 2012 is at 0.420 cents per kWh a rate that Yukon consumers must pay?

h) Does Yukon Energy not consider the fixed monthly charge a rate that Yukon consumers must pay?

ANSWER:

(a)

Please see Attachment 1 to this response.

Please note that the attachment includes Rider J at 18.74% which was approved by Yukon Utilities Board Order 1999-5. Please note that the Rider J was reduced from 18.74% to 14.93% by Yukon Utilities Board Order 2003-2 effective January 1, 2003.

(b)

Please see Attachment 1 to this response.

(c) through **(f)**

Please see Table 1 below.

Table 1:
YEC's Total Sales and Revenues from Sales for 1999 and 2011

		1999	2011
Total Sales	GW.h	251.4	368.7
Total Revenues from Sales	$millions	23.2	34.0

(g)

Rider F is a rate paid by/refunded to Yukon consumers to reflect fluctuations in the prices for which the YEC and YECL pay for diesel fuel, without the requirement for specific application to, and approval from, the Board. Rider F is not part of the revenue requirement review process and not part of the base rates approved based on revenue requirement reviews.

(h)

Yukon Energy considers each part of the rates as approved by the Board a rate that Yukon consumers must pay, including any monthly fixed charges approved by the Yukon Utilities Board based on consolidated YEC and YECL revenue requirements and cost of service study reviews. The cost of the fixed monthly charge, up until July 1, 2011, included both the base component plus the Rider J applied to these amounts as a percentage. This Rider J amount was rolled into base rates at July 1, 2011. Since the 1996/97 GRA, the only reason for changes in the effective cost of the fixed monthly

charge is the implementation of Rider J in 1998/1999 and the subsequent reductions to Rider J in 2003 and 2008/09.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: ***1997 01 01***
Supercedes: 1996 07 01

RATE SCHEDULE - 1160

RESIDENTIAL SERVICE

HYDRO, NON-GOVERNMENT

AVAILABLE:

In Carcross, Carmacks, Champagne, Elsa, Faro, Haines Junction, Johnson's Crossing, Keno, Marsh Lake, Mayo, Ross River, Tagish, Teslin and Whitehorse.

APPLICABLE:

To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

RATE:

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

(a)	Customer Charge	$11.90
(b)	Energy Charge	
	For the first 1,000 kW.h	9.86¢/kW.h
	All over 1,000 kW.h	10.45¢/kW.h

MINIMUM MONTHLY BILL:

Shall be $11.90.

RATE MODIFICATIONS APPLICABLE:

For multiple residence service on one meter, see Rider A; 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.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: ***1997 01 01***
Supercedes: 1996 07 01
Page 1 of 1

RATE SCHEDULE - 1260

RESIDENTIAL SERVICE

SMALL DIESEL, NON - GOVERNMENT

AVAILABLE:

In Beaver Creek, Burwash, Destruction Bay, Pelly Crossing, Stewart Crossing and Swift River.

APPLICABLE:

To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

RATE:

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

(a)	Customer Charge	$11.90
(b)	Energy Charge	
	For the first 1,000 kW.h	9.86¢/kW.h
	All over 1,000 kW.h	12.36¢/kW.h

MINIMUM MONTHLY BILL:

Shall be $11.90.

RATE MODIFICATIONS APPLICABLE:

For multiple residence service on one meter, see Rider A; 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.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: *1997 01 01*
Supercedes: 1996 07 01

RATE SCHEDULE - 1360

RESIDENTIAL SERVICE

LARGE DIESEL, NON - GOVERNMENT

AVAILABLE: In Watson Lake, Dawson, Upper Liard and Lower Post.

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

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

(a)	Customer Charge	$11.90
(b)	Energy Charge	
	For the first 1,000 kW.h	9.86¢/kW.h
	All over 1,000 kW.h	10.45¢/kW.h

MINIMUM MONTHLY BILL: Shall be $11.90.

RATE MODIFICATIONS APPLICABLE: For multiple residence service on one meter, see Rider A; 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.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: *1997 01 01*
Supercedes: 1996 07 01

RATE SCHEDULE - 1460

RESIDENTIAL SERVICE

OLD CROW DIESEL, NON - GOVERNMENT

AVAILABLE: In Old Crow.

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

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

(a)	Customer Charge	$11.90
(b)	Energy Charge	
	For the first 1,000 kW.h	9.86¢/KW.h
	All over 1,000 kW.h	25.77¢/kW.h

MINIMUM MONTHLY BILL: Shall be $11.90.

RATE MODIFICATIONS APPLICABLE: For multiple residence service on one meter, see Rider A; 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.

RATE SCHEDULE - 2160

GENERAL SERVICE

HYDRO, NON - GOVERNMENT

AVAILABLE:

In Carcross, Carmacks, Champagne, Elsa, Faro, Haines Junction, Johnson's Crossing, Keno, Marsh Lake, Mayo, Ross River, Tagish, Teslin and Whitehorse.

APPLICABLE:

To any use of electric energy not inconsistent with safe and adequate service to all non - government customers of the Company, except as more favorable options may apply.

RATE:

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

(a) Demand Charge

All kW of billing demand	$6.00 per kW

(b) Energy charge

For the first 2,000 kW.h	8.31¢ per kW.h
For energy in excess of 2,000 kW.h	10.45¢ per kW.h

MINIMUM MONTHLY BILL:

Shall be the Demand Charge but not less than $30.00.

BILLING DEMAND:

The billing demand may be estimated or measured and will be the greater of the following:

(a) The highest metered demand during the billing period.

(b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September.

(c) The estimated demand.

(d) 5 kilowatts.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: ***1997 01 01***
Supercedes: 1996 07 01
Page 2 of 2

Rate Schedule - 2160 (Continued)

POWER FACTOR:

The foregoing rate is designed on the assumption that the customer will maintain a power factor of 90 percent or better during the period of his peak load. In those cases in which, by estimate or test, such power factor is not maintained, the customer's demand will be measured in kV.A and for the purposes of application of the foregoing rate, one kV.A shall be taken as one kW.

RATE MODIFICATIONS APPLICABLE:

For customers who have small constant loads, and whose monthly energy requirements can be estimated closely, see Rider B. 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.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: ***1997 01 01***
Supercedes: 1996 07 01

RATE SCHEDULE - 2260

GENERAL SERVICE

SMALL DIESEL, NON - GOVERNMENT

AVAILABLE: In Beaver Creek, Burwash, Destruction Bay, Pelly Crossing, Stewart Crossing and Swift River.

APPLICABLE: To any use of electric energy not inconsistent with safe and adequate service to all non - government customers of the Company, except as more favorable options may apply.

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

(a) Demand Charge

All kW of billing demand	$6.00 per kW

(b) Energy charge

For the first 2,000 kW.h	8.31¢ per kW.h
For energy in excess of 2,000 kW.h	12.36¢ per kW.h

MINIMUM MONTHLY BILL: Shall be the Demand Charge but not less than $30.00.

BILLING DEMAND: The billing demand may be estimated or measured and will be the greater of the following:

(a) The highest metered demand during the billing period.

(b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September.

(c) The estimated demand.

(d) 5 Kilowatts.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: *1997 01 01*
Supercedes: 1996 07 01

Rate Schedule - 2260 (Continued)

POWER FACTOR:

The foregoing rate is designed on the assumption that the customer will maintain a power factor of 90 percent or better during the period of his peak load. In those cases in which, by estimate or test, such power factor is not maintained, the customer's demand will be measured in kV.A and for the purposes of application of the foregoing rate, one kV.A shall be taken as one kW.

RATE MODIFICATIONS APPLICABLE:

For customers who have small constant loads, and whose monthly energy requirements can be estimated closely, see Rider B. 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.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: ***1997 01 01***
Supercedes: 1996 07 01

RATE SCHEDULE - 2360

GENERAL SERVICE

LARGE DIESEL, NON - GOVERNMENT

AVAILABLE: In Watson Lake, Dawson, Upper Liard and Lower Post.

APPLICABLE: To any use of electric energy not inconsistent with safe and adequate service to all non - government customers of the Company, except as more favorable options may apply.

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

(a) Demand Charge

All kW of billing demand	$6.00 per kW

(b) Energy charge

For the first 2,000 kW.h	8.31¢ per kW.h
For energy in excess of 2,000 kW.h	10.45¢ per kW.h

MINIMUM MONTHLY BILL: Shall be the Demand Charge but not less than $30.00.

BILLING DEMAND: The billing demand may be estimated or measured and will be the greater of the following:

(a) The highest metered demand during the billing period.

(b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September.

(c) The estimated demand.

(d) 5 Kilowatts.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: ***1997 01 01***
Supercedes: 1996 07 01

Rate Schedule - 2360 (Continued)

POWER FACTOR:

The foregoing rate is designed on the assumption that the customer will maintain a power factor of 90 percent or better during the period of his peak load. In those cases in which, by estimate or test, such power factor is not maintained, the customer's demand will be measured in kV.A and for the purposes of application of the foregoing rate, one kV.A shall be taken as one kW.

RATE MODIFICATIONS APPLICABLE:

For customers who have small constant loads, and whose monthly energy requirements can be estimated closely, see Rider B. 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.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: ***1997 01 01***
Supercedes: 1996 07 01

RATE SCHEDULE - 2460

GENERAL SERVICE

OLD CROW DIESEL, NON - GOVERNMENT

AVAILABLE: In Old Crow.

APPLICABLE: To any use of electric energy not inconsistent with safe and adequate service to all non - government customers of the Company, except as more favorable options may apply.

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

(a) Demand Charge

All kW of billing demand	$6.00 per kW

(b) Energy charge

For the first 2,000 kW.h	8.31¢ per kW.h
For energy in excess of 2,000 kW.h	25.77¢ per kW.h

MINIMUM MONTHLY BILL: Shall be the Demand Charge but not less than $30.00.

BILLING DEMAND: The billing demand may be estimated or measured and will be the greater of the following:

(a) The highest metered demand during the billing period.

(b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September.

(c) The estimated demand.

(d) 5 Kilowatts.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: ***1997 01 01***
Supercedes: 1996 07 01

Rate Schedule - 2460 (Continued)

POWER FACTOR:

The foregoing rate is designed on the assumption that the customer will maintain a power factor of 90 percent or better during the period of his peak load. In those cases in which, by estimate or test, such power factor is not maintained, the customer's demand will be measured in kV.A and for the purposes of application of the foregoing rate, one kV.A shall be taken as one kW.

RATE MODIFICATIONS APPLICABLE:

For customers who have small constant loads, and whose monthly energy requirements can be estimated closely, see Rider B. 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.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

Effective: ***1999 12 01***
Supercedes: 1998 09 01
Page 1 of 2

RIDER J

YUKON ENERGY CORPORATION REVENUE SHORTFALL RIDER

AVAILABLE: To all electric service throughout the Yukon Territory.

APPLICABLE: To all electric service retail rates except Rate Schedule 32 and Rate Schedule 39, to recover the approved 1997 revenue shortfall resulting from Anvil's Faro mine closure in 1997.

RATE: Surcharge rider of 18.74% to all customers other than Rate Schedule 32 and Rate Schedule 39 customers.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

RATE SCHEDULE - 1160
RESIDENTIAL SERVICE
HYDRO, NON-GOVERNMENT

AVAILABLE:

In Carcross, Carmacks, Champagne, Dawson, Elsa, Faro, Haines Junction, Johnson's Crossing, Keno, Marsh Lake, Mayo, Pelly Crossing, Stewart Crossing, Ross River, Tagish, Teslin and Whitehorse.

APPLICABLE:

To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

RATE:

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

(a)	Customer Charge	$14.65
(b)	Energy Charge	
	For the first 1,000 kW.h	12.14¢/kW.h
	Between 1,001 - 2,500 kW.h	12.82¢/kW.h
	For energy in excess 2,500 kW.h	13.99¢/kW.h

MINIMUM MONTHLY BILL:

The minimum monthly charge is the customer charge of $14.65.

RATE MODIFICATIONS APPLICABLE:

For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

TERMS AND CONDITIONS OF SERVICE:

The Company's Terms and Conditions of Service 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 Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

RATE SCHEDULE - 1260
RESIDENTIAL SERVICE
SMALL DIESEL, NON – GOVERNMENT

AVAILABLE: In Beaver Creek, Burwash, Destruction Bay and Swift River.

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

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

(a)	Customer Charge	$14.65
(b)	Energy Charge	
	For the first 1,000 kW.h	12.14¢/kW.h
	Between 1,001 - 2,500 kW.h	12.82¢/kW.h
	For energy in excess 2,500 kW.h	13.99¢/kW.h

MINIMUM MONTHLY BILL: The minimum monthly charge is the customer charge of $14.65.

RATE MODIFICATIONS APPLICABLE: For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

TERMS AND CONDITIONS OF SERVICE: The Company's Terms and Conditions of Service 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 Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

RATE SCHEDULE - 1360
RESIDENTIAL SERVICE
LARGE DIESEL, NON – GOVERNMENT

AVAILABLE: In Lower Post, Upper Liard and Watson Lake.

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

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

(a)	Customer Charge	$14.65
(b)	Energy Charge	
	For the first 1,000 kW.h	12.14¢/kW.h
	Between 1,001 - 2,500 kW.h	12.82¢/kW.h
	For energy in excess 2,500 kW.h	13.99¢/kW.h

MINIMUM MONTHLY BILL: The minimum monthly charge is the customer charge of $14.65.

RATE MODIFICATIONS APPLICABLE: For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

TERMS AND CONDITIONS OF SERVICE: The Company's Terms and Conditions of Service 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 Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

RATE SCHEDULE - 1460
RESIDENTIAL SERVICE
OLD CROW DIESEL, NON - GOVERNMENT

AVAILABLE: In Old Crow.

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

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

(a)	Customer Charge	$14.65
(b)	Energy Charge	
	For the first 1,000 kW.h	12.14¢/kW.h
	Between 1,001 - 2,500 kW.h	12.82¢/kW.h
	For energy in excess 2,500 kW.h	30.77¢/kW.h

MINIMUM MONTHLY BILL: The minimum monthly charge is the customer charge of $14.65.

RATE MODIFICATIONS APPLICABLE: For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

TERMS AND CONDITIONS OF SERVICE: The Company's Terms and Conditions of Service 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 Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

RATE SCHEDULE - 2160
GENERAL SERVICE
HYDRO, NON - GOVERNMENT

AVAILABLE:

In Carcross, Carmacks, Champagne, Dawson, Elsa, Faro, Haines Junction, Johnson's Crossing, Keno, Marsh Lake, Mayo, Pelly Crossing, Steward Crossing, Ross River, Tagish, Teslin and Whitehorse.

APPLICABLE:

To any use of electric energy not inconsistent with safe and adequate service to all non - government customers of the Company, except as more favorable options may apply.

RATE:

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

(a) Demand Charge

All kW of billing demand	$7.39 / kW

(b) Energy charge

For the first 2,000 kW.h	10.00 ¢/kW.h
Between 2,001 - 15,000 kW.h	12.88 ¢/kW.h
Between 15,001 - 20,000 kW.h	15.68 ¢/kW.h
For energy in excess of 20,000 kW.h	12.86 ¢/kW.h

MINIMUM MONTHLY BILL:

Shall be the Demand Charge but not less than $36.95.

BILLING DEMAND:

The billing demand may be estimated or measured and will be the greater of the following:

(a) The highest metered demand during the billing period.

(b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September.

(c) The estimated demand.

(d) 5 kilowatts.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

Rate Schedule - 2160 (Continued)

POWER FACTOR:

The foregoing rate is designed on the assumption that the customer will maintain a power factor of 90 percent or better during the period of his peak load. In those cases in which, by estimate or test, such power factor is not maintained, the customer's demand will be measured in kV.A and for the purposes of application of the foregoing rate, one kV.A shall be taken as one kW.

RATE MODIFICATIONS APPLICABLE:

For customers who have small constant loads, and whose monthly energy requirements can be estimated closely, see Rider B. For fuel adjustment Rider, see Rider F.

TERMS AND CONDITIONS OF SERVICE:

The Company's Terms and Conditions of Service 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 Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

RATE SCHEDULE - 2260
GENERAL SERVICE
SMALL DIESEL, NON - GOVERNMENT

AVAILABLE: In Beaver Creek, Burwash, Destruction Bay and Swift River.

APPLICABLE: To any use of electric energy not inconsistent with safe and adequate service to all non - government customers of the Company, except as more favorable options may apply.

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

(a) Demand Charge

All kW of billing demand	$7.39 / kW

(b) Energy charge

For the first 2,000 kW.h	10.00 ¢/kW.h
Between 2,001 - 15,000 kW.h	12.88 ¢/kW.h
Between 15,001 - 20,000 kW.h	15.68 ¢/kW.h
For energy in excess of 20,000 kW.h	15.22 ¢/kW.h

MINIMUM MONTHLY BILL: Shall be the Demand Charge but not less than $36.95.

BILLING DEMAND: The billing demand may be estimated or measured and will be the greater of the following:

(a) The highest metered demand during the billing period.

(b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September.

(c) The estimated demand.

(d) 5 Kilowatts.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

Rate Schedule - 2260 (Continued)

POWER FACTOR:

The foregoing rate is designed on the assumption that the customer will maintain a power factor of 90 percent or better during the period of his peak load. In those cases in which, by estimate or test, such power factor is not maintained, the customer's demand will be measured in kV.A and for the purposes of application of the foregoing rate, one kV.A shall be taken as one kW.

RATE MODIFICATIONS APPLICABLE:

For customers who have small constant loads, and whose monthly energy requirements can be estimated closely, see Rider B. For fuel adjustment Rider, see Rider F.

TERMS AND CONDITIONS OF SERVICE:

The Company's Terms and Conditions of Service 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 Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

RATE SCHEDULE - 2360
GENERAL SERVICE
LARGE DIESEL, NON - GOVERNMENT

AVAILABLE: In Lower Post, Upper Liard and Watson Lake.

APPLICABLE: To any use of electric energy not inconsistent with safe and adequate service to all non - government customers of the Company, except as more favorable options may apply.

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

(a) Demand Charge

All kW of billing demand	$7.39 / kW

(b) Energy charge

For the first 2,000 kW.h	10.00 ¢/kW.h
Between 2,001 - 15,000 kW.h	12.88 ¢/kW.h
Between 15,001 - 20,000 kW.h	15.68 ¢/kW.h
For energy in excess of 20,000 kW.h	12.86 ¢/kW.h

MINIMUM MONTHLY BILL: Shall be the Demand Charge but not less than $36.95.

BILLING DEMAND: The billing demand may be estimated or measured and will be the greater of the following:

(a) The highest metered demand during the billing period.

(b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September.

(c) The estimated demand.

(d) 5 Kilowatts.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

Rate Schedule - 2360 (Continued)

POWER FACTOR:

The foregoing rate is designed on the assumption that the customer will maintain a power factor of 90 percent or better during the period of his peak load. In those cases in which, by estimate or test, such power factor is not maintained, the customer's demand will be measured in kV.A and for the purposes of application of the foregoing rate, one kV.A shall be taken as one kW.

RATE MODIFICATIONS APPLICABLE:

For customers who have small constant loads, and whose monthly energy requirements can be estimated closely, see Rider B. For fuel adjustment Rider, see Rider F.

TERMS AND CONDITIONS OF SERVICE:

The Company's Terms and Conditions of Service 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 Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

RATE SCHEDULE - 2460
GENERAL SERVICE
OLD CROW DIESEL, NON - GOVERNMENT

AVAILABLE: In Old Crow.

APPLICABLE: To any use of electric energy not inconsistent with safe and adequate service to all non - government customers of the Company, except as more favorable options may apply.

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

(a) Demand Charge

All kW of billing demand	$7.39 / kW

(b) Energy charge

For the first 2,000 kW.h	10.00 ¢/kW.h
Between 2,001 - 15,000 kW.h	12.88 ¢/kW.h
Between 15,001 - 20,000 kW.h	15.68 ¢/kW.h
For energy in excess of 20,000 kW.h	31.72 ¢/kW.h

MINIMUM MONTHLY BILL: Shall be the Demand Charge but not less than $36.95.

BILLING DEMAND: The billing demand may be estimated or measured and will be the greater of the following:

(a) The highest metered demand during the billing period.

(b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September.

(c) The estimated demand.

(d) 5 Kilowatts.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 1997 01 01

Rate Schedule - 2460 (Continued)

POWER FACTOR:

The foregoing rate is designed on the assumption that the customer will maintain a power factor of 90 percent or better during the period of his peak load. In those cases in which, by estimate or test, such power factor is not maintained, the customer's demand will be measured in kV.A and for the purposes of application of the foregoing rate, one kV.A shall be taken as one kW.

RATE MODIFICATIONS APPLICABLE:

For customers who have small constant loads, and whose monthly energy requirements can be estimated closely, see Rider B. For fuel adjustment Rider, see Rider F.

TERMS AND CONDITIONS OF SERVICE:

The Company's Terms and Conditions of Service 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 Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2011 07 01
Supercedes: 2005 04 01

RIDER B
UNMETERED GENERAL SERVICE FLAT RATE

AVAILABLE: Throughout the Company's service area.

APPLICABLE: To customers whose use is low or intermittent.

RATE: For service rendered in any one billing month, the kW.h consumption shall be determined from the nameplate rating of the customer's equipment and then calculated at the available General Service rate.

MINIMUM MONTHLY BILL: Shall be the greater of the calculated monthly bill or the minimum of the available General Service rate.

SPECIAL CONDITIONS: To obtain this rate, the customer is required to pay 100 percent of the Company's cost of providing service, including service drop, etc. Ownership of these facilities will remain with, and be maintained by the Company. Should the required extension exceed 300 metres of overhead construction, an extra flat rate amount of $1.80 per 300 metres per month will be charged for maintenance costs.

TOPIC: **CSTP Stage 1**

REFERENCE: **Page 1-4**

PREAMBLE:

"... because of third party contributions..."

QUESTION:

a) Please list all third party contributions to CSTP Stage 1.

ANSWER:

(a)

Page 1-4 of the Application (footnote 9) notes as follows regarding third party contributions to CSTP Stage 1.

- $10.45 million from the Yukon Government;

- $7.2 million from Minto Explorations for the CSTP Main Line and $10.8 million for the Minto Spur line; and

- $7 million from YDC (including approximately $2 million as required by agreement with Yukon Energy pursuant to the Purchase Power Agreement (PPA) with Minto Mine as amended May 14, 2007 [Section 3.1(m)] related to any amount of the Carmacks-Minto Landing Capital Cost Contribution principal amount in excess of $7.2 million as required under Section 5.1 of the PPA as amended).

TOPIC: **Debt Refinancing in 2011**

REFERENCE: **Page 1-5**

PREAMBLE:

QUESTION:

a) What was the amount remaining on the Flex Term Debt and had the term on this instrument expired, and if not what was the end date?

b) What was the amount remaining on the Mayo Dawson Note and had the term on this instrument come to an end and if not what was the end date?

c) ".. as well as other YDC debt held by YEC..." is this intended to say YEC debt held by YDC?

d) Please provide a complete list of this other debt, the amounts on each of the instruments, the terms (end dates), and the interest rates.

e) Please provide a listing of all the new debt instruments, the terms, and the applicable interest rates (are they all at 4.25%)?

f) Is the reduction in costs (to YEC and ratepayers) a decrease in YDC revenue?

g) Does YDC provide financing to YEC for its capital projects, and if so will this reduction not result in a reduced YDC ability to finance YEC projects?

ANSWER:

(a)

The outstanding balance of the Canada Flex Term Note at December 31, 2010 was $24.111 million. Per paragraph 1 (b) of the Flex Term Note the interest was payable until the whole of the principal is paid off. Please see YUB-YEC-1-26(a).

This debt was refinanced through YDC's $81.891 million new long-term debt.

(b)

The outstanding balance of the Yukon Development Corporation Flexible Promissory Note for Mayo-Dawson Project at December 31, 2010 was $14.707 million. Per section 1.1 (b)(ii) of the Promissory Note interest expense calculated as set out in the Promissory Note was payable up to and including March 31, 2044. Please see YUB-YEC-1-26(b).

This debt was refinanced through YDC's $81.891 million new long-term debt.

(c) and **(d)**

The text referenced various debt that YDC provided to YEC.

As regards the "other YDC debt", please see Table 1 below for the list of YDC's long-term debts (excluding Flexible Promissory Note for Mayo-Dawson and Canada Flexible Debt Note) refinanced through new long-term debt in 2011.

Table 1:
List of YDC's Long-term Debts Refinanced through New Long-term Debt

	Balance as of December 31, 2010	Due Date
YDC's $27.3 million unsecured term note bearing interest at 5.88%, repayable monthly and semi-annual principal payments	$20.887 million	December 31, 2023
YDC's unsecured advance bearing interest at 5.28%	$8.2 million	Due one year after demand
YDC's unsecured advance bearing interest at 4.65%	$3.9 million	Due one year after demand
YDC's unsecured advance bearing interest at 6.03%	$3.6 million	Due one year after demand
YDC's unsecured advance bearing interest at 5.34%	$3.6 million	Due one year after demand
YDC's unsecured advance bearing interest at 5.40%	$2.8 million	Due one year after demand

Please see the response to CW-YEC-1-38 (a) and (b) for complete details.

(e)

Yukon Development Corporation's $81.891 million new long-term debt is one debt instrument and the interest rate is 4.25% per year.

(f)

Yes, the refinancing of YDC's long-term debts reduces the interest payments from YEC to YDC for the refinanced debt instruments.

Please see the response to CW-YEC-1-38.

(g)

Please see the response to CW-YEC-1-38(e) as regards future financing sources for YEC projects, including non-YDC sources. Debt refinancing was done with the agreement of YDC to secure lower market-based rates. YEC works to establish reasonable terms for its borrowings with YDC (or other parties). It is not within YEC's purview to determine YDC's management of its funds, or its decisions to financially support or not support YEC projects.

TOPIC: **Re Non-Industrial Load Growth**

REFERENCE: **Page 1-6**

PREAMBLE:

QUESTION:

a) Please provide the non-industrial load growth from 2005 to 2011 in percentages by month (e.g. x% in January, y% in February, ..., z% in December).

b) Please outline what portions of the residential load growth is due to the growth in numbers of customers and what portion is due to the usage per customer. Please include all Yukon residential customers.

ANSWER:

(a)

Please see Table 1 below for YEC's 2009-2011 actual non-industrial sales increase by month. Actual data for 2005-2008 was available to be reviewed as part of the 2008/2009 GRA and is not considered to be relevant to the current revenue requirement proceeding for the 2012/13 test years.

Table 1:
YEC's 2009-2011 Actual Non-Industrial Sales Increase (%)

Month	YEC Non-industrial sales Increase over previous year		
	2009	2010	2011
January	7.7%	-8.5%	14.5%
February	6.2%	-2.9%	4.8%
March	1.4%	1.7%	19.8%
April	6.7%	2.0%	2.4%
May	6.2%	3.9%	6.7%
June	-6.3%	10.7%	2.0%
July	-2.1%	5.8%	2.3%
August	-4.9%	5.0%	-4.7%
September	7.0%	4.7%	3.6%
October	1.2%	3.3%	6.7%
November	3.4%	7.3%	7.2%
December	-5.3%	17.8%	-9.9%

(b)

Please see Table 2 that shows monthly increase in number of YEC residential customers and usage per customer for 2009-2011 actuals. YEC does not have access to the same information for all Yukon residential customers for these same years.

As Table 2 shows the number of YEC's residential customers increased by 2.1% in 2009 over 2008, 1.1% in 2010 over 2009 and 2.9% in 2011 over 2010, while usage per customer increased by 2.6% in 2009 over 2008, but decreased by 3.5% in 2010 from 2009, and again increased by 8.5% in 2011 over 2010. The annual average increase in 2011 over 2009 shows that both number of customers and usage per customer increased within 2 to 2.3% range.

Table 2:
Change in Number of YEC's Residential Customers
and Usage per Customer for 2009-2011 Actual Years

Month	Change in YEC's residential customer and usage per customer							
	2009		2010		2011		Annual average: 2011 over 2009	
	# of customers	Usage per customer	# of customers	Usage per customer	# of customers	Usage per customer	# of customers	Usage per customer
January	1.7%	15.5%	1.6%	-8.8%	2.2%	2.9%	1.9%	-3.1%
February	1.4%	-2.4%	1.6%	-12.8%	3.5%	21.4%	2.5%	2.9%
March	0.5%	8.0%	2.4%	-15.9%	3.4%	35.3%	2.9%	6.7%
April	1.6%	1.6%	1.0%	-3.0%	4.0%	3.4%	2.5%	0.2%
May	2.3%	-0.5%	1.3%	0.0%	2.6%	13.8%	2.0%	6.7%
June	1.9%	6.5%	1.1%	-4.1%	2.5%	0.2%	1.8%	-2.0%
July	3.0%	3.3%	0.5%	-4.6%	2.6%	0.0%	1.6%	-2.3%
August	3.2%	-6.7%	0.4%	5.5%	2.7%	-3.2%	1.6%	1.1%
September	2.1%	3.2%	0.4%	-0.4%	2.9%	4.4%	1.6%	2.0%
October	2.9%	0.1%	0.1%	7.4%	3.0%	2.7%	1.6%	5.0%
November	2.5%	-1.5%	1.5%	-1.3%	2.6%	3.5%	2.0%	1.1%
December	2.1%	0.1%	1.2%	6.0%	2.5%	11.0%	1.9%	8.5%
Annual average	2.1%	2.6%	1.1%	-3.5%	2.9%	8.5%	2.0%	2.3%

TOPIC: **Increase in Baseload Diesel to meet Load Growth**

REFERENCE: **Page 1-7**

PREAMBLE:

QUESTION:

a) What would be the projected increase in rates for 2012 if 100% (rather than 101%) of long-term average hydro generation were assumed for 2012?

b) What would be the projected further increase in rates for 2013 if 100% (rather than 101.8%) of long-term average hydro generation were assumed for 2013?

c) In what year does Yukon Energy propose that long-term average hydro generation starts being used for setting retail and industrial rates?

ANSWER:

(a) and **(b)**

Please see the response to YUB-YEC-1-3(a).

(c)

Yukon Energy does not in the current Application propose a specific year for long term average hydro generation to start being used to set retail and industrial rates.

The transition approach adopted in the current Application is justified in part on the basis of current favourable water supply conditions – however, such conditions cannot be expected to last beyond the test years. In order to ensure that the DCF is appropriately built up and robust enough to mitigate rate impacts in the event of a drought it is also important, among other measures to ensure that Yukon Energy incremental diesel fuel costs are funded during a drought, that the fund continue to be built up in the near term. The quantum, cap and other issues related to funding future drought-related costs, and addressing resultant impacts on rates, are acknowledged to be not yet addressed in the

DCF update recommendations set out in Attachment 3.2 of the Application (see page 3.2-5).

Separate from dealing specifically with funding drought-related costs and monitoring short-term water supplies for grid hydro generation, load growth on the system will increase the pressure to fully reflect long term average diesel generation in rates. This is demonstrated by the following examples:

- At the forecast loads for 2013, long-term average diesel generation at 18.2 GW.h reflects the impact of severe drought years combined with the years when no diesel is required; diesel at 59% or more of long-term average [10.7 GW.h or more] occurs only approximately 54% of the years.

- In contrast, as load grows the percentage of years with diesel at 59% or more of long-term average increases. For example, at approximately 586 GW.h/year load level[1] the expected long-term average diesel generation at 135 GW.h reflects a situation when diesel at 59% or more of long-term average [110 GW.h or more] occurs over 95% of the years.

In summary, at 2013 forecast loads diesel at 59% of long-term average will tend to reflect what occurs during roughly half of the years. However, with higher loads that could soon materialize, diesel at only 59% of long-term average will tend in most years to see actual annual diesel costs that are well above 59% of long-term average (with the result that, unless rates are at 100% of long term average, the DCF will tend each year to be continually depleted).

[1] Estimated load for 2015 with non-industrial growth rate at 2.26% per year over 2013 GRA forecast plus Victoria Gold and Brewery Creek mines connected to the grid (see Appendix A to Overview of 20-year Resource Plan: 2011-2030, YECL-YEC-1-18).

TOPIC: **System Sales and Generation**

REFERENCE: **Page 2-2**

PREAMBLE:

"Industrial load growth to date continues to bring higher revenues that tend to more than offset any related incremental costs."

QUESTION:

a) Does this statement refer to the present industrial customers (Minto and Alexco) only?

b) Will this be the case for any new industrial customer that connects in 2012 or 2013 (with 44% and 56% incremental diesel generation respectively for load growth as noted on page 1-7), and if so at what magnitude of load (in MW) would this no longer be the case? Please provide some substantiation.

c) Does the present blend of growth in all non-industrial load result in lower revenues than any related incremental costs? If so please provide some substantiation.

ANSWER:

(a)

The statement refers to industrial load growth to date – Minto mine and Alexco mine are the only industrial customers on the integrated grid at this time.

(b) and **(c)**

Please see YUB-YEC-1-2(a) and CW-YEC-1-1(a).

TOPIC: **System Sales and Generation**

REFERENCE: **Page 2-2**

PREAMBLE:

"... as a result of this sustained interruption a number of secondary sales customers have converted to primary supply for their electric heating loads."

QUESTION:

a) Given that space heating (including electric) has a load factor of only 30% and that it is winter focused when we peak with diesel generation, why were these secondary customers allowed to convert to primary electric heat?

b) Why were they not required to use their other heating systems which were a requirement for them to get secondary service in the first place?

ANSWER:

(a) and **(b)**

Secondary sales customers served under Rate Schedule 32 that wish to discontinue service as secondary sales customers and instead be served as firm General Service or Industrial customers, where such service is available and applicable, cannot be prevented from doing so.

Rate Schedule 32 provides, however, that customers taking Secondary Energy will not be allowed to have these loads shifted to be served by any firm (primary) service without providing the distributing utility (i.e., Yukon Energy or YECL) with 12 months notice (unless waived at Yukon Energy's discretion). Once any such Secondary Energy load is switched to firm service, it will not be able to switch back to Secondary Energy service in the future.

TOPIC: **System Sales and Generation**

REFERENCE: **Page 2-2**

PREAMBLE:

"... actual diesel generation exceeded ... 10.55 GWh in 2011 ..."

QUESTION:

a) On page 1-7 the long term average diesel generation for 2011 is indicated at 5.6 GWh per year. Please explain the difference in these numbers.

ANSWER:

(a)

The generation of 10.55 GW.h in 2011 is actual diesel generation excluding diesel requirements related to capital projects and hydro generation plant construction activities. The number on page 1-7 (5.6 GW.h) is calculated long-term average expected diesel generation based on the Table 3.2-1 provided in Appendix 3.2 (Update to Diesel Contingency Fund (DCF)).

TOPIC: **System Sales and Generation**

REFERENCE: **Page 2-6**

PREAMBLE:

Whitehorse Copper Tailings [Eagle Industrial Minerals]: Once connected it appears that the project will not be operational during the coldest months of the year (December through February). This will mean that they will not add to the winter peak (electric heating) and less of their annual energy will be generated by diesel, a desirable customer from all appearances.

QUESTION:

a) Will a lower generation cost be reflected in a lower power purchase cost for this customer?

b) Will Eagle Industrial Minerals be a Yukon Energy customer or a YECL customer? Please explain.

ANSWER:

(a)

This customer will be required to pay for service in accordance with the approved Rate Schedule 39, and any applicable rate riders. Average purchase power costs under this rate are affected by peak billing demand during the defined winter months and a customer's average load factor relative to billing demand.

(b)

This industrial customer will be served by Yukon Energy. Please see response to YECL-YEC-1-20.

TOPIC: **System Sales and Generation**

REFERENCE: **Pages 2-13/14**

PREAMBLE:

Re diesel generation: At the top of page 2-14 diesel fuel efficiencies of 3.77 kWh per litre at Whitehorse, 3.8 kWh per litre in Faro, and 3.72 kWh per litre in Dawson are indicated. Table 2.2 indicates that all of the diesel generation proposed for 2012 and 2013 takes place in Whitehorse, Faro, and Dawson.

QUESTION:

a) Please indicate how diesel generation in these three locations combined can result in an average fuel efficiency of only 3.67 kWh per litre when each of these locations have higher efficiencies?

b) Please indicate why the average fuel efficiency is not a weighted average based on the generation distribution indicated in Table 2.2?

ANSWER:

(a) and **(b)**

The fuel efficiency of 3.67 kW.h/litre shown on page 2-14 of the 2012/13 GRA Application is a simple average of 3.77 kW.h/litre in Whitehorse, 3.8 kW.h/litre in Faro and 3.72 kW.h/litre in Dawson and 3.37 kW.h/litre in Mayo and for comparison purposes only.

The forecast diesel expenses for the test years are calculated by using diesel generation distribution as shown in Table 2.2 of the Application and fuel efficiencies for each community as shown above. As per Page 3-5, the 2013 diesel generation is 10.7 GW.h using 2.85 million litres, or a weighted average efficiency of 3.75 kW.h/litre.

TOPIC: **System Sales and Generation**

REFERENCE: **Page 2-16**

PREAMBLE:

"In summary, under N-1, there is a surplus capacity of approximately 7.2 MW in 2012 and 6.5 MW in 2013."

QUESTION:

a) Please show exactly the mathematical calculations that lead to the numbers in this summary – what load must be served and how was it derived?

ANSWER:

(a)

Please see Table 1 below for detailed calculation of the N-1 capacity surplus forecasts for 2012 and 2013. The N-1 assessments do not include industrial loads.

Table 1:
Yukon Integrated System N-1 Capacity Surplus/(Shortfall) Forecast

		MW
1	Total Integrated System - Winter Capacity (excl. YECL's Fish Lake)	116.2
2	N-1 excludes Aishihik Hydro GS and Haines Junction diesel (YECL)	-38.8
3=1+2	Total Integrated System - Winter Capacity after N-1 event	77.5
4	Forecast Non-industrail peak for 2012	70.3
5=3-4	N-1 Capacity Surplus for 2012	7.2
6	Forecast Non-industrail peak for 2013	71
7=3-6	N-1 Capacity Surplus for 2012	6.5

Note: Forecast non-industrial peaks in lines 4 and 6 exclude estimated peak demand of 1 MW for Haines Junction.

Please see Table 2 below for breakdown of Yukon Integrated System installed winter capacity from Line 1 in Table 1 above.

Table 2:
Yukon Integrated System Installed Winter Capacity

	MW
Whitehorse Hydro (winter for all units)	24.0
Whitehorse diesel	22.5
Faro diesel	8.9
Aishihik Hydro	37.0
Mayo Hydro	11.0
Mayo diesel	1.7
Dawson diesel	4.0
YECL diesel	7.2
Total Integrated System - Winter Capacity (excl. YECL's Fish Lake)	116.2

TOPIC: **System Sales and Generation**

REFERENCE: **Tab 2 DSM**

PREAMBLE:

Conspicuous by its absence in this tab is any indication of reductions in forecast sales due to DSM/conservation activities that ratepayers are asked to start paying for in 2012.

QUESTION:

a) Please explain fully why this is not included.

ANSWER:

(a)

As noted in Tab 5 of the Application, DSM is considered to be a supply option with broad public support and where there is a clear commitment to proceed. A DSM plan and specific programs are in the process of being developed at this time. Tab 5 (section 5.2.1.5) and Tab 6 (Section 6.2) review the significant amount of DSM related planning and consultation work has been undertaken by Yukon Energy individually and by Yukon Energy in coordination with Yukon Government, Yukon Development Corporation and Yukon Electrical in order to implement a robust and aggressive DSM/SSE program, and to meet the Yukon Utilities Board directive #3 from Order 2009-8.

DSM savings (in terms of reduced forecast sales) are not forecast in Tab 2 sales forecasts as some lead time is required before energy savings can be translated into electrical energy available (with the amount of lead time required expected to vary by initiative), and there was no reasonable basis when the GRA was prepared to estimate any potential load reductions by customer class or overall during the test years. Typical DSM programs are implemented over a three to five year period at which time they are usually evaluated and modified based on the results of that evaluation.

TOPIC: **System Sales and Generation**

REFERENCE: **Tab 2 IPP and Net Metering**

PREAMBLE:

Yukon Energy has been working on IPP and Net Metering policies for some considerable time.

QUESTION:

a) When will these policies come into effect?

b) If in the test years why do they not appear in Tab 2 offsetting load growth and new Yukon Energy supply projects?

ANSWER:

(a) and **(b)**

Yukon Energy provided a detailed update regarding the current status of the IPP Policy and Net Metering policy in Tab 6 of the GRA. As indicated, it is Yukon Energy's understanding is that the policy is in the process of being finalized and approved by the Yukon Government. Yukon Energy is not directly involved with those approval processes and is not in a position to comment further on the timelines for release of the draft policy.

Given the above, there was no basis to include these projects or policies as offsets to load growth or as supply options in the test years in the current GRA. When these are included, it will be necessary to include as well the related forecasts of costs that are to be recovered from ratepayers.

TOPIC: **Revenue Requirement**

REFERENCE: **Page 3-3 Re Fuel and Purchased Power**

PREAMBLE:

QUESTION:

a) Please provide a table of monthly hydro and diesel generation on the WAF grid + MD Grid (or consolidated grid) in GWh for each of the years 2008 through 2011 by month.

b) Please reconcile and explain the statement "*Due to low water conditions and non-activation of the DCF, fuel costs in 2011 were material* ..." to the statement "... *Secondary sales have been interrupted ... except for temporary resumption in September 2011 due to high water levels in Aishihik Lake...*" on page 2-2, the [sic] and the statement and footnote on page 4-4 that says "... *secondary sales were suspended ... due to low water*[4]. [4]*Except for the period from September 1, 2010 until September 1, 2011 when they were temporarily resumed due to high water in Aishihik Lake*.", and with our experience of a wet summer last year.

ANSWER:

(a)

Please see Table 1 below which provides consolidated monthly grid hydro and diesel generation (i.e., summation of WAF grid and MD grid generation) for the 2008-2011 period.

Table 1:
YEC's 2008-2011 Monthly Hydro Generation

Month	Monthly Hydro and Diesel Generation (GW.h)							
	2008		2009		2010		2011	
	Hydro	Diesel	Hydro	Diesel	Hydro	Diesel	Hydro	Diesel
January	36.0	0.0	37.9	0.8	36.3	0.2	39.3	2.4
February	32.2	0.1	37.2	0.1	35.5	0.0	35.1	1.4
March	29.3	0.0	32.5	0.0	32.8	0.0	35.5	3.1
April	25.6	0.1	29.7	0.0	29.6	0.2	28.4	1.7
May	23.4	0.2	28.3	0.2	29.2	0.0	29.4	0.8
June	23.9	0.0	24.6	0.0	25.4	0.0	26.0	1.0
July	24.0	0.0	25.5	0.3	26.4	0.3	27.6	0.2
August	25.3	0.0	25.3	0.2	27.6	0.7	27.4	0.5
September	24.4	0.0	26.9	0.4	27.6	0.1	29.1	0.4
October	27.2	0.3	29.6	0.2	28.8	0.2	29.5	3.5
November	32.4	0.1	35.5	0.1	37.3	0.6	39.1	0.7
December	38.1	0.8	38.1	0.4	40.4	2.8	37.9	0.1
Total	**341.7**	**1.7**	**371.0**	**2.6**	**377.0**	**5.1**	**384.4**	**15.9**

(b)

Please note that Footnote 4 at page 4-4 should be clarified to read: "Secondary sales were suspended September 1, 2010 until September 1, 2011, when they were temporarily resumed due to high water in Aishihik Lake" (the "except" should be deleted).

Secondary Sales were suspended from September 2010 to September 2011[1]. Secondary sales were resumed in September 2011 due to high water in Aishihik Lake as the footnote indicates. This is consistent with the discussion noted at page 2-2 of the Application which notes, "secondary sales have been interrupted on a sustained basis since September 2010 (except for temporary resumption in September 2011 due to high water in Aishihik Lake)…."

Page 3-3 notes material fuel costs in 2011 due to non-activation of the DCF and low water conditions. As noted on Page 3-4, in 2011, 10.55 GWh of diesel generation was

[1] The suspension of secondary sales from September 2010 to September 2011 was driven by the following conditions: (1) Marsh Lake water levels were at, or slightly above, the full supply level;
(2) Aishihik Lake levels were also low in 2010, reaching just above 914.5 metres above sea level (ASL), approximately 0.66 metres below full supply level (FSL; equivalent to 75% full reservoir); and (3) Mayo Lake also experienced low water levels in 2010, barely reaching 665 metres ASL (0.86 metres below FSL; equivalent to 67% full reservoir).

required (this does not include 5.38 GWh of diesel generation related to capital projects being undertaken in 2011) compared to 4.28 GWh in 2010 (excludes 0.85 GW.h related to capital projects in 2010) and 7.5 GWh forecast in 2012 and 10.7 GWh forecast in 2013.

Table 1 provided in response to (a) above shows the month-to-month diesel generation during 2010 and 2011, highlighting the extent to which low water conditions in fall 2010 through to spring 2011 resulted (with no DCF activation) in material fuel costs for YEC operations in both 2010 and 2011. Thereafter, in 2011, capital project diesel requirements were addressed due to shutdowns at the Aishihik and Mayo generating stations.

The availability of the Aishihik Generating Station after the commissioning of the third turbine in August 2011 provided enough hydro capacity for the Corporation to temporarily resume secondary sales from the latter part of August to the end of September. The cumulative effect of high summer precipitation, important snow cover and downtime to allow construction and commissioning activities associated with the third turbine contributed to bring Aishihik Lake levels at the full supply level at the end of the summer. Secondary sales were interrupted on October 1st to conserve hydro capacity to meet upcoming winter loads.

In 2011, notwithstanding a ‘wet summer”, Whitehorse Rapids Generating Station experienced limited hydro supply for a second year in a row.

Rain events in 2011 were not sufficient to raise water levels in the southern lake systems to allow YEC to have enough hydro capacity to resume secondary sales (see Table 2 below). As shown in Table 2 below, the higher precipitation was focused during the summer months in 2011, followed by below average precipitation in September and October. Overall, precipitation was below average for the year 2011.

Table 2:
Comparison of Whitehorse 2011 Total Precipitation
with 1970-2000 Normal Precipitation

MONTH	2011 TOTAL PRECIPITATION (mm)	1970-2000 NORMALS (mm)	VARIANCE
JAN	18.0	16.7	1.3
FEB	7.6	11.4	-3.8
MAR	2.0	10.4	-8.4
APR	1.4	7.0	-5.6
MAY	**27.6**	**15.2**	**12.4**
JUN	**32.0**	**30.3**	**1.7**
JUL	**55.4**	**41.4**	**14.0**
AUG	**59.2**	**39.4**	**19.8**
SEP	12.4	34.1	-21.7
OCT	9.9	23.8	-13.9
NOV	26.5	19.2	7.3
DEC	25.9	18.5	7.4
TOTAL	277.9	267.4	-10.5

Source: Environment Canada National Climate Data and Information Archive (http://www.climate.weatheroffice.gc.ca/Welcome_e.html).

TOPIC: **Revenue Requirement**

REFERENCE: **Page 3-5**

PREAMBLE:

"These test year forecasts are adopted to address the transition to annual long-term average levels and the potential future use of LNG at materially lower cost than diesel..."

QUESTION:

a) Why is a transition period to long term average diesel use levels required when diesel was not "on the margin" in 2011 as Yukon Energy repeatedly argued during the Rider F policy review proceeding?

ANSWER:

(a)

As noted in further detail below the Diesel Contingency Fund was not activated in 2011 and could not be activated until required updates (as discussed in Appendix 3.2 of the Application) were addressed.

The transition period is proposed for 2012 and 2013 to mitigate rate impacts in these years and facilitate transition to inclusion in future revenue requirements of the full diesel generation cost based on forecast annual long-term average hydro generation, i.e., this is a transition on a go forward basis. As noted in the Application at page 3 (as well as in Tab 2, Section 2.3.2 and Tab 3, Appendix 3.2) diesel is considered to be on the margin in the test years and the current Application includes provisions for the DCF to be "switched on" as of January 1, 2012.

In the Rider F policy review hearing, Yukon Energy simply noted various factors explaining why the DCF could not be triggered at that time, including the need for changes in operating rules to be proposed and approved and also including the Board's decision (Order 2010-13) which recognized that diesel was not forecast to be "on the margin" as this term is used to trigger the DCF. YEC's evidence in the Mayo B Part 3 Application and the 2009 Phase II Rate Application also estimated approximately

$1 million in diesel generation costs at long term average diesel requirements with the 2009 GRA load. In light of all relevant evidence, Board Order 2011-15 directed Yukon Energy to address these DCF change matters in its next GRA, or by July 1, 2012, whichever was earlier.

TOPIC: **Revenue Requirement**

REFERENCE: **Pages 3-6/7 Re Labour Expenses**

PREAMBLE:

Of the increase in 12.26 FTEs between 2009 and 2013 virtually all of this appears to be in the President, Resource Planning, and Finance categories (Table 3.4). It would seem that Yukon Energy is getting very top heavy and/or bureaucratic.

QUESTION:

a) In general terms please discuss why this is necessary and cost effective for ratepayers?

b) How many of these new positions are term and will come to an end over the next 4 years?

c) What actions are being taken to reduce the labour force in future or to prevent further increases?

ANSWER:

(a)

Please refer to section 3.3.5 of the Application for a detailed explanation and justification of each position.

(b)

The following six positions are scheduled to end in the next four years as they are terms:

- Environmental Coordinator – March 2013;
- Resource Planning Engineer – April 2013;
- SCC Operator – June 2013;

- Energy Conservations Administrator – July 2013;

- Manager, Energy Conservation – August 2013; and

- Backfill Controller – February 2014.

(c)

YEC takes the decision to increase labour complement very seriously. New positions must be thoroughly justified in part to ensure the work required is recurring and permanent (otherwise it would be more cost efficient to hire consultants for the period of time that increased work load is required).

Please refer to YUB-YEC-1-14(c) which lists the new positions added since 2009.

In general terms, all of these positions were added to reflect increased workload as the utility deals with increased growth, increased assets, increased regulatory requirements and the need to perform detailed and multi-year planning. In the absence of these staff positions, this work would have had to be conducted at higher cost by consultants.

TOPIC: **Rates**

REFERENCE: **Pages 4-10 to 13 Wholesale Rates**

PREAMBLE:

QUESTION:

a) What incremental cost of diesel does Yukon Energy propose to use for the Hydro Zone to apply to the ERA?

b) Please show how this incremental cost was calculated.

c) If this is the Hydro Zone incremental rate set in Board Order 2010-13 please explain why.

d) Please show two sample monthly calculations of ERA as proposed by Yukon Energy, one with the actual wholesale purchase above the forecast and one with the actual wholesale purchase below forecast.

ANSWER:

(a) through **(d)**

The proposed incremental cost of diesel for the ERA is not the Hydro Zone incremental rate set in Board Order 2010-13.

The proposed incremental cost of diesel for the ERA is equal to the DCF incremental cost as forecast in the GRA, which is calculated based on the GRA proposed fuel prices, average diesel unit fuel efficiency, and average diesel unit incremental O&M cost per kWh (3 c/kWh per 2009 GRA). The forecast GRA DCF incremental diesel cost is 31.68 cents/kW.h.

Please see the response to YUB-YEC-1-30(b) for more details as well as examples of the ERA calculations.

TOPIC: **Capital Projects**

REFERENCE: **Page 5-1 Yukon Energy Major Capital Project Policies**

PREAMBLE:

QUESTION:

a) Did Yukon Energy not make a commitment in the past to bring major capital projects of a specified cost (or higher) to the Board for review prior to proceeding to construction? If this was in the form of a policy please provide a copy this policy.

b) Should the Mayo hydro substation and the Aishihik generating station redundancy not have received prior Board scrutiny by virtue of their costs?

ANSWER:

(a) and **(b)**

The 2006 20-Year Resource Plan noted (at page 1-1) Yukon Energy's commitment to seek YUB review, prior to construction, of any new capital project costing $3 million or more. In light of the current regulatory context in Yukon, this was a commitment to make best efforts for such a review. There is no formal policy document that can be provided for review in this regard.

Yukon does not have a formal Certificate of Public Convenience and Necessity (CPCN) process for YUB approval of YEC or YECL capital projects. In the current Yukon regulatory context, the YUB approves the capital costs to be included in rate base (i.e., determines prudence of expenditure in order for costs to be recovered from ratepayers through rates).

Outside of a General Rate Application, there are two avenues for YUB review of capital projects:

1. **Approach #1: Directions from Government under Section 17 or 18 of the PUA** – This approach has been uses in the past for the 1991/92 Cost of Service

and Rate Design hearing, the 1992 YEC/YECL Resource Plan review and the 2006 20-Year Resource Plan review.

2. **Approach #2: Part 3 of the Public Utilities Act (PUA) Energy Project Certificate and Energy Operation Certificate** – This approach requires an OIC designating a project as a "regulated project[1]" under the Public Utilities Act (subject to the provisions of Part 3 of the Act). Prior to OIC designation, no application pursuant to Part 3 of the PUA can be made, or is required to be made, by a utility. Further, no YUB review can commence under Part 3 prior to a reference by the Minister pursuant to Part 3 after the necessary OIC designation and the necessary subsequent utility application. This was not used prior to 2007 and has since been used for a Part 3 review of the Carmacks Stewart Transmission Project and the Mayo Hydro Enhancement Project (Mayo B). This approach in the past has considered only one project at a time (based on terms of reference provided by the Minister of Justice to the YUB) and results in a report and recommendations from the YUB to the Minister (no orders or directions) in relation to issuance of an energy certificate required to construct the project and an operation certificate required to operate the project.

Absent a review being triggered as noted above, the only means available for YEC to instigate a review of a capital project or projects is through a General Rate Application proceeding. Yukon Energy continues to bring before the Board for review in this GRA, and in previous GRAs, information on its ongoing major capital projects.

With regard to Aishihik Redundancy and Mayo Hydro Substation projects, the following are also noted regarding YUB review of these projects prior to construction:

- The Aishihik Redundancy project was undertaken to rectify a serious system reliability issue relating to redundancy identified as a result of a major system outage on January 29, 2006. The January 29, 2006 event identified very serious security of supply issues to Whitehorse during peak winter times that needed to be addressed. Attachment 1 to this response provides a copy of the April 11, 2006 letter to the YUB setting out Yukon Energy's Outage Response and Reliability Plans following the January 29, 2006 event. Following this event YEC

[1] 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." Terms are defined in the Act.

was asked by the YUB to provide a response that outlined the circumstances of the outage, how YEC responded to the emergency; the likelihood for the event recurring; what emergency plans YEC had in place for such an event, and what other system vulnerabilities were present and how they were being addressed. This letter provided the detailed information to the YUB and interested parties (and was filed as part of the interrogatory responses in the 2008/ 2009 GRA (as response to LE-YEC-1-5)).

- The Mayo Hydro substation also required major refurbishment and upgrades to continue operating in a safe and reliable manner.

Both projects were undertaken to address issues related to existing infrastructure that were required to be addressed to ensure safe and reliable operation of the Yukon grid. They were not new supply options or greenfield projects.

YUKON ENERGY

FAXED 4/11/06

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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	

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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	

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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

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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

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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		

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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**

TOPIC: **Capital Projects**

REFERENCE: **Page 5-5/6 Mayo B Project**

PREAMBLE:

The following questions are to help Leading Edge understand the useful peaking capacity available from the expanded Mayo hydro installations prior to any expanded storage range on Mayo Lake.

QUESTION:

a) What is the long term annual average water flow (in cubic meters per second – CMS) available at present?

b) What was the annual average generating capacity (in MW) and annual average energy (in GWh) that would have been available from Mayo A alone prior to the Mayo B installation?

c) What is the minimum water flow (riparian flow) in CMS that must now be released through the Mayo A plant?

d) What annual average generating capacity (in MW) and annual energy (in GWh) does this represent?

e) Can YEC confirm that the long term annual average water flow available to the Mayo B plant is (a) – (c)?

f) What annual average generating capacity (in MW) and annual energy (in GWh) does this represent, assuming that all of it is useful?

g) Can YEC confirm that water run through the Mayo A plant cannot be subsequently run through the Mayo B plant?

h) Can YEC confirm that under long term average water conditions and with the forecast electrical loads in the two test years not all of the potential additional

energy available from the installation of Mayo B is useable? If this assumption is not correct please explain.

i) At what integrated grid load does using Mayo A for peaking reduce the annual useful energy available from Mayo B?

ANSWER:

(a)

The long-term average water flow for the Mayo system, based on 28 years of water records from 1981-2008 is 21.5 cubic metres per second ("cms").

(b), **(c)** and **(d)**

The specific annual average output of any given plant is dependent on the system loads and the characteristics of each of the other plants on the system. The capabilities of Mayo A (without Mayo B) and Mayo A (with Mayo B) were given in response to Interrogatory YUB-YEC-1-21 REVISED in the Mayo B Part III application, in Table 1 of that response, as follows:

Table 1: Mayo A and Mayo B output

Mayo A and B plant output (GW.h/year) and Capacity Factor at a 468 GW.h grid load level

	Mayo A generation (GW.h/year)	Capacity factor at 5.4 MW installed capacity	Mayo B generation (GW.h/year)	Capacity factor at 10.1 MW assumed peak capacity
No Mayo B	36.1	76.4%	n/a	n/a
Mayo B (with Mayo Lake Enhanced Storage)	13.7	29.1%	59.2	66.9%
Mayo B - no Mayo Lake Enhanced Storage	14.0	29.5%	56.0	63.3%

The minimum flows through "Zone 2" (the area between the Mayo A plant and the Mayo B plant, encompassing flows through either Mayo A or through the Wareham spillway) are 6 cms from May 1 to September 30 of each year, and 5 cms for the remainder of the year.

(e) and **(f)**

No. The long term average flows in part (a) include flows which at times exceed the combined capacity of Mayo A and Mayo B, and which can therefore only arise as spills.

The proportion of this water flow that is useful at Mayo B in shown in the response to part (d) above.

(g)

Confirmed.

(h)

Confirmed. Focusing on the grid benefits that are available from the development of Mayo B, this is discussed in detail in the Application, Tab 5, Appendix 5.3 which sets out the calculations in support of the net grid benefits Mayo B brings to the system.

(i)

There is no single answer to this question. In general, Mayo A is not relied upon for peaking in either the economic models or the design of the intake system.

At times, under any grid load, there will be flows (e.g., very large freshets) that must either be used for Mayo A peaking or be spilled at Wareham. At these times, the use of Mayo A for peaking does not reduce the capability of Mayo B at all.

During most times, however (particularly in key winter periods), the water stored at Mayo Lake (with or without Mayo Lake Enhanced Storage) is needed to be prioritized to Mayo B, even at current grid loads. In addition, similar to the Whitehorse plant, the use of Mayo A for daily peaking may prove problematic for ice conditions and should generally not be relied upon for this purpose.

TOPIC: **Capital Projects**

REFERENCE: **Page 5-5/6 Mayo B Project**

PREAMBLE:

QUESTION:

a) Do the penstocks for Mayo A and Mayo B have a common intake on Wareham Lake?

b) Can these two penstocks be isolated from each other as required for penstock maintenance on one facility without disrupting the operation of the other?

c) If the answer to (a) is no, please explain why not.

d) If the answer to (a) in no, does Yukon Energy plan to install isolating mechanisms in future and if so what would they cost?

e) Some photos of the Mayo B construction show very deep excavations for the penstock. How deep are the penstocks buried i.e. what is the minimum earth cover over it?

f) How was the minimum cover determined?

g) What would have been the risks if it had been reduced?

h) What would have been the incremental excavation cost saving for 1 meter or 2 meter reduced excavation and burial depths?

i) Please provide a detailed listing of the projected final cost by component and also by contractor (including YEC internal costs).

j) Please provide copies of Yukon Energy's agreements with NND with respect to Mayo B and Mayo Lake enhanced storage.

ANSWER:

(a)

Yes, the penstocks for Mayo A and Mayo B have a common intake on Wareham Lake (i.e., the old Mayo Hydro facility intake gate/dam).

(b)

No the two penstocks cannot be isolated from each other and shut down separately as required for penstock maintenance on one facility without disrupting operation of the other due to the fact that they share a common headgate. However, the TIVs can be used to isolate and work on individual units one at a time.

(c)

The decision for the penstock for Mayo A and Mayo B to share a common intake was undertaken due to cost implications of constructing a separate Mayo B intake.

(d)

There are currently no plans to install separate isolating devices and as such there are no current available cost estimates for this work.

(e)

The penstock elevation alignment was governed by the hydraulic gradient and minimizing excavation requirements, while balancing cut/fill. A minimum 4.0 metres of cover is required when the penstock is completely installed in the trench areas (i.e., crown of penstock is 4 metres or more below grade). Five metres of cover is required when the penstock is less than 4 metres below grade (i.e. the fill is mounded over the penstock).

(f)

The minimum cover was determined by creating a thermal model with inputs including historical climate data for Mayo (air temperature and snow cover), water temperature

entering the penstock, ground temperatures and frost penetration, and thermal properties of the natural ground conditions and the penstock backfill (including soil moisture content and areas with permafrost). Without the thermal requirements, the minimum cover to provide pipe confinement and overburden equipment loads would have been in the order of 2.0 metres.

(g)

Risks that may result from the minimum cover being reduced would include freezing and ice buildup in the penstocks, which would restrict flow and create the potential for ice formation breaking off and passing through the turbines.

(h)

Reduced excavation was not available without substantial losses in hydraulic capacity. The water conveyance system through the tunnel was oriented in a negative gradient (uphill) to minimize excavation depth over the major section of the penstock. The project evaluated the option of reducing the 5.0 metre cover requirement to 3.0 metres plus insulation/ thermal siphons and estimated 5.0 metre cover cost at approximately 50% of the latter. Further, the excavation/cover material quantities were essentially balanced over the alignment.

(i)

Please see also response provided to CW-YEC-1-27(a) and (b) for final cost by component. See Table 1 below for costs by component and by contractor.

(j)

The Project Agreement with Nacho Nyak Dun First Nation is confidential and cannot be provided.

Table 1:

Mayo B Projected Final Cost Estimate by Component and by Contractor

Component	Contractor	Cost ($000)
Construction	Peter Kiewit Infrastructure Co	84,219
	YEC Owner Costs	0
	ES&G	96
Sub-Total		**84,315**
Turbine & Generator Supply	ABB Inc.	5,274
	YEC Owner Costs	0
	ES&G	7
		5,281
Detailed Engineering	KGS Group	5,976
	ES&G	10
Sub-Total		**5,986**
Assigned to Substation	Mayo A Sub Allocation	750
Sub-Total		**750**
Owner Contingencies	Salmon Rearing Channel	400
Sub-Total		**400**
Contract Administration	KGS Group	4,623
	Metro Chrysler Ltd,	32
	Whitehorse Motors Ltd.	30
	YEC Owner Costs	8
	ES&G	4
Sub-Total		**4,696**
Owner Admin Costs	Aasman Design Inc.	44
	Alkan Air Limited	10
	Aon Reed Stenhouse Inc.	761
	Archbould Photography	7
	Davis LLP	201
	Ecofor Consulting Ltd	11
	Environmental Dynamics Inc.	172
	Fireweed Helicopters	2
	First Nation Of Na-Cho Nyak Du	52
	Goldrush Production	100
	Intergroup Consultants Ltd.	76
	JJRM Project Ltd.	446
	Ketza Construction Corp	1,110
	Laberge Environmental Services	5
	MacKay LLP	20
	Nacho Nyak Dun Development Cor	1
	Northwestel Inc.	99
	RLH INDUSTRIES INC	8
	Solid Gold Communications	4
	Underhill Geomatics Ltd.	4
	Wilf's Contracting Ltd.	4
	YEC Labour	372
	YEC Owner Costs	248
	ES&G	2
	YEC - Diesel Allocation	387
Sub-Total		**4,146**

Table 1:
Mayo B Projected Final Cost Estimate by Component and by Contractor
(Continued)

Component	Contractor	Cost ($000)
Land Acquisition	YEC Owner Costs	250
	Yukon Government	0
Sub-Total		**250**
Interest (AFUDC)	AFUDC	477
Sub-Total		**477**
Pre-Construction Permitting & Regulatory and Planning Costs	Aasman Design Inc.	2
	Alkan Air Limited	31
	Amicus Reporting Group	2
	Bluewater Biosciences	77
	City of Whitehorse	26
	Davis LLP	703
	Ecofor Consulting Ltd	34
	Environmental Dynamics Inc.	998
	Fireweed Helicopters	74
	First Nation Of Na-Cho Nyak Du	533
	Government Of Yukon	135
	Intergroup Consultants Ltd.	1,985
	J&B Contracting	120
	Katopodis Ecohydraulics Ltd.	4
	KGS Group	4,214
	Laberge Environmental Services	4
	Paddock Drilling Ltd.	228
	Peter Kiewit Infrastructure Co	353
	Public Interest Advocacy Centr	16
	Thomas R. Payne & Associates	1
	Threlkeld Consulting Ltd.	20
	Trans North Helicopters	10
	Underhill Geomatics Ltd.	203
	Wilf's Contracting Ltd.	37
	Yukon Conservation Society	2
	YEC Labour	253
	YEC Owner Costs	130
	AFUDC	161
	ES&G	33
	YDC - NND Infrastructure Fee	-100
Sub-Total		**10,287**
Funding/Contributions	GIF Claims	-51,438
	YDC Contribution	-30,150
Sub-Total		**-81,588**
Total		**35,000**

TOPIC: **Capital Projects**

REFERENCE: **Pages 5-6 to 9 Aishihik Third Turbine**

PREAMBLE:

QUESTION:

a) Please explain how the completed project is different from the project scope contemplated originally (page 5-8 line 12).

b) What was the estimated cost saving attributed to each of these measures?

c) Will any of the cost saving measures result in increased operational, maintenance, or future capital costs? If so please explain the reason for selecting them nonetheless.

d) Of the projected final cost of $13.8 million how much will have been paid to AECOM for their work in this project?

e) Please provide two detailed cost listings of the projected final cost, one by component and one by contractor (including YEC internal costs).

ANSWER:

(a) through **(c)**

Since April 2009, the overall scope of the Aishhik Third Turbine project did not materially change.

(d)

In total, approximately $1.159 million will be paid to AECOM for their work on the Aishihik 3rd Turbine project.

(e)

Please see Table 1 below for cost listings of the projected final cost by component and see Table 2 below for cost listing by contractor (including YEC internal costs) – differences between Table 1 and Table 2 are due to rounding.

Table 1:
Aishihik Third Turbine Projected Final Cost by Component

Component	Cost
Rock Excavation	$1,132,765
Generating Hall	$773,270
Turbine Generator	$4,056,114
Supply Electro-Mechanical	$713,994
Penstock Installation	$884,079
Turbine Generator Installation	$569,360
Auxiliary System Installation	$821,815
Electrical Installation Generating Hall	$322,673
Electrical Installation Generating Control Room	$589,037
Testing and Commissioning	$114,735
Diesel Fuel	$636,759
Mobilization	$386,152
Estimated Construction Field Cost:	**$11,000,752**
Preliminary Design:	$762,955
Detail Design:	$609,702
Construction Management:	$350,264
YEC Cost (Owner's Cost):	$843,580
Construction Financing Cost:	$249,486
Subtotal:	**$13,816,740**
YDC - Contributions	-$5,000,000
Total Cost Net of Contributions	**$8,816,740**

Table 2:
Aishihik Third Turbine Projected Final Cost by Contractor

Contractor	Expense
AECOM Canada Ltd.	$1,159,411
Aasman Design Inc.	$14,406
AFUDC	$182,212
American Governor Company	$13,449
BBA Inc.	$8,651
Canpac Divers Inc.	$22,023
Cap Engineering	-$181,628
CAP Engineering	$442,168
ES&G	$67,275
Flowmetrix Technical Services	$17,174
Ketza Construction Corp	$61,284
KGS Group	$35,672
Klohn Crippen	$94,438
L&S Electric of Canada Inc.	$132,539
Meerholz Canada	$19,139
North American Construction	$4,219,000
Northgate Industries Ltd.	$120,702
Orbis Engineering Field Service	$40,479
Pacific Blasting & Demolition	$1,132,765
Peter Kiewit Infrastructure Co.	$62,259
Precision North Mechanical	$953
Schneider Electric Canada Inc.	$28,670
Schweitzer Engineering Laboratory	$4,990
UMA Engineering Ltd.	$44,438
Underhill Geomatics Ltd.	$2,233
Voith Hydro Inc.	$3,906,401
YEC Diesel	$636,759
YEC Labour	$793,406
YEC Owner Costs	$692,784
YEC Travel	$46,139
Subtotal	**$13,820,189**
YDC - Contributions	-$5,000,000
YEC A/R	-$3,450
Total Net of Contributions	**$8,816,739**

TOPIC: **Capital Projects**

REFERENCE: **Pages 5-9 to 11 Mayo Hydro Substation Enhancements**

PREAMBLE:

QUESTION:

a) One of the reasons given for the $10.15 million project is the addition of the Mayo B plant, yet its allocation was only $0.6 million – for a simple tap to the bus with appropriate disconnects according to the footnote. Based on the actual costs being experienced in the reconstruction of this substation and the Aishihik substation, is this still the appropriate cost allocation for a least cost connection?

b) If the answer to (a) is yes, is the $0.6 million least cost connection the same interconnection cost as would be required of a 10 MW independent power producer connecting to an existing substation? If not please explain fully.

ANSWER:

(a)

The current Application has increased the $0.600 million assignment of costs to Mayo B to $0.750 million.

Please see response to YECL-YEC-1-33; YECL-YEC-1-34, CW-YEC-1-29 and UCG-YEC-1-56(b).

(b)

Yukon Energy cannot comment specifically on the cost for connecting a 10 MW independent power producer to one of its existing substations.

TOPIC: **Capital Projects**

REFERENCE: **Pages 5-14 to 16 Aishihik Generating Station Redundancy**

PREAMBLE:

QUESTION:

a) Of the projected final cost of $6.356 million what will have been paid to AECOM for their work in this project?

b) Please provide two detailed listings of the projected final cost, one by component and one by contractor (including YEC internal costs).

c) Please discuss Yukon Energy's confidence level in AECOM in light of their involvement in the Aishihik third turbine and Aishihik generating station redundancy projects both of which experienced significant cost overruns.

ANSWER:

(a)

In total, approximately $0.471 million will have been paid to AECOM for the Aishihik Redundancy Project.

(b)

Please see Table 1 below which provides costs by component and Table 2 below which provides costs by contractor. Note that the component breakdown below totals to $6.108 million as at end of 2011 (and not $6.365 total for the project included in Application Table 5.2). As noted in the Application, an additional $0.257 million is forecast to be required in 2012; this amount is estimated to address project wrap-up activities and outstanding items such as gauges, performance testing, minor deficiencies' corrections, and other matters. This additional spending provides for the Final Cost Estimate of $6.365 million included in the 2012/2013 GRA.

Table 1:

Aishihik Redundancy Project Projected Final Costs to End of 2011 by Component

Component	Cost
Building	$848,914
Supply Electro-Mechanical	$1,990,377
Electrical Installation in Generating	$900,245
Electrical Installation Generating Control Room	$250,660
Testing and Commissioning	$330,907
Mobilization	$125,983
Diesel Fuel	$190,343
Estimated Construction Field Cost:	**$4,637,429**
Contingency:	$0
Detail Design:	$591,667
Construction Management:	$306,323
YEC Cost (Owner's Cost):	$493,736
Construction Financing Cost:	$78,732
TOTAL CAPITAL COST:	**$6,107,887**

Table 2:
Aishihik Redundancy Project Projected Final Costs to End of 2011 by Contractor

Contractor	Expense
AECOM Canada Ltd.	$471,063
AFUDC	$74,143
ATCO Structures and Logistics	$135,900
Cap Engineering	$181,628
CAP Engineering	$78,910
EBA Engineering Consultants Ltd.	$6,611
ES&G	$4,589
Meerholz Canada	$13,689
North American Construction	$3,179,145
Northgate Industries Ltd.	$120,701
Orbis Engineering Field Service	$217,957
Peter Kiewit Infrastructure Co.	$62,259
Powell Electrical Systems Inc.	$481,861
Schneider Electric Canada Inc.	$28,670
YEC Diesel	$190,343
YEC Labour	$423,755
YEC Owner Costs	$359,346
YEC Travel	$77,317
TOTAL	**$6,107,887**

(c)

To be clear, issues with the Aishihik Third Turbine Project and the Aishihik Redundancy Project related to cost estimating, i.e., the estimates provided by AECOM did not accurately reflect the costs to do the work. Please see response to YUB-YEC-1-34 which addresses YEC's response to issues with the estimating process, steps to avoid this situation in the future and recourse taken against AECOM.

TOPIC: **Capital Projects**

REFERENCE: **Page 5-28 and pages 5-39 to 41 (see also pages 6-2 to 9) DSM**

PREAMBLE:

QUESTION:

a) In Board Orders 2009-2 and 2009-8 the YUB instructed Yukon Energy and YECL to file a DSM plan, including DSM initiatives. Since such a plan has not been filed as ordered please provide an update on activities and progress towards meeting this order as of the time of responding to this IR.

ANSWER:

(a)

YEC acts as chair of the DSM Working Group which has been meeting regularly since 2011, and bi-weekly in 2012 to complete research and collaborate on pilot projects leading to a five year DSM Plan.

In early 2012 YEC completed the Conservation Potential Review (CPR) in close collaboration with YECL and Yukon Government and with involvement of stakeholders. This comprehensive research document provides a detailed report of territorial electricity use. It is available as a public reference document at the link below.

http://www.yukonenergy.ca/energy/projects/dsm/#related_downloads

YEC and YECL have been working together through Q1 and Q2 of 2012 to complete a Market Characterization study which will provide insight into opportunities and barriers in the Yukon supply chain. The two utilities are currently working from the baseline of all research completed in the test years to build a suite of robust, verifiable programs, which achieve the lowest cost of conserved energy (CCE) possible.

The DSM working group is currently in the draft stage of the five year DSM plan which will be submitted to the YUB upon completion.

For further updates on projects and planning activities please see response to YUB-YEC-1-46(c) and YUB-YEC-1-46(d).

TOPIC: **Capital Projects**

REFERENCE: **Pages 5-33 to 35 Gladstone Creek Diversion**

PREAMBLE:

QUESTION:

a) Can Yukon Energy confirm that while the project would provide up to 36.6 GWh per year (on average), intended primarily for winter use, it will not add any additional winter capacity (in contrast to Marsh Lake storage)?

ANSWER:

(a)

Confirmed.

TOPIC: **Capital Projects**

REFERENCE: **Pages 5-36 to 38 Mayo Lake Enhanced Storage**

PREAMBLE:

QUESTION:

a) Yukon Energy states that the project would add a potential 4 GWh per year to the grid system (presumably at the Mayo power plant). What is the long term annual average increased water flow to the Mayo hydro installations in CMS?

b) Would the increased storage also result in an increase in winter peaking capacity to the power plant?

c) If the answer to (b) is yes, would that mean increased peaking using Mayo A without foregoing useful energy at Mayo B because Mayo B is already at full capacity?

ANSWER:

(a)

The Mayo Lake project serves to provide additional storage range, largely to permit years with very large freshet flows (spring snowmelt) to be stored, rather than being spilled at the Wareham dam.

As noted in LE-YEC-1-19(a), the long term average water flow at the Mayo Generating Station intake is 21.5 cms based on 28 years of data. For consistency with the response to LE-YEC-1-19(b) and the Mayo B Part 3 hearing, the following sets out the usable versus spilled flows under the Mayo scenarios using 21 years of data (21.1 cms long term average water flow), with the distribution of this flow as shown in Table 1.

Table 1:
Distribution of Long-term Average Water Flow at Mayo Generating Station

Mayo Generating Station flow (cms)

	Without Mayo B	without Mayo Lake Enhanced Storage	with Mayo Lake Enhanced Storage
Mayo A	14.3	5.8	5.8
Mayo B		13.1	13.8
spillage	6.8	2.2	1.5
total	21.1	21.1	21.1

(b)

No. The potential for any material winter peaking at the Mayo plant is limited under all scenarios, as described see LE-YEC-1-19(i). In addition, the major benefit of the Mayo Lake project is to provide added storage, largely to capture years of above-average freshet flows, to permit this water to be sustained until later winter, when flows would be required to be curtailed absent this added range.

(c)

Please see part (b).

TOPIC: **Capital Projects**

REFERENCE: **Pages 5-45/46 LNG**

PREAMBLE:

QUESTION:

a) Please table all reports, studies, construction plans, and LNG contracts that Yukon Energy has prepared / entered into that show that LNG is appropriate and cost effective for Yukon in its present circumstances aside from the downloads on the Yukon Energy website.

b) When does Yukon Energy expect to have its LNG plant operational?

c) Where will the LNG plant be located?

d) What is the planned capacity of the plant?

e) Will it be a combined heat and power plant?

ANSWER:

(a)

Please see response to YUB-YEC-1-49 for a summary of current information that YEC can provide on LNG. Beyond what is referenced in this response and on YEC's web site, there are no reports, studies, construction plans, or LNG contracts that YEC is able to provide at this time.

(b)

The Application assumes that the earliest that LNG power generation could occur at Whitehorse is in late 2014. Current planning work is assessing all relevant options in this regard.

(c), **(d)** and **(e)**

As reviewed in response to YUB-YEC-1-49:

- YEC plans that the natural gas power generation facilities will initially be developed at (or close to) its site in Whitehorse; as to the liquefaction plant, options in Alberta and British Columbia are being examined for initial LNG supply.

- Planned capacity for LNG power generation will depend on the forecast grid load to be supplied. The 2011 Resource Plan examined potential capacity of 22 MW for Scenario A loads (with Victoria Gold) and 30 MW for Scenario B loads (with Victoria Gold and Carmacks Copper). Ongoing planning studies continue to assess the potential requirement under each load scenario.

- YEC is looking at options where heat from the LNG generation would be used, to the extent that is feasible, for district energy systems in Whitehorse.

TOPIC: **Capital Projects**

REFERENCE: **Table 5.2 Re Generation Expenditure**

PREAMBLE:

QUESTION:

a) Minto mine diesel upgrades and SCADA: Page 6-13 indicates that Yukon Energy did not purchase the Minto diesels and so cannot be in rate base, why then should this $490,000 project related to these diesels be added into rate base?

ANSWER:

(a)

The original plan was to purchase these units for integration into YEC's dispatch and as such SCADA control was mandatory. As negotiations continued the decision was made not to purchase these units, with Minto retaining ownership and control of the units. However, it was decided to continue proceeding with SCADA as its implementation was mostly complete and completion would provide YEC with a full ability to monitor these units which are connected to the integrated system. With this monitoring, YEC can access essential information on the activity of the units, to ensure that they are operated in a manner that maximizes overall coordination and grid reliability, and to ensure they do not adversely affect the operation of the YEC electrical grid.

TOPIC: **Capital Projects**

REFERENCE: **Table 5.2 Re Generation Expenditures: Aishihik River icing study mitigation – bridge ($665,000), Aishihik River icing study – berm ($455,000), Aishihik elevator modernization project ($398,000), and Aishihik third turbine spare parts ($368,000).**

PREAMBLE:

QUESTION:

a) Please provide a detailed rationale for each of these four generation projects not being included in the Aishihik third turbine project?

b) Please provide two detailed listings of the cost details for each of these projects, one by component and one by supplier / consultant (including Yukon Energy's internal cost) for all amounts of $20,000 or more.

ANSWER:

(a)

The following four projects were justified based on issues related to operation of the current Aishihik facility and as such were not related to the specific Aishihik Third Turbine Project.

- **Aishihik River Icing Bridge** – This work was undertaken in order to comply with existing Aishihik Generation plant licence requirements (HY99-011). The rationale and justification for this project is based on prior feasibility study work undertaken in 2007/2008 with regard to icing in the Aishihik River. These studies determined there was potential for damage to the heritage bridge due to ice build-up. It was recommended that the bridge be raised.

  These studies were undertaken prior to a decision to proceed with the Aishihik Third Turbine Project in 2009 and the Carmacks Stewart Transmission Project – Stage 2 (in 2010). Since the installation of the Aishihik Third Turbine it has been observed that the maintenance of a consistent flow of water in the river helps to

mitigate ice build-up at that location. Therefore the completion of the Aishihik Third Turbine project and the Carmacks Stewart Transmission Project – Stage 2, have provided additional information for review as the maintenance of a consistent river flow is helping to alleviate the build-up of downstream ice at this location. Therefore, in 2012 the need to proceed with specific capital work is being re-evaluated with this new information.

- **Aishihik River Icing Berm** – This project was completed in order to comply with our license requirements. Prior feasibility studies on icing in the Aishihik River, conducted years before determined that a low lying area of the Aishihik River was prone to flooding due to ice build-up. The study recommended that an earthen berm be built to mitigate flooding in the low lying areas. This was completed in 2011.

- **Aishihik Elevator Modernization** – This project was required due to the aging infrastructure at the Aishihik facility and was required to ensure that operational personnel were provided with safe and reliable access to the AH1 and AH2 turbine/generators. This was required to ensure the continued save and reliable operation of the Aishihik Generation facility generally and was not a requirement of the Aishihik Third Turbine Project.

- **Aishihik Third Turbine Spare Parts** – This project was not included within the Aishihik Third Turbine Project as approval from the Board had already been received for that project, and it was decided to set up a different project for spares.

(b)

For the Aishihik River Icing Bridge please note that the project is still under review and being re-evaluated in 2012. Spending to date is less than $20,000.

For Aishihik River Icing Berm – please see Tables 1 and 2 below for component and vendor breakdowns.

Table 1:
Aishihik River Icing Berm – Costs by Component

Component		
AFUDC	$	7,230
Airfare	$	1,755
Car/Equipment Rental	$	1,249
Consultants	$	111,288
Contractors	$	290,446
ES&G (buildup)	$	5,557
Mass Media Advertising	$	662
Materials	$	44
Meals	$	205
Parts & Service	$	12,123
Regular time	$	24,247
Telephone & Fax	$	14
TOTAL	**$**	**454,821**

Table 2:
Aishihik River Icing Berm – Costs by Vendor

Vendor		
KGS Group		
Engineering & Design Services	$	105,933
Steelwater Contracting		
Installation contractor	$	294,861
YEC Labour		
Labour	$	24,247
TOTAL	**$**	**425,041**

The difference of $29,780 in total expense between Table 1 and Table 2 relates to contractor costs not included in Table 2 for contractors with total expense less than $20,000.

- **Aishihik Elevator Modernization** – Please see Tables 3 and 4 below for component and vendor breakdowns.

Table 3:
Aishihik Elevator Modernization – Costs by Component

Component	
AFUDC	$ 5,419
Brokerage & Release Fees	$ 53
Car/Equipment Rental	$ 3,385
Contractors	$ 275,068
ES&G (buildup)	$ 129
Incidentals	$ 560
Janitorial	$ 89
Materials	$ 8,869
Meals	$ 2,378
Overtime @ double time	$ 7,135
Parts & Service	$ 47,206
Regular time	$ 47,841
TOTAL	**$398,132**

Table 4:
Aishihik Elevator Modernization – Costs by Vendor

Vendor	
Thyssenkrupp Elevator	
Supply and Installation Contract	$ 309,285
YEC Labour	
Labour	$ 54,976
TOTAL	**$364,261**

The difference of $33,871 in total expense between Table 3 and Table 4 relate to contractor costs not included in Table 2 for contractors with total expense less than $20,000.

- **Aishihik Third Turbine Spare Parts** – Please see Tables 5 and 6 below for component and vendor breakdowns.

Table 5:
Aishihik Third Turbine Spare Parts – Costs by Component

Component		
AFUDC	$	17,080
Contractors	$	600
ES&G (Buildup)	$	1,530
Materials	$	347,765
TOTAL	**$**	**366,975**

Table 6:
Aishihik Third Turbine Spare Parts – Costs by Vendor

Vendor		
Voith Hydro Inc.		
Supply of Parts	$	334,765
TOTAL	**$**	**334,765**

The difference of $32,210 in total expense between Table 5 and Table 6 relate to contractor costs not included in Table 2 for contractors with total expense less than $20,000.

TOPIC: **Capital Projects**

REFERENCE: **Tables 5.4 to 5.7 Feasibility Study Costs: Wind Feasibility – Ferry Hill**

PREAMBLE:

QUESTION:

a) Please provide two detailed listings of the cost for this project to the end of 2011 ($427,617), one by component and one by supplier / consultant (including Yukon Energy's internal cost) for all amounts of $20,000 or more.

b) Please provide detailed breakdowns for proposed expenditures of $100,000 in each of 2012 and 2013.

ANSWER:

(a)

Table 1 below provides a breakdown of actual expenditures over $20,000 by task by component and by Supplier / Consultant for the Wind Feasibility Project by end of 2011.

Table 1:
Actual Expenditures by Task by Component for Wind Feasibility Project

Supplier / Consultant	Component	Amount
Metlogics Consulting Ltd.	Wind Monitoring Tower - Equipment ($140,476) and Construction Supervision ($99,000)	$239,476
Natural Power Consultants Ltd.	Feasibility Study and Wind Monitoring Support	$109,384
YEC – Internal Cost	Labour, Travel, Materials, Admin, ES&G, AFUDC	$31,628
Other costs below $20,000		$47,129
Total		**$427,617**

(b)

Table 2 below provides a detailed breakdown of forecast expenditures for the 2012 and 2013 test years.

Table 2:
2012/2013 Forecast Expenditures by Task by Component for Wind Feasibility Project

Test Year	Proposed Activity	Amount
2012	Wind Monitoring – Ferry Hill	$10,000
	Operation and Maintenance – Ferry Hill	$25,000
	Wind Energy mini-workshop	$50,000
	YEC Internal Cost (Labour, Travel, Materials, Admin, AFUDC)	$15,000
Total 2012 Forecast		**$100,000**
2013	Wind Monitoring and Analysis – Ferry Hill	$25,000
	Environmental Baseline Data Collection	$60,000
	YEC Internal Cost (Labour, Travel, Materials, Admin, AFUDC)	$15,000
Total 2013 Forecast		**$100,000**

TOPIC: **Capital Projects**

REFERENCE: **Tabs 5 and 10 hydro projects and depreciation of capital projects and related capital expenditures.**

PREAMBLE:

Leading Edge wishes to understand the depreciation of new hydro plants and the treatment of capital improvements and re-investments that take place in hydro plants over the course of the lives over which they are depreciated.

QUESTION:

a) Can Yukon Energy confirm that its new hydro plant facilities, including Mayo B and Aishihik third turbine will be depreciated over 65 years?

b) Is it not also true that these hydro plants contain many components that will need to be replaced or updated or upgraded with new capital investments over the course of their service lives since they have average service lives shorter than 65 years (for example transformers, switchgear, substations, generators, governor systems, turbine runners, dams, spillway equipment, water licences, etc.)?

c) Are such capital investments depreciated over the remaining service life of the overall hydro facility or over the anticipated service life of the component, or something different? Please explain the rationales used.

d) When calculating the levelized cost of energy from these new hydro plants does Yukon Energy's modeling include estimated costs for capital reinvestments required over the course of their service lives?

e) Please provide a table of the sum of the capital cost expended (on any component) on each of the Mayo hydro plant, the Whitehorse Rapids hydro plant, and the Aishihik Hydro plant in each year since Yukon Energy assumed ownership in 1987 to the present but not including expenditures related to Mayo B and Aishihik third turbine.

ANSWER:

(a)

Not confirmed. The hydro assets constructed are capitalized by class and depreciated according to the rate applicable for that class. In this Application, the Yukon Energy has applied for the depreciation rates shown in Table 1 below.

Table 1:
Depreciation Rates for YEC's Hydro Plant Asset Main Sub-classes

Description	Depreciation Rate	Years Amortized Over	
Structures and Improvements	1.39	72	Proposed depreciation rate
Reservoirs, Dams and Waterways	0.97	103	Proposed depreciation rate
Waterwheels, Turbines and Generation	1.18	85	Proposed depreciation rate
Accessory Electrical Equipment	2.22	45	
Misc Power Plant Equipment	3.33	30	

(b)

As described in part (a) above, hydro assets with shorter lives are grouped and depreciated in the appropriate asset class reflecting the expected life cycle of that type of asset. For example, with reference to Table 1 above, there are components of "structures and improvements" that would be expected to last less than 72 years, and others that are expected to last longer than 72 years.

(c)

Capital assets are depreciated over the estimated average service life of the class of asset constructed (depreciation rates are not set for individual assets, but rather for classes of assets – see YECL-YEC-1-55(a)).

(d)

For simplicity of the analysis YEC used a 65-year life. However, based on new proposed depreciation rates the Mayo B assets amortize over approximately 89 years, Aishihik Unit #3 assets amortize over approximately 82 years. There are no costs included in levelized cost analysis for hypothetical future reinvestment. Similarly no residual value is

included for any useable or enduring components of the assets that extend beyond the average life.

(e)

Please see Table 2 below for hydro plant capital expenditures for 2000-2011. Data from the period prior to 2000 is much more time consuming to decipher as it is based on older accounting systems.

Table 2:
YEC Hydro Plant Capital Expenditures (excludes Mayo B and AH3)
($000s)

Year	Hydro Plants (excludes Mayo B and AH3 costs)		
	Mayo Hydro	Aishihik Hydro	Whitehorse Hydro
2000	299.7	180.8	235.1
2001	27.6	187.7	77.3
2002	3,303.1	53.0	1,299.4
2003	969.0	1,116.5	52.8
2004	1,206.6	(50.8)	812.7
2005	281.9	221.4	607.9
2006	161.4	1,388.7	467.4
2007	6.9	144.6	262.1
2008	46.3	66.1	254.4
2009	253.5	86.3	577.2
2010	1,352.6	65.4	1,197.5
2011	1,039.5	524.9	873.7
Total 2000-2011	8,948.2	3,984.6	6,717.3

TOPIC: **Board Directives**

REFERENCE: **Page 6.8 Directive #7 re brushing activities: Appendix 12.2 provides Yukon Energy with a number of recommendations with alternatives in some cases.**

PREAMBLE:

QUESTION:

a) Please describe in detail the recommendations that Yukon Energy is field testing and what is involved in the field tests.

b) Are there any recommendations with which Yukon Energy disagrees or which Yukon Energy considers impractical? If so please list those recommendations and Yukon Energy's reasons for their views.

ANSWER:

(a)

Yukon Energy is field testing the following recommendations from the Brushing Study provided in Appendix 12.2 of the Application:

- **Recommendation #1 -** Remove trees under the conductors in locations designated as Critical as soon as possible, as per cyclic plan.

- **Recommendation #4 -** Establish a schedule of cyclic maintenance by right-of-way including separate schedules for Critical, Priority and Hazard tree locations. From the Appendix D Proposed 2012 Forward Work Schedule – 1st Cycle (ECI Work Priority Recommendations), the following is noted:
  - 1A L356 has been completed as first priority;
  - 2A L172 is underway;
  - 2A L453 is planned to commence the first week of August;
  - 5A L174 will commence in August as identified by patrol;
  - L171, L170B completed as identified by patrol;

- **Recommendation # 6 -** Establish a list or database of danger and hazard tree locations and develop a priority program to determine which trees should be removed first. The Database was established and cutting is based on cyclic plan schedule and patrol recommendations;
- **Recommendation #7 -** Develop vegetation maintenance clearance specifications for transmission and sub-transmission voltages and policy standards specific to YEC needs and conditions. YEC has reviewed the ECI draft TVMP and adopted this plan; and
- **Recommendations # 8 -** Consider contracting alternatives to reduce maintenance cost and develop additional qualified vendors to perform vegetation maintenance on the YEC system (including herbicide application).

YEC has been in discussions with three new brushing contractors all of which are anxious to establish a relationship with YEC and have indicated their interest in tendering for the 2013 brushing work.

(b)

The following recommendations are still under evaluation and consideration as the existing budget cannot support the mob/demob costs were YEC to adhere to the recommendation:

1. Remove trees under the conductors in locations designated as Critical as soon as possible.

2. Remove trees under the conductors in locations designated as Priority before the next growing season (June 2011).

3. Remove all trees designated as Hazard over the next two years.

4. Budget funds to address Critical locations as they are identified.

The following recommendations are still under evaluation and consideration as the program/pilot has not been developed or presented for approval to adhere to this:

1. Implement Integrated Vegetation Management (IVM) as the guiding maintenance principle on the YEC system.

2. Establish an herbicide test plot area.

TOPIC: **Board Directives**

REFERENCE: **Page 6-13/14 Directive #16: While Yukon Energy has provided short business case discussions on projects of over $1 million requested to be added into rate base, it has not provided any supporting analyses.**

PREAMBLE:

QUESTION:

a) Please provide the supporting analyses (spreadsheets etc.) for all projects over $1 million with the exception of Mayo B and CSTP Stage II which have been adequately reviewed in past.

ANSWER:

(a)

Please see response to YUB-YEC-1-32(c) for review of business case information related to major capital projects over $1 million.

As noted, supporting analysis has been provided as required in the past for Mayo B and CSTP Stage 2 - Yukon Energy notes that this observation also applies to Aishihik Third Turbine. As reviewed in the referenced YUB IR, the nature of the business case information for other major capital projects is governed by very different considerations than those applicable to Mayo B, CSTP Stage 2 or Aishihik Third Turbine, e.g., system safety and reliability, replacement of existing financial systems, meeting new Whitehorse subdivision requirements (not affect rates in test years), and potential grid connections for possible new mines where all potential costs are forecast to be funded fully by customer contributions.

TOPIC: **Board Directive**

REFERENCE: **Page 6.1-4/5 Appendix 6.1 hydro generation KPIs:**

PREAMBLE:

QUESTION:

a) The Forced Outage rate is missing from the Table 1-1 and Figure 1-1, please provide this information.

b) In addition to the Forced Outage rate the planned outage rate would be very useful too, and should be easy to calculate (100% less forced outage rate and less unit availability?). Please provide this information.

ANSWER:

(a)

The Forced Outage rate is provided in Appendix 6.1, page 6.1-8 Table 1.3. Please see updated tables in response to question (b) below.

The Forced Outage rate is not provided in Figure 1-1 as showing a 0.5% forced outage rate against other parameters in excess of 50% would not provide meaningful results in that format.

(b)

Please see the updated versions of Table 1-1 and Table 1-2 from Appendix 6.1 of the Application which update hydro and diesel units forecast availability rates for 2012 and 2013 as well as include forced and planned outage rates for actual years and forecasts for the test years.

Table 1-1:
Hydro Generation KPIs

Year	Capacity Factor	Unit Availability	Operating Factor	Forced Outage Rate	Planned Outage Rate
2009	57.74%	94.54%	81.20%	0.45%	5.01%
2010	59.60%	95.73%	81.30%	0.38%	3.89%
2011	48.42%	64.19%	52.62%	0.22%	35.59%
F-2012	52.98%	**89.86%**	70.00%	NA	10.14%
F-2013	52.94%	**94.06%**	70.00%	NA	5.94%

The planned outage rate is higher in 2011 due to construction of Mayo B and Aishihik 3rd Turbine in that year. Please note that forced outages are not forecast due to the unplanned nature of such outages. The forced outage rate can be expected to approximate the level experienced in prior years, i.e., approximately 0.5%. Planned outages were forecast for 2012 and 2013 using preventative maintenance schedules and are included in updated Table 1-1 above.

Table 1-2:
Diesel Generation KPIs

Year	Capacity Factor	Unit Availability	Operating Factor	Forced Outage Rate	Planned Outage Rate
2009	0.84%	89.53%	1.21%	4.79%	5.68%
2010	2.13%	89.88%	3.01%	0.85%	9.35%
2011	6.15%	95.84%	8.71%	3.07%	1.11%
F-2012	2.03%	**95.43%**	4.11%	NA	4.57%
F-2013	2.91%	**97.12%**	5.86%	NA	2.88%

TOPIC: **Technical Reports**

REFERENCE: **Appendix 12.2 Pages 12.2-36/37: L250, the Mayo**

PREAMBLE:

QUESTION:

a) Keno City line is listed as being of H frame construction, yet this line was a single pole structure line (tangents structures in any case). Did the consultant actually inspect the line? Please clarify and explain.

ANSWER:

(a)

The Mayo-Keno City line is listed as being of H-frame construction; however, this line is a single pole structure line with H-Frame dead-ends. The consultant inspected the line and the H frame construction identified is a typographical error.

TOPIC: **Technical Reports**

REFERENCE: **Appendix 12.2 page 12.2-38**

PREAMBLE:

QUESTION:

a) Did Yukon Energy complete the brushing on all of the recommended priority spans in 2011 as recommended? If not please explain.

ANSWER:

(a)

YEC did not complete brushing on all of the recommended priority spans in 2011 as there was insufficient funding. An internal analysis was conducted to prioritize the requirements with partial brushing being completed or planned on the following lines: L170A, L170B, L171, L172 underway, L174 and L453 planned for this August, and L356 (completed).

TOPIC: **Other Matters**

REFERENCE:

PREAMBLE:

In 2011 the YUB held a proceeding on Rate Schedule 39, specifically to review Yukon Energy's request to escalate industrial rates as required by OIC 2007/94. At that time Leading Edge wished to submit IRs on matters related to industrial rates [refer to letter from Leading Edge to the YUB dated January 10, 2011] that was not specifically on the topic of the escalation of rates. Yukon Energy [in a letter dated January 14, 2011] objected to these matters being raised in the proceeding and cited as Yukon Energy's 2008 GRA as having been one opportunity to raise these issues. The Board ruled that the proceeding was to deal with the escalation only. It follows then that this GRA is a suitable proceeding at which to ask these IRs.

QUESTION:

a) Is it YEC's interpretation that it has an obligation to serve any potential new industrial customer that requests service, even if no grid connection to that industrial customer presently exists? If so please reference the relevant portions of any Acts, or OICs that Yukon Energy relies on for that interpretation.

ANSWER:

(a)

Yukon Energy has previously noted in the 2006 20-Year Resource Plan and in the 2009 Mayo B Part 3 Application that it has an obligation to serve industrial loads as well as non-industrial loads that are able to connect to the integrated grid. Yukon Energy is considered under the Public Utilities Act to have a typical utility obligation to serve new industrial customers that request electrical service where these customers locate within areas presently served by Yukon Energy grid power.

Historically, this has been interpreted to mean:

- Where new industrial customers are located within areas presently served by Yukon Energy grid power, Yukon Energy must take into consideration its typical utility "obligation to serve" new loads that request electrical service.

- Yukon Energy is not automatically required to serve new industrial loads that are located far away from the current Yukon grid unless the customer (or government) is prepared to fund directly the transmission costs and risks required for Yukon Energy to connect the new load to the grid[1].

- It is assumed that customers isolated from the grid would be supplied by on-site diesel generation with all costs being excluded from YUB consideration for the purpose of Yukon wide regulated rate setting (in accordance with OIC 1995/90).

In the context of new industrial customers, "obligation to serve" reflects a well established regulatory framework that provides guidance in how to think about and balance competing interests in a manner that is principled and fair for the utility as well as all classes of customer.

- In general, this framework confirms a regulated utility's obligation to serve new and existing customers in its franchise area, subject to certain rules (including ability to require new customers to pay certain "connection costs" related to new utility assets needed to connect them to the grid).

- The framework provides a principled basis for addressing new industrial (or other) customer connections, where the new customer pays for the local connection costs of system expansion, while other system costs of expansion (e.g., costs beyond the local connection, including generation costs) are the responsibility of all customers (including the new industrial customer), form part

[1] Pursuant to the Maximum Utility Investment policy for industrials described in the 2009 Phase II Rate Application, and approved by Order 2010-13, transmission or distribution costs driven by new industrial customers are assumed to be funded by the industrial customer themselves (or by government), except to the extent that there is a cost effective case for Yukon Energy to invest in hooking up new industrial customers at a benefit to current ratepayers (pursuant to principles established in the Terms and Conditions of Service).

of the utility revenue requirement, and are recovered from all customers through rates.

- This framework also sets rates to all connected customers without discrimination against specific customers, classes of customer or when a customer connected (e.g., new versus old customers are treated the same).

The “obligation to serve” regulatory framework also acts to prevent connection of new industrial customers who are unable to take full responsibility for their local connection cost, e.g., because the new load is too far from the grid, or will have too short a life, etc.

TOPIC: **Other Matters**

REFERENCE:

PREAMBLE:

The addition of the Eagle Industrial Minerals to the industrial customer class on the now integrated grid will increase marginal diesel requirements to 56% (from Table 3.2-2) from 49% in 2012 (as per Table 3.2-1) of any further new load.

QUESTION:

a) Which party or parties are covering the cost for the additional diesel generation in the case of Eagle Industrial Minerals?

b) If the industrial loads as a whole increase as a result of the addition of Carmacks Copper (52 GWh per year) the marginal diesel generation required on an annual basis will then increase to about 70% of any new supply. Carmacks Copper will require between 56% and 70% of its power requirement to be met by diesel. Victoria Gold (100GWh per year) would require up to about 85% or more diesel (extrapolating Table 3.2-2 and assuming that Carmacks Copper does not connect). How does or would Yukon Energy calculate what it considers to be a fair allocation of these additional costs to these mines individually or as an industrial class?

c) Since the connection of any new industrial customer increases the percentage of diesel generation required to meet the overall electrical load on the grid is that new industrial customer responsible for the full cost of the incremental increase in diesel generation?

d) If the answer to the above is no, would the industrial customer class as a whole be responsible for the full cost of the incremental increase in diesel generation?

ANSWER:

(a) through **(d)**

The question assumes that each new mine is "responsible" for the incremental diesel generation that is expected, on a long term average basis, to be required from overall growth of the integrated grid. The question ignores any similar suggestion regarding any other source of growth on this grid, e.g., Whistle Bend or other major new subdivisions to accommodate strong and ongoing non-industrial growth.

Attempts to assign responsibility for new "incremental" diesel generation to specific customers or customer classes are fraught with serious issues of principle.

In principle, each customer and each customer class contributes to load on the grid, and to the current "incremental" load at any time of day or season of the year. Every kW.h consumed is a part of the load that must be served from existing and new resources, regardless as to the length of time that customer has been on the system (e.g., old house versus new house, old industry versus new industry).

Within the current regulatory compact it would be considered rate discrimination to make an individual customer or class of customers who receive comparable utility service pay rates that were designed based on fundamentally different methodologies (e.g., average cost versus incremental cost, new versus old service).

Using a similar argument to the proposals advanced in this question, the operators of the Faro mine previously argued for a rate lower than would be determined by proper embedded cost analysis, arguing that the incremental costs of adding the Faro mine were only 5 cents/kW.h despite the embedded or "average" cost allocation yielding a higher rate. The YUB consistently rejected that argument from the Faro mine. OIC 1995/90 (Section 6) also directed that rates to industrial customers be sufficient to recover the costs of service to that customer class, with such costs to be determined by treating the whole of Yukon as a single rate zone, e.g., when the Faro mine was the only such customer, this required that mine to pay a share of diesel costs for diesel served communities not connected to the WAF grid.

Contrary to OIC 1995/90 (Section 4), such rate discrimination as suggested in this question would also not appear to be in accordance with principles established in Canada for utilities, including those of a province regulating hydro and non-hydro electric utilities.

TOPIC: **Other Matters**

REFERENCE: **For 2014 and beyond when OICs 2012/68 and 2007/94 are no longer in effect.**

PREAMBLE:

QUESTION:

a) If any new industrial customer were to request connection to the integrated grid would they, under OICs 1995/090, or any other legislation now in effect, be required to be served at the present Rate Schedule 39 with the stipulated escalation to the demand and energy charges?

b) If the connection of any such new industrial customer further increases the percentage of diesel generation required to meet the overall electrical load on the grid absent that industrial customer, would that new industrial customer be responsible for the full cost of the incremental increase in diesel generation?

c) If the answer to the above is no, would the industrial customer class as a whole be responsible for the full cost of the incremental increase in diesel generation?

ANSWER:

(a)

Yes. Rate Schedule 39 is applicable to all major industrial customers engaged in manufacturing, processing or mining, with an electric service capacity in excess of 1,000 kW. The specific OIC directions applicable to Rate Schedule 39 may change from time to time, as evidenced by the recent changes effected by OIC 2012/68.

(b) and **(c)**

Please see LE-YEC-1-38 and YUB-YEC-1-2.

TOPIC: **Other Matters**

REFERENCE: **Re Increase in Future Generation Costs**

PREAMBLE:

QUESTION:

a) In future when YEC develops (or purchases) new generation resources (hydro or other forms of generation) that are more costly than our present mix of "heritage" resources, how does YEC foresee allocating the increased costs between retail load and industrial load (regardless of whether YEC or YECL serves that load)?

b) Should such new generation sources have long amortization periods (such as the 65 years for Mayo B) that are well beyond the anticipated lives of the industrial customers that are being served, how does YEC plan to allocate responsibility for the financial risk of such facilities becoming surplus to the needs of the grid?

ANSWER:

(a)

All generation costs will be allocated according to the principles set out in the approved Cost of Service Study, and subject to any OIC direction. These principles have been subject to review and approval by the Board in the 1990s and more recently in the 2009 Phase II GRA proceeding. In the past, these principles were applied to major new hydro asset costs such as the Whitehorse 4 unit that came into service shortly before the transfer of NCPC assets to Yukon Energy.

(b)

The decision to proceed with any major new generation (or other resource) must address all risks that are load-related or that arise due to any other factor. It is incumbent on YEC (or any other proponent) to bring forward, for YUB review, a thorough analysis of the risks of each project or contractual commitment, and the mechanisms to address these risks. The specific facts relevant to each project and/or commitment will need to be

considered in each instance, and in the context of expected future loads and cost options as then forecast.

These risk factors were fully considered in Yukon Energy's business cases for recent major projects such as the Carmacks Stewart Transmission Project, Mayo B, and the Aishihik Third Turbine. The 2011 Resource Plan also fully considered load risks, affordability and flexibility when assessing the various future resource options, highlighting the load risks specific to capital intensive generation options that offer little if any flexibility to adapt to changing load conditions.

In general, the appropriate focus is on avoiding risky new capital intensive generation projects rather than attempting to allocate the "financial risk" of any such bulk power generation project to any individual customer or customer class. All customers consuming energy (kW.h) contribute to the need for new resources. However, if there are special load related risks that arise for a particular new generation project, these risks can (and must) be considered in light of the costs, benefits, and other characteristics of the generating plant that are provided for all customers.

TOPIC: **Other Matters**

REFERENCE: **Re Rate Schedule 39**

PREAMBLE:

QUESTION:

a) What changes to Rate Schedule 39 does YEC contemplate will be required following the expiry of OIC 2012/68 besides escalation of the demand and energy charges?

b) Will changes be required to the demand ratchet clause (Billing Demand (b))?

c) Will changes be required to encourage the industrial customers to be energy efficient or participate in YEC's DSM programs?

d) If in future the industrial rate class load grows at a faster rate than the load from retail classes what other adjustments to Rate Schedule 39 would YEC anticipate would be required?

ANSWER:

(a) through **(d)**

Yukon Energy has not at this time developed any proposals for future changes to Rate Schedule 39 following the expiry of OIC 2012/68 at the end of 2013.

Utilities Consumers' Group
(UCG)

TOPIC:

REFERENCE: April 27, 2012 Application Cover Letter

PREAMBLE:

QUESTION:

a) Please provide a full explanation of how an application filed April 27, 2012 requesting approval of a revenue requirement and rates effective January 1, 2012 should not be treated as an application requesting / endorsing rate retroactivity.

b) Please provide examples of decisions by regulators in other jurisdictions which allow utilities to fully recover a test year revenue requirement despite applying for that recovery during the test year.

c) Please confirm that the following decisions by the Ontario Energy Board deny the applicant utilities from recovering the full test year revenue requirement in a late filing situation similar to what has happened with YEC's current application:

Ontario Energy Board Docket EB-2009-0177
Decision dated January 25, 2010

Ontario Energy Board Docket EB-2008-0246
Decision dated July 10, 2009

Ontario Energy Board Docket EB-2008-0241
Decision dated June 1, 2009

ANSWER:

(a)

The Application does not request rates effective January 1, 2012. It requests interim Rider J effective July 1, 2012 and Rider R effective January 1, 2013. The Application requests approval of a revenue requirement and revenue requirement shortfall for

calendar year 2012, consistent with each of YECL and YEC's previous GRA applications for 2008/09 which were similarly filed following January 1, 2008.

(b)

YEC does not regularly track the specific filing dates of other utilities' applications and utility board decisions. Outside of Yukon, YEC is aware of the following examples:

Northwest Territories Public Utilities Board – NTPC 2006/08 GRA
Northwest Territories Public Utilities Board – NTPC 2001/03 GRA
Northwest Territories Public Utilities Board – NUL(NWT) 2005/06 GRA
Northwest Territories Public Utilities Board – NUL(NWT) 2008/10 GRA

(c)

YEC cannot confirm the stated information.

TOPIC:

REFERENCE: April 27, 2012 Application Cover Letter

PREAMBLE:

QUESTION:

a) Please provide details of all stakeholder consultations conducted by YEC during development of this application prior to submitting it to the YUB.

b) Please provide documentation related to issues discussed during these consultations and a list of all parties involved.

c) Please confirm that the Board's of Directors of YEC and YDC approved the General Rate Application as provided to the YUB. Please identify the dates on which these approvals were provided.

ANSWER:

(a) and **(b)**

YEC did not conduct stakeholder consultations on the contents of the GRA prior to filing.

(c)

Yukon Energy's Board of Directors approved the filing of a GRA in February. The GRA documentation was completed following this approval.

TOPIC:

REFERENCE: April 27, 2012 Application Cover Letter, Page 1

YEC states "*This GRA deals primarily with Yukon Energy revenue requirement matters for the 2012 and 2013 test years. It does not address in any material way cost of service and general rate design matters that would require joint work with the Yukon Electrical Company Limited ("YECL"). Rate increases are proposed by Yukon Energy for each test year through implementation of Rider J and Rider R (both applicable to retail and industrial customers throughout Yukon) to recover the Revenue Requirements to supply customers in 2012 and 2013."*

Board Order 2010-13, Appendix A – Reasons for Decision

"29. Therefore, the Board directs the Companies to file a joint COS study within six months of the expiry of OIC 2008/149. The Board further directs the Companies to incorporate all findings and directions of this Decision into the next COS study."

PREAMBLE:

QUESTION:

a) Please confirm YEC's understanding that the conditions within OIC 2008/149 have effectively been extended to December 31, 2013 as a result of OIC 2012/068, which was issued the day before YEC submitted its current application.

b) Please provide details of any discussions or information sharing that YEC was a party to related to the development of OIC 2012/068.

c) Please provide details on the progress made to date and the expected schedule for completing and filing the joint COS study as directed by the YUB in Board Order 2010-13.

d) Please confirm YEC's understanding that the applied for riders would be considered rates as defined within the *Public Utilities Act*.

e) Please explain YEC's proposal to use an across-the-board rider instead of establishing cost-based, rider-free base rates to recover applied-for revenue requirements.

f) Please explain how and why YEC made the decision 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.

g) Please confirm whether YEC had discussions with the Yukon government regarding this Phase 1 only approach.

h) Please explain how the YUB can make any decisions on the applied-for rates until after a joint YEC/YECL Phase II application has been reviewed.

ANSWER:

(a)

Confirmed.

(b)

OIC 2012/68 is a specific direction of the Yukon Government – this question is outside the scope of the current proceeding.

(c)

Please see YECL-YEC-1-1.

(d)

Confirmed.

(e)

OIC 2012/68 prevents rate rebalancing between rate classes, i.e., the Board must ensure until the end of 2013 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and, subject to the 3.4% already approved effective January 1, 2012, to the class of major industrial customers.

In the 2008/2009 YEC GRA, Yukon Energy applied for rates to be implemented in a manner that was not "across-the-board", reflecting updated information on costs related to the various rate components, while still reflecting the limitations on inter-class rebalancing contained in OIC 2008/149. The Board instead concluded that across-the-board rate adjustments were appropriate.

(f)

Please see YECL-YEC-1-1.

(g)

Not confirmed.

(h)

Consistent with longstanding practice in Yukon and throughout Canada, Board decisions that a utility is failing to recover its revenue requirement are the basis for changes to rates, with or without any "Phase II" or other analysis.

TOPIC:

REFERENCE: April 27, 2012 Application Cover Letter, Page 2

YEC states "*To ensure that YEC has a reasonable ability to recover its prudent costs for 2012 (as may be finally approved by the Board after a full hearing), the Application includes a request to implement overall rate adjustments of 6.4% for retail customers and 2.9% for industrial customers through implementation of Rider J (applicable to retail customers and industrial customers), effective July 1, 2012 on an interim refundable basis. Any required "true up" between the utility and ratepayers for 2012 will be part of the Board's final order setting out rates arising from this Application*".

PREAMBLE:

QUESTION:

a) Please confirm YEC's understanding of the Board's decision in Order 2012-05 granting 2012 interim refundable rates that the Board only preserved YEC's opportunity to recover the revenues ultimately determined by the Board to be just and reasonable for recovery in 2012 and that this did not necessarily preserve YEC's right to recover the full 2012 revenue requirement determined by the Board.

b) Please confirm that half ($1.725 million) of the proposed 2012 revenue shortfall will be collected through interim rider J during 2012.

c) Please explain fully how YEC plans to collect the proposed revenue shortfall going forward into both test years (i.e., will the rider J continue into 2013 and perpetuity or will it be terminated on December 31, 2012 and only the Rider R be implemented for 2013 for 12 months?).

ANSWER:

(a)

Not confirmed. The Board's awarding of interim rates does not preserve nor fail to preserve any rights of the utility. The order simply implements interim and refundable rates pending and subject to the final decisions of the Board.

(b)

The collections are estimated at $1.719 million. It is not precisely half of the $3.455 million 2012 shortfall, as sales in the first half of the year are not identical to sales in the last half of the year.

(c)

As set out in Tab 4, YEC's GRA proposed that the new Rider J (6.4% for non-industrial, 2.9% for industrial) will continue indefinitely as a final rate, as will Rider R (6.5%, including application to charges under Rider J).

TOPIC:

REFERENCE: May 30, 2012 Summary and Overview Presentation, Slide 6

YEC states that this application represents "*Yukon Energy's first requested increase in firm retail rates since 1998/99 rate review after closure of Faro mine*".

PREAMBLE:

QUESTION:

a) Please confirm that the February 19, 2010 joint Phase II application by YEC and YECL requested (i) elimination of the general purpose Rate Riders (Riders J and R) from customer bills; and (ii) adjustments to retail base rates to fully reflect approved 2009 costs.

b) Please confirm that the bills of Yukon ratepayers have continued to change since 1997 due to the reliance by YEC and YECL on across-the-board percentage rate riders (e.g., Riders F, J and R) to recover approved rate revenue requirements and changes to fuel costs beyond what was provided by 1997 base rates.

c) 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 1997, January 1998, January 1999, January 2000, January 2001, January 2002, January 2003, January 2004, January 2005, January 2006, January 2007, January 2008, January 2009, January 2010, January 2011, January 2012, July 2012 and January 2013 assuming that the 2012 and 2013 rate adjustments proposed by YEC are approved. Please provide details of the bill calculations and indicate overall percentage changes in the total bill for each year.

ANSWER:

(a)

Confirmed. Adjustments to rates were implemented on a revenue neutral basis, by utility and by class.

(b)

Generally confirmed, however note specifics below:

1) Yukon Energy's previous Rider J, which was a component of YEC's revenue requirement collection, was not increased following 1999 (it was decreased at times, such as 2003).

2) The previous Rider R was a YECL rider to recover YECL's rate increases in their 2008/09 GRA.

3) Rider F is an adjustment made from time-to-time solely related to the flow-through of diesel fuel price changes. When implemented it is a not a component of paying for YEC's changing basic costs of providing power, but solely related to world fuel price variability. Please see LE-YEC-1-1(g).

(c)

Please see tables 1 through 3 below for Whitehorse Residential monthly bills for January 2009, January 2010, January 2011, January 2012, July 2012 and January 2013 for 1,000 KW.h, 1,200 KW.h and 1,400 KW.h monthly consumption.

Attachment 1 attached is a graph prepared as part of the 2009 Phase II proceeding showing each change in residential non-government rates and rate relief since 1987. The requested detailed information for 1997-2008 was available to be reviewed as part of the previous GRAs and is not readily compiled or directly relevant to the current revenue requirement proceeding for the 2012/13 test years.

The full bill (including GST) before government rate relief in December 1999 (the last time Yukon Energy's rate was increased) was $129 for 1000 kW.h of usage.

Table 1:
Whitehorse Residential Monthly Bills for January 2009, January 2010, January 2011, January 2012, July 2012 and January 2013 for 1,000 KW.h Monthly Consumption

Line #	First Block Energy Use - Customer Use per month: 1,000 kWh			Jan-09		Jan-10		Jan-11		Jan-12		2012/13 GRA Proposed Jul-12 2012 Proposed Rates		Jan-13 2013 Proposed Rates	
				Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates														
1	Customer Charge (per month)			$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)			$0.0986	$98.60	$0.0986	$98.60	$0.0986	$98.60	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]			$0.0186	$18.60	-$0.0035	-$3.54	-$0.0009	-$0.90	$0.0035	$3.52	$0.0042	$4.20	$0.0042	$4.20
4=(1+2)*Rider G rate	Rider G (%)														
5=(1+2)*Rider J rate	Rider J (%)			11.45%	$12.65	12.46%	$13.77	12.46%	$13.77						
6=(1+2)*Rider R rate	Rider R (%)			5.00%	$5.53	10.53%	$11.63	10.53%	$11.63		$0.00				
7=(1+2)*Rider J rate	Proposed Rider J (%)											6.40%	$8.71	6.40%	$8.71
8=(1+2)*Rider R rate	Proposed Rider R (%)													6.50%	$9.41
9=Sum(1:8)	Total Before Tax Rebate, RSF/IER, GST				$147.3		$132.4		$135.0		$139.6		$149.0		$158.4
	Total Rate Charges excluding Rider F														
9A=9-3	Total Rate Charges excluding Rider F				$128.7		$135.9		$135.9		$136.1		$144.8		$154.2
	Change from last rate				*$3.85*		*$8.17*		*$0.00*		*$0.15*		*$8.71*		*$9.41*
					-2.9%		*6.4%*		*0.0%*		*0.1%*		*6.4%*		*6.5%*
	Less: Rebates														
10=(1+2+7+8)*Rebate	Income Tax Rebate (%)	-0.50%	-0.75%		-$0.55		-$0.55		-$0.55		-$1.02		-$1.09		-$1.16
11	RSF Customer charge	-$1.1900			-$1.19										
12=kWh*RSF Rebate	RSF Energy (1st block kW.h)	-$0.0174			-$17.38										
13=kWh*IER	Interim Electrical Rebate (IER)		-$0.0266				-$26.60		-$26.60		-$26.60		-$26.60		-$26.60
14=Sum(9:13)	Total After Rebates, before GST				$128.2		$105.2		$107.8		$111.9		$121.3		$130.6
15=14*1.05	Total After GST (5%)				$134.6		$110.5		$113.2		$117.5		$127.3		$137.1
	Change from last rate				*$11.2*		*$24.1*		*$2.8*		*$4.3*		*$9.8*		*$9.8*
					9.1%		*-17.9%*		*2.5%*		*3.8%*		*8.3%*		*7.7%*

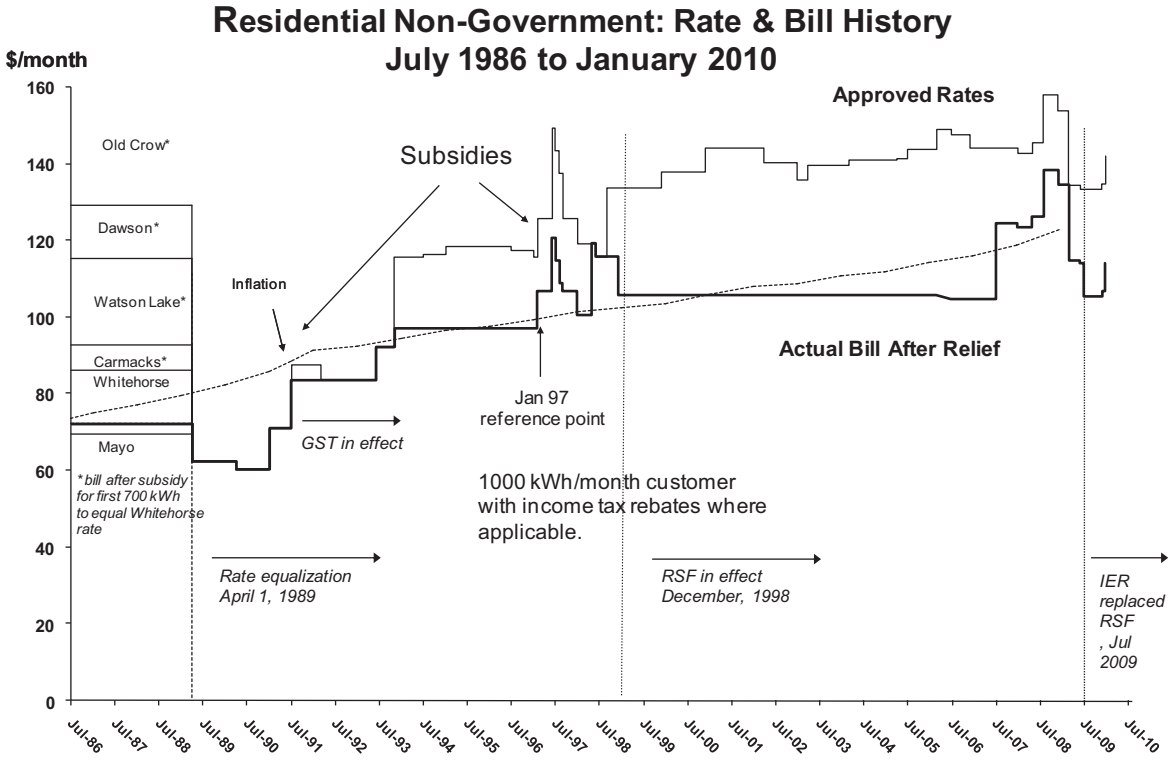
Table 2:
Whitehorse Residential Monthly Bills for January 2009, January 2010, January 2011, January 2012, July 2012 and January 2013 for 1,200 KW.h Monthly Consumption

Line #	First Block Energy Use - Customer Use per month:	1,200 kWh		Jan-09		Jan-10		Jan-11		Jan-12		2012/13 GRA Proposed Jul-12		Jan-13	
												2012 Proposed Rates		2013 Proposed Rates	
				Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates														
1	Customer Charge (per month)			$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)		1,000	$0.0986	$98.60	$0.0986	$98.60	$0.0986	$98.60	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
	Second Block Energy (kWh)		200	$0.1045	$20.90	$0.1045	$20.90	$0.1045	$20.90	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64
3=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]			$0.0186	$22.32	-$0.0035	-$4.25	-$0.0009	-$1.08	$0.0035	$4.22	$0.0042	$5.04	$0.0042	$5.04
4=(1+2)*Rider G rate	Rider G (%)														
5=(1+2)*Rider J rate	Rider J (%)			11.45%	$15.05	12.46%	$16.37	12.46%	$16.37						
6=(1+2)*Rider R rate	Rider R (%)			5.00%	$6.57	10.53%	$13.83	10.53%	$13.83		$0.00				
7=(1+2)*Rider J rate	Proposed Rider J (%)											6.40%	$10.35	6.40%	$10.35
8=(1+2)*Rider R rate	Proposed Rider R (%)													6.50%	$11.18
9=Sum(1:8)	Total Before Tax Rebate, RSF/IER, GST				$175.3		$157.4		$160.5		$165.9		$177.1		$188.3
	Total Rate Charges excluding Rider F														
9A=9-3	Total Rate Charges excluding Rider F				$153.0		$161.6		$161.6		$161.7		$172.0		$183.2
	Change from last rate				*-$4.5*		*$9.6*		*$0.0*		*$0.1*		*$10.3*		*$11.2*
					-2.9%		*6.4%*		*0.0%*		*0.1%*		*6.4%*		*6.5%*
	Less: Rebates														
10=(1+2+7+8)*Rebate	Income Tax Rebate (%)	-0.50%	-0.75%		-$0.66		-$0.66		-$0.66		-$1.21		-$1.21		-$1.21
11	RSF Customer charge	-$1.1900			-$1.19										
12=kWh*RSF Rebate	RSF Energy (1st block kW.h)	-$0.0174			-$17.38										
13=kWh*IER	Interim Electrical Rebate (IER)		-$0.0266				-$26.60		-$26.60		-$26.60		-$26.60		-$26.60
14=Sum(9:13)	Total After Rebates, before GST				$156.1		$130.1		$133.3		$138.1		$149.3		$160.4
15=14*1.05	Total After GST (5%)				$163.9		$136.6		$139.9		$145.0		$156.7		$168.5
	Change from last rate				*$13.4*		*$27.3*		*$3.3*		*$5.1*		*$11.7*		*$11.7*
					8.9%		*-16.7%*		*2.4%*		*3.6%*		*8.1%*		*7.5%*

Table 3:
Whitehorse Residential Monthly Bills for January 2009, January 2010, January 2011, January 2012, July 2012 and January 2013 for 1,400 KW.h Monthly Consumption

Line #	First Block Energy Use - Customer Use per month:	1,400 kWh		Jan-09		Jan-10		Jan-11		Jan-12		2012/13 GRA Proposed Jul-12		Jan-13	
												2012 Proposed Rates		2013 Proposed Rates	
				Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates														
1	Customer Charge (per month)			$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)		1,000	$0.0986	$98.60	$0.0986	$98.60	$0.0986	$98.60	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
	Second Block Energy (kWh)		400	$0.1045	$41.80	$0.1045	$41.80	$0.1045	$41.80	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28
3=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]			$0.0186	$26.04	-$0.0035	-$4.96	-$0.0009	-$1.26	$0.0035	$4.93	$0.0042	$5.88	$0.0042	$5.88
4=(1+2)*Rider G rate	Rider G (%)														
5=(1+2)*Rider J rate	Rider J (%)			11.45%	$17.44	12.46%	$18.98	12.46%	$18.98						
6=(1+2)*Rider R rate	Rider R (%)			5.00%	$7.62	10.53%	$16.03	10.53%	$16.03		$0.00				
7=(1+2)*Rider J rate	Proposed Rider J (%)											6.40%	$11.99	6.40%	$11.99
8=(1+2)*Rider R rate	Proposed Rider R (%)													6.50%	$12.96
9=Sum(1:8)	Total Before Tax Rebate, RSF/IER, GST				$203.39		$182.35		$186.05		$192.26		$205.20		$218.15
	Total Rate Charges excluding Rider F														
9A=9-3	Total Rate Charges excluding Rider F				$177.4		$187.3		$187.3		$187.3		$199.3		$212.3
	Change from last rate				*$5.2*		*$10.0*		*$0.0*		*$0.0*		*$12.0*		*$13.0*
					-2.9%		*5.6%*		*0.0%*		*0.0%*		*6.4%*		*6.5%*
	Less: Rebates														
10=(1+2+7+8)*Rebate	Income Tax Rebate (%)	-0.50%	-0.75%		-$0.76		-$0.76		-$0.76		-$1.40		-$1.40		-$1.40
11	RSF Customer charge	-$1.1900			-$1.19										
12=kWh*RSF Rebate	RSF Energy (1st block kW.h)	-$0.0174			-$17.38										
13=kWh*IER	Interim Electrical Rebate (IER)		-$0.0266				-$26.60		-$26.60		-$26.60		-$26.60		-$26.60
14=Sum(9:13)	Total After Rebates, before GST				$184.1		$155.0		$158.7		$164.3		$177.2		$190.1
15=14*1.05	Total After GST (5%)				$193.3		$162.7		$166.6		$172.5		$186.1		$199.7
	Change from last rate				*$15.6*		*$30.5*		*$3.9*		*$5.8*		*$12.3*		*$13.6*
					8.8%		*-15.8%*		*2.4%*		*3.5%*		*7.7%*		*7.3%*

Residential Non-Gov't 1000 KWh Rate and Bill Changes Over Time: 1986 to 2010



TOPIC:

REFERENCE: YEC 2008/2009 GRA, Page 10

YEC states "*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*".

PREAMBLE:

QUESTION:

a) Please explain what YEC has done since the 2008/2009 GRA to add new renewable supply sources in order to avoid reliance on high cost baseload diesel generation.

ANSWER:

(a)

YEC has done extensive work on these topics covering numerous planning projects to assess the feasibility of new options, completed multiple major projects (such as Mayo B, Aishihik 3rd turbine, and CSTP Stage II) and continued its work on overall system bulk power resource planning.

Please see Tab 5 of the Application in regard to planning studies and major capital (e.g., Mayo B, CSTP Stage II), as well as the 20-Year Resource Plan: 2011-2030 Overview provided as an attachment to YECL-YEC-1-18.

TOPIC:

REFERENCE: May 30, 2012 Summary and Overview Presentation, Slide 9

YEC states "Yukon non-government residential rates remain lowest of utilities North of 60".

PREAMBLE:

QUESTION:

a) For each of the jurisdictions identified on this slide, please provide details of the bill calculations, the revenue-to-cost ratios underpinning the rates used within this comparison, details of the customer base and cost of service upon which these rates were designed, the legislation under which these rates are regulated and copies of the regulatory or political decisions that approved the charging of the rates used in this comparison.

ANSWER:

(a)

The information request is extensive and impractical to compile, and relates to cost of service and rate policy and regulatory considerations in other jurisdictions which is not relevant to a Yukon revenue requirement review and is consequently considered out-of-scope.

TOPIC:

REFERENCE: May 30, 2012 Summary and Overview Presentation, Slide 10

YEC states "Note: 8.49% ROE approved in 2009 GRA".

PREAMBLE:

QUESTION:

a) Please confirm that YEC was directed by the Board to use an ROE of 8.64% for 2008 and an ROE of 8.49% for 2009 and that the Board has not approved a ROE for any year beyond 2009.

ANSWER:

(a)

Confirmed.

TOPIC:

REFERENCE: April 27, 2012 Application, Part 2, Page 2

YEC states "In 2008, Yukon Energy filed a General Rate Application that sought a 3.48% rate decrease (later reduced to 2.47% after Order 2009-8 and 2009-10) in firm retail rates for non-industrial customers. This rate decrease was facilitated by the completion of the Carmacks-Stewart Transmission Line – Stage 1 which connected the Minto mine and Pelly Crossing to the Whitehorse-Aishihik-Faro ("WAF") grid and allowed for sale of surplus hydro to Minto mine through a Purchase Power Agreement ("PPA"). Completion of this grid connection provided net benefits to ratepayers through the applied for rate reductions, while securing a long-term legacy asset for the benefit of existing and future ratepayers".

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*".

PREAMBLE:

QUESTION:

a) 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.

b) Please explain how YEC's commitment to "overall rate reductions" has been reflected in overall bill reductions for ratepayers.

ANSWER:

(a)

It is not possible to precisely disentangle the effects of one existing customer from the remainder of the GRA filing. Information Request YUB-YEC-1-36 from the 2008/09 GRA calculated that at that time the effect of the Minto connection and its enabling of the CSTP Stage I project benefitted ratepayers by $2.572 million per year (2009$). Since that time, the core infrastructure that was put in place originally largely to leverage the benefits of the Minto connection has been able to be expanded and further developed through CSTP Stage 2 and Mayo B, which helps provide added renewable power supplies for all customers. Outside of base rates being $2.572 million higher on the basis of impacts that had already been achieved by 2009, it is not possible to create a 5 year scenario (from 2008 to 2013) of “what would have happened” had Minto not been connected to the grid and none of the related or subsequent system development occurred.

(b)

The overall rate reductions arising from the Minto connection were part of the 2008 and 2009 rate reductions, which remain in the base rates and bills today.

TOPIC:

REFERENCE: April 27, 2012 Application, Part 2, Page 3

YEC states "*Ongoing non-industrial growth reflects overall Yukon economic expansion plus other factors such as an apparent increase in reliance on electric heat*".

PREAMBLE:

QUESTION:

a) Please provide evidence relied upon to come to the conclusions identified in this statement.

ANSWER:

(a)

Please see the extensive documents made available for the Energy Conservation Workshop and the Conservation Potential Review, available at: http://www.yukonenergy.ca/energy/public_engagement/energyworkshop/

In particular, please see Section 5 of the Residential Sector Final Report, available at: http://www.yukonenergy.ca/downloads/db/1141_Conservation%20Potential%20Review%20Final%20Report%202012%20-%20Residential%20Chapter1.pdf

TOPIC:

REFERENCE: April 27, 2012 Application, Part 2, Page 3

YEC states "Industrial connected growth continues to be material – but industrial load growth to date also continues to bring higher revenues that tend to more than offset any related incremental costs".

PREAMBLE:

QUESTION:

a) Please provide all cost allocation and revenues evidence relied upon to come to the conclusions identified in this statement.

ANSWER:

(a)

Please see the response to YUB-YEC-1-2(a).

TOPIC:

REFERENCE: April 27, 2012 Application, Part 2, Page 3

YEC states "*With diesel once again "on the margin", as was the case (to a lesser extent) when the Faro mine was operating, measures are once again required to enable customer rates to recover diesel costs based on long-term average annual hydro generation (rather than fluctuating short-term hydro forecasts) and a reactivated Diesel Contingency Fund to address variances in diesel generation costs due to hydro generation variability. To mitigate the impact of incorporating full long-term average diesel costs into rates, the Application provides for diesel generation costs in the test years based on annual hydro generation forecasts slightly higher than forecast annual long-term average (with the result that forecast diesel generation is still less than long-term average). This revenue requirement measure is proposed for 2012 and 2013 to mitigate rate impacts in these years and facilitate transition to inclusion in future revenue requirements of the full diesel generation cost based on forecast annual long-term average hydro generation*".

October 6, 2008 GRA Application, Revenue Requirement, Page 3-21 – 3-22

YEC states: "*The Diesel Contingency Fund ("DCF") established in the 1996/97 GRA Negotiated Settlement. This account serves to stabilize Yukon Energy's costs to serve firm loads on WAF, due to variances in water flows (and resulting hydro generation variances). The account, in effect, can be either credited or debited each month for one of two reasons:*

When diesel in "on the margin" (defined as being used to meet long-term firm energy requirements of the system, not just periodic peaking requirements), the account stabilizes the diesel costs related to water flow variations. The premise of the account in these situations is that, when hydro varies positive or negative from forecast, that variance is met effectively 1 for 1 with changes in diesel generation compared to what would have occurred had the hydro variance not occurred.

- *When diesel in not on the margin, the account can in certain circumstances be used to pay for the costs of generation using diesel (when monthly diesel generation exceeds 250 MW.h notwithstanding that it is not required to meet base loads under normal flows, i.e., in the case of a drought that requires diesel*

generation even though hydro should be able to fully satisfy the system outside of limited peaking use).

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.

There is no comparable DCF fund for the Mayo-Dawson system. Yukon Energy does not at this time anticipate a requirement for such a fund during 2008 and 2009."

PREAMBLE:

QUESTION:

a) Please provide data identifying the amount of diesel generation "on the margin" at the time when the Faro mine was operating and confirm that diesel was not on the margin in 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

b) Please explain when the Diesel Contingency Fund was "deactivated".

c) Please provide details of debits / credits / balances related to the Diesel Contingency Fund for 2007, 2008, 2009, 2010, 2011 and 2012 (to date). Please provide detailed explanations for each transaction.

d) Please provide details of the requirement to file annual DCF reports with the YUB and provide copies of the DCF annual reports for 2008, 2009, 2010 and 2011.

e) Please confirm that secondary and industrial sales customers are not entitled to receive any benefits from the Diesel Contingency Fund.

f) Please describe how the DCF will be allocated if triggered.

ANSWER:

(a)

The last full year of Faro mine operation (1996) diesel generation was 104.6 GW.h. Under the previous definition of "diesel on the margin" (e.g., Faro mine operating), diesel was not on the margin in 2008, 2009, 2010, or 2011. For 2012 and 2013, this definition is no longer proposed to be used.

(b)

The DCF was last used for payments related to water flow variations in December 1999. The DCF fund has remained in place since that time and retains a scope to pay for water flow variations. However, the DCF mechanics have not been updated to reflect current system configuration (e.g., the interconnection of WAF with Mayo-Dawson).

(c)

The only transactions in the DCF since the beginning of 2007 has been the monthly interest accrual.

(d)

The last report to the YUB was the 2008 report (see Attachment 1). That report highlighted the need to update the DCF for the evolving grid system and the necessity of a full regulatory review, as is happening in this GRA.

(e)

Not confirmed. Industrial customers, like all firm power customers, benefit from stable rates set based on a relationship to long-term average water conditions. This is only made possible by the presence of the DCF. No customers or customer classes benefit individually from the DCF, but collectively, all firm power customers share in the rate stability benefits (during both floods and droughts) that arise due to the DCF.

Secondary sales customers are only sold generation arising from surplus water conditions, and as such bear no relation to the DCF.

(f)

The DCF is intended to be a balancing account that operates every month and year. As such it is continually “triggered”. In the event the DCF balance is insufficient to withstand the impacts of a drought, and a rider must be imposed on customers, it is expected that any such rider would be an equal cents/kW.h across-the-board charge on all firm power customers in Yukon.



YUKON ENERGY CORPORATION
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WHITEHORSE
YUKON Y1A 6S7
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Our File: 2700-05-03

March 29, 2010

Yukon Utilities Board
P.O. Box 31728
Whitehorse, YT
Y1A 6L3

Attention: Mr. Bruce McClennan, Chair

Re: 2008 Diesel Contingency Fund Filing

In accordance with the negotiated settlement resulting from the 1996/97 Revenue Requirement and Rate Design Application, Yukon Energy is to file with the Board a report on the operation of the Diesel Contingency Fund for each year.

For the 2008 year, Yukon Energy was involved in a general review of its rates, which includes activities extending well beyond the 2008 year-end (the 2008/09 General Rate Application and follow up joint YEC/YECL Phase II Rate Application). These regulatory reviews include consideration of matters related to diesel generation forecasts and the potential need to update the methods of operation of the DCF. The Phase II Rate Application document has now been finalized and submitted to the Board for review. As part of that process, the utilities have not sought any changes to the DCF at this time.

No DCF report was filed at year-end 2008 pending YEC's and the Board's review of these matters. While the DCF operating rules will require attention in future to address a number of circumstances, including updating long-term average hydro generation values, fund "triggers", and potentially a means to address secondary sales, no changes are yet being proposed to the fund.

Consequently, in order to ensure a complete record for the Board's files, please find attached the schedules and tables related to the Diesel Contingency Fund for 2008:

1. Diesel Contingency Fund Continuity Schedule for 2008,
2. Diesel Contingency Fund Calculation Tables for 2008, and
3. As required by the DCF negotiated settlement, also attached is an internal memo regarding the 2009 forecast of available water.

Following is the general information on Diesel Contingency Fund operations for 2008:

- The opening balance of the Diesel Contingency Fund as at January 1, 2008 was $856,020.84.
- The Closing Balance of the Fund as at December 31, 2008 was $882,693.40.
- The net change in the Fund of $26,672.56 is attributable to interest of $29,389.43 net of account service fees of ($2,716.87). There was no other activity impacting the fund.
- Long term average annual non-diesel generation for purposes of this report remains unchanged as follows:
  - Whitehorse Rapids Hydro – 246 GWh
  - Aishihik Hydro – 105 GWh
  - Fish Lake Hydro – 10 GWh
  - Haeckel Hill – Wind Turbine – 0.3 GWh

- Actual diesel generation for 2008 was 1,214,174 kWh. Diesel was not on the margin for any month of the 2008 period.

- During December 2008 diesel generation exceeded the on the margin threshold of 250 MW.h/month used within the Diesel Contingency Fund as a determinant to indicate that all diesel generation during a month is presumably required only for baseload serving purposes. Upon review it is evident that the diesel generation was for unplanned maintenance or peaking purposes and not due to low water flow variances. As this generation does not meet the overall intent and purpose of the Diesel Contingency Fund it has been excluded from the December 2008 calculation so that there is no impact on the Diesel Contingency Fund for this generation.

- As per the attached memorandum written by Ron Gee, Resource Management Engineer, diesel consumption for generation or capacity requirements is not expected in 2009.

If there are any questions related to the filing of this report or management of the Diesel Contingency Fund please contact the undersigned.

Sincerely,

Ed Mollard, CGA
Chief Financial Officer

YUKON ENERGY CORPORATION
DIESEL CONTINGENCY FUND
CONTINUITY SCHEDULE

FOR THE YEAR			
2008	Opening balance		856,020.84
	DCF Rider Drawdown		-
	YEC buildup - Fuel	-	
	YEC buildup - O&M		-
	YECL Net withdrawals		-
	Interest Income/Service Fees		26,672.56
	Ending Balance		882,693.40

T:\Diesel Contingency Fund\2008\2008 DCF Schedule Summary of Continuity Schedules

2008 DCF Calculations

TABLE 1: YUKON ENERGY CORPORATION - actual to Dec 31,2008
Continuity Schedule, Year Ending Dec. 31, 2008 - Diesel Contingency Fund Calculations - WAF System ($000)

	Line#		Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	TOTAL
Actual generation - KWh															
Hydro	1	Manual Input:	33,185,929	28,610,041	29,877,857	23,686,146	21,345,165	21,790,016	21,745,269	22,940,550	22,307,493	25,080,823	29,832,970	35,346,066	313,708,326
Wind	1a	Manual Input:	0	0	25,100	0	174,790	39,780	70,500	19,900	0	0	101,390	6,460	438,890
Diesel	2	Manual Input:	37,323	76,111	0	0	186,358	0	0	840	0	218,668	31,256	663,515	1,214,174
Total	3	Line 1 + Line 2	33,203,251	28,686,152	29,902,957	23,686,146	21,706,313	21,829,776	21,815,769	22,960,290	22,307,493	25,299,491	29,965,616	36,016,126	315,359,390
Forecast Generation - KWh															
Hydro	4	Manual Input:	30,406,829	27,721,714	28,992,170	23,816,498	24,702,218	30,569,932	30,771,955	30,871,930	31,799,615	32,502,676	30,765,229	29,775,138	351,687,596.00
Wind	4b	Manual Input:	30,000	28,000	29,000	25,000	24,000	15,000	15,000	20,000	25,000	30,000	30,000	30,000	309,000.00
Diesel	5	Manual Input:	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total	6	Line 4 + Line 5	42,276,069	38,310,982	38,957,763	35,407,737	34,228,539	32,177,942	32,133,010	32,242,342	33,267,290	36,144,441	38,790,457	41,656,346	435,892,918.00
Variance - KWh															
Hydro and wind	7	Line 1 - Line 4	2,729,305	1,890,327	(117,213)	(177,352)	(3,206,263)	(9,145,156)	(8,971,187)	(7,930,380)	(9,517,122)	(7,451,853)	(850,886)	5,547,380	(37,242,380)
Diesel	8	Line 2 - Line 5	(11,802,123)	(10,485,157)	(11,937,593)	(11,564,239)	(9,315,963)	(1,203,010)	(1,346,054)	(1,349,672)	(1,442,675)	(3,393,097)	(7,963,975)	(11,187,693)	(82,991,148)
Total (favourable)	9	Line 3 - Line 6	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,280,052)	(10,959,797)	(10,844,950)	(8,814,841)	(5,640,210)	(120,233,528.00)
Expected diesel generation - KWh:															
Greater of (savings to a maximum of forecast diesel):															
Diesel on margin (1=yes, 0=no)	10	Manual Input	-	-	-	-	-	-	-	-	-	-	-	-	
(YEC generation requirement at long term average Hydro capability)															
Forecast generation	11	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Total variance	12	Line 9	(9,072,818)	(8,624,830)	(12,054,806)	(11,741,591)	(12,522,226)	(10,348,166)	(10,317,241)	(9,280,052)	(10,959,797)	(10,844,950)	(8,824,841)	(5,640,210)	(120,233,528.00)
	13	Line 11 + Line 12	2,766,628	1,936,438	(117,213)	(177,352)	(3,019,905)	(9,145,156)	(8,971,187)	(7,931,540)	(9,517,122)	(7,233,185)	(829,610)	6,210,998	(36,028,206.00)
Expected generation	14	Line 13 if Line 10=1; other=0	-	-	-	-	-	-	-	-	-	-	-	-	-
Maximum savings available	14a	Line 5	11,839,446	10,561,268	11,937,593	11,564,239	9,502,321	1,203,010	1,346,054	1,350,512	1,442,675	3,611,765	7,995,231	11,851,208	84,205,322.00
Actual diesel generation	15	Line 2	37,323	76,111	-	-	186,358	-	-	840	-	218,668	31,256	663,515	1,214,174.00
Diesel savings (excess) (KWh)	16	Line 14-Line 15(max line 14a)	-	-	-	-	-	-	-	-	-	-	-	0.00	-
Standard efficiency(kwh/l)	17	Manual Input	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Standard litres - 000 litres	18	Line 16/Line 17	-	-	-	-	-	-	-	-	-	-	-	-	-
Standard price($ per litre)	19	Manual Input	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600	0.9600
Reserve Buildup (drawdown)															
YEC Variable O&M costs($ per KWh)	20	Manual Input	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
YEC Fuel savings (excess)	21	Line 18 x Line 19	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC Variable O&M costs	22	Line 20 x Line 16	-	-	-	-	-	-	-	-	-	-	-	-	-
YEC buildup (drawdown)	23	Line 21+22	-	-	-	-	-	-	-	-	-	-	-	-	-
YECL buildup (drawdown)	24	See Table 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total buildup (drawdown)	25	Line 23 +24	-	-	-	-	-	-	-	-	-	-	-	-	-
Reserve balance (Excluding interest and service fees)															
Beginning reserve	26	Line 36 prior period	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	
Reserve Buildup (drawdown)	27	Line 25	-	-	-	-	-	-	-	-	-	-	-	-	-
Rider drawdown	28		-	-	-	-	-	-	-	-	-	-	-	-	-
Forest fire impact	29														
Ending reserve balance	30	Line 26+27+28+29	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	856,020.84	
Interest Calculation:															
Monthly interest rate	31	Investment Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Monthly interest earned	32	Re-invested interest:	3,297.73	2,870.19	2,843.68	2,821.04	2,428.57	2,383.06	2,347.39	2,172.81	2,378.75	2,339.96	1,925.31	1,891.01	29,399.43
Service fees	33	Investment Fees	(674.41)	0.00	0.00	(672.62)	0.00	0.00	(678.64)	0.00	0.00	(691.20)	0.00	0.00	(2,716.87)
Net interest earned	34	Line 32+33	2,623.32	2,870.19	2,843.68	1,848.42	2,428.57	2,383.06	1,668.74	2,172.81	2,378.75	1,648.70	1,925.31	1,891.01	26,572.56
Cumulative net interest earned	35		2,623.32	5,493.51	8,337.19	10,185.61	12,614.18	14,997.24	16,665.98	18,838.79	21,217.54	22,866.24	24,791.55	26,672.56	
Ending reserve balance including interest	36	Line 30+35	858,644.16	861,514.35	864,358.03	866,206.45	868,635.02	871,018.08	872,686.82	874,859.63	877,238.38	879,887.08	880,812.39	882,693.40	

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3/26/2010

YUKON ENERGY

YUKON ENERGY CORPORATION
MEMORANDUM

DATE: May 5, 2008

TO: Melaine Fillion

FROM: Ronald Gee

RE: 2008 Forecast of Available Water on WAF Grid

The present sales forecast for 2008 on the Whitehorse-Aishihik-Faro (WAF) system is approximately 312.9 GWh's.

The Aishihik Lake reservoir is currently near its low for the year at an elevation of 914.27m. Inflows for 2008 are expected to be above average and therefore the forecasted peak elevation in October will reach the peak operating level of 915.1m. With the Carmacks to Stewart Crossing transmission line and Minto Mine spur expected to be in operation in 2008, the Aishihik Lake level will be brought up to near full supply level. The Aishihik system is expected to have full use of energy and capacity from the plant for the winter of 2008/09. Operationally, there is no scheduled maintenance of the Aishihik hydro units that would impact the winter generating capability of the hydro plant.

Marsh Lake reservoir is presently at 653.91m. The lake level will begin rising in the next week and is forecast to be completely full by the fall. Winter drawdown of the lake will begin in November and continue through to May 2009. Energy and capacity at Whitehorse Rapids will be constrained by the decreasing water flow in the Yukon River as the winter progresses. This decrease in generating capability is the normal operating situation for Whitehorse Rapids. Scheduled hydro maintenance is not expected to impact the winter generating capability of the Whitehorse Rapids Hydro Plant.

With the current sales forecast and the expectation of full hydro reservoirs in the fall, there is no forecast diesel generation for energy requirements expected in 2008.

Diesel generation in 2008 may occur for the following reasons: For maintenance purposes to ensure operational readiness, diesel peaking during periods of unseasonably cold temperatures and in the event of an unplanned hydro shut down. The total amount of diesel for the above purposes is not expected to exceed the thresholds specified in the calculation of the Diesel Contingency Fund. Attached is a forecast of the WAF generation levels for 2008.

\documents\memo\rg3132

Actual Data to May 3 / 08

AISH INFLOW 120 % OF LTA
2008 WAF FORECAST

WEEK ENDING	ACTUAL OR PROJ SYST GEN (GWH)	PROJ OR FORE SYST GEN AVG (MW)	ACTUAL OR FORE WHSE GEN AVERAGE (MW)	ACTUAL AISH INFLOW CMS.W	PROJ AISH OUTFLOW CMS	PROJECT AISH ELEV (m)	PROJ OR FORE AISH GEN AVG (MW)	ACTUAL OR FORE DIES GEN AVG (MW)
2008								
5-Jan	33.203251	43.886	25.768	3.221	8	914.824	18.118	0.000
12-Jan		44.193	24.621	3.169	8	914.793	19.570	0.002
19-Jan		42.098	23.761	4.305	8	914.767	18.336	0.000
26-Jan		43.625	23.952	0.761	8	914.727	19.673	0.000
2-Feb	29.686152	51.714	25.272	1.646	8	914.691	25.957	0.485
9-Feb		50.776	24.248	2.889	8	914.643	26.367	0.160
16-Feb		40.893	23.452	-0.850	8	914.579	17.425	0.016
23-Feb		35.832	23.105	0.126	8	914.539	12.728	0.000
1-Mar	26.902957	38.750	22.153	1.501	8	914.512	16.597	0.000
8-Mar		37.120	21.666	-3.643	8	914.465	15.455	0.000
15-Mar		35.866	20.902	2.359	8	914.443	14.964	0.000
22-Mar		35.808	20.665	3.517	8	914.426	15.143	0.000
29-Mar		35.109	20.800	0.537	8	914.397	14.309	0.000
5-Apr	25.382887	34.207	21.273	-4.190	8	914.349	12.934	0.000
12-Apr		33.606	20.760	0.608	8	914.321	12.846	0.000
19-Apr		33.277	19.553	4.681	8	914.310	13.724	0.000
26-Apr		31.252	19.922	-2.930	8	914.268	11.330	0.000
3-May	22.70213	30.351	19.131	9.205	8	914.276	11.220	0.000
10-May		30.514	18.314	13.215	6	914.306	12.200	0.000
17-May		30.514	18.314	14.540	6	914.341	12.200	0.000
24-May		30.514	19.914	16.283	5	914.387	10.600	0.000
31-May		30.514	19.914	21.686	5	914.455	10.600	0.000
7-Jun	20.879176	28.999	19.299	25.666	5	914.540	9.700	0.000
14-Jun		28.999	19.299	26.666	5	914.628	9.700	0.000
21-Jun		28.999	21.049	24.095	4	914.711	7.950	0.000
28-Jun		28.999	21.049	25.743	4	914.542	7.950	0.000
5-Jul	21.54486	28.970	25.401	24.154	4	914.625	3.569	0.000
12-Jul		28.958	25.389	24.837	4	914.675	3.569	0.000
19-Jul		28.958	25.389	27.676	4	914.730	3.569	0.000
26-Jul		28.958	25.389	24.308	4	914.813	3.569	0.000
2-Aug	21.435453	28.916	28.916	22.165	4	914.888	0.000	0.000
9-Aug		28.811	28.811	19.706	4	914.952	0.000	0.000
16-Aug		28.811	28.811	19.230	4	914.809	0.000	0.000
23-Aug		28.811	28.811	17.744	4	914.865	0.000	0.000
30-Aug		28.811	28.811	17.071	4	914.919	0.000	0.000
6-Sep	23.306207	31.861	28.292	16.672	4	914.971	3.569	0.000
13-Sep		32.370	28.801	15.053	4	915.016	3.569	0.000
20-Sep		32.370	25.051	12.654	6	915.043	7.319	0.000
27-Sep		32.370	25.051	11.586	6	915.066	7.319	0.000
4-Oct	27.945126	35.336	25.636	10.278	6	915.084	9.700	0.000
11-Oct		37.561	27.861	10.982	6	915.104	9.700	0.000
18-Oct		37.561	27.861	7.664	6	915.111	9.700	0.000
25-Oct		37.561	27.861	6.211	6	915.112	9.700	0.000
1-Nov	30.949948	38.336	28.636	4.585	6	915.106	9.700	0.000
8-Nov		42.986	24.036	4.432	12	915.075	18.950	0.000
15-Nov		42.986	24.036	4.579	12	915.045	18.950	0.000
22-Nov		42.986	24.036	5.037	12	915.016	18.950	0.000
29-Nov		42.986	24.036	4.890	12	914.987	18.950	0.000
6-Dec	33.357305	44.571	23.871	4.606	13	914.953	20.700	0.000
13-Dec		44.835	24.133	4.655	13	914.918	20.702	0.000
20-Dec		44.835	24.133	4.778	13	914.885	20.702	0.000
27-Dec		44.835	24.133	4.132	13	914.848	20.702	0.000

TOPIC:

REFERENCE: April 27, 2012 Application, Part 2, Page 5

YEC states "In the event there are secondary sales, secondary revenues will be credited directly to the DCF (without any Rider F related adjustment or impact for price changes), thereby helping to fund the long-term risks related to hydro generation water condition fluctuation. This treatment maintains a logical connection to the updated DCF and is intended to support rate stability going forward. Assigning secondary sales revenues to the DCF ensures that all such temporary revenues from surplus hydro conditions will go to funding future fossil fuel generation due to below average water conditions".

PREAMBLE:

QUESTION:

a) Please explain how this proposal ensures that costs incurred related to secondary sales will be offset by revenues received.

ANSWER:

(a)

Secondary sales are surplus energy sales made at negligible cost to the system. They are only made available when water can either be used to supply secondary customers or be spilled (wasted). As such there are basically no costs of secondary sales to offset.

Further, this approach continues to ensure all secondary sales revenues are credited to the benefit of firm rate customers, but the method is different than in past GRA. In this case the revenues are credited to the DCF which is an account established for ratepayer benefits to offset future drought costs.

TOPIC:

REFERENCE: April 27, 2012 Application, Part 2, Page 7

YEC states that it wants to establish a "placeholder" expense of $1.100 million related to costs for the current GRA Application, anticipated to be incurred over 2012 and 2013 for preparation and review of the Application and reimbursement of related intervenor and YUB costs, to be amortized over the 2 test years (2012 and 2013).

PREAMBLE:

QUESTION:

a) Instead of recovering GRA-related costs in advance of a prudency review, please explain why it would not be better for ratepayers from rate stability and cost responsibility perspectives to simply accumulate GRA-related costs actually incurred in a deferral account and then determining how prudently incurred costs would be recovered over a future time period. Please comment on whether YEC would be in favour of such an approach.

b) Please provide examples of how other jurisdictions treat GRA-related costs and how these are recovered from ratepayers.

ANSWER:

(a)

The description provided in the question is in concept what is done now – GRA costs are accumulated, reviewed and approved by the Board, and amortized over the period of the GRA (in this case 2012 and 2013). There is no basis to simply defer 2012 and 2013 costs to some undefined "future time period".

(b)

YEC has not done any new research into how GRA costs are treated in other jurisdictions. For previous YEC comments on practice from other jurisdictions, see Attachment 1.

YUKON ENERGY CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 6S7
(867) 393-5300

December 30, 2011

Mr. Bruce McLennan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. McLennan,

RE: Consultation regarding the review and update of Yukon Utilities Board Scale of Costs and Rules of Practice

On November 8, 2011, the Yukon Utilities Board (the "Board" or the "YUB") informed interested parties that it was conducting a review of its Scale of Costs and considering changes to its Rules of Practice to bring the rules up to date. Comments were to be submitted by December 30, 2011.

The Board provided as an attachment a copy of the Board's research on cost provisions and scales of costs of other public utilities Boards or Commissions across Canada. The Board also provided for reference the current Rules of Practice (including the Scale of Costs), the Intervenor Cost Awards Policy, and Intervenor Expense Claim spreadsheet.

Yukon Energy has reviewed the November 8, 2011, letter and attachments and herein provides comments and recommendations for the Board's consideration on three matters:

- Principles underlying intervenor cost awards policy
- Principles underlying applicant hearing cost reviews
- Comments on the scale of costs

PRINCIPLES UNDERLYING INTERVENOR COST AWARDS POLICY

Intervenor cost awards are typically approved by utility regulators across Canada to encourage and facilitate effective and efficient participation by interested parties who have a substantial interest in the outcome of the regulatory process. The principle of providing for partial or full reimbursement of the costs of intervenors who aid the Board, and who cannot otherwise afford to participate without some cost-sharing assistance from the process, is well-established in Canada. Such reimbursements are

provided in order to encourage further public participation in the review process, and to recognize the value an intervention has provided to the Board's review[1]. However, such assistance is provided with clear constraints to ensure inefficient or frivolous behavior is not compensated. It is also common that such costs may not be reimbursed 100%, in part to recognize that the intervenor group is present on the basis of an interest in the outcome that justifies their participation – cost awards are intended to aid in participation, not to drive it. These costs are necessarily reviewed and awarded at the conclusion of a proceeding as they are in essence based on the performance of the intervenor and the quality of the contribution made to the process and to the Board's understanding of the issues.

The overall objective is "to ensure that the costs of hearings are reasonable relative to the matters involved", and in this regard the scale "sets general principles and amounts" to be applied in the awarding of costs. In this respect cost awards are reviewed based on criteria that include:

- The effectiveness of a Party's participation – including considerations regarding whether such participation was duplicative of others' efforts;
- The relevance of the intervention to the issues at hand;
- Whether the costs were reasonably and prudently incurred; and
- Whether the Party was diligent in the efficient presentation of its position.

Generally, the criteria noted in the Cost Award Policy continue to be reasonable criteria for testing whether an intervenor merits some or full recovery of their costs.

PRINCIPLES UNDERLYING APPLICANT HEARING COST REVIEWS

The recent practice in Yukon is to require applicant utilities to file their hearing costs as "claims" under the current Intervenor Cost Award Policy and Intervenor Expense Claim format. This approach has been recently adopted despite these cost award and expense claim processes clearly being unrelated to the applicant's costs[2].

In Yukon Energy's view, this amended approach misapplies the relevant Board policy (which is fundamentally about *claims for reimbursement* – i.e., a cheque from the utility to an intervenor). As reviewed further below, in Yukon Energy's view the amended approach is also inconsistent with the normal practice for regulation of utilities in Canada, and leads to a starkly different review threshold for the small component of a utilities' revenue requirement related to hearings, in contrast to the evidentiary threshold for review of all of the other components of the utilities' costs in rates.

[1]Jurisdictions typically provide intervenor cost awards for bona fide third party costs related to any professional assistance (legal or consulting) retained by the intervenor in order to review the evidence and advise the Board on particular issues of concern.
[2] For example, the Rules of Practice specifically defines and Intervenor as "… a party other than the applicant …"

By Reviewing "Claims" The Board Applies an Incorrect Standard of Review

At its core, it is important to recognize that, unlike intervenors, applicants have no option to participate or not participate in a hearing. During a hearing, applicants must also address all issues and questions raised by intervenors and the Board, however many or few such issues and questions ultimately arise. As such, applicants do not control nor drive the costs of a proceeding. In this regard, the costs of an applicant are akin to the costs of the Board, in that in each case the costs are integral to their respective roles and are unavoidable.

For this reason, to the utilities, the costs to prepare for and attend hearings are viewed as a necessary and integral component of their revenue requirement and expenses for rate setting purposes. The sole purpose of the entire revenue requirement setting process is to determine that the utilities' overall costs are reasonable and prudent. This is done based on a varying level of review depending on the nature of the costs and the ability of the utility to support their forecasts of costs. For the two utilities combined, this process is applied to some $50 million in annual costs. In no case in the review of revenue requirements are utilities required to provide copies of specific receipts for amounts spent, or the specific division of labour for the services they retain between, for example, senior lawyers versus articling students, or consultants versus production staff. The entire regulatory structure is designed to ensure that the utilities have a reasonable opportunity to recover their required costs and earn a fair return.

In contrast, for proceedings since the 2005 Required Revenues and Related Matters hearing, the applicant utilities have been required to go through the normal hearing process to assess the matters at hand (including, for GRAs, the full revenue requirement) and then following this process go through a separate detailed and documentation-heavy process of filing extensive information and justification for hearing-related costs, which have made up a small fraction of the utilities' revenue requirement. Unlike intervenors, the process for utilities is not designed to provide for some form of audit of the utilities' claimed costs prior to providing them with a cheque for reimbursement. Such auditing and compliance with financial policies is already incorporated in the financial oversight functions of the utility, the processes and policies for which are open to review by the Board in the GRA.

For this reason, Yukon Energy submits that the approach that has been developed for intervenors pursuant to the Cost Award Policy is inappropriate to apply to utilities, and that the appropriate assessment of utility costs is as part of the reasonableness assessment conducted on all costs contained with the overall revenue requirement.

Yukon Approach to Reviewing "Claims" Inconsistent with Normal Regulatory Principles

The Board's present practice with respect to applicant hearing costs appears generally inconsistent with Yukon practice prior to the most recent hearings and with practice in other jurisdictions YEC has reviewed, with the exception of Alberta.

Every other jurisdiction reviewed other than Alberta includes all hearing costs incurred by the utilities as a component of testing their revenue requirement, and includes all hearing-related costs in their respective

regulated costs for the appropriate years, without any special or separate process for review of the utilities' "claims" for these costs. In particular, it is Yukon Energy's understanding that all major jurisdictions with Crown-owned utilities, regulating hydro and non-hydro electric utilities, have processes that markedly differ from the recent practice in Yukon; specifically this includes Northwest Territories, Newfoundland, Manitoba, Quebec and British Columbia.

In short, in Yukon Energy's view the appropriate process for the review and approval of applicant costs for hearings as part of overall costs to be recovered though rates for YEC, consistent with "normal principles" as outlined in OIC 1995/90 for jurisdictions with comparable Crown-owned utilities regulating hydro and non-hydro based utilities, is as set out above[3] – that is, consistent with and concurrent with the revenue requirement review and not based on separate post hearing intervenor cost awards policies.

Specific Comments on Recent YUB Review of YEC Claims

In the recent experience regarding the review of applicant utilities' cost claims, the review process has failed to recognize the separate and distinct roles of applicants and intervenors in the public review process and the separate types of activities, requirements and costs that must be incurred. In this regard, the following considerations are noted:

- Applicant costs are effectively incurred as a necessary part of its business or operations as a regulated utility.
- Applicants that require an approval from the YUB must engage in the formal review process and cannot realistically limit their level of participation in the process.
- An applicant must participate actively in the process, and typically cannot reasonably coordinate with others to increase efficiency or reduce duplication.
- Applicants begin to incur costs related to their application prior to a formal process with the YUB commencing, i.e., costs to prepare and file an application.

In contrast to an intervenor, for whom the cost award policy was designed, the following key activities must be undertaken by an applicant to prepare, present and defend an application for a material regulatory approval:

- ***Production services required*** [i.e., coordinating the necessary analysis, drafting and review of materials and production of final and filed document]. A significant filing, such as a revenue requirement or rate application, is labour intensive and requires significant analysis, writing, review and production to ensure an accurate, clear and coherent document is provided. This includes the retention of services for functions that are required for any large document production – document management, editing, layout, formatting, proofing, copying, assembly,

[3] Section 3 of OIC 1995/90 provides with regard to 'normal principles' as follows: "Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with principles established in Canada for utilities, including those principles established by regulatory authorities of the Government of Canada or of a province regulating hydro and non-hydro electric utilities."

etc. As the Board requires the applicant to make multiple copies available for public review in all communities, documents are required to be print ready and multiple copies are required to be printed. These services are separate and apart from the work of utility analysts, accountants, managers and consultants working on preparation of the utility's core business plan and regulatory proposals.

Once an Application is filed, document production services continue and are fundamental to the efficient and effective conduct of the hearing process, i.e., in the 2008/2009 General Rate Applications the applicants each received between 700 (YECL) and 850 (YEC) IRs. Each question must be entered into templates by production staff and each response must be tracked, compiled (particularly subparts), formatted, pdf'd, consolidated into one document, produced in the appropriate formats and distributed. Further, in these recent proceedings intervenors and the Board have requested that where other IRs are referenced, links be included in the consolidated pdf which is an extra task for these service providers. This requires production staff to review each response and insert links where appropriate. There is no option but to engage some form of production services for a GRA at a specific and identifiable cost. YEC further notes that applications and other filed documents that are well laid out and organized aid the hearing process.

- ***Multiple parties required, including more junior supporting analysts*** [includes all aspects of coordination, drafting and finalization of responses and production activities] - Applicants are subject to more rigourous testing of evidence including materially more intensive interrogatory requirements than intervenors (see for example the magnitude of interrogatories noted above for the 2008/2009 GRAs). Generally, aside from the effort required to research or accumulate data for each individual interrogatory response, as well as draft and review responses, a great deal of effort is required to coordinate the process and ensure accuracy and consistency of information provided. Multiple parties are required from the various utility departments, differing professional backgrounds, and consulting support to complete the assignment, along with support and production services (as noted above). Often, both the utility and consultants will utilize a mix of more senior and junior staff and analysts to more efficiently and expeditiously handle the massive volume of material that must be prepared, and to cost effectively engage support resources that are lower cost than having senior people (staff or consultants) address every detail.

- ***Witness panel preparation*** – Applicants are necessarily subject to a great deal of scrutiny as part of the public review process and especially during the oral hearing where the applicant witness panel will be subject to cross examination by the Board and intervenors. It is a very difficult and infrequent experience for most witnesses to appear on a panel, even for those who have appeared on panels a number of times during their career. More importantly, there is limited time at a hearing and to best help the Board, it is critical that each panel fully engage in preparation as a critical means of ensuring that the witnesses can work together on the specific material to be covered, and can efficiently provide testimony in a clear and coherent fashion that facilitates an understanding of the issues and helps ensure the review process unfolds in an

efficient and effective manner. Dedicated witness preparation time is an essential component of this process, and a reasonable and necessary expenditure of time and money for the utility as part of its revenue requirement.

- ***Disbursements*** – Applicants incur certain costs prior to the Application being filed, including disbursements related to required travel for in person meetings. Where feasible issues are addressed via email or conference call; however, prior to a filing and during the hearing process (e.g., meetings for the witness panel to prepare their testimony) some travel for in person meetings is inevitably required for Yukon utility applications. Such disbursements that occur outside the oral hearing dates are a necessary part of the application process and must be recognized.

Hearing activities require significant effort on the part of an applicant – in this respect YEC and YECL (both small, northern utilities with relatively infrequent regulatory proceedings), do not have and cannot justify hiring dedicated internal staff resources for GRA processes. As a result, both utilize regulatory support from outside sources. This is also consistent with each of the other electrical utilities in NWT and Nunavut. Consequently, applicant costs to retain and utilize required outside resources and expertise are reasonable and prudently incurred, and are a necessary part of the operations of a regulated utility to be recovered in rates.

COMMENTS ON THE SCALE OF COSTS

In order to facilitate the administration of claims for costs, the Scale of Costs (Schedule 1 of the Rules of Practice) sets out maximum hourly fees and disbursement rates for intervenor costs. The Scale of Costs should be aligned with the objective of encouraging and supporting efficient interventions by allowing intervenors to be partly or fully supported financially in presenting their case where they can establish that their participation in the public review process has helped the Board deal with the matters before it.[4] The Scale of Costs has also been applied in recent hearings (as noted above) to applicant hearing costs (maximum hourly fees for lawyers and professional consultants, and disbursements rates).

Yukon Energy has reviewed the Board's attached review of the scale of costs from other Canadian jurisdictions. This review confirms that the current Scale of Costs in Yukon is no longer aligned with that of many other jurisdictions. In order to ensure that interventions are not discouraged and the hearing process continues to benefit from informed interventions the scale of costs should be updated. Yukon Energy has only completed a cursory review of the information, but is aware that the NWT has in effect determined that the Alberta Utilities Commission cost scale was reflective of current market conditions, and applied them in the case of hearings on YECL's sister company, Northland Utilities (NWT) Limited. Beyond recommending that the Scale of Costs be updated to reflect current market rates and certain other matters noted below, Yukon Energy has no specific recommendation regarding the Scale of Costs maximum hourly rates to be adopted at this time.

[4] The current scale of costs notes, it should represent "a fair and reasonable contribution by consumers to provide interested parties with adequate, competent and professional assistance in making an effective submission to the Board."

The current YUB scale of costs notes for professional fees that "the fee will be deemed to include and cover all overhead charges implicit in the normal operation of professional office including meals" (with some exceptions). For example, it has been YEC's experience that consultants and other professionals do not include meals as part of the overhead expenses included in fees.

Aside from concerns about treatment of specific disbursements, Yukon Energy notes that this provision is appropriate when it applies to typical overheads such as costs for office space or stationery, but is inappropriate when extended to cover professional staff engaged in document management, research, production, editing etc. where the fees for document production professionals are individually billed and not included as part of the senior lawyers' or consultants' normal fees. Some lawyers and consultants do not include overhead costs related to support staff in normal professional fees charged and therefore normally bill these separately. This is of particular concern in circumstances where a standard developed based on principles related to intervenor costs awards is sought to be applied to applicant costs where there are materially different requirements and levels of activity (see comments above re: Specific Comments on Recent YUB Review of YEC Claims).

The Scale of Costs was last reviewed and updated in 1995. It is recommended that the maximum fees and disbursements be reviewed on a more regular basis to ensure they remain aligned with market rates.

If you have any questions regarding the above please contact the undersigned at 867.393.5338 or ed.mollard@yec.yk.ca.

Yours truly,

YUKON ENERGY CORPORATION



Ed Mollard
Chief Financial Officer

TOPIC:

REFERENCE: April 27, 2012 Application, Part 2, Page 7

YEC states that it wants to amortize total incurred cost of $0.026 million related to the regulatory review of the Rate Schedule 39 Escalation Proceeding over two years.

PREAMBLE:

QUESTION:

a) Please confirm that these costs will only be recovered from industrial customers to whom Rate 39 applies. If not, please provide a full explanation including examples from other jurisdictions that allow costs incurred for the industrial class to be recovered from other ratepayers.

ANSWER:

(a)

Not confirmed. This is for two reasons:

1) There is no basis to charge these costs solely to the industrial class. The regulatory proceeding, similar to all other rate design proceedings, was about rate setting that ultimately affects all classes. As such these are not "costs incurred for the industrial class".

2) There is no means for these costs to "only be recovered" from any single class, as recovery of all YEC and YECL cost changes are required to apply equally to all classes, pursuant to OIC.

TOPIC:

REFERENCE: April 27, 2012 Application, Part 2, Page 7

YEC states "that it wants to amortize total incurred cost of $0.054 million related to the regulatory review of the Alexco Explorations Power Purchase Agreement over 5 years which is the currently anticipated economic life of the substantial terms of the Alexco PPA".

PREAMBLE:

QUESTION:

a) Please confirm that these costs will only be recovered from Alexco. If not, please provide a full explanation including examples from other jurisdictions that allow costs incurred for a specific customer to be recovered from other ratepayers.

ANSWER:

(a)

Please see UCG-YEC-1-15.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 1 - Introduction, Page 1-1

YEC states that the forecast ROE in each test year, absent new rates, shows continued material deterioration in financial performance underlining the need for increases in rates.

October 6, 2008 Application, Introduction, Page 1-9

YEC states *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.*

PREAMBLE:

QUESTION:

a) Please explain how YEC's excess earnings in past years have been shared with ratepayers.

b) Please provide details of how YEC has reduced ongoing costs to offset other cost pressures.

c) Please restate Table 1.1 by showing the allowed and actual ROE for 2005, 2006, 2007, 2008, 2009, 2010 and 2011 and the actual dollars associated with the under / over earnings.

d) Please provide details of YEC's efforts to date to consider a performance-based regulation mechanism including earnings sharing.

e) 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)

In UCG-YEC-1-19(d) from the 2008/09 GRA, Yukon Energy addressed this UCG concept, as follows:

> 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.

(b)

Please see pages 1-4 to 1-5 of the Application.

(c)

The requested detailed information for 2005-2008 was available to be reviewed as part of the previous GRAs (e.g., UCG-YEC-1-19(b) from the 2008/09 GRA) and is not directly relevant to the current revenue requirement proceeding for the 2012/13 test years.

Actual ROE for 2009-2010 are provided in Table 3.15 (2009 at 7.92% and 2010 at 7.45%), while actual 2011 ROE is 6.58%. The dollar value differences between these actual ROEs and the approved 8.49% level are as follows: 2009 - $0.333 million; 2010 - $0.643 million; 2011 - $1.416 million.

(d)

In UCG-YEC-1-19(c) from the 2008/09 GRA, Yukon Energy addressed this UCG concept, as follows:

> 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.

(e)

Please see UCG-YEC-1-17(a).

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 2, Page 2-3

YEC states "Total forecast sales are 382.6 GW.h for the 2012 test year and 395.9 GW.h for the 2013 test year. Total forecast sales for 2012 include 296.0 GW.h of primary (firm) wholesale sales, 52.3 GW.h of primary Major Industrial sales, 34.3 GW.h of firm Retail sales (i.e., all firm sales other than wholesale or Major Industrial), and total forecast sales for 2013 include 298.2 GW.h primary wholesale sales, 62.3 GW.h Major Industrial sales, 35.3 GW.h firm Retail sales. No secondary sales are forecast to be available in the test years".

PREAMBLE:

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, 2008, 2009, 2010 and 2011 and their percentage of revenue requirement.

ANSWER:

(a) through **(c)**

Please see response to CW-YEC-1-35(a) and LE-YEC-1-24. DSM programming is still being developed. The DSM working group is currently in the draft stage of the five year DSM plan which will be submitted to the YUB upon completion. As noted in the response

to LE-YEC-1-12 typical DSM programs are implemented over a three to five year period at which time they are usually evaluated and modified based on the results of that evaluation. As such it is premature to at this time discuss the results of audit processes.

(d)

Please see response to YUB-YEC-1-46(d) for actual costs to date.

The annual cost for the DSM project in the revenue requirement (return on ratebase and amortization) approximates $0.15 million in 2012 and $0.32 million in 2013 or approximately 0.4% and 0.7% of revenue requirement for 2012 and 2013 respectively.

As a percentage of the overall revenue requirement, the DSM spending that is forecast to occur is as follows:

- 2.7% for 2012 (including IDSM); and
- 3.5% for 2013 (including IDSM).

The difference between the above values is because DSM spending is amortized over future periods, and not expensed in the year incurred.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 2, Page 2-3

YEC states "Each year Yukon Electrical provides Yukon Energy with an Integrated Grid firm wholesale purchase power forecast reflecting its forecast grid firm retail sales less its forecast generation from its Fish Lake hydro plant. Yukon Energy reviews and adjusts the Yukon Electrical forecasts in light of the most recent information available.

For GRA forecast purposes, available preliminary actual results for 2011 were considered and the 2011 actual YECL wholesale sales were adjusted to reflect expected in-service of a new Fish Lake hydro unit #1 in 2013 and to reflect adjustments for weather conditions based on 10 year average Heating Degree Days (HDD). A percentage growth increase of 2.26% per year was then applied to the adjusted 2011 actual wholesale sales (normalized assuming operation of both Fish Lake units) for each of 2012 and 2013 and additional sales were included for 2012 to reflect continuing shut down of Fish Lake Unit #1 until January 2013".

PREAMBLE:

QUESTION:

a) Please provide a comparative table showing the differences between YEC's and YECL's load forecasts by customer class for 2012 and 2013.

b) Please provide a comparative table of the forecast load forecasts versus actual by customer class for 2005, 2006, 2007, 2008, 2009, 2010 and 2011. Please explain how this data has been weather normalized if applicable.

c) Please explain what discussions YEC has had with YECL to determine how best to forecast load in the Yukon and whether YECL has supported the current forecast.

ANSWER:

(a)

The sales forecasting relationship between YEC and YECL is to determine YEC sales under Rate Schedule 42 Wholesale Primary. Therefore the Companies do not exchange load forecasts by customer class. For further information regarding the 2012 and 2013 forecasts please refer to YECL-YEC-1-15(d).

(b)

Comparative load forecasts are provided in Table 1 below with actual sales for 2009 to 2011 for wholesale transactions. As noted in part (a) above, YEC does not typically have access to YECL forecasts by customer class. YEC cannot speak as to whether or how YECL weather normalizes its data. When testing the reasonableness of its 2012 forecast, YEC performed some basic heating degree days analysis of 2011 actual sales to align the forecast to the 10 year average of heating degree days.

Table 1:
Comparative YEC and YECL Load Forecasts

	2009	2010	2011	2012	2013
Primary Energy (GWh):					
YEC Forecast	266.9	274.0	277.1	296.0	298.2
YECL Forecast	263.2	275.3	273.3	289.0	292.5
Actual	266.4	275.5	289.6	-	-
Secondary Sales (GWh):					
YEC Forecast	16.6	17.6	-	-	-
YECL Forecast	6.9	17.2	-	-	-
Actual	16.8	10.1	0.5	-	-

(c)

YEC and YECL only discuss how to best forecast the Primary and Secondary energy sales between companies. The companies do not engage in discussions regarding how to best forecast the customer class loads in Yukon.

The process for discussion of load forecasts is that in the fall of the preceding year YECL typically provides YEC with a business plan load forecast for purchase of power for the upcoming year. For example, in 2011 YECL provided its 2012 load forecast in September and during refinement discussions in late October advised that the Fish Lake hydro unit would not be in service until six months later than originally planned which led to revisions to the forecast wholesale purchases.

Please also see response to YECL-YEC-1-3 for detailed explanation of wholesale forecast.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 2, Page 2-4

YEC states that the 2012 and 2013 test years include three Major Industrial customers - Minto mine (in service in late 2008), Alexco mine (in service in late 2010) and Whitehorse Copper Tailings (forecast in service starting in mid-2013).

PREAMBLE:

QUESTION:

a) Please provide monthly details of Minto's electricity use, demand and bill component totals for 2008, 2009, 2010, 2011, 2012 (to date and forecast) and 2013 (forecast).

b) Please provide monthly details of Alexco's electricity use, demand and bill component totals for 2010, 2011, 2012 (to date and forecast) and 2013 (forecast).

c) Please provide monthly details of Whitehorse Copper's electricity use, demand and bill component totals for 2013 (forecast).

ANSWER:

(a)

Please see Table 1 for Minto mine 2009-2011 actual, January-May 2012 year-to-date actual, 2012 and 2013 forecast sales, measured and billed demand. Actual data for 2008 was available to be reviewed as part of the 2008/2009 GRA and is not considered to be relevant to the current revenue requirement proceeding for the 2012/13 test years.

Table 1:
Minto Mine 2009-2011 Actual, January-May 2012 Year-to-Date Actual, 2012 and 2013 Forecast Sales, Measured and Billed Demand

Month	Minto mine								
	2009 Actual			2010 Actual			2011 Actual		
	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)
January	2,459.9	4,099	4,116	2,158.8	4,250	4,250	2,847.6	4,511	4,511
February	2,277.7	4,040	4,116	2,184.0	3,696	4,250	2,503.2	4,511	4,511
March	2,435.8	3,914	4,116	2,637.6	3,864	4,250	2,738.4	4,544	4,544
April	2,399.8	3,696	4,116	2,091.6	4,090	4,250	2,620.8	4,376	4,544
May	2,455.6	4,066	4,116	2,318.4	4,091	4,250	2,595.6	4,284	4,544
June	2,315.2	3,872	4,116	1,755.6	3,856	4,250	2,410.8	4,074	4,544
July	2,343.6	3,956	4,116	2,259.6	4,082	4,250	2,318.4	4,158	4,544
August	2,259.6	3,923	4,116	2,562.0	4,234	4,250	2,746.8	4,259	4,544
September	2,419.2	3,772	4,116	2,570.4	4,368	4,368	2,637.6	4,343	4,544
October	2,486.4	3,990	4,116	2,276.4	4,435	4,435	2,595.6	4,400	4,544
November	2,469.6	4,192	4,192	2,856.0	4,343	4,435	2,646.0	4,444	4,544
December	3,032.4	4,192	4,192	2,864.4	4,511	4,511	3,158.4	4,502	4,544
Annual	29,354.7	3,976	4,129	28,534.8	4,152	4,312	31,819.2	4,367	4,539

Table 1:
Minto Mine 2009-2011 Actual, January-May 2012 Year-to-Date Actual, 2012 and 2013 Forecast Sales, Measured and Billed Demand (continued)

Month	Minto mine								
	2012 Year-to-date			2012 Forecast			2013 Forecast		
	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)
January	2,688.0	4,603	4,603	2,833.3	NA	4,875	3,652.1	NA	6,500
February	2,452.8	4,603	4,603	2,833.3	NA	4,875	3,298.6	NA	6,500
March	2,730.0	4,376	4,603	2,833.3	NA	4,875	3,652.1	NA	6,500
April	2,730.0	4,402	4,603	3,083.3	NA	4,875	3,534.2	NA	6,500
May	2,830.8	4,553	4,603	3,083.3	NA	5,720	3,652.1	NA	6,500
June				3,083.3	NA	5,720	3,534.2	NA	6,500
July				3,583.3	NA	6,500	3,652.1	NA	6,500
August				3,583.3	NA	6,500	3,652.1	NA	6,500
September				3,583.3	NA	6,500	3,534.2	NA	6,500
October				3,583.3	NA	6,500	3,652.1	NA	6,500
November				3,583.3	NA	6,500	3,534.2	NA	6,500
December				3,583.3	NA	6,500	3,652.1	NA	6,500
Annual	13,431.6	4,507	4,603	39,250.0		5,828	43,000.0		6,500

(b)

Please see Table 2 for Alexco mine 2010-2011 actual, January-May 2012 year-to-date actual, 2012 and 2013 forecast sales, measured and billed demand. Prior to commencing as industrial customer in late 2010, Alexco was served under general service rate class.

Please note that the measured and billing demand information provided in the table below is combination of the mine and the mill. In some instances the mine and the mill do not peak at the same time which results in the fluctuations in measured and billed demand.

Table 2:
Alexco Mine 2009-2011 Actual, January-May 2012 Year-to-Date Actual, 2012 and 2013 Forecast Sales, Measured and Billed Demand

Month	Alexco mine					
	2010 Actual			2011 Actual		
	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)
January				1,033.0	2,328	2,383
February				903.2	2,310	2,383
March				997.1	2,177	2,383
April				934.1	2,031	2,383
May				979.7	2,242	2,383
June				859.9	2,220	2,383
July				917.8	2,210	2,399
August				948.1	2,195	2,399
September				855.3	2,111	2,383
October				998.1	1,451	2,383
November	756.2	2,313	2,313	980.6	2,185	2,383
December	964.2	2,330	2,369	1,032.6	2,171	2,345
Annual	1,720.4	2,322	2,341	11,439.5	2,136	2,382

Table 2:

Alexco Mine 2009-2011 Actual, January-May 2012 Year-to-Date Actual, 2012 and 2013 Forecast Sales, Measured and Billed Demand (continued)

Month	Alexco mine								
	2012 Year-to-date			2012 Forecast			2013 Forecast		
	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)
January	983.6	2,336	2,362	1,069.3	NA	2,300	1,213.3	NA	2,600
February	1,031.9	1,806	2,362	1,069.3	NA	2,300	1,213.3	NA	2,600
March	1,057.2	2,354	2,420	1,069.3	NA	2,300	1,213.3	NA	2,600
April	1,150.6	2,275	2,420	1,069.7	NA	2,300	1,215.3	NA	2,600
May	1,036.0	2,309	2,420	1,069.7	NA	2,300	1,215.3	NA	2,600
June				1,069.7	NA	2,300	1,215.3	NA	2,600
July				1,107.0	NA	2,300	1,217.3	NA	2,600
August				1,107.0	NA	2,300	1,217.3	NA	2,600
September				1,107.0	NA	2,300	1,217.3	NA	2,600
October				1,107.0	NA	2,300	1,217.3	NA	2,600
November				1,107.0	NA	2,300	1,217.3	NA	2,600
December				1,107.0	NA	2,300	1,217.3	NA	2,600
Annual	5,259.3	2,216	2,397	13,059.0		2,300	14,590.0		2,600

In the GRA filing, Yukon Energy erroneously used a 2012 and 2013 peak billing demand for Alexco of 3500 kVA for the purposes of forecasting revenues at existing rates. The effect of this error is to over forecast revenues by approximately $0.22 million (2012) and $0.16 million (2013).

(c)

Please see Table 3 for 2013 monthly sales and demand forecast for Whitehorse Copper Tailings. The mine is forecast to be connected to the grid starting July 2013.

Table 3:

2013 Monthly Sales and Demand Forecast for Whitehorse Copper Tailings

Month	Whitehorse Copper Tailings 2013 Forecast		
	Sales (MW.h)	Measured Demand (KVA)	Billing Demand (KVA)
January			
February			
March			
April			
May			
June			
July	967.2	NA	2,220
August	967.2	NA	2,220
September	936.0	NA	2,220
October	967.2	NA	2,220
November	936.0	NA	2,220
December			
Annual	4,773.6		2,220

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 2, Page 2-9

YEC states Firm residential retail sales have grown from 11,676 MW.h in 2009 (actual) to 12,325 MW.h in 2012 (forecast) and 12,408 MW.h in 2013 (forecast). The average annual growth rate is 1.5% in 2013 (forecast) compared to 2009 (actual). This reflects ongoing modest growth in the number of customers and the average use per customer over the previous three years.

PREAMBLE:

QUESTION:

a) Please provide monthly details of firm residential retail sales for 2008, 2009, 2010, 2011, 2012 (to date and forecast) and 2013 (forecast).

b) Please provide monthly details of the number of firm residential customers for 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

c) Please provide monthly details of the number of residential customers using electricity for space heating for 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

d) Please provide a table showing revenue requirement per residential customer for 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast). Please include details of the calculation of these averages.

ANSWER:

(a) and **(b)**

Please see Table 1 below for YEC's residential monthly average customers and monthly residential sales for 2009-2011 actual, 2012 year-to-date, 2012 and 2013 forecast. Actual data for 2008 was available to be reviewed as part of the 2008/2009 GRA and is not considered to be relevant to the current revenue requirement proceeding for the 2012/13 test years.

Table 1:

YEC's Residential Monthly Average Customers and Monthly Residential Sales for 2009-2011 Actual, 2012 Year-to-Date, 2012 and 2013 Forecast

Month	YEC's Residential customers and sales											
	2009		2010		2011		2012 Year-to-date		2012 Forecast		2013 Forecast	
	Monthly Average # of customers	Monthly Sales (MW.h)	Monthly Average # of customers	Monthly Sales	Monthly Average # of customers	Monthly Sales	Monthly Average # of customers	Monthly Sales	Monthly Average # of customers	Monthly Sales	Monthly Average # of customers	Monthly Sales
January	1,411	1,493.9	1434	1,384.7	1,465	1,455.6	1,492	1,538.4	1,481	1,484.0	1,491	1,468.6
February	1,411	1,213.8	1433	1,075.3	1,483	1,350.7	1,493	1,418.1	1,500	1,302.0	1,510	1,310.2
March	1,400	1,152.5	1434	993.0	1,483	1,389.4	1,490	1,196.2	1,498	1,196.3	1,509	1,193.6
April	1,437	990.0	1451	969.9	1,509	1,042.9	1,508	1,074.5	1,526	1,050.4	1,537	1,053.1
May	1,471	817.2	1490	827.8	1,529	966.4	1,516	936.8	1,544	899.9	1,554	920.1
June	1,479	810.8	1496	786.1	1,534	808.0			1,549	831.6	1,559	830.2
July	1,491	787.1	1499	755.2	1,538	774.6			1,551	800.7	1,561	798.5
August	1,496	705.8	1502	747.9	1,543	743.9			1,551	752.5	1,561	762.1
September	1,498	820.2	1504	820.0	1,547	880.5			1,553	859.3	1,563	863.6
October	1,485	825.0	1487	887.0	1,532	938.5			1,537	906.1	1,549	926.8
November	1,453	988.7	1475	990.5	1,513	1,051.9			1,517	1,037.3	1,528	1,042.4
December	1,446	1,071.3	1463	1,149.1	1,500	1,307.6			1,504	1,205.0	1,516	1,239.2
Annual	1,457	11,676.2	1,472	11,386.4	1,515	12,710.0	1,500	6,164.1	1,526	12,325.2	1,536	12,408.5

(c)

YEC does not have details regarding number of customers using electricity for space heating.

(d)

YEC cannot provide the requested information as this requires a cost of service study for the requested years.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 2, Page 2-9

YEC states that the 2013 forecast indicates a 3.15% average annual increase in Yukon Energy's general service sales over 2009 (actual). In sum, firm general service retail sales in 2009 (actual) were 19,672 MW.h, and are forecast to increase to 21,693 MW.h in 2012 and 22,620 MW.h in 2013.

PREAMBLE:

QUESTION:

a) Please provide monthly details of firm general service retail sales for 2008, 2009, 2010, 2011, 2012 (to date and forecast) and 2013 (forecast).

b) Please provide monthly details of the number of firm general service customers for 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

c) Please provide a table showing revenue requirement per general service customer for 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast). Please include details of the calculation of these averages.

ANSWER:

(a) and **(b)**

Please see Table 1 below for YEC's residential monthly average customers and monthly general service sales for 2009-2011 actual, 2012 year-to-date, 2012 and 2013 forecast. Actual data for 2008 was available to be reviewed as part of the 2008/2009 GRA and is not considered to be relevant to the current revenue requirement proceeding for the 2012/13 test years.

Table 1:

YEC's General Service Monthly Average Customers and Monthly Residential Sales for 2009-2011 Actual, 2012 Year-to-Date, 2012 and 2013 Forecast

Month	YEC's General Service customers and sales											
	2009		2010		2011		2012 Year-to-date		2012 Forecast		2013 Forecast	
	Monthly Average # of customers	Monthly Sales (MW.h)	Monthly Average # of customers	Monthly Sales	Monthly Average # of customers	Monthly Sales	Monthly Average # of customers	Monthly Sales	Monthly Average # of customers	Monthly Sales	Monthly Average # of customers	Monthly Sales
January	409	1,446.9	416	1,930.2	433	1,802.8	433	2,007.4	424	1,891.3	431	1,992.2
February	410	1,479.9	419	1,751.6	433	1,659.2	433	1,828.8	424	1,682.1	428	1,759.4
March	404	1,443.0	422	1,563.5	435	1,702.0	434	1,731.1	424	1,634.7	429	1,727.2
April	417	1,490.3	433	1,601.0	449	1,558.3	444	1,718.0	437	1,616.7	443	1,702.9
May	463	1,426.2	480	1,619.1	490	1,744.2	487	1,621.0	483	1,633.4	490	1,749.7
June	477	1,946.5	485	2,449.2	491	2,371.0			495	2,082.7	502	2,184.3
July	483	1,986.3	493	2,419.1	489	1,900.8			504	2,227.9	511	2,305.2
August	484	2,055.3	489	2,074.0	490	1,502.2			504	1,890.7	511	1,984.7
September	481	2,126.6	492	2,313.1	495	2,027.3			506	2,118.4	515	2,211.9
October	431	1,619.1	468	1,828.5	472	1,820.1			461	1,610.6	470	1,623.8
November	425	1,488.8	432	1,592.0	456	1,478.4			432	1,624.4	435	1,640.4
December	420	1,163.0	426	1,578.1	434	1,739.0			431	1,680.3	435	1,737.9
Annual	442	19,671.8	455	22,719.4	464	21,305.1	446	8,906.3	460	21,693.2	467	22,619.6

(c)

YEC cannot provide the requested information as this requires a cost of service study for the requested years.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 2, Page 2-17

PREAMBLE:

QUESTION:

a) Please provide an update to Table 2.1 which includes actual 2011 sales for the full year.

b) Please provide a table showing the total actual monthly kWh usage in 2009, 2010, 2011, 2012 and 2013 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 2009, 2010, 2011, 2012 and 2013 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.

Please identify the source of the information provided.

ANSWER:

(a)

Please see YECL-YEC-1-2.

(b) and **(c)**

Yukon Energy does not have access to this information, as most customers in Yukon are served at the retail level by YECL, not YEC.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-5

YEC states "Forecast fuel prices for the 2012/2013 test years are $1.0513 per litre for Whitehorse, $1.0885 per litre for Faro, $1.168 per litre for Dawson and $1.0966 per litre for Mayo and reflect the most recent fuel prices for YEC. This is higher than the fuel price forecast at the 2009 approved fuel prices of $0.96/litre, $0.992/litre, $0.975/litre and $0.967/litre respectively".

PREAMBLE:

QUESTION:

a) Please provide details of the actual prices paid for diesel fuel in 2008, 2009, 2010 and 2011. Please include references to locations and amounts.

b) Please identify YEC's procurement practice and policy with respect to diesel fuel.

ANSWER:

(a)

Please see tables provided below for actual prices paid for fuel as well as locations and amounts from 2009 through 2011. Actual data for 2008 was available to be reviewed as part of the 2008/2009 GRA and is not considered to be relevant to the current revenue requirement proceeding for the 2012/13 test years.

Table 1A:

Actual Price per Litre for 2009 as per North 60 Contract Price

Month	Whitehorse	Faro	Mayo	Dawson	Average
Jan-09	$ 0.7803	$ 0.8137	$ 0.8211	$ 0.8399	**$ 0.8138**
Feb-09	$ 0.7473	$ 0.7807	$ 0.7881	$ 0.8069	**$ 0.7808**
Mar-09	$ 0.6483	$ 0.6817	$ 0.6891	$ 0.7079	**$ 0.6818**
Apr-09	$ 0.7203	$ 0.7537	$ 0.7611	$ 0.7799	**$ 0.7538**
May-09	$ 0.7353	$ 0.7687	$ 0.7761	$ 0.7949	**$ 0.7688**
Jun-09	$ 0.7173	$ 0.7507	$ 0.7581	$ 0.7769	**$ 0.7508**
Jul-09	$ 0.8143	$ 0.8477	$ 0.8551	$ 0.8739	**$ 0.8478**
Aug-09	$ 0.7443	$ 0.7777	$ 0.7851	$ 0.8039	**$ 0.7778**
Sep-09	$ 0.8373	$ 0.8707	$ 0.8781	$ 0.8969	**$ 0.8708**
Oct-09	$ 0.7713	$ 0.8047	$ 0.8121	$ 0.8309	**$ 0.8048**
Nov-09	$ 0.8133	$ 0.8467	$ 0.8541	$ 0.8729	**$ 0.8468**
Dec-09	$ 0.7943	$ 0.8277	$ 0.8351	$ 0.8539	**$ 0.8278**
Average per Location	**$ 0.7603**	**$ 0.7937**	**$ 0.8011**	**$ 0.8199**	**$ 0.7938**

Table 1B:

Actual Litres Consumed (2009)

FUEL PURCHASES LITRES (2009)													
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
511 Faro	-	24,586	-	-	-	30,053	-	50,248	-	30,100	-	-	134,987
512 Dawson	47,172	-	-	48,112	-	-	-	-	48,074	48,002	-	-	191,359
513 Mayo	-	-	-	-	-	-	-	-	-	-	-	-	-
571 Whitehorse	204,184	21,184	9,120	-	31,036	-	68,097	-	14,848	-	18,867	118,356	485,693
Totals	**251,356**	**45,770**	**9,120**	**48,112**	**31,036**	**30,053**	**68,097**	**50,248**	**62,922**	**78,102**	**18,867**	**118,356**	**812,039**

Table 2A:

Actual Price per Litre for 2010 as per North 60 Contract Price

Month	Whitehorse	Faro	Mayo	Dawson	Average
Jan-10	$ 0.8253	$ 0.8587	$ 0.8661	$ 0.8849	**$ 0.8588**
Feb-10	$ 0.7813	$ 0.8147	$ 0.8221	$ 0.8409	**$ 0.8148**
Mar-10	$ 0.8323	$ 0.8657	$ 0.8731	$ 0.8919	**$ 0.8658**
Apr-10	$ 0.8663	$ 0.8997	$ 0.9071	$ 0.9259	**$ 0.8998**
May-10	$ 0.9093	$ 0.9427	$ 0.9501	$ 0.9689	**$ 0.9428**
Jun-10	$ 0.8363	$ 0.8697	$ 0.8771	$ 0.8959	**$ 0.8698**
Jul-10	$ 0.8413	$ 0.8747	$ 0.8821	$ 0.9009	**$ 0.8748**
Aug-10	$ 0.8353	$ 0.8687	$ 0.8761	$ 0.8949	**$ 0.8688**
Sep-10	$ 0.8893	$ 0.9227	$ 0.9301	$ 0.9489	**$ 0.9228**
Oct-10	$ 0.9323	$ 0.9657	$ 0.9731	$ 0.9919	**$ 0.9658**
Nov-10	$ 0.8863	$ 0.9197	$ 0.9271	$ 0.9459	**$ 0.9198**
Dec-10	$ 0.8993	$ 0.9327	$ 0.9401	$ 0.9589	**$ 0.9328**
Average per Location	**$ 0.8612**	**$ 0.8946**	**$ 0.9020**	**$ 0.9208**	**$ 0.8947**

Table 2B:

Actual Litres Consumed (2010)

FUEL PURCHASES LITRES (2010)													
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
511 Faro	-	-	-	2,231	-	14,108	-	13,012	-	28,796	9,516	17,659	85,321
512 Dawson	47,060	-	-	56,721	-	-	-	142,431	-	-	138,099	322,854	707,165
513 Mayo	-	-	-	-	-	-	-	-	-	12,002	-	-	12,002
571 Whitehorse	36,547	-	-	-	-	-	81,186	55,049	-	-	55,407	432,509	660,698
Total	**83,608**	**-**	**-**	**58,952**	**-**	**14,108**	**81,186**	**210,492**	**-**	**40,798**	**203,022**	**773,022**	**1,465,186**

Table 3A:

Actual Price per Litre for 2011 as per North 60 Contract Price

Month	Whitehorse	Faro	Mayo	Dawson	Average
Jan-11	$ 0.9083	$ 0.9417	$ 0.9491	$ 0.9679	**$ 0.9418**
Feb-11	$ 0.9583	$ 0.9917	$ 0.9991	$ 1.0179	**$ 0.9918**
Mar-11	$ 1.0273	$ 1.0607	$ 1.0681	$ 1.0869	**$ 1.0608**
Apr-11	$ 1.0773	$ 1.1107	$ 1.1181	$ 1.1369	**$ 1.1108**
May-11	$ 1.1013	$ 1.1347	$ 1.1421	$ 1.1609	**$ 1.1348**
Jun-11	$ 1.0783	$ 1.1117	$ 1.1191	$ 1.1379	**$ 1.1118**
Jul-11	$ 0.9833	$ 1.0167	$ 1.0241	$ 1.0429	**$ 1.0168**
Aug-11	$ 1.0103	$ 1.0437	$ 1.0511	$ 1.0699	**$ 1.0438**
Sep-11	$ 1.0783	$ 1.1117	$ 1.1191	$ 1.1379	**$ 1.1118**
Oct-11	$ 1.0633	$ 1.0967	$ 1.1041	$ 1.1229	**$ 1.0968**
Nov-11	$ 1.0633	$ 1.0967	$ 1.1041	$ 1.1229	**$ 1.0968**
Dec-11	$ 1.0143	$ 1.0515	$ 1.0596	$ 1.0798	**$ 1.0513**
Average per Location	**$ 1.0303**	**$ 1.0640**	**$ 1.0715**	**$ 1.0904**	**$ 1.0640**

Table 3B:

Actual Litres Consumed (2010)

FUEL PURCHASES LITRES (2011)													
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
511 Faro	56,465	30,093	32,073	16,989	0	67,891	0	0	27,077	167,134	28,013	7,053	432,788
512 Dawson	277,308	190,183	335,524	396,660	144,221	47,094	95,149	0	47,521	239,172	134,667	-0	1,907,499
513 Mayo	0	0	0	36,897	16,000	0	8,015	44,000	0	53,197	0	0	158,109
571 Whitehors	224,176	136,358	457,478	32,481	51,282	141,035	28,247	92,977	51,298	449,182	37,096	18,047	1,719,658
Totals	**557,949**	**356,635**	**825,076**	**483,028**	**211,503**	**256,020**	**131,411**	**136,977**	**125,896**	**908,684**	**199,777**	**25,100**	**4,218,054**

(b)

Diesel fuel supply is procured by competitive public tender. Proponents are required to provide pricing for fuel delivered to each of YEC facilities in Whitehorse, Dawson, Mayo and Faro. Prices are generally updated monthly for market price fluctuations.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-6

YEC states "*Table 3.3 indicates the actual expense for 2009 and 2010 was $14.4 million and $14.35 million respectively, and increased to $15.8 million in 2011. Total operating and maintenance costs are forecast to increase to $17.496 million for 2012 and $18.385 million for 2013. This is a $4.3 million increase in 2012 over 2009 approved (33% increase) and further $0.89 million increase in 2013 over 2012 forecast (5% increase)*".

PREAMBLE:

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 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

c) Please provide a table showing non-fuel operating and maintenance costs per customer for 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast). Please include details of the calculation of these averages.

ANSWER:

(a)

Details with respect to the increase in labour costs and the amount of labour costs transferred to capital projects are provided in Table 1 below.

Table1:

Labour Cost Increases and Labour Charged to Capital and Deferred Projects

($000)

	Actual 2009	Actual 2010	Actual 2011	GRA 2012	GRA 2013
O&M labour	3,937	3,913	4,005	5,275	5,380
Admin labour	3,725	3,808	4,338	3,910	3,998
Labour expense	**7,662**	**7,721**	**8,343**	**9,185**	**9,378**
Labour charged to Capital/ Deffered Cost Projects	2,228	2,842	3,139	2,833	2,891
Labour charged to YDC/3rd Parties	133	117	164	126	129
Total Labour Charged to Other Areas:	**2,361**	**2,959**	**3,303**	**2,959**	**3,020**
Total	**10,023**	**10,680**	**11,646**	**12,144**	**12,398**
Yearly Increase as a %		6.55%	9.04%	4.28%	2.09%
Economic increase January 1st each year		3.50%	3.00%	2.25%	2.25%
Number of new positions added		6.75	6.00	0.00	0.00

Specific information on the new positions added is provided in YUB-YEC-1-14(c).

(b)

See Attachment 1 for those staff positions that earned more $100,000 in total compensation for the year. Since 2009, YEC has now been determined to be subject to ATIPP legislation. As such, we cannot disclose the actual compensation figure as we believe this would be a violation of this act.

(c)

Please see Table 2 below for the requested information.

Table 2:
Non-Fuel Operating and Maintenance Expense per Customer

	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
Total OM&A ($000)	14,401	14,353	15,964	17,496	18,385
Total customers*	1,899	1,927	1,979	1,986	2,003
Average OM&A costs per customer ($000s)*	7.58	7.45	8.07	8.81	9.18

* Average OM&A costs per customer are provided as requested. Number of customers provided only includes YEC residential and general service customers. 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.

UCG-YEC-1-25(b)

Positions Titles with Compensation Amounts Greater Than $100K for 2009

	Title
	Maintenance Electrician
	Distribution Technologist
U	Powerline Tech.-Whse
N	SCC Operator 1
I	Plant Operator 1
O	Maintenance Mechanic
N	SCC Operator 2
	Coordinator, Electrical Projects
C	Network/Systems Administrator
O	SCC Operator 2
N	Network/Systems Administrator
T	Coordinator, Property & Security
R	SCC Operator 1
A	Coordinator, Mechanical Projects
C	Maintenance Mechanic
T	Revenue & Financial Analyst
	Maintenance Electrician
	Network/Systems Administrator
	Maintenance Electrician
	Maintenance Mechanic
	Plant Operator 2
	Maintenance Electrician
	Leadhand Electrical Maintenance
	Leadhand Mechanical Maintenace
	Maintenance Mechanic
	Maintenance Electrician
	Plant Operator 2- Mayo
	Leadhand SCC & Material Management
	Powerline Tech.-Dawson
	Powerline Tech-Mayo
	Powerline Tech-Whse
	Sr. Powerline Tech.-Dawson
	Sr. Powerline Tech.- Faro
	Leadhand Transmission & Distribution
O	Corporate Secretary
U	Manager, Health & Safety
T	Supervisor, Communications
	Electrical Engineer
O	Electrical Engineer
F	Civil Engineer
	Supervisor, Mechanical and Civil Engineering
S	Supervisor, Financial and Risk Management
C	Manager, Environmental Assessment & Licensing
O	Controller
P	Director, Technical Services
E	Director, Resource Planning & Regulatory Affairs
	Director, Operations
	Chief Financial Officer
	Director, HR & IT
	Vice President, Operations & Engineering
	President & CEO

UCG-YEC-1-25(b)
Positions Titles with Compensation Amounts Greater Than $100K for 2010

	Title
	Maintenance Mechanic
U	Plant Operator 1
N	Maintenance Electrician
I	SCC Operator 2
O	Maintenance Electrician
N	Communications, Protection and Control Tech.
	SCC Operator 2
C	Maintenance Electrician
O	Revenue & Financial Analyst
N	Powerline Tech-Whse
T	Distribution Technologist
R	Safety Coordintator
A	Plant Operator 2
C	Maintenance Mechanic
T	Network/Systems Administrator
	Network/Systems Administrator
	Coordinator, Property & Security
	Maintenance Mechanic
	Coordinator, Mechanical Projects
	SCC Operator 1
	Buyer
	A/IT Coordinator
	Maintenance Mechanic
	Powerline Tech.-Whse
	Leadhand Electrical Maintenance
	Plant Operator 2- Mayo
	Powerline Tech.-Dawson
	Maintenance Electrician
	Leadhand SCC & Material Management
	Leadhand Mechanical Maintenace
	Maintenance Electrician
	Powerline Tech-Mayo
	Sr. Powerline Tech.- Faro
	Sr. Powerline Tech.-Dawson
	Leadhand Transmission & Distribution
O	Corporate Secretary
U	Manager, Health & Safety
T	Director, Major Projects
	Supervisor, Communications
O	Electrical Engineer
F	Supervisor, Mechanical and Civil Engineering
	Manager, Operations
S	Manager, Environmental Assessment & Licensing
C	Civil Engineer
O	Supervisor, Financial and Risk Management
P	Controller
E	Electrical Engineer
	Director, Technical Services
	Director, Resource Planning & Regulatory Affairs
	Director, Operations
	Chief Financial Officer
	Director, HR & IT
	President & CEO

UCG-YEC-1-25(b)
Positions Titles with Compensation Amounts Greater Than $100K for 2011

	Title
	Financial Administrator
	Maintenance Electrician
U	Plant Operator 1
N	Plant Operator 2
I	Revenue & Financial Analyst
O	Distribution Technologist
N	Maintenance Mechanic
	Safety Coordintator
C	SCC Operator 2
O	Network/Systems Administrator
N	Network/Systems Administrator
T	Maintenance Mechanic
R	Network/Systems Administrator
A	Maintenance Electrician
C	Capital Mechanic
T	Powerline Tech-Whse
	Buyer
	Maintenance Electrician
	Maintenance Mechanic
	Powerline Tech-Whse
	SCC Operator 1
	Maintenance Electrician
	Powerline Tech.-Whse
	Maintenance Electrician
	Leadhand Hydro Maintenance
	Coordinator, Mechanical Projects
	Powerline Tech.-Dawson
	Leadhand Mechanical Maintenace
	Leadhand Electrical Maintenance
	Plant Operator 2- Mayo
	Maintenace Mechanic
	Sr. Powerline Tech.-Dawson
	Sr. Powerline Tech.- Mayo
	Communications, Protection and Control Tech.
	Capital Electrician
	Corporate Secretary
O	Supervisor, Electrical Engineering
U	Manager, SCC and T&D
T	Electrical Engineer
	Manager, IT
O	Manager, Health & Safety
F	Director, Major Projects
	Supervisor, Communications
S	Electrical Engineer
C	Supervisor, Mechanical and Civil Engineering
O	Manager, Operations
P	Manager, Environmental Assessment & Licensing
E	Civil Engineer
	Supervisor, Financial and Risk Management
	Controller
	Electrical Engineer
	Director, Technical Services
	Director, Resource Planning & Regulatory Affairs
	Director, Operations
	Chief Financial Officer
	Director, HR & IT
	President & CEO

UCG-YEC-1-25(b)
Positions Titles with Compensation Amounts Greater Than $100K for 2012 BP

	Title
	Financial Analyst
	SCC Operator 1
	Drafts Person
	Financial Administrator
	Drafts Person
U	Maintenance Electrician
N	Maintenance Electrician
I	Plant Operator 1
O	SCC Operator 2
N	Revenue & Financial Analyst
	Distribution Technologist
C	Coordinator, Mechanical Projects
O	Maintenance Mechanic
N	Capital Mechanic
T	Network/Systems Administrator
R	Communications, Protection and Control Tech.
A	HR & Records Management Advisor
C	SCC Operator 2
T	Network/Systems Administrator
	Maintenace Mechanic
	Maintenance Electrician
	SCC Operator 2
	Safety Coordintator
	Network/Systems Administrator
	Maintenance Electrician
	Plant Operator 2
	Maintenance Electrician
	Maintenance Mechanic
	Maintenance Electrician
	Maintenance Mechanic
	Buyer
	Plant Operator 2- Ais
	Powerline Tech-Whse
	Powerline Tech-Mayo
	Leadhand Electrical Maintenance
	Leadhand Hydro Maintenance
	Powerline Tech.-Whse
	Leadhand Mechanical Maintenace
	Leadhand, Transmission & Distribution
	Sr. Powerline Tech.- Mayo
	Sr. Powerline Tech.-Dawson
	Powerline Tech.-Dawson
	Energy Conservation Administrator
	Manager, Electrical Operations
	Environmental Coordinator
O	Coordinator, Property & Security
U	Manager, Energy Conservation
T	Resource Planning Engineer
	Corporate Secretary
O	Electrical Engineer
F	Electrical Engineer
	Supervisor, Electrical Engineering
S	Supervisor, Communications
C	Electrical Engineer
O	Controller
P	Manager, SCC and Mechanical Operations
E	Manager, Health & Safety
	Manager, IT
	Civil Engineer
	Manager, Operations
	Manager, Environmental Assessment & Licensing
	Supervisor, Mechanical and Civil Engineering
	Manager, Reporting & Special Projects
	Supervisor, Financial and Risk Management
	Director, Resource Planning & Regulatory Affairs
	Director, Technical Services
	Director, Operations
	Director, Major Projects
	Chief Financial Officer
	Director, HR & IT
	President & CEO

UCG-YEC-1-25(b)
Positions Titles with Compensation Amounts Greater Than $100K for 2013 BP

	Title
	Financial Analyst
	SCC Operator 1
	Drafts Person
	Financial Administrator
	Drafts Person
U	Maintenance Electrician
N	Maintenance Electrician
I	Plant Operator 1
O	SCC Operator 2
N	Revenue & Financial Analyst
	Distribution Technologist
C	Coordinator, Mechanical Projects
O	Maintenance Mechanic
N	Capital Mechanic
T	Network/Systems Administrator
R	Communications, Protection and Control Tech.
A	HR & Records Management Advisor
C	SCC Operator 2
T	Network/Systems Administrator
	Maintenace Mechanic
	Maintenance Electrician
	SCC Operator 2
	Safety Coordintator
	Network/Systems Administrator
	Maintenance Electrician
	Plant Operator 2
	Maintenance Electrician
	Maintenance Mechanic
	Maintenance Electrician
	Maintenance Mechanic
	Buyer
	Plant Operator 2- Ais
	Powerline Tech-Whse
	Powerline Tech-Mayo
	Leadhand Electrical Maintenance
	Leadhand Hydro Maintenance
	Powerline Tech.-Whse
	Leadhand Mechanical Maintenace
	Leadhand, Transmission & Distribution
	Sr. Powerline Tech.- Mayo
	Sr. Powerline Tech.-Dawson
	Powerline Tech.-Dawson
	Energy Conservation Administrator
	Manager, Electrical Operations
	Environmental Coordinator
O	Coordinator, Property & Security
U	Manager, Energy Conservation
T	Resource Planning Engineer
	Corporate Secretary
O	Electrical Engineer
F	Electrical Engineer
	Supervisor, Electrical Engineering
S	Supervisor, Communications
C	Electrical Engineer
O	Controller
P	Manager, SCC and Mechanical Operations
E	Manager, Health & Safety
	Manager, IT
	Civil Engineer
	Manager, Operations
	Manager, Environmental Assessment & Licensing
	Supervisor, Mechanical and Civil Engineering
	Manager, Reporting & Special Projects
	Supervisor, Financial and Risk Management
	Director, Resource Planning & Regulatory Affairs
	Director, Technical Services
	Director, Operations
	Director, Major Projects
	Chief Financial Officer
	Director, HR & IT
	President & CEO

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-6

YEC states "The remainder of the $4.3 million increase in 2012 forecast over 2009 approved costs is comprised of an increase in labour expense in 2012 of $2.305 million (53% of total increase over 2009 approved) and in 2013 of $0.193 million over 2012 forecast (22% of total increase over 2012 forecast). This reflects additional positions, as well as negotiated and step increases. Full Time Equivalent (FTE) positions are forecast to increase by 12.26 FTEs in 2013 compared to 2009 approved with most of the increase in 2010 (7.38 FTEs). The average annual increase in salaries per FTE is 4.3% from 2009 approved to 2013 forecast".

PREAMBLE:

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 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

b) Please provide individual amounts paid by YEC to each member of the Board of Directors for 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

c) Please explain how YEC and YDC-related costs are tracked and allocated within YEC's revenue requirement.

ANSWER:

(a)

Please see Table 1 below.

Table 1:
Labour Expense by Component ($000s)

	2009 Actuals	2010 Actuals	2011 Actuals	2012 Forecast	2013 Forecast
Production					
Overtime	206	189	192	224	229
Standby	104	107	138	187	191
Labour	1,466	1,562	1,519	1,530	1,550
Fringe	1,019	1,085	1,146	1,063	1,087
Total	**2,795**	**2,943**	**2,995**	**3,003**	**3,057**
Transmission					
Overtime	69	35	53	134	137.18
Standby					
Labour	227	168	196	175	178.85
Fringe	158	116	148	122	124.29
Total	**453**	**319**	**396**	**431**	**440**
Distribution					
Overtime	28	31	31	24	25
Standby	107	25	75	101	104
Labour	243	248	209	268	274
Fringe	169	173	158	186	190
Total	**546**	**477**	**473**	**579**	**592**
General					
Overtime	7	13	9	11	12
Standby					
Labour	80	101	75	138	141
Fringe	56	70	57	96	98
Total	**143**	**184**	**141**	**245**	**251**
Administration					
Overtime	50	45	57	57	58
Standby					-
Labour	2,168	2,213	2,455	2,874	2,938
Fringe	1,507	1,538	1,852	1,997	2,042
Total	**3,725**	**3,797**	**4,363**	**4,927**	**5,038**

* There are no profit sharing or incentive plans in the GRA revenue requirement.

(b)

Please see Table 2 below for the requested information. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 2:
Total Honoraria Paid to YEC Board Members for 2009-Forecast 2012/2013

Positon	2009	2010	2011	GRA 2012	GRA 2013
Director 1	$ 1,100	$ 3,400	$ 6,600	$ 6,500	$ 6,500
Director 2	$ 1,100	$ 4,400	$ 7,100	$ 6,500	$ 6,500
Director 3	$ 4,000	$ 200	$ 7,700	$ 6,500	$ 6,500
Director 4	$ 7,500	$ 4,200	$ 3,300	$ 6,500	$ 6,500
Director 5	$ 8,300	$ 5,200	$ 8,800	$ 6,500	$ 6,500
Director 6	$ 8,350	$ 7,350	$ 8,300	$ 6,500	$ 6,500
Director 7	$ 15,200	$ 9,500	$ 10,600	$ 11,000	$ 11,000
Chair	$ 17,900	$ 27,100	$ 54,900	$ 54,000	$ 54,000
Total	**$ 65,459**	**$ 63,360**	**$ 109,311**	**$ 104,000**	**$ 104,000**

(c)

YEC costs are budgeted by position based on function. There are no YDC-related costs in YEC's revenue requirement.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-6, Table 3.3

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the non-fuel operating and maintenance expenses included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

c) Please provide an explanation for any variances between the 2011 actual, 2012 forecast and 2013 forecast and the non-fuel operating and maintenance expenses cost level last approved by the YUB for 2009.

d) Please explain what is meant by using columns labelled “existing” and “proposed” for 2012 and 2013; in particular, explain the significance the reader is supposed to draw when the existing and proposed values in the same year are identical for the majority of categories.

ANSWER:

(a)

Please see Table 1 below for the requested update that includes 2011 actual. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 1:
Non-Fuel Operating and Maintenance Expenses ($000)

	2009 GRA compliance	Actual 2009	Actual 2010	Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Labour	$ 6,880	$ 7,663	$ 7,720	$ 8,368	$ 9,185	$ 9,185	$ 9,378	$ 9,378
Production[1]	798	963	1,236	1,478	1,449	1,449	1,437	1,437
Transmission	612	755	476	714	760	760	853	853
Distribution	178	114	111	184	201	201	226	226
General O&M	858	1,002	1,010	1,195	1,094	1,094	1,154	1,154
Administration	2,544	2,729	2,621	2,855	3,429	3,429	3,885	3,885
Insurance and Reserve for Injuries/Damages	1,052	887	887	874	935	1,066	995	1,126
Property Taxes	256	288	291	297	312	312	326	326
Total OM&A (Tab 7, Schedule 10)	$ 13,178	$ 14,401	$ 14,353	$ 15,964	$ 17,365	$ 17,496	$ 18,254	$ 18,385

Note:
1. Production function includes Fish Ladder cost for 2009-2013 years, which was under Administration function in 2009 GRA.

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

(c)

Please refer to Section 3.3 of the Application for discussion of non-fuel operating and maintenance expenses variances over 2009 GRA approved levels.

(d)

For 2012 and 2013 “Existing” columns refer to “without GRA” forecasts while “Proposed” refer to “with GRA” forecasts. Where the values in a year are identical as between “Existing” and “Proposed” it means that the value is not affected by any changes to be approved as part of the GRA filing.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-7, Table 3.4

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the employee complement included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

c) Please provide an explanation for any variances between the 2011 actual, 2012 forecast and 2013 forecast and the Employee Complement level last approved by the YUB for 2009.

ANSWER:

(a)

Please see Table 1 below for the requested update that includes 2011 actual. The 2008 information was not complied for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 1:
Employee Complement History

	2009 GRA compliance	Actual 2009	Actual 2010	Actual 2011	GRA 2012	GRA 2013
President	2.50	4.50	5.50	5.50	4.50	4.50
Communications	1.00	1.00	1.00	1.00	1.00	1.00
Human Resources & Info. Mgmt.	7.00	5.00	6.00	7.10	6.25	6.25
Resource Planning and Environment	1.00	2.00	2.00	6.00	7.00	7.00
Finance, Cust. Acctg. & Purchasing	12.81	14.08	13.69	15.75	17.00	17.00
Operations	40.10	40.61	41.49	41.44	41.25	41.25
Engineering Services	12.00	12.00	15.44	14.00	13.00	13.00
Health, Safety & Environment	3.33	2.00	2.00	2.00	2.00	2.00
Total	79.74	81.19	87.12	92.79	92.00	92.00

Note:
1. The employee complement numbers are net of allocation to YDC.

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

(c)

Please refer to Section 3.3 of the Application for discussion of labour expenses variances over 2009 GRA approved levels.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-7, Table 3.5

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the production costs included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

c) Please provide an explanation for any variances between the 2011 actual, 2012 forecast and 2013 forecast and the Production cost level last approved by the YUB for 2009.

d) Please explain what is meant by using columns labelled "existing" and "proposed" for 2012 and 2013; 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)

Please see Table 1 below for the requested update that includes 2011 actual. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 1:
Production Costs ($000s)

	2009 GRA compliance	Actual 2009	Actual 2010	Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Labour	$ 2,179	$ 2,796	$ 2,943	$ 2,995	$ 3,003	$ 3,003	$ 3,057	$ 3,057
Diesel	194	333	297	615	425	425	439	439
Hydro	560	602	895	852	938	938	909	909
Wind	8	6	6	5	27	27	18	18
Operation Supervision	36	22	38	6	59	59	72	72
Total Production	$ 2,977	$ 3,759	$ 4,179	$ 4,473	$ 4,452	$ 4,452	$ 4,494	$ 4,494

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

(c)

Please refer to Section 3.3.1 of the Application for discussion of production cost variances over 2009 GRA approved levels.

(d)

For 2012 and 2013 “Existing” columns refer to “without GRA” forecasts while “Proposed” refer to “with GRA” forecasts. Where the values in a year are identical as between “Existing” and “Proposed” it means that the value is not affected by any changes to be approved as part of the GRA filing.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-8, Table 3.6

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the transmission costs included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

c) Please provide an explanation for any variances between the 2011 actual, 2012 forecast and 2013 forecast and the Transmission cost level last approved by the YUB for 2009.

d) Please explain what is meant by using columns labelled "existing" and "proposed" for 2012 and 2013; 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)

Please see Table 1 below for the requested update that includes 2011 actual. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 1:
Transmission Costs ($000)

	2009 GRA compliance	Actual 2009	Actual 2010	Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Labour	$ 482	$ 453	$ 319	$ 396	$ 431	$ 431	$ 440	$ 440
Brushing	377	387	268	434	505	505	639	639
Other Non-Labour	235	369	208	280	255	255	214	214
Total Transmission	$ 1,094	$ 1,208	$ 795	$ 1,110	$ 1,190	$ 1,190	$ 1,293	$ 1,293

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

(c)

Please refer to Section 3.3.2 of the Application for discussion of transmission cost variances over 2009 GRA approved levels.

Please see the response to YUB-YEC-1-17 for further details.

(d)

For 2012 and 2013 “Existing” columns refer to “without GRA” forecasts while “Proposed” refer to “with GRA” forecasts. Where the values in a year are identical as between “Existing” and “Proposed” it means that the value is not affected by any changes to be approved as part of the GRA filing.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-9, Table 3.7

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the distribution costs included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

c) Please provide an explanation for any variances between the 2011 actual, 2012 forecast and 2013 forecast and the Distribution cost level last approved by the YUB for 2009.

d) Please explain what is meant by using columns labelled “existing” and “proposed” for 2012 and 2013; 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)

Please see Table 1 below for the requested update that includes 2011 actual. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 1:
Distribution Costs ($000)

	2009 GRA compliance	Actual 2009	Actual 2010	Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Labour	$ 521	$ 546	$ 477	$ 473	$ 579	$ 579	$ 592	$ 592
Brushing	46	17	16	68	93	93	113	113
Other Non-Labour	132	97	96	116	108	108	113	113
Total Distribution	$ 699	$ 660	$ 588	$ 657	$ 780	$ 780	$ 819	$ 819

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

(c)

Overall distribution costs have increased on average by 3.7%-4.0% annually as compared to 2009 GRA approved amount, which is not materially above the inflationary pressure. Most of the increase is driven by higher brushing expense partially offset by decrease in other non-labor costs.

(d)

For 2012 and 2013 “Existing” columns refer to “without GRA” forecasts while “Proposed” refer to “with GRA” forecasts. Where the values in a year are identical as between “Existing” and “Proposed” it means that the value is not affected by any changes to be approved as part of the GRA filing.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-10, Table 3.8

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the general operating and maintenance costs included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

c) Please provide an explanation for any variances between the 2011 actual, 2012 forecast and 2013 forecast and the General Operating and Maintenance cost level last approved by the YUB for 2009.

d) Please explain what is meant by using columns labelled “existing” and “proposed” for 2012 and 2013; 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)

Please see Table 1 below for the requested update that includes 2011 actuals. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 1:
General Operating and Maintenance ($000)

					Forecast		Forecast	
	2009 GRA compliance	Actual 2009	Actual 2010	Actual 2011	Existing 2012	Proposed 2012	Existing 2013	Proposed 2013
Labour	$ 94	$ 143	$ 184	$ 141	$ 245	$ 245	$ 250	$ 250
Transportation	394	401	419	449	427	427	451	451
Maintenance of Company Owned Properties	384	471	489	650	581	581	611	611
SCADA Communication	80	130	102	96	86	86	93	93
Total General O&M	$ 952	$ 1,145	$ 1,194	$ 1,336	$ 1,339	$ 1,339	$ 1,405	$ 1,405

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

(c)

Please see the response to YUB-YEC-1-19.

(d)

For 2012 and 2013 “Existing” columns refer to “without GRA” forecasts while “Proposed” refer to “with GRA” forecasts. Where the values in a year are identical as between “Existing” and “Proposed” it means that the value is not affected by any changes to be approved as part of the GRA filing.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-11, Table 3.9

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the administration costs included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

c) Please provide an explanation for any variances between the 2011 actual, 2012 forecast and 2013 forecast and the Administration cost level last approved by the YUB for 2009.

d) Please provide details and explanations of the cost incurred to operate the fish hatchery that were included in the approved 2009 revenue forecast, 2011 actual, 2012 forecast and 2013 forecast.

e) Please provide an explanation and details of the spending on training in 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast). Was any of this training available and / or taken within the Yukon? Why or why not?

f) Please provide total compensation levels for positions for which staff were recruited in 2009, 2010 and 2011 and will be recruited in 2012 (forecast) and 2013 (forecast).

g) Please provide details of costs identified under regulatory affairs for 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

h) Please explain what is meant by using columns labelled “existing” and “proposed” for 2012 and 2013; 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)

Please see Table 1 below for the requested update that includes 2011 actual. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 1:
Non-Fuel Operating and Maintenance Expenses ($000)

					Forecast		Forecast	
	2009 GRA compliance	Actual 2009	Actual 2010	Actual 2011	Existing 2012	Proposed 2012	Existing 2013	Proposed 2013
Labour	$ 3,605	$ 3,725	$ 3,797	$ 4,363	$ 4,927	$ 4,927	$ 5,038	$ 5,038
Resource Planning	17	18	24	128	26	26	26	26
Communications	105	98	119	98	306	306	295	295
Customer Accounting	206	182	185	194	190	190	191	191
Environmental Mgmt	52	50	82	152	338	338	569	569
General	734	886	611	801	910	910	1,099	1,099
Information Systems	425	595	548	388	569	569	607	607
Fish Hatchery	136	159	176	140	182	182	187	187
Fish Ladder[1]	26							
Safety	162	187	201	177	177	177	189	189
Training	211	205	150	184	260	260	260	260
Recruitment	169	138	192	83	120	120	120	120
Board of Directors	148	113	100	289	180	180	168	168
Union	26	9	72	25	23	23	23	23
Regulatory Affairs	57	27	77	156	34	34	34	34
Material Management	43	(6)	64	18	33	33	35	35
Contracting	11	60	17	8	15	15	16	16
Professional Development	15	9	2	15	17	17	17	17
DSM Administration					49	49	49	49
Total Administration	$ 6,148	$ 6,453	$ 6,418	$ 7,218	$ 8,357	$ 8,357	$ 8,923	$ 8,923

Note:
1. Fish Ladder cost for 2009-2013 included in Production Function.

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

(c)

Please refer to section 3.3.5 of the Application for discussion of Administration expenses variances over 2009 GRA approved levels.

Please see to the response to YUB-YEC-1-20(c) for further details.

(d)

Please see Table 2 provided below.

Table 2:
Fish Hatchery Expenditures ($000s)

	2009 Compliance	2011 Actual	2012 Forecast	2013 Forecast
Contractors	268	239	280	285
Misc expenses		1	2	2
Total Cost	268	240	282	287
Less: Grant/Funding	(133)	(100)	(100)	(100)
Net Cost	**136**	**140**	**182**	**187**

Notes:
1) Contractor Costs include building costs (electicity, heat, telephone), fish food, hatchery staff costs and management fee.
2) YG Contribution is based on agreement with YG for hatchery funding.

(e)

Due to the very specialized nature of equipment and the expertise needed by employees there are times when training must be taken outside of the territory as it is not available locally. However, a significant amount of training is done within Yukon. To ensure better use of training dollars, where feasible, instructors are brought to Yukon in order to train a

number of employees. Yukon Energy has also partnered with other agencies such as Yukon College and the City of Whitehorse to develop training courses for employees.

Details of the spending on training in 2009, 2010, 2011, 2012 (forecast) are provided in Attachment 1 to this response. No training is forecast in 2013.

(f)

Please see Table 3 below for the requested information.

Table 3:
Recruited Employees and Compensation Ranges

Position	Year Added	Revision	Salary Range Minimum	Salary Range Maximum
Casual Maintenance Electrician	2009		$66,789	$78,574
Casual Maintenance Mechanic	2009		$66,789	$78,574
Casual Labourer	2009		$37,145	$43,700
SQL/Sharepoint Administrator	2010		$77,064	$90,664
Communications Protection & Control Technologist	2010		$69,127	$81,324
Director of Major Projects	2010	Manager Resource Planning (2011)	recruitment not activated	
Electrical Engineer	2010	Financial Administrator (2012)	$62,841	$73,930
Capital Mechanic	2010		$69,127	$81,324
Capital Electrician	2010		$69,127	$81,324
Permanent Part Time Plant Operator – Faro	2010		$38,450	$45,236
Manager of Energy Conservation	2011		$82,135	$123,203
Energy Conservation Administrator	2011		$70,164	$82,544
Environmental Coordinator	2011		$77,064	$90,664
Resource Planning Engineer	2011		$75,001	$112,501
Term SCC Operator	2011		$60,403	$71,061
Backfill Controller	2011		$82,135	$123,203

Please note that the following positions were created by changes to the existing FTE and as such there is no net impact on the employee compliment due to these changes:

- Manager of IT;
- Manager of SCC and Mechanical;
- Manager of Electrical Transmission and Distribution; and
- Safety Coordinato.

(g)

Details for costs identified under regulatory affairs for 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast) are as provided in Table 4 below.

Table 4:
Regulatory Affairs Expense ($000s)

	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2012 Forecast
Travel		3		4	4
Legal	22	21	40		
Consultants	3	52	115	30	30
Miscellaneous	1	2	1		
Total	**27**	**77**	**156**	**34**	**34**

(h)

For 2012 and 2013 “Existing” columns refer to “without GRA” forecasts while “Proposed” refer to with GRA forecasts. Where the values in a year are identical as between “Existing” and “Proposed” it means that the value is not affected by any changes to be approved as part of the GRA filing.

2009 Training Costs

Department	# of Employees	Training Description	Cost ($)	Location
Resource Planning				
Director, Resource Planning & Regulatory Affairs	1	Supply options alternatives (Geothermal, wind,	2,454	Toronto
Director, Resource Planning & Regulatory Affairs	1	Environmental Law & Regulation North of 60	2,772	Edmonton
		Sub-Total Resource Planning	**5,226**	
Finance				
CFO	1	CICA CFO Leadership Program 2010	2,799	Edmonton
CFO	1	Leadership	5,900	Vancouver
Financial Administrator	1	CPA - Payroll Year End (last taken 2007)	350	Whitehorse
Financial Administrator	1	Taxible Benefits & Allowances 2010	375	Whitehorse
Financial Administrator	1	Pension & Benefits - Payroll Perspective 2010	375	Whitehorse
Financial Administrator	1	Taxible Benefits & Allowances 2010	375	Whitehorse
Financial Administrator	1	Pension & Benefits - Payroll Perspective 2010	375	Whitehorse
Financial Administrator	1	2009 Year End Requirements	99	Whitehorse
Financial Administrator	1	SharePoint - Hands-on Introduction	1,548	Whitehorse
Controller	1	CICA Handbook Accounting - 6 Seats	1,650	Whitehorse
Revenue & Financial Analyst	1	Project Management	950	Yukon College
Revenue & Financial Analyst	1	Advanced Project Management	950	Yukon College
Procurment & Contract Administrator	1	Negotiation Strategy	2,116	Edmonton
Procurment & Contract Administrator	1	NIGP Contract Writing	94	Whitehorse
Procurment & Contract Administrator	1	Principles of Transportation & Logistics	500	Whitehorse
Procurment & Contract Administrator	1	Principles of Operations and Inventory Control	375	Whitehorse
Procurment & Contract Administrator	1	Contract Risk and Insurance	84	Whitehorse
Procurment & Contract Administrator	1	Procurement Law Update - Mitigating Risk	219	Whitehorse
Procurment & Contract Administrator	1	Standard PO Terms & Conditions	84	Whitehorse
		Sub-Total Finance	**19,218**	
HR & IT				
HR Advisor	1	Conflict Mgmt or a Supervision Course	250	Whitehorse
HR Advisor	1	Building Data Driven SharePoint Application	5,365	Toronto
HR Advisor	1	The Basics of Content Type	140	Whitehorse
HR Advisor	1	Labour Relations	2,523	Vancouver
Director, HR & IT	1	IT Project Management	2,747	Vancouver
Director, HR & IT	1	IT Management Program 2010	10,628	Kingston
Maintenance Electrician	1	Cisco Technician Entry	3,000	Vancouver
Network Administrator	1	2010 Windows Srver 2008	6,423	Toronto
Network Administrator	1	Coaching & Mentoring & Leading - 2010	2,737	Vancouver
Network Administrator	1	SCADA Security	5,057	Vancouver
		Sub-Total HR & IT	**38,870**	
Environment				
Various	Various	Visible Emission Evaluation Cert	545	Whitehorse
Various	Various	Spill Response	5,060	Inuvik
		Sub-Total Environment	**5,605**	
President				
Corporate Secretary	1	Administration /Corporate Governance	2,834	Ottawa
Corporate Secretary	1	ATIPP Training - 2010	1,693	Whitehorse
Supervisor, Communication	1	Turning Stats into Stories	275	Whitehorse
VP, Ops & Engineering	1	Leadership/Technical	1,387	Atlanta
Admin Assistant/Receptionist	1	The Basics of Content Type	140	Whitehorse
Admin Assistant/Receptionist	1	Yukon Administrative Professionals Conferenc	200	Whitehorse
Admin Assistant/Receptionist	1	SharePoint - Data Driven - 2010	3,501	Toronto
Records Management Analyst	1	The Basics of Content Type	138	Whitehorse
		Sub-Total President	**10,168**	
Health & Safety				
Manager, H&S	1	Overview of Electrical Operations		EITI, BC
Various	Various	Arc Flash Training	18,686	Whitehorse
Various	Various	Defensive Driving (*Partnering with YTG to	0	Whitehorse
Various	Various	Confined Space / Self Rescue	0	Whitehorse
Various	Various	Standard First Aid	3,608	Whitehorse
Various	Various	Crane Operator	2,533	Yukon
Various	Various	JHSC Rep / Member Training	1,040	Whitehorse
Various	Various	Subscribe to online WHMIS/TDG	0	Whitehorse
Various	Various	Medical Monitoring (audiograms, D/L	0	Yukon
Safety Coordinator	1	Auditor Training Program	190	Whitehorse
Safety Coordinator	1	Principles of H&S Management	95	Whitehorse
		Sub-Total Health & Safety	**26,152**	
Operations				
Leadhand, Electrical Maintenance	1	PLC Maintenance for GE Fanuc	3,510	Birmingham
Maintenance Electrician	1	SEL 351 R Recloser control	3,733	Washington
Maintenance Electrician	1	Hands on Relay school (Basic)	4,720	Pullman Wash
6 SCC Operators	6	SOS International - Power Starters	7,100	On Line
Various	Various	Metering Course	7,353	Yukon
Maintenance Mechanic	1	American Governor School	5,202	Wiscosion
Leadhand, Mchanical Maintenance	1	Fluid Life	4,498	Edmonton
Leadhand, Mchanical Maintenance	1	Coaching & Mentoring & Leading - 2010	2,425	Vancouver
Director, Operations	1	Power Transformers and Fluid Diagnostics	3,654	San Francisco
Manager, Operations	1	Effective Equipment Maintenance	2,507	Edmonton
Manager, Operations	1	MP-201 Advanced Maintenance Planning	2,032	Edmonton
PLT	1	Powerline Technician - 3rd level	4,901	Industry Training International Inc
PLT	1	Powerline Technician - 2nd level - Studying	3,705	Whitehorse
Maintenance Electrician	1	Power System Electrician	10	NAIT
PLT	1	Powerline Technician	4,930	Industry Training International Inc
Plant Operator	1	Industrial Mechanic - 1st level	368	NAIT
Maintenance Electrician	1	Power System Electrician	3,393	NAIT
		Sub-Total Operations	**64,041**	
Engineering Services				
Supervisor, Electrical Engineering	1	Essential Management Skills	3,980	Vancouver
Supervisor, Electrical Engineering	1	Leadership Development	399	Whitehorse
Draftsperson/Land Use Administrator	1	Microstation 3D Level 1 & 2	2,508	Edmonton
Draftsperson/Land Use Administrator	1	Microstation 3D Level 1 & 2	2,385	Edmonton
Draftsperson/Land Use Administrator	1	SharePoint - Hand-on Introduction	1,548	Whitehorse
Director, Engineering Services	1	IRIS HydroGen Course or	3,525	Idaho
9 Employees	9	Local Short Courses	1,325	Whitehorse
		Sub-Total Engineering Services	**15,669**	
Corporate				
Various Employees	Various	RRSP Seminar	584	Whitehorse
Various Employees	Various	Office 2007 rollout	15,842	Whitehorse
Various Employees	Various	2008 training costs	2,470	
		10% Contingency	1,181	
		Sub-Total CORPORATE	**20,078**	
		Total 2009 Training Costs	**205,028**	

2010 Training Costs

Department	# of Employees	Training Description	Cost ($)	Location
Resource Planning & Environment				
Manager, Environment	1	Communication Skills for Managers	1,711	Vancouver
Various	Various	Spill and Other Environmental Emergency Response training	3,336	Whitehorse
		Sub-Total Resource Planning & Environment	**5,046**	
Finance				
Financial Administrator	1	Excel for Accountants - YT CGA	400	Whitehorse
Financial Administrator	1	Excel for Accountants - YT CGA	400	Whitehorse
Financial Administrator	1	Excel for Accountants - YT CGA	400	Whitehorse
Financial Administrator	1	Taxible Benefits & Allowances	375	Whitehorse
Financial Administrator	1	Intro to Business Writing	379	Whitehorse
Financial Administrator	1	CPS - Enhancing Communication Skills	99	Online
Financial Administrator	1	Excel for Accountants - YT CGA	400	Whitehorse
Revenue & Financial Analyst	1	Excel for Accountants - YT CGA	400	Whitehorse
Contoller	1	Excel for Accountants - YT CGA	400	Whitehorse
Contoller	1	Ethics for Accountants	150	Whitehorse
Contoller	1	Building Your Communications Toolbox	500	Whitehorse
Contoller	1	Having Difficult Conversations Using Emotions	129	Whitehorse
Contoller	1	Conflict Management	500	Whitehorse
Contoller	1	Communications Skills	1,000	Whitehorse
Supervisor, Financial & Risk Mangement	1	Canadian GAAP - Accounting Refresher	2,307	Van
Sr. Office Administrator	1	CIS Cash Posting Process	1,047	Whitehorse
Procurement & Contract Administrator	1	Understanding Local Pref	77	On line
Procurement & Contract Administrator	1	Do I Have to Take Low Bid	78	On Line
Procurement & Contract Administrator	1	Show Them The Money	77	On line
Procurement & Contract Administrator	1	How to Craft and RFP	1,674	Edmonton
CFO	1	CICA CFO Leadership Program	2,623	Alta/BC
CFO	1	Ethics for Accountants	150	Whitehorse
		Sub-Total Finance	**13,565**	
HR & IT				
Network Administrator	1	Windows Server 2008 Administration	3,590	Toronto
IT Coordinator	1	TTC - Cisco Course	3,248	Online
IT Coordinator	1	Communictaions Skills	950	Whitehorse
SQL Server Database Administrator	1	SharePoint	5,350	Toronto
Various	Various	Cisco Course	17,500	Whitehorse
Various	Various	Technical Writing Training	5,000	Whitehorse
Director, HR & IT	1	Advanced HR	5,476	Calgary
HR Advisor	1	Negotiations Level 1	575	Whitehorse
HR Advisor	1	Human Resources Workshop/Conference	1,261	Vancouver
		Sub-Total HR & IT	**42,950**	
President & Admin				
Corporate Secretary	1	Administration /Corporate Governance	1,988	Banff/Ottawa
Corporate Secretary	1	Access & Privacy Conference	1,804	Edmonton
Supervisor, Communications	1	Understanding Residential Energy Usa	2,005	Seattle
Admin Assistant/Receptionist	1	Introduction to Business Writing	379	Whitehorse
Admin Assistant/Receptionist	1	Communication Skills	1,000	Whitehorse
Admin Assistant/Receptionist	1	Sharepoint - Building Data Driven	1,370	Toronto
		Sub-Total President & Admin	**8,546**	
Operations				
Maintenance Electrician	1	Protective relay maintenance	4,257	Portland
Leadhand, Electrical Maintenance	1	Preventative Maintenance	1,504	Vancouver
Maintenance Electrician	1	Telecom DC Power & Cordex Power Systems	2,838	Vancouver
Maintenance Electrician	1	Automated relay testing - 2011	597	Washington
Maintenance Electrician	1	Fundamentals of Power System Operation, Maintenance & Safety	3,798	Edmonton
Maintenance Electrician	1	Fundamentals of Power System Operation, Maintenance & Safety	3,697	Edmonton
Leadhand, SCC	1	Maint Planning & Scheduling	2,002	Los Angeles
PLT Linecrew	1	Equipotential Bonding & Grounding	3,646	Whitehorse
2 Powerline Technicians	2	Class 1 Driver Training	2,275	Whitehorse
Mechanical / Plant Operator Group	1	Lube Oil Handling	13,248	Whitehorse
Leadhand, Hydro Maintenance	1	Leadership	1,102	Whitehorse
Leadhand, Hydro Maintenance	1	Communications Skills	950	Whitehorse
Leadhand, Electrical Maintenance	1	PSE	3,598	Edmonton
Apprentice Powerline Technician	1	3rd Year PLT	3,730	Edmonton
Maintenance Electrician	1	PSE	585	Edmonton
Maintenance Electrician	1	PSE	3,770	Edmonton
Various	Various	Plant Sub-stn Switching & Isolation	6,041	Whitehorse
Manager, Operations	1	Reliability Bootcamp	2,881	Vancouver
Director, Operations	1	Hydrogenerator Maintenance Course	3,383	Portland, Ore
		Sub-Total Operations	**63,902**	
Engineering Services				
Electrical Engineer	1	L&S Electric Hydro Control Systems	3,647	Wisconsion
Electrical Engineer	1	Writing Course Athabasca University	751	Corsp.
Supervisor, Mechanical/Civil Engineering	1	Facilities Construction Estimating & Costworks	3,368	Seattle
Electrical Engineer	1	Transmission line protection	4,314	Washington
Draftsperson	1	Intro Electrical	75	Whitehorse
Hydrological/Civil Engineer	1	Geotechnical/Permafrost Conference	2,877	Calgary
		Sub-Total Engineering Services	**15,032**	
Corporate				
Various HR	Various	Competency/Apprenticeship training	2,518	Calgary
		Sub-Total Corporate	**2,518**	
		Total 2010 Training Costs	**153,864**	

2011 Training Costs

Department	# of Employees	Training Description	Cost ($)	Location
Resource Planning & Environment				
Director, Resource Planning & Regulatory Affairs	1	Strategic Decision Making	2,494	Vancouver
Resource Planner	1	KGS Modeling Training	237	Winnipeg
Manager, Environment	1	Adaptive Mgt & Impact Assessment	735	Vancouver
Manager, Environment	1	ISO 14001 (EMS) Internal Audit	2,047	Calgary
Environmental Coordinator	1	ISO 14001 (EMS) Internal Audit	2,050	Calgary
Environmental Coordinator	1	ISO 14001 (EMS) Essentials	2,559	Calgary
2 persons	2	Visible Emissions Training	5,940	Whitehorse
25 persons	25	Spill Response Training	1,147	Whitehorse
		Sub-Total Resource Planning & Environment	**17,209**	
Health & Safety				
Safety Coordinator	1	Fire Safety 1	203	Corresp.
Safety Coordinator	1	Fire Safety 2 -	622	Corresp.
Manger, H&S	1	Measurement & Evaluation In OHS Managed Systems	671	Whitehorse
		Sub-Total Health & Safety	**1,496**	
Finance				
CFO	1	Essential Skills for Pension Committee Mbrs	2,660	Vancouver
Buyer	1	Bullet Proof your RFP	500	Whitehorse
Buyer	1	Neglected (But Important) RFP Practices	500	Whitehorse
Procurement & Contract Administrator	1	Procurement Webinars (5) # taken = 2	225	On line
Procurement & Contract Administrator	1	Bullet Proof your RFP	500	Whitehorse
Supervisor Financial & Risk Management	1	IFRS FS Presentation & Note Disclosure	2,158	Vancouver
Controller	1	Ethics, Rules & Standards for New CGA's	359	Whitehorse
Financial Administrator	1	CPA Courses (2)	1,178	Whitehorse
Financial Administrator	1	PD Webinar - CPA (1)	99	On line
Financial Administrator	1	PD Webinar - CGA (1)	129	On line
Financial Administrator	1	PD Webinar - CGA (1)	387	On line
Financial Administrator	1	Conflict Resolution	575	Whitehorse
Manager, Financial Reporting & Special Projects	1	Understanding, Managing & Coping with Change	2,337	Vancouver
Manager, Financial Reporting & Special Projects	1	Documenting Your Organizational Process	415	Vancouver
Financial Administrator	1	Conflict Resolution Skills Practice	150	Whitehorse
Financial Administrator	1	Microsoft Excel Tools	150	Whitehorse
AP Clerk	1	Microsoft Excel Tools	150	Whitehorse
		Sub-Total Finance	**12,473**	
HR & IT				
SQL/Database Administrator	1	SQL Server 2008 Reporting Services	4,678	Toronto
Network Administrator	1	Enterprise vault for Exchange	465	Toronto
IT Developer	1	SharePoint 2010 appls w/.net	7,024	Toronto
Manager, IT	1	Essential Management Skills	4,530	Vancouver
Mangaer, IT	1	Executing Strategy: From Concept to Action	1,650	Vancouver
IT Group	1	MS Internet Info Server (exchange, SP, Ent.Vault	9,185	onsite
Director, HR&IT	1	Intro to IT Fundamentals	2,985	Vancouver
Director, HR&IT	1	Labour Relations - Jan 2012	1,795	Vancouver
		Sub-Total HR & IT	**32,313**	
President & Admin				
Manager, Energy Conservation	1	BC Hydro's PowerSmart Workshop	442	Vancouver
Energy Conservation Coordinator	1	BC Hydro's PowerSmart Workshop	442	Vancouver
Corporate Secretary	1	Completion of ATIPP course x2	833	Correspondnece1800
Supervisor, Communications	1	BC Hydro's PowerSmart Workshop	1,348	Vancouver
Admin Assistant/Receptionist	1	Conflict Mgmt CR011	600	Whitehorse
Admin Assistant/Receptionist	1	Building your communications toolbox CR002	500	Whitehorse
Admin Assistant/Receptionist	1	SharePoint For Project Management	950	Whitehorse
		Sub-Total President & Admin	**5,115**	
Operations				
Leadhand, Electrical Maintenance	1	Substation Mtce 1	4,698	Oregon
Maintenance Electrician	1	PowerLine Carrier Maintenance	3,895	New Jersey
Maintenance Electrician	1	Level 1 thermograghy training	3,483	Vancouver
Maintenance Electrician	1	Automated relay testing	4,475	PullmanWa
Maintenance Electrician	1	Protective Relay Maintenance Generation	5,011	Dallas TX
SCC Operator	1	Principles for System Reliability	3,775	Spokane, WA
SCC Operator	1	Principles for System Reliability	4,304	Spokane, WA
Sr. Powerline Technician	1	Best Practices Workshop	794	Calgary
Apprentice Powerline Technician	1	Class 3 Driver Training	250	Whitehorse
Powerline Technician	1	Class 1 Driver Training	1,100	Whitehorse
Plant Operator	1	Chainsaw Safety	1,040	Whitehorse
Plant Operator	1	Chainsaw Safety	850	Whitehorse
Leadhand, Diesel Maintenance	1	Excel 2010 Level 1	229	Whitehorse
Leadhand, Diesel Maintenance	1	Excel 2010 Level 2	229	Whitehorse
Various	Various	American Governor Gateshaft Training	20,100	Whitehorse
Leadhand, Electrical Maintenance	1	4th Year PSE	3,246	Edmonton
Maintenance Electrician	1	2nd Year PSE	100	Edmonton
Maintenance Electrician	1	3rd Year PSE	3,525	Edmonton
Apprentice Powerline Technician	1	1st year PLT	2,642	Edmonton
Manager, Operations	1	MMP Program, courses 1-4 of 8	3,206	On-Line
Director, Operations	1	The Leader's Window	1,634	Vancouver
		Sub-Total Operations	**68,583**	
Engineering Services				
Supervisor, Electrical Engineering	1	Meeting the leadership challenge	4,503	Vancouver
Supervisor, Electrical Engineering	1	Communications Skills for Managers	885	Vancouver
Electrical Engineer	1	Technical Writing Workshop	250	Whitehorse
Electrical Engineer	1	Beckwith Protection Course	4,854	Florida
Electrical Engineer	1	L&S Hydro Control Seminar	5,396	Wisconsin
Electrical Engineer	1	Technical Writing Workshop	250	Whitehorse
Supervisor, Mechanical & Civil Engineering	1	Seismic Design and Retrofit of Equipment and Piping	1,601	Florida
Hydrological & Civil Engineering	1	River Ice Workshop	2,538	Winnipeg
Hydrological & Civil Engineering	1	Advanced Permafrost Engineering	1,209	Whitehorse
Coordinator, Mechanical Engineering	1	Principles of Hydraulics	4,432	Ontraio
Draftsperson/Landuse Administrator	1	Excel Level I	520	Edmonton
Various	Various	Bentley Learn Subscription	6,495	Whitehorse
		Sub-Total Engineering Services	**32,933**	
Corporate				
Various Employees	Various	SP 2010 New Features Overview Trng	9,205	Yukon
Various Employees	Various	Training Videos	2,885	
		2010 Training Costs Carried Forward	105	
		Sub-Total Corporate	**12,195**	
		Total 2011 Training Costs	**182,318**	

2012 Training Budget

Department	Training Description	# of Employees	Estimated Training Costs	Training Location	YTD Committed	YTD Actual
Resource Planning & Environment						
Director, Resource Planning & Regulatory Affairs	Essential Management Skills - Sauder	1	**3,375**	Vancouver	1,899	0
Resource Planner	Resource Planning	1	**2,768**	Porland, OR	2,768	0
Manager, Environment	Planning for Effective Public Participation	1	**3,150**	TBD		0
Environmental Coordinator	Field Sampling Techniques/Contaminated Site	1	**2,900**	Vancouver		0
Various Employees	EMS Orientation	Various	**500**	Whitehorse		0
Various Employees	Spill Prevention and Response Training	Various	**4,500**	Whitehorse		0
	Sub-Total Resource Planning & Environment		**17,193**		**4,667**	**0**
Health & Safety						
Manager, H&S	Obligations & Liabilities for the Safety Professional	1	**525**	Whitehorse	525	0
Safety Coordinator	Emergency Preparedness Response	1	**600**	Corresp.		0
	Sub-Total Health & Safety		**1,125**		**525**	**0**
Finance						
Supervisor, Financial & Risk Management	IFRS Training	1	**2,700**	Vancouver		0
Financial Administrator	Payroll Training CPA Year End	1	**500**	Whitehorse		0
Financial Administrator	CPA - unknown	1	**500**	Whitehorse		0
Financial Administrator	Writing Course at College	1	**500**	Whitehorse		0
Financial Administrator	Database Course at College	1	**500**	Whitehorse		0
Financial Administrator	Public Speaking	1	**625**	Whitehorse	625	0
Manager, Financial Reporting & Special Projects	Dealing with Anger	1	**300**	Whitehorse		0
Manager, Financial Reporting & Special Projects	Ethics	1	**600**	Whitehorse	500	100
Manager, Financial Reporting & Special Projects	Accounting/Finance Related Update	1	**2,500**	Vancouver		0
CFO	Coaching for Leadership Excellence	1	**2,825**	Vancouver		0
CFO	Ethics	1	**600**	Whitehorse	500	100
Manager, Property & Risk Management	Asset Management Best Practices	1	**2,500**	Vancouver	1,825	675
Buyer	RFP Practices	1	**500**	Whitehorse		0
Buyer	RFP Law	1	**500**	Whitehorse		0
Procurement & Contract Administrator	Procurement Webinars (5)	1	**375**	On line		0
Procurement & Contract Administrator	RFP Law	1	**500**	Whitehorse		0
Procurement & Contract Administrator	RFP Practices	1	**500**	Whitehorse		0
Warehouse Administrator	Inventory and Operations Management PMAC	1	**600**	Distance		0
	Sub-Total Finance		**17,625**		**3,450**	**875**
HR & IT						
Network Administrator	Microsoft Administration Technology Course	1	**5,500**	Toronto	5,500	0
IT Developer	Microsoft Visual Studio 2010	1	**5,500**	Vancouver	5,500	0
Vacant	SharePoint/Building 2010 Enterprise Solutions	Vacant	**5,500**	B.C.	0	0
Manager, IT	Cisco Nexus Administration	1	**6,000**	Vancouver	1,914	4,086
Director, HR & IT	HR Course	1	**3,745**	Vancouver	3,059	686
Director, HR & IT	IT Management Program	1	**2,986**	Ontario	1,500	1,486
Director, HR & IT	Introduction to Information Technology	1	**1,500**	Vancouver	1,500	0
HR Advisor	Orientation, Mentoring & Training	1	**395**	Whitehorse	395	0
HR Advisor	Yukon College Course	1	**700**	Whitehorse		0
	Sub-Total HR & IT		**31,826**		**19,368**	**6,258**
President & Admin						
VP	TBD	1	**5,000**			0
Supervisor, Communications	How to Produce Podcasts	1	**1,250**	Whitehorse		0
Corporate Secretary	Crown Corporation Governance	1	**4,450**	Ottawa		0
Corporate Secretary	ATIPP Correspondence	1	**850**	Online	850	0
Admin Assistant/Receptionist	SharePoint	1	**1,000**	Whitehorse		0
Admin Assistant/Receptionist	Administrative Training x 2	1	**1,200**	Whitehorse	575	0
Records Management Analyst	Electronic Records Management	1	**2,000**	TBD		0
	Sub-Total President & Admin		**15,750**		**1,425**	**0**
Energy Conservation						
Manager, Energy Conservation	Project Management Graduate Certificate	1	**3,600**	Online		0
Manager, Energy Conservation	Basics of Energy Management	1	**485**	Online		0
Manager, Energy Conservation	Developing an Energy Management Master Plan	1	**695**	Online		0
Manager, Energy Conservation	AESP Conference & Principles of DSM Course	1	**3,615**	Toronto	3,615	0
Energy Conservation Coordinator	Intro to Keyboarding	1	**300**	Whitehorse		0
Energy Conservation Coordinator	Advances in Lighting	1	**131**	Whitehorse	0	131
	Sub-Total Energy Conservation		**8,826**		**3,615**	**131**
Operations						
Leadhand, Electrical Maintenance	Circuit Breaker Maintenance	1	**4,325**	Texas		0
Maintenance Electrician	SEL Relay Testing Basics	1	**3,250**	California		0
Maintenance Electrician	SEL Transmission Substation Relay Testing	1	**3,243**	California	758	2,485
Maintenance Electrician	PowerLine Carrier Maintenance	1	**4,195**	USA		0
Maintenance Electrician	Substation Maintenance I	1	**3,975**	Oregano		0
SCC Operator	Principles for System Reliability	1	**3,895**	Spokane, WA		0
SCC Operator	Principles for System Reliability	1	**3,895**	Spokane, WA		0
All PLT's	Metering Course	1	**7,500**	TBD		0
All PLT's	Fortis Standards Training	1	**2,000**	TBD		0
For 8 Plant Operators	Power Starter Course	8	**4,800**	Online		0
For 2 Plant Operators	Chain Saw Safety Course	2	**1,750**	Whitehorse		0
Maintenance Mechanic	Maintenance Repair & Set Up of Industrial	1	**3,800**	Burnaby		0
Vacant	Governor Training	Vacant	**4,850**	Wisconsin		0
Leadhand, Hydro Maintenance	Governor Training	1	**4,850**	Wisconsin	4,850	0
Maintenance Electrician	3rd Year PSE	1	**3,628**	Edmonton		3,628
Maintenance Electrician	4th Year PSE	1	**3,700**	Edmonton		0
Apprentice Powerline Technician	2nd year PLT	1	**3,700**	Edmonton	3,700	0
Coordinator, Special Projects	MMP - HR Management	1	**956**	Online	0	956
Coordinator, Special Projects	MMP - Financial Management	1	**894**	Online		0
Coordinator, Special Projects	MMP - Developing & Implementing Maintenance	1	**924**	Online		0
Manager, SCC & Mechanical Mainteance	Accounting for Non-Financial Managers	1	**3,695**	Vancouver		0
Manager, Electrical Maintenance	Management Training	1	**3,650**	TB	3,650	0
Various	Brushing Inspection & Vegetation Survey Training	Various	**8,795**	Whitehorse	8,795	0
	Sub-Total Operations		**86,270**		**21,753**	**7,069**
Engineering Services						
Director, Engineering Services	PPA Course	1	**4,850**	TBD		0
Electrical Engineer	Advances in Lighting	1	**131**	Whitehorse	0	131
Electrical Engineer	Arc Flash Training	1	**3,650**	TBD		0
Distribution Technician	Distribution & Transmission	1	**3,150**	TBD		0
Supervisor, Mechanical/Civil Engineering	Carry-over of Pipe Design Course Costs	1	**883**	USA	0	883
Coordinator, Mechanical Projects	Effective Communications	1	**500**	Whitehorse		0
Capital Mechanic	Further Basic Computer Skills	1	**500**	Whitehorse		0
Hydrological/Civil Engineering	Hydro Vision Workshop	1	**4,100**	USA		0
Draftsperson/Land Use Administrator	Utility Workshop	1	**4,150**	TBD		0
	Sub-Total Engineering Services		**21,914**		**0**	**1,014**
Corporate						
Various Employees	SharePoint 201	Various	**20,000**	Whitehorse		0
Various Employees	Office 2010	Various	**20,000**	Whitehorse		0
Various Employees	RRSP	Various	**789**	Whitehorse		0
	Sub-Total Corporate		**40,789**		**0**	**0**
	Total 2012 Training Costs		**241,318**		**51,188**	**15,347**

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-17, Table 3.10

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the insurance and reserve for injuries & damages costs included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

c) Please provide an explanation for any variances between the 2011 actual, 2012 forecast and 2013 forecast and the Insurance and Reserve for Injuries & Damages cost level last approved by the YUB for 2009.

ANSWER:

(a)

Please see Table 1 below for the requested update that includes 2011 actual. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 1:
Insurance and Reserve for Injuries and Damages ($000)

					Forecast		Forecast	
	2009 GRA compliance	Actual 2009	Actual 2010	Actual 2011	Existing 2012	Proposed 2012	Existing 2013	Proposed 2013
Insurance	$ 952	$ 787	$ 787	$ 774	$ 835	$ 835	$ 895	$ 895
Reserve Appropriation (RFID)	100	100	100	100	100	231	100	231
Total	$ 1,052	$ 887	$ 887	$ 874	$ 935	$ 1,066	$ 995	$ 1,126

Note:
1. Actual 2009 reserve appropriation was reduced from $0.150 million to $0.1 million to comply with YUB Order 2009-8.

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

However it is noted that Reserve for Injuries & Damages (RFID) appropriation approved for 2009 GRA remained the approved amounts for 2010 and 2011 due to the fact that RFID is an account maintained as approved by the Board as noted in section 3.3.6 of the Application.

(c)

Please refer to Section 3.3.6 of the Application for discussion of Insurance and RFID expenses variances over 2009 GRA approved levels.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-19, Table 3.12

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the property tax provision included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

c) Please provide details of the property tax paid by community for 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

d) Please provide an explanation for any variances between the 2011 actual, 2012 forecast and 2013 forecast and the Property Tax cost level last approved by the YUB for 2009.

e) Please provide documentation outlining YEC's requirement to make payments in lieu of property taxes to municipalities.

ANSWER:

(a)

Actual 2011 Property Tax expense was $0.297 million. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

(c)

Property tax by community is as noted in the Table 1 below.

Table 1:
Property Tax by Community

	2009	2010	2011	2012 (forecast)	2013 (forecast)
Whitehorse	164,151	165,615	172,264	180,877	189,491
Dawson	82,107	82,958	82,592	86,721	90,851
Faro	38,254	38,562	38,562	40,490	42,418
Mayo	3,198	3,246	3,246	3,409	3,571
Carmacks	65	65	65	68	72
	287,776	290,446	296,729	311,566	326,402

(d)

YEC has forecast a 5% increase in property taxes for each of 2012 and 2013. This forecast increase is based on assumed tax rate increases.

(e)

Yukon Energy is owned by the Yukon Government and therefore it makes payment in lieu of property taxes to municipalities instead of actually paying property taxes.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-23

YEC states "*Given the various factors and data available for the analysis, Yukon Energy has determined it appropriate to update its depreciation rates based on the results of the KPMG study. Certain of Yukon Energy's major assets (e.g., certain hydro plant, diesel production and main transmission assets) are indicated to have longer service lives than calculated in the depreciation study conducted in YEC's 2005 Required Revenues and Related Matters filing. With longer service lives the required annual deprecation provision is lower. As set out in Table 3.14 below, this factor decreased the 2012 depreciation expenses by approximately 33% ($2.307 million, net of customer contributions and amortization of fire insurance recoveries), and decreased 2013 depreciation expense by approximately 32% ($2.392 million, net of customer contributions and amortization of fire insurance recoveries)*".

PREAMBLE:

QUESTION:

a) Please provide details on the impact of the proposed change in depreciation expense on the overall revenue requirement for 2012 and 2013 including the change in rate base and return.

b) Please confirm that one impact of the proposed change in depreciation expense will be to increase rate base and the return on rate base in 2012, 2013 and all following years.

c) Please confirm that, on an actual basis, vehicle depreciation is expensed as part of gross O&M and then 100% capitalized through direct capitalization.

ANSWER:

(a)

The proposed changes in depreciation rates decreased the 2012 and 2013 revenue requirements by $2.3 million and $2.4 million respectively (lower net depreciation expense).

The impact of this proposed change on YEC's rate base is approximately $1.2 million higher mid-year ratebase for 2012 and $3.5 million higher mid-year ratebase for 2013. At an average cost of capital of 5.54% and 5.85% in 2012 and 2013 respectively, this equates to approximately $0.066 million higher return in 2012 and $0.205 million higher return in 2013.

(b)

Confirmed.

(c)

Not confirmed.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 10, Page 10-1

KPMG states "*While this preliminary document sets forth our conclusions, please note that it is not intended to be considered a complete narrative report. This document will be supplemented by a complete narrative report fully outlining our assumptions and methodologies which will be delivered at a future date*".

PREAMBLE:

QUESTION:

a) Please provide a copy of the "complete narrative report" provided by KPMG and the details of when it was received by YEC.

b) Please provide details of discussions / correspondence between YEC and KPMG that allowed YEC to move forward with it proposed changes to depreciation rates based on KPMG's preliminary document.

c) Please confirm that YEC's Board of Director's approved moving forward with the proposed change in depreciation rates.

d) Please explain why asset data as at December 31, 2010 was used for the depreciation study.

e) Please provide details of the asset classes as well as the relative weighting of each class with regards to total cost as at December 31, 2011 (actual), December 31, 2012 (forecast) and December 31, 2013 (forecast).

ANSWER:

(a)

Please see the complete narrative report provided as Attachment 1 to YECL-YEC-1-55(a). The final report, with narrative, was received during the responses to interrogatories.

(b)

YEC held discussions with KPMG indicating that the preliminary report was suitable for filing with the GRA, and that the narrative report was solely to expand upon the rationales used by KPMG in coming to the conclusions indicated.

(c)

YEC's Board of Directors approved of the company filing the GRA.

(d)

The KPMG study was initiated prior to December 31, 2011 data being available.

(e)

Please see Table 1 below for the requested information.

Table 1:
YEC's Fixed Assets by Asset Class

Asset Class	December 31, 2011	% of total cost	December 31, 2012	% of total cost	December 31, 2013	% of total cost
	Actual		Forecast		Forecast	
Land	1,127	0.2%	1,127	0.2%	1,127	0.2%
Hydro Plant - 140003	246,956	53.2%	251,896	52.2%	254,732	51.7%
Diesel Production - 140004	25,680	5.5%	25,984	5.4%	27,696	5.6%
Wind Turbine - 140005	3,149	0.7%	3,149	0.7%	3,199	0.6%
Main Transmission Facilities - 140006	134,495	29.0%	145,718	30.2%	146,338	29.7%
Sub Transmission Lines - 140007	15,492	3.3%	15,492	3.2%	15,492	3.1%
Distribution System - 140008	12,773	2.7%	13,859	2.9%	14,884	3.0%
Building and Other Equipment - 140009	20,327	4.4%	21,001	4.3%	24,747	5.0%
Transportation - 140014	4,578	1.0%	4,739	1.0%	4,864	1.0%
Total	**464,576**	**100.0%**	**482,963**	**100.0%**	**493,077**	**100.0%**

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 10, Page 10-10

KPMG states "*The comparable companies relied upon in our study included, but was not limited to the following*" and then lists BC Hydro, Manitoba Hydro, Newfoundland Labrador Hydro and 14 other companies.

PREAMBLE:

QUESTION:

a) Please provide details of the other companies relied upon.

b) Please explain how each of these companies is "comparable" to YEC and rank them from most comparable to least comparable with justification for the resulting rankings.

ANSWER:

(a)

Please see the complete narrative report provided as Attachment 1 to YECL-YEC-1-55(a), pages 16 to 19.

(b)

Specific quantitative rankings were not conducted. Comparable companies were selected on the basis of owning and operating the same type of hydro and electrical generation and transmission assets as YEC. For further detail please see the complete narrative report provided as Attachment 1 to YECL-YEC-1-55(a), pages 16 to 19.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 10, Pages 10-16 and 10-17

PREAMBLE:

QUESTION:

a) Please provide a table showing annual depreciation expense by account based on existing depreciation rates for 2010 and 2011 and the annual depreciation expense by account based on existing and proposed depreciation rates for 2012 and 2013.

ANSWER:

(a)

Please see Attachment 1 for the requested information. Note that this information is gross depreciation while the GRA reports depreciation net of disallowed depreciation of $4,000 each year.

Yukon Energy Corporation
Depreciation Expenses for 2010 and 2011 Actual Years, Forecast for 2012 and 2013

in $ thousands

Description	Object Account	Sub Account	2010 Actual	2011 Actual	Existing Rates 2012 Forecast	Proposed Rates 2012 Forecast	Existing Rates 2013 Forecast	Proposed Rates 2013 Forecast
Land Rights	140002	106	2	2	2	2	2	2
	140002 Total		2	2	2	2	2	2
Structures and Improvements	140003	200	231	126	761	423	784	436
Resevoirs Dams and Waterways		205	1,463	1,790	3,387	1,643	3,480	1,688
Waterwheels, Tubines and Gener		506	160	134	450	344	464	356
			-	-	1	1	1	1
Accessory Electric Equip		600	143	143	119	119	122	122
			-	-	142	142	142	142
Misc Power Plant Equip		700	14	82	104	104	113	113
			-	-	81	81	81	81
Hydro Fences		730	1	1	1	1	1	1
Spare Hydro Parts	Spare parts	750	-	-	-	-	-	-
	140003 Total		2,013	2,277	5,047	2,860	5,189	2,940
Structures and Improvements	140004	200	38	38	38	21	38	21
Building & Improvements		201	8	8	8	6	8	6
Fuel Holders, Products and Acc		403	40	41	41	41	46	46
Generating Equipment and Prime		500	411	533	550	413	553	415
Minto Generating Equipment		508	15	25	41	41	41	41
Accessory Electric Equip		600	66	94	3	3	14	14
			-	-	94	94	94	94
			-	-	1	1	1	1
Misc Power Plant Equip		700	38	49	52	52	62	62
	140004 Total		615	788	827	671	856	699
Wind Turbine	140005	400	105	105	105	105	106	106
	140005 Total		105	105	105	105	106	106
Poles and Fixtures	140006	300	636	772	959	738	973	749
			-	-	4	4	4	4
Brushing		304	195	218	266	266	266	266
Survey Costs		305	56	60	69	69	69	69
Overhead Conductors/Poles		402	315	343	401	401	401	401
Overhead Conductors/Towers		404	6	6	6	6	6	6
Substation Equipment		710	519	721	1,204	891	1,209	895
Substation Buildings		720	1	13	165	120	292	213
Substation Fences		730	2	5	13	13	14	14
	140006 Total		1,729	2,140	3,086	2,507	3,234	2,616
Poles and Fixtures	140007	300	(159)	80	80	80	80	80
Poles & Fixtures Minto Mine		301	459	221	221	221	221	221
Brushing Minto Mines		306	67	36	36	36	36	36
Survey Costs Minto Mine		307	(23)	8	8	8	8	8
Overhead Conductors		401	(61)	22	22	22	22	22
Underground Conductors/Conduit		405	2	2	2	2	2	2
Overhead Conductors Minto Mine		407	160	77	77	77	77	77
			-	-	-	-	-	-
Substation Equipment Minto Min		711	559	559	559	559	559	559
	140007 Total		1,004	1,004	1,004	1,004	1,004	1,004
Poles and Fixtures	140008	300	103	112	128	128	152	152
Brushing		304	1	1	1	1	1	1
Survey Costs		305	13	14	15	15	15	15
Overhead Conductors		401	2	2	2	2	2	2
Overhead Services		410	49	50	50	50	50	50
Underground Services		510	0	0	0	0	0	0
Meters		610	9	9	9	9	9	9
Meter Equipment		620	10	10	11	11	12	12
Substation Equipment		710	30	30	31	31	33	33
Substation Buildings		720	1	1	1	1	1	1
Street Lights		815	14	14	14	14	14	14
Line Transformers		905	83	93	92	92	95	95
			-	-	0	0	0	0
Sentinel Lights		961	1	1	1	1	1	1
	140008 Total		318	339	356	356	386	385
Survey Costs Land	140009	110	0	0	0	0	1	1
Structures and impr hydro		200	12	13	24	24	25	25
Building and Improvements		201	208	211	213	155	213	155
Office Furniture & Equip		202	68	70	2	2	3	3
			-	-	69	69	69	69
Communication Site Towers		210	1	1	1	1	1	1
Communication Site Fences		220	2	2	2	2	2	2
Computer Hardware		320	(50)	282	348	348	370	370
			-	-	10	10	10	10
Computer Software		330	140	165	22	22	290	290
			-	-	148	148	148	148
Tools and Instruments		505	41	37	56	56	66	66
Wind Monitoring Equipment		507	7	7	7	7	7	7
Communication Equip		605	170	183	190	190	192	192
			-	-	9	9	9	9
Company Owned Houses/Land		810	1	1	1	1	1	1
Company Owned Houses		820	40	40	41	41	41	41
	140009 Total		640	1,013	1,143	1,085	1,450	1,392
Utility Vehicles	140014	411	18	14	30	30	46	46
Sedans and Statonwagons		412	6	6	14	14	14	14
Trucks and Pole Trailers		420	0	2	5	5	5	5
Pole Trailers > 10,000 lb		430	1	1	1	1	1	1
Trucks 3/4 to 2 ton		440	146	168	191	191	191	191
Trucks > 3 ton		470	27	28	28	28	28	28
Foremost		490	23	40	40	40	40	40
	140014 Total		222	259	309	309	325	325
Waterwheels, Turbines, & Gener	140203	506	57	57	55	55	55	55
	140203 Total		57	57	55	55	55	55
Subtotal			**6,703**	**7,983**	**11,933**	**8,953**	**12,606**	**9,524**
True-up			**(225)**	**(224)**	**(204)**	**(535)**	**(204)**	**(535)**
Subtotal			**6,478**	**7,759**	**11,730**	**8,418**	**12,402**	**8,989**
Disposals			892	143				
Total Depreciation Expense			**7,369**	**7,902**	**11,730**	**8,418**	**12,402**	**8,989**
Amortization of Contributions			(1,846)	(2,175)	(4,533)	(3,536)	(4,582)	(3,569)
Amortization of Fire Insurance Proceeds			(270)	(270)	(270)	(262)	(270)	(262)
Net Depreciation Expense			**5,253**	**5,457**	**6,926**	**4,620**	**7,550**	**5,158**

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-21

YEC states "*The largest component of deferred charges relates to planning and study costs, regulatory hearing costs and licensing costs related to maintaining licences of YEC's hydro facilities and air emission permits. The amortization of planning costs is the largest component of the deferred 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, and other small projects. The requirement for Yukon Energy to undertake significant planning activities to ensure the next generation of low cost supply resources are available to meet growth on the integrated grid and displace requirements for costly diesel generation was reviewed in the 2008/2009 GRA. Since that time, Yukon Energy has continued with the planning work outlined in the 2008/2009 GRA. The new planning cost accounting policy included in this Application (provided in Appendix 5.1) is required to address the unprecedented levels of planning costs incurred in Work in Progress (WIP) since 2009 and ensure that these costs are included in rates in a manner that does not result in undue rate impacts for ratepayers. Forecast amortization of feasibility studies costs increase to $1.64 million in 2012 and $2.69 million in 2013 (a $2.0 million increase from 2009 approved expense) as set out in Tab 5. Under this approach large projects in Feasibility WIP (expenses to date >$1 million) are closed out before the end of the test period and amortized over 10 years to mute rate impacts over this period. This includes close outs in 2011 of Atlin Storage ($2.314 million) and Geothermal ($1.947 million) and close outs in 2012 of Marsh Lake Storage ($4.030 million), Gladstone Diversion ($3.893 million) and Waste-to-Energy ($1.128 million net of contributions). All other projects in Feasibility WIP (less than $ 1million) are closed out over the test period and begin to be amortized over 5 years*".

April 27, 2012 Application, Tab 5, Page 5-27

YEC states "*Progression through the planning process on each major deferred cost project has been carefully monitored and controlled by staged approvals for expenditures that apply to each project phase. In effect, each phase requires an approval to define the scope of work and the deliverable to be completed before*

progressing to the next stage. During the planning phase ongoing assessment may determine that a project is not economic based on current conditions – in the event that a project is deemed uneconomic at the end of a planning phase, work would be delayed until suitable conditions arise and the project is considered economically feasible. If, and when, a project successfully progresses through the planning and feasibility phase and procures necessary regulatory approvals it will advance (where appropriate, and subject to final tenders and other required approvals) to the construction stage. Due to the unprecedented levels of planning costs incurred since 2009, a new planning cost accounting policy (provided in Appendix 5.1 to Tab 5) is included in this Application to ensure that these costs are addressed and included in rates in a manner that moderates near-term rate impacts for ratepayers".

PREAMBLE:

QUESTION:

a) Please provide details of other jurisdictions that have allowed planning costs to be amortized as proposed by YEC.

b) Please provide details of all reports, ongoing assessments and approvals for major deferred projects.

c) For the feasibility studies shown in tables 5.3, 5.4, 5.5, 5.6 and 5.7 as closed, please identify which of the studies resulted in capital expenditures.

d) Where feasibility studies have resulted in capital projects, please explain why the study costs are not being amortized as per the resulting capital investment.

e) For the feasibility studies shown in tables 5.3, 5.4, 5.5, 5.6 and 5.7 as closed, please provide a detailed listing of all deferred charges, descriptions of the charges incurred and a description of the reason for incurring the costs.

ANSWER:

(a)

Please see response to YUB-YEC-1-39 and YECL-YEC-1-43 which set out the rationale underlying the update to the previous policy and details the changes in the proposed policy to the previous policy.

The previous policy, when established, took note of similar amortization of allowed planning costs in other jurisdictions.

In the review and update of the policy, Yukon Energy reviewed planning cost policies in other jurisdictions such as Northwest Territories, British Columbia and Manitoba. Yukon Energy was most interested in how other jurisdictions experiencing material requirements to invest in aging infrastructure and develop new sources of supply were addressing issues related to material accumulated deferred planning costs in WIP. As noted in YECL-YEC-1-43, many of the changes to the policy are also to provide for greater clarity and are essentially based on the structure provided in the previous policy.

In each of the three jurisdictions reviewed, planning costs continue to be amortized. The Northwest Territories Power Corporation, for example, continues to defer and generally amortizes over five years study costs that do not lead to a capital asset. BC Hydro relies on specific deferral accounts to address rate impacts and planning cost risks related to single large projects. Prior to the 2009/10 fiscal year, Manitoba Hydro planning study costs related to uncommitted major generation or transmission facilities were recorded as deferred charges and amortized over 15 years; if there was reasonable assurance that a project would proceed to construction, any unamortized balance related to that project was transferred from deferred charges to construction work in progress. Since that time, Manitoba Hydro has expensed planning study costs that do not meet a "reasonable assurance" test (which is met upon entering into process agreements and/or similar arrangements with impacted communities, application to commence the environmental licensing or regulatory process, commitment to commence capital construction or such other date as specifically approved by the Executive Committee).

In this regard Yukon Energy reviewed the “reasonable assurance” test applied by Manitoba Hydro and determined that specifying a similar test within the policy would help provide clarity regarding at what stage deferred costs could be deferred as part of

Capital WIP related to a specific project. Similarly, like Manitoba Hydro, Yukon Energy adopted a 10 year amortization policy for planning costs for projects that ultimately do not proceed after having met a "reasonable assurance" test. However, unlike Manitoba Hydro, Yukon Energy did not proceed to expense all planning costs that do not meet the "reasonable assurance" test. This was done to address the following Yukon requirements:

- The policy must recognize the requirement to undertake planning studies work prior to developing credible information and plans for a project to the point of meeting a "reasonable assurance" test and (provided the costs are prudently incurred) the basis for recovering these costs through rates as prudent expenditures that benefit all ratepayers.

- The policy should recognize the need to ensure rate stability over time (i.e., through deferring and amortizing costs over a defined period instead of expensing such costs in the year incurred).

Other changes (such as having costs that do not meet reasonable assurance close out in annual stages and the one-time transition approach for the test years) were implemented to address concerns related to material deferred costs in WIP at this time and to ensure that such costs were included in ratebase in a manner that did not result in rate shock.

(b)

Please see response to YUB-YEC-1-25(a) and YUB-YEC-1-40(b).

(c)

Please see CW-YEC-1-40(d).

(d)

Studies undertaken to define the project to be undertaken are deferred and amortized over 5 years once the study is complete pursuant to the previous policy and practice as well as under the proposed policy. Once there is a defined project or reasonable assurance that a capital project will proceed, planning and studies costs begin to be

deferred as part of Capital WIP and, if the project proceeds, are amortized over the life of the capital investment.

(e)

Please see the Application, and related IR responses, which provide information as required for major deferred cost projects (costs in excess of $1 million) as well as information on deferred cost projects with costs between $0.1 and $1.0 million, setting out the reasons for incurring these costs and describing the costs incurred.

Please see UCG-YEC-1-66(b) for a breakdown of costs for details on major deferred cost projects (in excess of $1 million).

Of the projects listed in Tables 5.3 – 5.7, most have been addressed in other IRs. With specific reference to Table 5.6, all projects listed up to and including Wareham Liquefaction Assessment were reviewed during the 2008/2009 GRA.

The remaining projects listed in Table 5.6 that include spending in the 2012 and 2013 test years have been reviewed in and Appendix 5.5 to Tab 5 of the current Application.

In similar format to Appendix 5.5 to Tab 5 of the Application, summaries for the remaining projects are provided in Table 1 below.

Table 1:
Additional Deferred Cost Project Descriptions – Tables 5.3 to 5.8

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Metering Audit	SSE	Independent audit of revenue metering system to verify YEC is using best practices to be in compliance with Measurement Canada.	$30,510		
Protection Event Collection System	Reliability	Install substation data concentrator at an initial trial site to enable YEC to relay outage event information to SCC for more timely and appropriate response to outages	$28,187		
AH0 Deluge System	SSE	Prepare report to improve fire suppression systems at AH plant in response to BCHIL Generation Assessment report and to address insurance concerns.	$25,519		
P125 Headgates Single Point	Legal	Hire consultant to assess safety of WH0, AH0 and MH0 headgates as a single point of isolation for underside work then work with YEC & OHs to show that risks are being managed adequately for safe work to proceed in these work locations.	$50,419		
Wareham Consequences Category Assessment	Business Improvements	2007 Dam Safety Guidelines have different classifications that have implications on previously recommended work. This project is being undertaken to determine how the change in regulatory regime impacts future projects.	$62,882		

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Mayo/Wareham Geotechnical Investigation	Business Improvements	Follow-up on recommendations from liquefaction studies by assessing need to perform seismic cone penetration tests and install new piezometers to address liquefaction potential and overall dam safety.	$44,562		
WAF/MD Modeling and Stability	Business Improvements	Purchase of software, development of a system model and collection of data on equipment and protection devices to complete model; project coordination study based on model to derive updated settings on protection relays; study of transient and steady state responses to system contingencies associated with the interconnection of WAF/MD networks.	$447,536		
Hydro Unit Performance Test	Demand	Performance tests to determine accurate flow, efficiency and performance of turbine/generators as units are old and have been modified too often to determine efficiency by any other method.	$340,200		
Communications Strategy Study	Business Improvements	Develop a 5-10 year strategic communications plan for Business and Operational requirements, to enable informed decision making regarding capital improvements for development of communications infrastructure.	$80,576		

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
P125/126 Hydrocarbon Containment	Legal/ Regulatory	Assess potential risks and provide recommendations in the context of relevant legislation and industry best practices regarding transport, transfer and use of hydrocarbons that could be released in the Whitehorse Diesel and Hydro plants.	$27,572		
IT Security Audit	Business Improvements	Perform security audit regarding computer configurations and information storage	$38,071		
Mayo River Salmon Enhancement	Business Improvements	Identify options for potential salmon enhancements to the Mayo River above the Wareham dam	$7,212		
Mayo Lake Control Structure - Fish Passage	Business Improvements	Identify options to enable fish passage between Mayo Lake and Mayo River	$2,569		
Western Copper - Aerial Photo Mapping & Route Selection	Demand	Costs incurred in 2006 (mainly aerial photography) regarding transmission line route to connect Western Copper	$30,233		
Short-term Energy Storage Feasibility	Demand	Feasibility study of a short term energy storage facility to address integration of non-dispatchable supply such as wind, solar, IPPs, net metering and provide spinning reserve and enhance grid stability	$44,200		

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Atlin Grid Connection Feasibility Study	New Capacity	Assess technical, financial and willingness of the Taku River Klingit First Nation to sell surplus power from their Pine Creek hydro plant to the Yukon.	$109,941	$50,000	
Mayo Lake Outlet Channel Bathymetry & Water Output	Business Improvements	Update bathymetry of the Mayo Lake outlet channel and complete an analysis regarding the potential need for dredging the channel and consideration of possible means to protect the west end of Mayo Lake from erosion.	$13,250	$55,000	
Faro FD1 Mirrlees Generator Assessment Radiator Repair	Business Improvements	Investigate and assess the condition of the generator and its suitability for running at full load for extended periods of time. A cost estimate will be provided if the generator is deemed unsuitable for services at full load; otherwise, repairs will be undertaken if approved.		$50,000	
Hydraulic Wood Removal System for Spill Gates at Whitehorse	Business Improvements	Install a hydraulic lift system that can remove debris from the spillgates in Whitehorse, reducing potential risks to employees related to heavy lifting near open water.		$75,000	
Whitehorse Dam Break and Mapping	Business Improvements	Construct a new dam break and conduct inundation mapping at Whitehorse Rapids.		$80,000	

1

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-25, Table 3.15

PREAMBLE:

QUESTION:

a) Please update this table by adding columns for 2008 and 2011 Actual.

b) Please confirm that without Board approvals since 2009, the capital structure, cost of debt and return on equity provisions included in the revenue requirement approved for 2009 remained the approved amounts for 2010 and 2011.

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.

d) With respect to the unsecured advances from YDC:
   i. Please provide a detailed description of the purpose for each of the unsecured advances from YDC.
   ii. 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.
   iii. Please explain how this method of interest calculation was determined.
   iv. 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.

e) With respect to the TD Canada Trust term note, please explain why this term note was not refinanced through YDC at a lower rate in January 2011.

f) 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? Please provide a copy of any independent audits conducted since 2008.

ANSWER:

(a)

Please see Table 1 below for the requested update that includes 2011 actual. The 2008 information was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

Table 1:
Cost of Capital

					Forecast		Forecast	
	2009 GRA compliance	Actual 2009	Actual 2010	Actual 2011	Existing 2012	Proposed 2012	Existing 2013	Proposed 2013
Average Cost of Debt	6.15%	6.22%	6.38%	3.61%	3.40%	3.38%	3.91%	3.90%
Return on Equity	8.49%	7.92%	7.45%	6.58%	4.38%	8.75%	-0.97%	8.78%
Average Cost of Capital	7.09%	6.90%	6.82%	4.83%	3.79%	5.53%	1.96%	5.85%

(b)

Not confirmed. There was no Board approved revenue requirement for 2010 and 2011, as they were not GRA test years.

(c)

Yukon Energy does not use a "deemed" capital structure. YEC has always been regulated on the basis of its actual capital structure financing ratebase.

(d)

Please see the Application pages 3-25 to 3-27, which describes the purpose of each YDC unsecured advance. For the test years, the only unsecured advances are those forecast for each of year-end 2011, 2012 and 2013 which serve the purpose of rebalancing Yukon Energy's debt:equity ratio.

The interest rates are set based on 120 basis points above the yield on long Canada bonds, which is the same method that has been in place since 1992 and reviewed multiple times by the Board and intervenors. There are no internally generated reports or

documents that serve to change the interest rate calculation since the studies filed with the YUB in the 1991/1992 GRA.

(e)

There is a typographical error in the Application. The TD Canada Trust term note matured in September 2011. The note was renewed at that time with TD at a rate of 4.02%. The Application incorrectly reflects the old rate of 7.81%. The cost of debt calculations reflect the updated rate. This typographical error does not affect forecasts in the Application.

(f)

YEC is subject to comprehensive annual audits of its financial results and position by the Office of the Auditor General of Canada. In addition, three program funding audits are in process but are not yet final (these audits relate to funding for various clean energy initiatives undertaken by the company; the funds appear in the application as offsets to the expenditures incurred).

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-27

YEC states "YEC has updated its forecast Return on Equity (ROE) based on a review of ROE methods and results in other jurisdictions to determine a reasonable low risk utility benchmark to use for the purposes of the current GRA filing. This review indicated that while the British Columbia Utilities Commission (BCUC) low risk utility benchmark has been used in proceedings since the 1996/97 GRA, the low risk utility benchmark in that jurisdiction has not been subject to review since 2009 (and as a consequence may be out of date). By contrast, the Alberta Utilities Commission (AUC) has recently completed a Generic Cost of Capital proceeding (with a Decision dated December 2011. The recent AUC proceeding has determined the benchmark ROE for a low risk utility to be 8.75% (by contrast, the more dated 2009 BCUC benchmark would provide for a low risk utility ROE in the 9.5% range)".

PREAMBLE:

QUESTION:

a) Please confirm that the BCUC determined that the allowed return on common equity for a low-risk benchmark utility in 2009 was 8.47% which would result in a proposed 8.49% ROE for YEC.

b) Please provide a calculation of YEC's average weighted cost of capital for 2012 and 2013 assuming a proposed 8.49% ROE.

c) Please provide a calculation of YEC's return on rate base using an 8.49% ROE for 2012 and 2013.

d) Please provide the revenue requirement impact of using a return on equity of 8.49% in 2012 and 2013.

e) Please confirm YEC's understanding that the British Columbia Utilities Commission is currently conducting a generic cost of capital review with a decision expected in late 2012 / early 2013.

f) If the BCUC review results in a lower benchmark for a low risk utility, will YEC agree to adopt this lower rate for purposes of setting rates in 2013?

g) Please provide a table comparing operating and financial statistics for YEC and utilities regulated by the BCUC.

h) To YEC's knowledge, have there ever been any discussions related to increasing the negative 0.5% adjustment (per OIC 1995/90) 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.

i) Please provide justification for YEC's proposed 52 basis points premium related specifically to YEC's risk in 2012 and 2013. Please provide the qualifications of the person providing this justification.

ANSWER:

(a)

Confirmed.

(b) through **(d)**

With an ROE OF 8.49 %:

- The average cost of capital for 2012 would be 5.42% and 5.73% for 2013;
- The return on Rate base would be approximately $12.096 million for 2012 and approximately $13.859 million for 2013; and

- The Revenue requirement would decrease by approximately $0.249 million for 2012 and $0.274 million for 2013.[1]

(e)

Confirmed.

(f)

No. As stated in Tab 8 of the Application, YEC calculated its requested ROE using the the AUC Generic ROE for 2011 of 8.75% approved in AUC Decision 2011-474.

(g)

In a form similar to Tab 8 in YEC's 2005 Revenue Requirements and Related Matters, Table 1 below compares size of operations and financial structures information for YEC and the BC utilities that YEC reviewed in developing its requested ROE.

Table 1:
Comparison of YEC to BC Utilities Size of Operations and Financial Structure

			FortisBC Energy Utilities		
Size of Operations	**YEC**	**FortisBC Inc.**	**FortisBC Energy Inc.**	**FortisBC Energy (V.I.) Inc.**	**FortisBC Energy (Whistler) Inc.**
	forecast 2012	**forecast 2012**	**forecast 2012**	**forecast 2012**	**forecast 2012**
Size of Operations					
Revenue ($millions)	39.857	294.484	1,245.100	195.100	11.400
Rate base ($millions)	223.000	1,145.253	2,736.507	787.864	42.139
Number of employees (FTE)	92	248	1,701	123	2
Number of customers	1,986	116,105	n/a	n/a	n/a
Financial Structure					
Debt:Equity Ratio	60:40	60:40	60:40	60:40	60:40
ROE Adder (%)	0.52%	0.40%	-	0.50%	0.50%

Notes

note 1 FortisBC Inc. revenue, rate base, customers, and employment as forecast in 2012-2013 Revenue Requirements Application.
note 2 FortisBC Inc. risk premium per BCUC Order G-199-11
note 3 FortisBC Energy Utilities revenue, rate base, and employment per 2012-2013 Revenue Requirements Application
note 4 FortisBC Energy Utilities risk premium and debt:equity ratio last approved in Order G-158-09
note 5 YEC figures per 2012/2013 General Rate Application

[1] $12.345 million for 2012 at 8.77% ROE as shown in Table 3.1 of the GRA Application minus $12.096 million at 8.49% as shown above; $14.130 million for 2013 at 8.77% ROE as shown in Table 3.1 of the GRA Application minus $13.859 million at 8.49% as shown above

(h)

No.

(i)

YEC has previously provided justification for this assessment and it has been reviewed and confirmed as reasonable by the YUB in each of YEC's last two GRAs. The overarching objective for the approach proposed by YEC is to reduce the regulatory burden and expense for Yukon ratepayers associated with preparing ROE evidence at each rate hearing.

As stated in the 2008/2009 GRA:

"In the 2005 hearing, the Board determined that the rate of return requested and the Application of the BCUC approach was reasonable, given Yukon Energy's level of risk in relation to other utilities within their peer group. It was noted by the Board that this was an expedient means of determining return for that period, and did not necessarily impose a precedent in the Yukon.[2] The Board agreed with Yukon Energy's assessment with respect to "risk premiums", i.e., that it fell somewhere between PNG at 65 basis points and FortisBC at 40 basis points, given the level of risk experienced by Yukon Energy in relation to other utilities within its peer group. Consequently, the Board agreed with YEC's assessment that 9.05% (9.55% less 0.5% per OIC 1998/32) was an appropriate rate of return on common equity for Yukon Energy, and noted that Yukon Energy remained at risk for their forecast annual deliveries, OM&A and capital expenditures for 2005."[2]

YEC's requested ROE premium over the benchmark utility ROE is the same as approved In Appendix A to YUB Order 2005-12 and confirmed in YUB Order 2008-09. YEC did not undertake a detailed review of the requested ROE premium over the benchmark ROE for 2012-2013 in an effort to reduce the regulatory burden and expense associated with preparing expert ROE evidence at each rate hearing.

[2] As per YEC 2008/2009 General Rate Application; dated September 2008.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-28

YEC states "*The Deferred Fuel Price Account ("Rider F") is established and maintained 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. Based on proposed changes to the DCF whereby any secondary sales revenues after January 1, 2012 would be credited directly to the DCF (and thereby not affect Yukon Energy revenues or income), it is proposed that Rider F no long be affected by variations in the ongoing quarterly adjustments to the prices of secondary sales, i.e., any secondary sales revenues after January 1, 2012 would be credited to the DCF without any Rider F related adjustment or impact for price changes*".

PREAMBLE:

QUESTION:

a) Please confirm that all customer classes except secondary sales customers are currently charged a Rider F surcharge of 0.420 ¢ per kW.h on all kWh consumed.

b) Please provide tables showing (i) the monthly debits/credits/balances in the Deferred Fuel Price Account and (ii) the recovery of Rider F revenue from each rate class in 2008, 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast).

c) Please confirm that the benchmark upon which Rider F is determined would be adjusted to match fuel costs approved for 2012 and 2013 in this proceeding.

ANSWER:

(a)

Confirmed.

(b)

The updated Rider F information was extensively reviewed in the recent Rider F proceeding and is now made available quarterly at the following link:

http://www.yukonenergy.ca/about/business/regulatory/riderffilings/

Yukon Energy cannot provide recovery information by rate class, as the vast majority of Rider F collections occur through YECL.

(c)

For Yukon Energy's portion of the Rider F calculations, this is confirmed.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 3, Page 3-28

YEC states "The Diesel Contingency Fund ("DCF") was established in the 1996/97 GRA Negotiated Settlement. The DCF is designed to ensure that the Fund (and utility ratepayers), rather than YEC earnings, pays for or benefits from changes to grid diesel generation due to fluctuations in grid hydro generation due to factors such as water condition changes that are beyond utility control. With the DCF in place, the YUB can set customer rates based on long-term forecast hydro generation rather than short-term forecast hydro generation. The DCF is maintained to address ongoing fluctuations in diesel requirements (and related fluctuations in rates, up or down) that ratepayers would otherwise be exposed to due to annual water availability. In effect, the DCF operates to smooth rate impacts so that ratepayers are not subject to ongoing rate instability from year to year depending on whether it is a flood or drought year. The DCF balance as at December 2011 is $0.902 million. This balance has been retained in the Fund (with interest) and no amounts (beyond interest) have been either credited or debited to the fund since December 31, 2007".

PREAMBLE:

QUESTION:

a) Please identify all of the parties that were part of the 1996/97 GRA Negotiated Settlement and which of these parties have agreed to change the negotiated settlement package to allow the proposed changes to the operation of the DCF.

b) Please confirm that, as noted in the YECL 2008/2009 GRA, completion of Yukon Energy's transmission facilities to Pelly Crossing in 2008 enabled YECL thereafter to secure approximately $600,000 ongoing fuel and other operating cost savings.

c) Please confirm that 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.

d) Please confirm that the cap for the DCF will remain at $4.04 million.

ANSWER:

(a)

The parties to the 1996/97 GRA negotiated settlement process were YEC, YECL, the City of Whitehorse, Anvil Range Mining Corporation, UCG, the Association of Yukon Communities, and the New ERA Electric Corporation.

Yukon Energy is proposing changes to the DCF as part of this GRA, and all parties who have registered as intervenors in this hearing will have the opportunity to test the current proposal. Yukon Energy has not specifically contacted the parties to the 1996/97 negotiated settlement.

(b)

As set out in UCG-YEC-1-33(b) from Yukon Energy's 2008/09 GRA, the annual savings to YECL for diesel generation at Pelly Crossing was estimated at that time to be approximately $0.6 million. Yukon Energy has not updated this number.

(c)

The Mayo–Dawson note served this purpose from the construction of the line in 2003 until 2011 when the note was refinanced as part of the financial transactions discussed at page 3-25 of the GRA. The Mayo-Dawson note was no longer required for its original purpose by 2011, as the costs of the line are now far exceeded by the savings that the line produces for ratepayers from eliminating baseload diesel generation at Dawson.

(d)

Confirmed. As set out at page 3.2-5, Yukon Energy has not developed a specific recommendation at this time to modify the current quantum and cap for the fund.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 4, Page 4-6

YEC states "Section 6(3) provided in OIC 2007/94 was replaced in April 2012 with a new OIC direction – OIC 2012/68. This new direction in effect requires that Rate Schedule 39 as approved in Board Order 2011-14 continue until December 31, 2013, except as follows:

1. *If rates charged to retail customers for all or any part of 2012 are to be increased, then for that same period the greater of that increase and the percentage increase approved in Board Order 2011-14 [i.e., 3.4%] is to apply to the class of major industrial customers; and*

2. *The Board must otherwise ensure until December 31, 2013 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers.*"

PREAMBLE:

QUESTION:

a) Please confirm that the currently forecasted revenue shortfalls of $3.455 million in 2012 and $7.685 million in 2013 were calculated based on rates effective in April 2012.

b) If the revenue shortfall projected for 2012 is based on existing firm rates including existing industrial rates, why wouldn't the industrial class be subject to the same percentage increase in revenue recovery as all other classes?

c) Please calculate the percentage rate increase required (versus the proposed 6.4%) in 2012 for all rate classes assuming that industrial rates were increased at the same level (i.e., no adjustment for previous rate changes in 2012).

d) Please calculate the percentage rate increase required (versus the proposed 6.4%) in 2012 for all rate classes assuming that industrial rates were increased at

the same level (i.e., no adjustment for previous rate changes in 2012) and assuming that YEC is only allowed to recover the proposed incremental 2012 revenue requirement for 8 months (May-December) instead of 12 months.

ANSWER:

(a)

Not confirmed. The forecasted revenue shortfalls are calculated for the whole year, i.e. January to December 2012 and January to December 2013.

(b)

Per Yukon Utilities Board ("YUB" or "Board") Order 2011-14 industrial rates increased by 3.4% effective January 1, 2012. Based on 2012/13 GRA revenue shortfall for 2012, the proposed further rate increase for industrial customer in 2012 is 2.90%, when combined with the 3.4% increase per in Board Order 2011-14, the cumulative 2012 increase of 6.4% is equal to the proposed rate increase for retail customers. This complies with OIC 2012/68 (please see Tab 11, page 11-1 and 11-2 of the 2012/13 GRA Application).

(c)

The rate increase for 2012 would be approximately 6.02%.

(d)

The requested calculation requires monthly breakdown of the proposed 2012 revenue requirement, which was not yet developed. As such the requested analysis cannot be performed at this time.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 6, Page 6.2.-7

YEC states "*YEC is required to adopt IFRS beginning with its 2012 fiscal year, including comparative figures for 2011*".

PREAMBLE:

QUESTION:

a) Please confirm that in March 2012, a month before YEC submitted its application to the YUB, the International Accounting Standards Board announced an additional one year IFRS adoption deferral to January 1, 2013 and that this deferral is available to rate-regulated entities (i.e., YEC).

b) Please confirm YEC's willingness to defer adoption of International Financial Reporting Standards until January 1, 2013 to allow issues associated with rate-regulated accounting under IFRS to be resolved.

ANSWER:

(a)

Confirmed.

(b)

Confirmed.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-2

YEC states "In the test years, 74% of Yukon Energy projected spending on capital works ($47.6 million) is on major projects over $1 million ($35.1 million). Yukon Energy's level of "normal" or ongoing spending on capital works, outside of such major projects, over the period 2009 (actual) to 2013 (forecast) varies from a low of approximately $5.4 million (2012) to a high of $10.5 million (2010) averaging $7.26 million per year. The average is higher than the average ongoing capital spending reports in the 2008/2009 General Rate Application hearing, which was approximately $5.1 million over the 2005 to 2009 period".

PREAMBLE:

QUESTION:

a) Please describe the discounted cash flow analysis used by YEC to determine the feasibility of capital projects and the minimum threshold profitability index that individual projects are required to achieve.

b) Please provide a list of all individual capital projects in 2009, 2010, 2011, 2012 and 2013 that fail to achieve a minimum threshold profitability index of 0.8.

c) Please identify YEC's depreciation expense per year in 2009, 2010, 2011, 2012 (forecast) and 2013 (forecast) and confirm that these amounts are used to fund capital expenditures in these years.

d) Please confirm that YEC's capital expenditures are not rolled into rate base until the project is completed and deemed to be used and useful.

ANSWER:

(a) and **(b)**

The concept of a profitability index is not relevant to a regulated utility which only earns "profits" as part of a return on regulated equity and does make decisions about required capital spending on the basis of changes to profitability. For a regulated utility, the appropriate test of a project's need and justification is either (a) required projects to maintain service levels and reinvest in assets, or (b) optional projects that help reduce rates as compared to other alternatives.

(c)

Please see UCG-YEC-1-39 Attachment 1. These amounts are not used to fund capital expenditures (depreciation does not represent "funds").

(d)

YEC's capital costs for assets are typically treated as work in progress (i.e., not included in rate base) until a project is sufficiently completed to come into service. Technically, YEC's capital spending is not included in rate base for the purpose of setting rates until approved by the Board, which includes review of various tests, including but not limited to the "used and useful" test referenced.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-5

YEC states that the Carmacks-Stewart Transmission Project – Stage 2 was energized on June 16, 2011, that project costs are not yet final although estimated to be $41.9 million, that the full $41.9 million is funded by Federal and Yukon government contributions, and that there is no impact to rate base and no impact on rates.

PREAMBLE:

QUESTION:

a) Please confirm that no matter what the final capital cost is for the Carmacks-Stewart Transmission Project – Stage 2, YEC will be provided contributions to offset all capital costs.

b) Please identify the revenue requirement impact of this project in 2011, 2012 and 2013 and the impact on rates for each customer class.

c) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

ANSWER:

(a)

Not confirmed.

(b) and **(c)**

As noted in the Application (Section 5.2.1.1, pages 5-4 and 5-5), the full $41.9 million estimated final completion cost is funded by federal and Yukon government contribution.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-6

YEC states that the Mayo Hydro Enhancement Project was commissioned ahead of schedule in December 2011, that the project's completed cost is forecast at approximately $116.6 million (excluding the Mayo Lake project), the net rate base cost is forecast at $35 million (i.e., $116.6 million less Federal and Yukon Government / YDC contributions of $81.6 million), and that flexible debt long-term financing has been secured by Yukon Energy from YDC to mitigate ratepayer risks related to costs exceeding 11 cents per kW.h (2012$) in any year for diesel generation displaced.

YUB Report to Yukon Minister of Justice, YEC Application for an Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Mayo Hydro Enhancement Project (May 17, 2010), Pages 12-13.

The YUB states "*To conclude, based on the load forecast and comments of YEC, there is enough generation in place to serve forecast loads, and based on this single criteria there is not a specific need for the Mayo B Project. However, based on the comments and analysis of YEC, there is clearly a demonstrated public benefit if Mayo B proceeds. The cost savings to Yukon ratepayers and other benefits from displacing diesel generation lead the Board to recommend that the public benefit is significant enough that, in concert with Board comments on other sections in this report, YEC should proceed with the Mayo B Project*".

YEC 2008-2009 General Rate Application, YECL-YEC-1-5 REVISED

YEC states "*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*".

YEC 2008-2009 General Rate Application, YUB-YEC-1-8

YEC states "*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%".

PREAMBLE:

QUESTION:

a) Please confirm that no matter what the final capital cost is for the Mayo Hydro Enhancement Project, the net rate base addition will be no more than $35 million.

b) Please identify the revenue requirement impact of this project in 2011, 2012 and 2013 and the impact on rates for each customer class.

c) Please explain the various levels of "feasibility stages of study" and how they relate to the confidence in project cost estimates.

d) Please provide a breakdown of all project component costs and an explanation of variances between the original budget of $120 million and the current estimate of $116.6 million.

e) Please identify the diesel fuel savings resulting from this project that have been incorporated into the proposed revenue requirements for 2012 and 2013.

f) Please explain why the costs for the Mayo Hydro Substation Enhancements and Mayo Head Gate Repairs were not identified as part of the Mayo Hydro Enhancement Project and its $120 million budget / business case when it was submitted to the YUB for review with respect to the Energy Project and Energy Operation Certificates (other than "the range of non-Mayo B material planning considerations and requirements associated with this substation" noted at the bottom of page 5-10).

g) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

ANSWER:

(a)

Not confirmed.

(b)

With regard to overall revenue requirement impacts of Mayo B the following are noted:

- **Mayo B costs:** The flexible debt long term financing secured by Yukon Energy from YDC will mitigate ratepayer risks related to costs exceeding 11 cents/kWh (2012$) in any of these years for diesel generation displaced. See Attachment 5.3 of Appendix 5.3. Total annual costs (depreciation and return) included in the Application for Mayo B approximates $1.4 million for 2012 and $1.7 million for 2013 (costs reflect impact of Mayo B Flexible Debt).

- **Mayo B diesel cost savings**: As reviewed at page 1-5 of the Application, at annual long-term average hydro generation the forecast diesel generation reduction from Mayo B is 20.7 GW.h in 2012 and 22.3 GW.h in 2013, with forecast savings in diesel generation fuel costs at approximately $5.9 million in 2012 and $6.4 million in 2013 and forecast savings in diesel O&M costs (at 3c/kW.h per 2009 GRA) at approximately $0.6 million in 2012 and $0.7 million in 2013; based on the GRA's proposed percent of long term average (LTA) diesel generation to be included in the revenue requirement, these cost savings impacts on the revenue requirement would be approximately $4.3 million for 2012 (66% LTA) and $4.2 million for 2013 (59% LTA).

- **Net Mayo B cost savings impacts:** Based on the above, the overall net revenue requirement impacts of Mayo B are savings of $2.9 million in 2012 and $2.5 million for 2013.

It is not feasible or relevant in this Application to address rate impacts for each customer class. It is required that these impacts be as directed in OIC 2012/68.

(c)

Feasibility stages are developed as appropriate for each project, and are specific to the project. Please see response to YUB-YEC-1-40(b).

(d)

Please see response to CW-YEC-1-27(a) and (b).

(e)

The diesel fuel savings from Mayo B that is included in the proposed revenue requirement is provided in (b) above.

(f)

The Mayo Hydro Substation Enhancement Project and the Mayo Head Gate Repairs are separate projects justified based on existing requirements related to the Mayo A facility and not Mayo B.

With regard to the Mayo Substation, please see YECL-YEC-1-38, LE-YEC-1-22, CW-YEC-1-29, and UCG-YEC-1-51.

(g)

The project was considered substantially complete at year end 2011, project costs and contributions were transferred to rate base at that time.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-9

YEC states that the Aishihik Third Turbine Construction project came into service in December 2011, that project's forecast completion budget cost is approximately $13.8 million, and that the net rate base cost is approximately $8.8 million after $5 million in 3rd party contributions.

September 2008 YEC 2008-2009 GRA Application, Page 5-13

YEC states "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). The Yukon Government has committed $5 million of no-cost capital towards the project. These government funds allow the project to proceed on an accelerated basis to provide net benefits without waiting until new mine connection arrangements are confirmed.

Construction costs are forecast to be $750,000 in test year 2008 with an additional $3,500,000 in test year 2009 (a further $4,250,000 is forecast for 2010). Yukon Energy costs for this project will be offset by Yukon Government funding contributions totalling $1,500,000 in 2008 and $3,500,000 in 2009 (for a total of $5,000,000 over the period)".

PREAMBLE:

QUESTION:

a) Please confirm whether the Aishihik 3rd Turbine project was submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please explain how the ratepayer costs for the Aishihik 3rd Turbine increased from the $3.5 million used to gain approval from the YUB to approximately $8.8 million now after the $5 million Yukon government contribution. Please provide a breakdown of all project component costs and an explanation of variances between the original budget of $8.5 million and the current estimate of $13.5 million.

c) Please provide details of the current economic assessment for the Aishihik 3rd Turbine project including detailed calculations of NPV ratepayer savings as a result of this project.

d) Please identify the revenue requirement impact of this project in 2011, 2012 and 2013 and the impact on rates for each customer class.

e) Please provide a breakdown of all project component costs and an explanation of variances between the original budget of $120 million and the current estimate of $116.6 million.

f) Please explain why the costs for the Aishihik Generation Station Redundancy was not identified as part of the Aishihik 3rd Turbine project when it was submitted to the YUB for review in the 2008/2009 GRA proceeding.

g) Please explain how the failure to not properly ground the Aishihik plant resulted in a fire/shut down of the plant and extended costs for remediation.

h) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

ANSWER:

(a)

This project has not been submitted to the Minister or the YUB for review pursuant to Part 3 of the Public Utilities Act.

See response to LE-YEC-1-18 which notes that a Part 3 review requires an OIC designating a project as a “regulated project” under the Public Utilities Act. Prior to OIC

designation, no application pursuant to Part 3 of the PUA can be made, or is required to be made, by a utility. No YUB review can commence under Part 3 prior to a reference by the Minister pursuant to Part 3 after the necessary OIC designation and the necessary subsequent utility application.

(b)

Please see Response to YUB-YEC-1-5(a) and (b) and YUB-YEC-1-32(a) and CW-YEC-1-28(a) and (b).

(c)

Please see response to YECL-YEC-1-32.

(d)

Total annual costs (depreciation and return) included in the Application for this project approximate $0.6 million for each of 2012 and 2013. The resulting forecast savings in diesel generation fuel (at long-term average hydro) and O&M costs equal approximately $1.0 million in 2012 and $1.2 million in 2013; based on the GRA's proposed percent of long term average (LTA) diesel generation to be included in the revenue requirement, these cost savings impacts on the revenue requirement would be approximately $0.66 million for 2012 (66% LTA) and $0.7 million for 2013 (59% LTA).

Based on the above, the overall net revenue requirement impacts of Aishihik Third Turbine are savings of $0.06 million in 2012 and $0.1 million for 2013.

Class level impacts cannot be assessed without a Cost of Service study. It is required that these impacts be as directed in OIC 2012/68.

(e)

The cited values do not relate to the Aishihik 3rd Turbine, but appear to be referencing Mayo B. For the Mayo B comparison of budget to actuals, please see the response to CW-YEC-1-27(a) and (b). For Aishihik 3rd Turbine, see CW-YEC-1-28 and LE-YEC-1-21.

(f)

The Aishihik Redundancy Project is not, and was never considered, part of the Aishihik Third Turbine project. Specifically, prior reviews of this project (i.e., the 2006 20-Year Resource Plan proceeding, the 2007 CSTP Part 3 hearing and the 2008/2009 GRA) did not include provision for redundancy at Aishihik plant within the scope of the Aishihik 3rd Turbine project.

Please see response to LE-YEC-1-18(b). The Aishihik Redundancy project was undertaken to rectify a serious system reliability issue relating to redundancy identified as a result of a major system outage.

(g)

The issue was not that the Aishihik plant is not properly grounded. The cause of the extended outage was that the main power cables connecting the generation to the transmission system failed.

(h)

The Aishihik Third Turbine project was considered substantially complete at the end of 2011 and transferred to rate base at that time. The Aishihik redundancy project was considered substantially complete at the end of 2011 and transferred to rate base at that time.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-10

YEC states "Added to the requirement to refurbish the substation, many ongoing external changes on the Yukon grid required material re-investment be done to the Mayo substation to ensure that it is equipped and fully capable of addressing the fundamental changes to the grid system at this time".

PREAMBLE:

QUESTION:

a) Please confirm whether the Mayo Hydro Enhancements Project was or will be submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please explain how much the Carmacks Stewart Transmission Project - Stage 2, the Mayo Hydro Enhancement Project and new industrial loads advanced the schedule for the Mayo Hydro Substation Enhancements.

c) Please identify where in previous Part 3 and Energy Project Certificate applications the Mayo Substation Enhancements project was identified as a cost that would have to be incurred.

d) Please explain how the two different transmission voltages from the Mayo line (69 kV) and the WAF line (168 kV) affected the costs of substation enhancements.

e) Please provide a component breakdown of all Mayo Hydro Substation Enhancements expenditures in 2010, 2011, 2012 and 2013.

f) Please confirm that the $0.750 million cost from the Mayo Substations Enhancements project identified as "assigned to Mayo B Project" is included in the current $116.6 million cost estimate for Mayo B.

g) Please identify specifically what costs are being assigned to the Mayo B project.

h) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

ANSWER:

(a)

The Mayo Hydro Enhancement Project (otherwise known as "Mayo B") was the subject of a Part 3 proceeding before the Board, as set out in the following link: http://www.yukonenergy.ca/about/business/regulatory/part3mayo/

(b)

Mayo Substation was 50 years old and in need of major refurbishment and upgrades to continue operating in a safe and reliable manner. Concerns regarding the project were documented in a June 2004 BC Hydro Engineering Report commissioned by YEC. The project was required to address these documented issues and ensure an appropriate level of service for Mayo 1 and Mayo 2 generators, Dawson and Elsa Transmission Line and the local Mayo town distribution. As such the timing for this project was primarily driven by existing system requirements.

The completion of the CSTP Stage 2 and Mayo Hydro Enhancement (Mayo B) Projects advanced the Mayo Substation Project by approximately one to two years in order to allow YEC to take advantage of the tendering process on CSTP Stage 2 to purchase the bulk of the substation equipment (i.e. switches, breakers) through that tendering process – saving the cost of that work. With regard to Mayo B, this allowed YEC to take advantage of, and gain efficiencies from, the contractors being on site (i.e. PKI, etc.) and to utilize the outages planned for the Mayo B work to complete some of the Mayo Substation work.

(c)

Please see responses to CW-YEC-1-29, LE-YEC-1-22 and YECL-YEC-1-33.

(d)

The WAF line is 138 kV, not 168 kV. The different voltages did not affect the costs of the Mayo substation, as the 138 kV service does not connect to this substation (138 kV service only exists on the southern system and CSTP).

(e)

See Table 1 below which provides a component breakdown by year for the Mayo Hydro Substation Enhancements for 2010, 2011 and 2012.

Table 1:
Mayo Hydro Substation Enhancement Expenditures
by Component: 2010 to 2012 Forecast

	2010	2011	2012 Fcst	Total
69kV Ring Bus	$0	$2,033,998	$2,890,502	$4,924,500
Mayo A Tie-in	$0	$380,065	$761,935	$1,142,000
Re-supply Shunt Reactor	$0	$0	$305,101	$305,101
Re-supply Mayo Town off 69kV	$0	$185,000	$1,005,020	$1,190,020
Keno 69kV Line Transfer	$0	$80,000	$125,072	$205,072
Dawson 69kV Line Transfer	$0	$90,000	$125,225	$215,225
Construction Field Cost:	**$0**	**$2,769,063**	**$5,212,855**	**$7,981,918**
Preliminary Engineering and Design:	$162,977	$0	$0	$162,977
Detailed Engineering Design:	$0	$690,757	$319,240	$1,009,997
Construction Management:	$0	$47,610	$265,075	$312,685
YEC Cost (Owner's Cost):	$0	$108,502	$229,170	$337,672
Construction Financing Cost:	$100	$31,988	$91,345	$123,433
Indirect Cost:	**$163,077**	**$878,857**	**$904,830**	**$1,946,764**
Contingency:	$0	$0	$225,000	$225,000
Total Capital Cost:	**$163,077**	**$3,647,920**	**$6,342,685**	**$10,153,682**

(f) and **(g)**

This cost of $750k is included in the Mayo B project total. Also see LE-YEC-1-22(a).

(h)

As set out in Tab 5, the Mayo Substation project is a 2012 capital addition.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-12

YEC states that after the inspection of the Mayo Head Gate, a comparison of available options for an emergency closure system were reviewed, a preferred option selected, the gate was designed, constructed and delivered to site with installation expected to occur during summer 2012.

PREAMBLE:

QUESTION:

a) Please confirm whether the Mayo Head Gate Repairs project was or will be submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please provide a component breakdown of all Mayo Head Gate Repairs project expenditures by year.

c) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

ANSWER:

(a)

This project has not been submitted to the Minister or the YUB for review pursuant to Part 3 of the Public Utilities Act.

See response to LE-YEC-1-18 which notes that a Part 3 review requires an OIC designating a project as a "regulated project" under the Public Utilities Act. Prior to OIC designation, no application pursuant to Part 3 of the PUA can be made, or is required to be made, by a utility. No YUB review can commence under Part 3 prior to a reference by

the Minister pursuant to Part 3 after the necessary OIC designation and the necessary subsequent utility application.

(b)

Table 1 below provides the budget as included in the GRA. Note that the 2009 and 2010 actuals in the table below are different than the GRA, due to accruals, but the totals for the 2 years are the same.

Table 1:
Mayo Intake Structure Headgate Repairs
Expenditure by Year: 2009 Actual to 2012 Forecast

Vendor	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	Total
Peter Kiewit Infrastructure Co			$268,663	$560,000	$828,663
KGS Group	$45,380	$135,890	$106,020	$65,000	$352,290
Canpac Divers Inc.		$31,769	$36,681		$68,450
Wilf's Contracting Ltd.	$2,700				$2,700
Aon Reed Stenhouse Inc.		$4,143			$4,143
YEC costs	$13,586	$32,545	$17,066	$15,000	$78,198
TOTAL	**$61,667**	**$204,347**	**$428,430**	**$640,000**	**$1,334,444**

(c)

As set out in Tab 5, the project is a 2012 capital addition.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-15

> YEC states that the Aishihik Generation Station Redundancy project was planned to be constructed on the same general timeline as the Aishihik Third Turbine installation and that the cost estimate has risen from $2.9 million to $6.356 million.

PREAMBLE:

QUESTION:

a) Please confirm whether the Aishihik Generation Station Redundancy project was or will be submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please provide a component breakdown of the Aishihik Generation Station Redundancy project expenditures by year.

c) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

ANSWER:

(a)

This project has not been submitted to the Minister or the YUB for review pursuant to Part 3 of the Public Utilities Act.

See response to LE-YEC-1-18 which notes that a Part 3 review requires an OIC designating a project as a "regulated project" under the Public Utilities Act. Prior to OIC designation, no application pursuant to Part 3 of the PUA can be made, or is required to be made, by a utility. No YUB review can commence under Part 3 prior to a reference by

the Minister pursuant to Part 3 after the necessary OIC designation and the necessary subsequent utility application.

(b)

Please see Table 1 below for review of project expenditures to the end of 2011 by component by year. Note that the component breakdown below totals to $6.108 million as at the end of 2011 (and not $6.365 million total for the project included in Application Table 5.2). An additional $0.257 million is forecast to be required in 2012; this amount is estimated to address project wrap-up activities and outstanding items such as gauges, performance testing, minor deficiencies' corrections, and other matters. This additional spending provides for the Final Cost Estimate of $6.365 million included in the 2012/2013 GRA.

Table 1
Aishihik Redundancy Project Expenditures to end of 2011 by Component

Vendor	2009	2010	2011	Total ($)
AECOM Canada Ltd.	100,710	176,852	193,502	471,063
ATCO Structures and Logistics			135,900	135,900
CAP Engineering			260,538	260,538
L&S Electric of Canada Inc.			-	-
North American Construction			3,179,145	3,179,145
Northgate Industries Ltd.		14,862	105,839	120,701
Orbis Engineering Field Servic			217,957	217,957
Peter Kiewit Infrastructure Co			62,259	62,259
Powell Electrical Systems Inc.		481,861		481,861
R.C. Cranes and Construction			18,558	18,558
Schneider Electric Canada Inc.			28,670	28,670
YEC - Owner Costs	857	32,502	1,097,877	1,131,236
Total	**101,567**	**706,076**	**5,300,244**	**6,107,887**

(c)

The project was completed in 2011 and transferred to rate base at year end 2011.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-17

YEC states that the total budget for the Whitehorse Spillway Improvements project is $1.35 million for activities to occur between 2011 and 2013.

PREAMBLE:

QUESTION:

a) Please confirm that all capital expenditures related to the Whitehorse Spillway Improvements project will occur between 2011 and 2013.

b) Please confirm whether the Whitehorse Spillway Improvements project was or will be submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

c) Please provide a component breakdown of the Whitehorse Spillway Improvements project expenditures by year.

d) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

ANSWER:

(a)

Confirmed. The GRA filing forecasts that the spending on the Whitehorse Spillway Improvements will be completed, at $1.25 million, by the end of 2013.

(b)

This project has not been submitted to the Minister or the YUB for review pursuant to Part 3 of the Public Utilities Act.

See response to LE-YEC-1-18 which notes that a Part 3 review requires an OIC designating a project as a "regulated project" under the Public Utilities Act. Prior to OIC designation, no application pursuant to Part 3 of the PUA can be made, or is required to be made, by a utility. No YUB review can commence under Part 3 prior to a reference by the Minister pursuant to Part 3 after the necessary OIC designation and the necessary subsequent utility application.

(c)

Please see Table 1 below for breakdown of expenditures by component by year.

Table 1:
Whitehorse Spillway Improvements Expenditures by Component by Year

	2011 Actual	2012 Forecast	2013 Forecast	Total
East Gate Work	$95,744	$560,000	$28,000	$683,744
West Gate Work	$0	$0	$530,000	$530,000
Subtotal	**$95,744**	**$560,000**	**$558,000**	**$1,213,744**
YEC Owners Cost	$500	$14,000	$15,000	$29,500
AFUDC	$196	$1,000	$2,000	$3,196
Total	**$96,440**	**$575,000**	**$575,000**	**$1,246,440**

(d)

The project is expected to be completed before the end of 2013 and transferred to ratebase in that year.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-18

YEC states that the Whistle Bend Subdivision Supply project will cost upwards of $12 million depending on system reinforcement requirements and that the project will not be in service before 2014 and that there will not be any impact on rates in 2012 and 2013.

PREAMBLE:

QUESTION:

a) Please confirm whether the Whistle Bend Subdivision Supply project was or will be submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please provide a component breakdown of the Whistle Bend Subdivision Supply project expenditures by year.

c) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

ANSWER:

(a)

This project has not been submitted to the Minister or the YUB for review pursuant to Part 3 of the Public Utilities Act.

(b) and **(c)**

Please also response to YECL-YEC-1-31(a) and YECL-YEC-1-35(a).

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-19

YEC states that the first phase of the JDE Enterprise Business System project will cost $3.24 million and be completed by April 2012. The timing and scope of subsequent phases of this project will be brought forward separately.

October 6, 2008 GRA 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.

October 6, 2008 GRA 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.

PREAMBLE:

QUESTION:

a) Please confirm whether the first phase of the JDE Enterprise Business System project was or will be submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please provide a component breakdown of the first phase of the JDE Enterprise Business System project expenditures by year.

c) Please identify all savings and productivity gains from the installation of these programs.

d) Please identify when other phases of this project will be undertaken, the scope of these subsequent phases and their estimated cost.

e) Please confirm whether the previous references to the replacement of YEC's Financial Systems Software and an Electronic Document Management system are part of this overall project.

f) Please provide copies of the assessment of all external consultants and describe any research they conducted into the business systems now in use throughout Canada.

g) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

ANSWER:

(a)

This project has not been submitted to the Minister or the YUB for review pursuant to Part 3 of the Public Utilities Act.

See response to LE-YEC-1-18 which notes that a Part 3 review requires an OIC designating a project as a "regulated project" under the Public Utilities Act. Prior to OIC designation, no application pursuant to Part 3 of the PUA can be made, or is required to be made, by a utility. No YUB review can commence under Part 3 prior to a reference by the Minister pursuant to Part 3 after the necessary OIC designation and the necessary subsequent utility application.

(b)

Please see Table 1 below.

Table 1:
Roll-out #1 Total Expense

	Fcst Final Estimate (2012/13 GRA)
System selection (includes current/future state analysis and procurement of system and implementation consultants)	344
Hardware purchase	135
Software	291
Consulting	
- project management	241
- Financial module implementation consultant	606
- Job Cost/CMMS implementation Consultant	176
- CMMS project advisor	165
YEC Internal Costs	449
Total	2407

(c)

The benefits accruing from this project are as follows:

- **Purchase requisition** – Within authorized signing authorities, staff submit requisitions for purchase of goods and services directly into the system. Requisitions are automatically routed to appropriate managers for approval. Subsequent to approval, the requisition is automatically sent to Procurement group for processing. Previously, this process was manual, requiring the purchaser to draft the requisition, walk the package around for approvals and submit to Procurement, who would then enter the information into the system.

- **Invoice Processing** – Similar to requisitions, invoices are electronically received into the system and following verification procedures by Procurement, payments are cued for payment. Previously, invoices were manually signed off and data entered prior to payment. Automation limits coding errors as accounts are set up at the requisition stage and programmed into the system. This further assists project/budget managers as they do not require their own log of codes (these managers previously did not have access to the system). Finally, time savings accrue at cheque signing – this step is now done electronically whereas under the old system cheques were required to be stamped with signatures.

- **Contract monitoring** – Previously, contract status was tracked manually by the procurement department. Under the new system, all purchases are set up in the system electronically. Budget managers can now check status on line directly where previously this required a request to procurement.

- **Equipment Maintenance** – As part of the new system, YEC acquired a maintenance management module. This will generate a number of benefits:
  - Ability to track maintenance costs and labour effort at the equipment level.
  - Planning and tracking of planned preventive maintenance and corrective repairs at the equipment level.
  - Allows for Reporting and availability of Key Performance Indicators (KPIs) and metrics against maintenance activities.
  - Contains an asset register of YEC's asset base.
  - Provides a foundation for future tracking and maintenance of critical spares inventory.

These benefits are expected to allow Yukon Energy to optimize maintenance activities and service potential of utility assets.

- **Inventory monitoring** – The new system has min/max levels that are programmable, previously this was managed manually by warehouse staff.

- **Time entry** – All staff are required to prepare bi-weekly time sheets. Under the old system, time sheets had to be entered twice – once for payroll purposes and secondly for coding labour charges into the financial system. Under the new system, time sheets will be created electronically by staff; all subsequent processing will run off this single data entry.

- **Fixed assets** – The new system is able to produce continuity schedules of fixed assets without the need for manual intervention. Under the old system, this schedule was created manually using spreadsheet software. Further the system has been programmed to accommodate IFRS conversion (via dual ledgers).

- **Control enhancement** – The system has an audit module to track changes to allow follow up as required.

- **Reports** – Quarterly management reports (budget to actual) for both operations and capital project monitoring. These reports were previously manually generated using spreadsheet software.

- **Cash Reconciliations** – Cash reconciliations should be more timely as they will be done through GP rather than an excel spreadsheet. Also, much of the work can be done prior to month end.

(d)

Current forecast costs are $0.500 million in 2012 and $0.250 million in 2013. Please see YUB-YEC-1-36(d). The scope of this work is still following internal approvals but generally the plans will encompass the following areas:

- Enter the balance of assets into the CMMS module;
- Complete automation of time sheet entry;
- Configure system for IFRS (if required)
- Enhance/automate monthly P-card transaction upload
- Integrate budget preparation and reporting into the system
- Develop data warehouse for historical data and related KPI and dashboard reporting and
- Complete automation of key reports.

At this time, Yukon Energy cannot confirm all of these items will be successfully executed in 2012/13. Subject matter experts are currently developing plans to move these items forward; these plans will require internal management review and approval before proceeding.

(e)

The Electronic Document Management System is not part of the Financial System Replacement.

The Financial System Replacement projected described in the 2008/2009 GRA was deferred by one year due to staff workload and availability issues. The project described in 2008/2009 was based on information available at that time, but was also further defined after the 2008/2009 GRA. Please see also YUB-YEC-1-36(b).

(f)

Please see response to YUB-YEC-1-36. Yukon Energy does not have copies of any research conducted by applicants into business systems now in use across Canada. For the purposes of selecting a system, YEC issued an expression of interest to prospective vendors; from this process 11 potential suppliers were identified and invited to participate in an RFP process. From this, YEC short-listed to 4 for full evaluation.

(g)

The project is planned to be completed before the end of 2013 and will be included in rate base in the test years.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-21

YEC states that the scope of the Victoria Gold Grid Connection project includes negotiating a Power Purchase Agreement with Victoria Gold, design and permitting of line and substations and construction of grid connection. Based on the system extension policy for industrial customers the customer contribution will fully cover all costs for these activities.

PREAMBLE:

QUESTION:

a) Please confirm whether the Victoria Gold Grid Connection project was or will be submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please identify when the Power Purchase Agreement is expected to be submitted to the YUB for approval.

c) Please provide a component breakdown of the Victoria Gold Grid Connection project expenditures by year.

d) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

e) Please confirm that this project will not result in any addition to revenue requirements recovered from non-industrial customers.

ANSWER:

(a)

This project has not been submitted to the Minister or the YUB for review pursuant to Part 3 of the Public Utilities Act.

See response to LE-YEC-1-18 which notes that a Part 3 review requires an OIC designating a project as a "regulated project" under the Public Utilities Act. Prior to OIC designation, no application pursuant to Part 3 of the PUA can be made, or is required to be made, by a utility. No YUB review can commence under Part 3 prior to a reference by the Minister pursuant to Part 3 after the necessary OIC designation and the necessary subsequent utility application.

(b)

Victoria Gold is not expected to require service until the end of 2014 at the earliest. A power purchase agreement will be submitted to the YUB for approval after such agreement has been concluded. Yukon Energy is currently in discussion with Victoria Gold; however, a PPA has not been concluded at this time.

(c)

A component breakdown is not available at this time.

(d) and **(e)**

Assuming the project proceeds, costs required to hook up mine to the grid will be fully recovered from the mine pursuant to the system extension policy approved by Order 2010-13 and implemented regarding prior industrial connections (Minto mine and Alexco mine).

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-22

YEC states that the costs related to the Western Copper Grid Connection project will be fully recovered from Western Copper.

PREAMBLE:

QUESTION:

a) Please confirm whether the Western Copper Grid Connection project was or will be submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please identify when the Power Purchase Agreement is expected to be submitted to the YUB for approval.

c) Please provide a component breakdown of the Western Copper Grid Connection project expenditures by year.

d) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

e) Please confirm that this project will not result in any addition to revenue requirements recovered from non-industrial customers.

ANSWER:

(a)

This project has not been submitted to the Minister or the YUB for review pursuant to Part 3 of the Public Utilities Act.

See response to LE-YEC-1-18 which notes that a Part 3 review requires an OIC designating a project as a "regulated project" under the Public Utilities Act. Prior to OIC designation, no application pursuant to Part 3 of the PUA can be made, or is required to be made, by a utility. No YUB review can commence under Part 3 prior to a reference by the Minister pursuant to Part 3 after the necessary OIC designation and the necessary subsequent utility application.

(b)

Western Copper is not expected to require service any sooner than sometime in 2015. A power purchase agreement is expected to be submitted to the YUB for approval as required after such agreement has been concluded. Yukon Energy is currently in discussion with Western Copper; however, a PPA has not been concluded at this time.

(c)

A component breakdown is not available at this time.

(d) and **(e)**

Assuming the project proceeds, costs required to hook up mine to the grid will be fully recovered from the mine pursuant to the system extension policy approved by Order 2010-13 and implemented regarding prior industrial connections (Minto mine and Alexco mine).

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-22

YEC states "Total spending on property, plant and equipment from 2009 to 2011 for projects less than $1 million averaged $7.9 million. The ongoing capital works spending on property, plant and equipment is forecast at $5.426 million, for projects added to rate base in 2012 and $7.107 million for 2013".

PREAMBLE:

QUESTION:

a) Please update Table 5.2 with actual 2007, 2008 and 2011 expenditures.

b) Please explain the treatment of these projects for rate base purposes and the timing of them being added to rate base.

c) Please provide a component breakdown of project expenditures by year for all projects with a cost estimate of $500,000 or more.

ANSWER:

(a)

Actual data for 2007 and 2008 was made available at the 2008/09 GRA.

With respect to 2011 data, please see YECL-YEC-1-42.

(b)

Table 5.2 shows the year of completion of each project, indicating the fiscal year for its addition to rate base.

(c)

Consistent with YEC's 2005 rate filing and 2008/09 GRA, YEC's 2012/13 GRA sets out extensive detail on all projects over $1 million. Details on spending by component is provided in the following IRs for the below-noted projects:

- CSTP Stage II – CW-YEC-1-26;
- Aishihik 3rd turbine – CW-YEC-1-28 and LE-YEC-1-21;
- Mayo B – LE-YEC-1-20;
- Aishihik Redundancy – LE-YEC-1-23;
- Aishihik River Berm; Aishihik Elevator Modernization; Aishihik Third Turbine Spare Parts – LE-YEC-1-29;
- Wind Feasibility – LE-YEC-1-30;
- Mayo Substation – UCG-YEC-1-51;
- Mayo Headgate – UCG-YEC-1-52;
- Whitehorse Spillway – UCG-YEC-1-54; and
- JDE Enterprise System – UCG-YEC-1-56.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-28

YEC is proposing that approximately $13.55 million in deferred cost be placed into rate base by the end of 2013 for four hydro enhancement projects: Marsh Lake ($4.8 million), Gladstone ($4.4 million), Atlin ($2.2 million) and Mayo Lake ($2.1 million).

PREAMBLE:

QUESTION:

a) Please update the Continuity Schedules of Deferred Costs under Tab 5 with actual 2007 and 2008 expenditures on these four projects.

b) Please confirm whether any of these four projects was or will be submitted to the Minister or the YUB to review under Part 3 of the *Public Utilities Act* per the YUB's recommendation in its January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025 that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

c) For each of these projects, please provide: (1) a chronology of the development from inception until this application; (2) all consultation materials including but not limited to letters to and from stakeholders, First Nations, other Governments, as well as meeting notes; (3) details of the process of decision making to go ahead with project studies; (4) a component breakdown of costs incurred including but not limited to internal costs and costs for outside consultants; and (5) details of the process used to choose consultants for each study, the names of project study consultants chosen and the cost breakdown for each consultant.

ANSWER:

(a)

Please see Attachment 1 to YUB-YEC-1-39 (j).

(b)

None of these four projects has been submitted to the Minister or the YUB for review pursuant to Part 3 of the Public Utilities Act.

See response to LE-YEC-1-18 which notes that a Part 3 review requires an OIC designating a project as a "regulated project" under the Public Utilities Act. Prior to OIC designation, no application pursuant to Part 3 of the PUA can be made, or is required to be made, by a utility. No YUB review can commence under Part 3 prior to a reference by the Minister pursuant to Part 3 after the necessary OIC designation and the necessary subsequent utility application.

(c)

Section 5.3.1, and the response to YUB-YEC-1-25 and YUB-YEC-1-40(b), provide a chronology of the development for each of these four projects, business cases, and decision making to date to go ahead with phases of development.

The following links are provided to public consultation materials on YEC's website for each of these four projects:

- **Marsh Lake Storage & Atlin Lake Storage**
http://yukonenergy.ca/energy/projects/marshenhancement/

- **Gladstone Diversion**
http://yukonenergy.ca/energy/projects/gladstone/

- **Mayo Lake Storage**
http://yukonenergy.ca/energy/projects/mayo_enhanced/

A breakdown of costs to the end of 2011 for Marsh Lake Storage (by task and by consultant) is provided in response to YUB-YEC-1-42.

A breakdown of costs to the end of 2011 for Atlin Lake Storage (by task and by consultant) is provided in response to YUB-YEC-1-44.

A breakdown of costs for Gladstone Diversion to the end of 2011 (by task and by consultant) is provided in response to YUB-YEC-1-43.

A breakdown of costs for Mayo Lake Enhanced Storage to the end of 2011 (by task and by consultant) is provided in response to YUB-YEC-1-45.

With regard to planning and studies work for Marsh Lake, Atlin and Gladstone, all three projects were tendered as part of one RFP process. Yukon Energy determined it did not have sufficient skilled staff or in house resources to dedicate towards project management tasks associated with advancing feasibility and planning processes for the renewable energy proposed in the Resource Plan. To advance these projects an RFP was issued to engage an external project manager to carry these projects through the feasibility and planning phases leading towards construction.

The selected Project Manager under the RFP process was required to work with the Director, Resource Planning and Regulatory Affairs (and any necessary external resources) to design and execute a variety of tasks to carry the projects through progressive planning phases towards construction with progress monitored and controlled through regulatory scheduled meetings as the project advanced through staged approvals (defined by Approvals for Expenditures [AFEs]) to achieve planning phase milestones.

Upon hiring a Project Manager (AECOM) the goals and processes of the working relationship were jointly defined and agreed to ensure work focused on identified tasks and spending remained within defined budgets. A scope of work was developed which identified tasks, responsibility areas, risks, associated timelines, deliverables and estimated costs, with expectation that cost estimates and timelines would be defined with further available information.

With regard to Mayo Lake – it is noted that this project was originally included as part of the Mayo B Project. As such, in order to advance the project efficiently, the consultants retained for the Mayo B project were retained to continue work on the Mayo Lake project. This includes EDI (aquatics); InterGroup (Project Management during EA phase) and KGS (engineering and modeling).

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-28

YEC is proposing spending on Demand Side Management initiatives to end of 2011 of $1.037 million (offset with $0.735 million contribution), forecast spending in 2012 of $1.074 million and forecast spending in 2013 to go into rate base of 1.635 million. Amounts each year are forecast to be closed at end of year and amortized over ten years pursuant to YEC's proposed DSM Accounting Policy.

PREAMBLE:

QUESTION:

a) Given YEC's evidence that Demand Side Management is widely recognized in utility resource planning to be feasible at relatively low cost for ongoing implementation with non-industrial and industrial customers, please provide details of YEC's DSM programs and types of expenditures (including consultant costs) since 2007.

b) Please provide details of the planning, feasibility and implementation program costs and savings expected to be incurred in 2011, 2012 and 2013.

c) Please provide details of how DSM-related costs will be recovered from ratepayers and details of that recovery by rate class.

ANSWER:

(a)

Please see response to YUB-YEC-1-46(c) and (d).

(b)

Please see response to YUB-YEC-1-46(c) and (d).

(c)

All DSM-related costs will be subject to a prudence review by the Yukon Utilities Board prior to being included in rates. Cost recovery by class will be pursuant to the approved cost of service.

All Energy Conservation employee hours are attributed to DSM projects and subject to the rigour of cost effectiveness tests as part of the administrative costs of each program. In the development of the DSM plan, all programs have been developed to include administration. The programs are all analyzed using the industry best practice of four cost-effectiveness tests (Total Resource Cost, Participant Cost, Rate Impact Measure, and Utility Cost/program Administrator Cost). Only programs which have a positive cost/benefit ratio (including both incentive and program costs) have been added to the DSM plan for implementation by the utilities.

See also response to YUB-YEC-1-52(d).

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-29

YEC is proposing spending on Waste to Energy/Biomass initiatives to end of 2011 of $0.741 million (offset with $0.113 million contribution) and forecast spending in 2012 of $0.613 million (offset with $0.113 million contribution). YEC is proposing that amounts deferred to the end of 2012 will be closed and amortized over 10 years starting in 2013.

PREAMBLE:

QUESTION:

a) Please provide details of YEC's Waste to Energy / Biomass programs and types of expenditures (including consultant costs) since 2007.

b) Please provide details of the program costs and benefits / savings expected to be incurred in 2011, 2012 and 2013.

c) Please provide details of how Waste to Energy / Biomass-related costs will be recovered from ratepayers and details of that recovery by rate class.

ANSWER:

(a) and **(b)**

Please see response to YCS-YEC-1-16 for detailed breakdown of costs by consultant. See also response to YUB-YEC-1-47 for further information that YEC can provide on Waste to Energy/Biomass.

No expected costs or savings/benefits are currently expected to be incurred in rates or revenue requirement during the test years.

(c)

Pursuant to the proposed Planning Cost Accounting Policy provided as Appendix 5.1, project costs will be deferred and closed out at the end of 2012. Costs closed out at the end of 2012 will be amortized over 10 years.

Costs related to Waste to Energy/Biomass will be recovered through rates in the same manner as other YEC costs. Such costs will be recovered from ratepayers pursuant to that last approved cost of service study.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-29

YEC is proposing spending on District Heating initiatives to end of 2011 of $0.070 million (offset with $0.53 million contribution), forecast spending in 2012 of $0.460 million, and forecast spending in 2013 of $0.50 million. YEC is proposing that amounts deferred will be closed and amortized over 5 years starting in 2014.

PREAMBLE:

QUESTION:

a) Please provide details of YEC's District Heating programs and types of expenditures (including consultant costs) since 2007.

b) Please provide details of the program costs and benefits / savings expected to be incurred in 2011, 2012 and 2013.

c) Please provide details of how District Heating-related costs will be recovered from ratepayers and details of that recovery by rate class.

ANSWER:

(a) and **(b)**

Please see response to YCS-YEC-1-17 for detailed breakdown of costs by consultant. See also response to YUB-YEC-1-48 for further information that YEC can provide on District Heating.

No expected costs or savings/benefits are currently expected to be incurred in rates or revenue requirement during the test years.

(c)

Costs related to District Heating will be recovered through rates in the same manner as other YEC costs. Such costs will be recovered from ratepayers pursuant to that last approved cost of service study.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-29

YEC is proposing spending on Liquified (sic) Natural Gas initiatives to end of 2011 of $0.169 million, forecast spending in 2012 of $1.500 million and another $1 million in 2013. YEC proposes to carry 2011 and 2012 costs in fixed assets WIP beyond 2012.

PREAMBLE:

QUESTION:

a) Please provide details of YEC's Liquified (sic) Natural Gas programs and types of expenditures (including consultant costs) since 2007.

b) Please provide details of the program costs and benefits / savings expected to be incurred in 2011, 2012 and 2013.

c) Please provide details of how Liquified (sic) Natural Gas-related costs will be recovered from ratepayers and details of that recovery by rate class.

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-49 for a summary of current information that YEC can provide on LNG. A cost breakdown of spending to the end of 2011 is provided in YCS-YEC-1-18. No expected costs or savings/benefits are currently expected to be incurred in rates or revenue requirement during the test years.

(c)

Costs related to LNG will be recovered through rates in the same manner as other YEC costs, with the fuel portion of costs being subject to the same DCF costing procedures as diesel fuel costs today (to address hydro-related variations in LNG generation requirements). The potential relevance of Rider F treatment will be examined.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-29

YEC is proposing spending on Geothermal initiatives to end of 2011 of $1.95 million (with amounts deferred to the end of 2011 closed and amortized over 10 years starting in 2012) and forecast spending in 2012 of $0.386 million (with amounts closed out at end of 2012 and amortized over 10 years) and another $0.30 million in 2013 (to be closed and amortized over 5 years).

PREAMBLE:

QUESTION:

a) Please provide details of YEC's Geothermal programs and types of expenditures (including consultant costs) since 2007.

b) Please provide details of the program costs and benefits / savings expected to be incurred in 2011, 2012 and 2013.

c) Please provide details of how Geothermal-related costs will be recovered from ratepayers and details of that recovery by rate class.

ANSWER:

(a)

Please see response to YUB-YEC-1- 50(e).

(b)

Please see response to YUB-YEC-1-50(e) for details of project costs in 2011, 2012 and 2013. The enduring value of this work will be the collection and assessment of data, as well as preliminary resource assessment of and prioritization of Yukon sites identified for further study.

(c)

As noted in the Application, deferred studies costs to date for this project will be deferred and amortized over the test years; pursuant to the proposed planning cost accounting policy, at the end of 2011 current balances will be crystallized and amortized over 10 years. Deferred costs in 2012 will be crystallized and amortized over 5 years. These amortization costs are included in the 2012/2013 Revenue Requirement to be collected via Rider J for 2012 and Rider R for 2013.

Cost recovery by class at this time is based on the across-the-board nature of Riders J and R.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 5, Page 5-47

YEC states that the projected total 2012 and 2013 spending on deferred cost activities outside of major projects over $1 million totals $2.89 million in 2012, and a total of $2.7 million for 2013. Spending in 2012 and 2013 on each deferred cost activity between $100,000 and $1 million totals $2.61 million for 2012 and $2.60 million in 2013.

PREAMBLE:

QUESTION:

a) Please explain the treatment of these projects for rate base purposes and the timing of them being added to rate base.

b) Please provide a component breakdown of project expenditures by year for all projects with a cost estimate of $500,000 or more.

ANSWER:

(a)

The treatment of the cited projects for the test years is summarized in Tables 5.6 (2012) and 5.7 (2013). Those projects that show balances in Work in Progress are not in rate base; all other balances shown in those tables are in rate base for the respective test year.

(b)

Consistent with YEC's 2005 rate filing and 2008/09 GRA, YEC's 2012/13 GRA sets out extensive detail on all projects over $1 million. Details on spending by component are provided in the following IRs for the below-noted projects:

- Geothermal - YUB-YEC-1-50(e);
- District Heating – YCS-YEC-1-17(a);

- Large Hydro – YUB-YEC-1-51(c);
- IFRS – CW-YEC-1(c);
- Wind – Ferry Hill – LE-YEC-1-30(a);
- Waste to Energy – YCS-YEC-1-16(a);
- Marsh Lake – YUB-YEC-1-42(i);
- Gladstone – YUB-YEC-1-43(d); and
- LNG – YCS-YEC-1-18(a).

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 7, Schedule 5

PREAMBLE:

QUESTION:

a) Please update this table with 2007, 2008 and 2011 actuals.

b) Please provide the allocation of total revenue requirements identified for 2007, 2008, 2009, 2010, 2011, 2012 and 2013 by rate class.

ANSWER:

(a)

Please see responses to UCG-YEC-1-27(a), UCG-YEC-1-28(a), UCG-YEC-1-29(a), UCG-YEC-1-30(a), UCG-YEC-1-31(a), UCG-YEC-1-32(a), UCG-YEC-1-33(a), UCG-YEC-1-34(a) and UCG-YEC-1-35(a) for tables with 2011 actuals. The information for 2007 and 2008 was not compiled for the current GRA as this information was available at the time of the 2008/09 GRA review proceeding.

(b)

YEC cannot provide the requested information as no revenue requirements identified for actual years. Please see Table 1 form the 2012/13 GRA Application for revenues collected from each rate class for 2009-2011 actual years and proposed for 2012 and 2013.

TOPIC:

REFERENCE: April 27, 2012 Application, Tab 7, Schedule 9

PREAMBLE:

QUESTION:

a) Please update this table with 2007, 2008 and 2011 actuals.

b) For each rate class, please provide a table showing revenues recovered in 2009, 2010 and 2011 above or below the allowed 2009 revenue recovery level.

ANSWER:

(a)

Please see response to YECL-YEC-1-2 for updated sales numbers for 2011 actuals. The information for 2007 and 2008 were not compiled for the current GRA as this information were available at the time of the 2008/09 GRA review proceeding.

(b)

YEC does not record revenues for each rate class by comparing to 2009 approved numbers and therefore cannot provide this information.

Please see response to UCG-YEC-1-17.

Yukon Conservation Society
(YCS)

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Yukon Conservation Society requests Yukon Energy Corporation (YEC) submit and present the *Wind Assessment Feasibility Study Final Report* dated January 2009, as released to YCS under an access to information request, to the Yukon Utilities Board and the Intervenors.

ANSWER:

(a)

Please see Attachment 1 to this response.

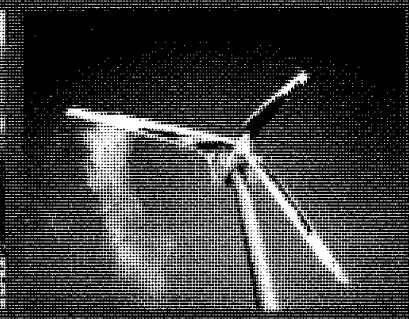
For a more detailed discussion of this project's economics in light of 2011 Resource Plan forecasts see the 2011 20-Year Resource Plan: 2011-2030 Overview provided as attachment to YECL-YEC-1-18. See also response to YCS-YEC-1-8.

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Wind Assessment Feasibility Study

Final Report

YUKON ENERGY

January 2009

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Monday, February 2, 2009

Hector Campbell. P. Eng., I.S.P.
Director, Resource Planning & Regulatory Affairs
Yukon Energy Corporation
Ph: (867) 393-5331
Fax: (867) 393-5323

Subject: **Wind Assessment Feasibility Study**
PO 22-0302-G581-00800-1000
Tecsult 05-18037

Dear Mr. Campbell,

TECSULT AECOM is pleased to submit to Yukon Energy Corporation (YEC) the Wind Assessment Feasibility Study - Report. The analysis is recognized with the wind data provided by YEC. The Conclusion of the study demonstrates the feasibility of a 20 MW Wind Energy Project at Mount Sumanik. The Total Capital Cost of the project is estimated around CAD $ 72M. Also, in the long term, a 20 MW Wind Project is economically more viable than a Diesel Plant of an equivalent size. The next step would be a Detailed Study including the design and install a 60 – 80 m measurement mast in order to further investigate the wind regime as well as the icing accumulation problem on Mount Sumanik.

We thank you for this opportunity and we hope to continue to serve you during the detailed study phase of this important project. We are very confident that the result of the detailed study, as recommended by us, will lead to a successful project. Looking forward to hearing from you soon. Please do not hesitate to call me at (514) 287-8500 ext 8351, if you may have any question.

Sincerely,

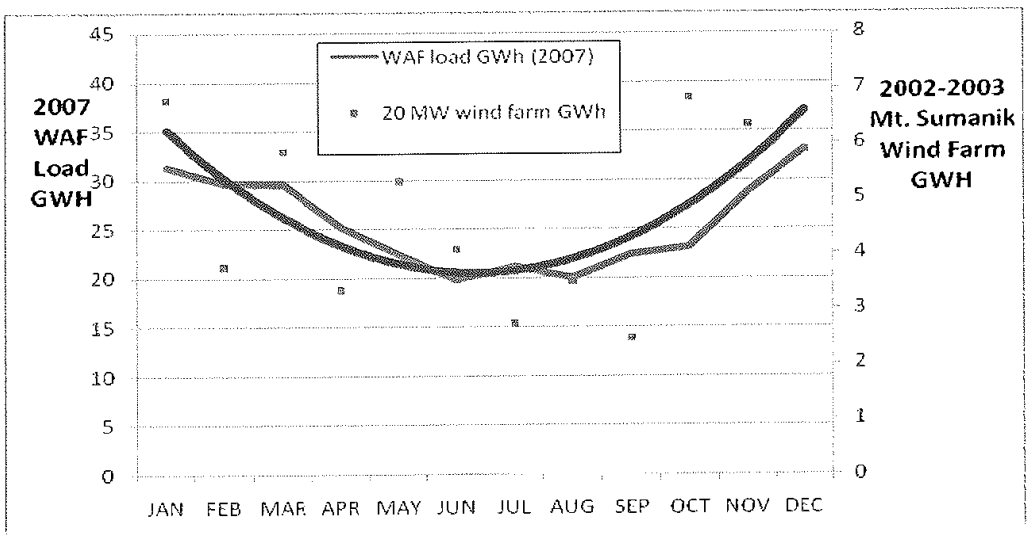
Georges Tadros, P. Eng.
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Executive Summary

Wind energy, specifically on Mt. Sumanik, is generally a good fit with Yukon Energy's electrical energy needs. It is most abundant in winter when system electrical loads are highest. Figure 1 below illustrates graphically how the availability of wind resources during the entire year matches the electrical load.

Figure 1 WAF load patterns compared to Mt. Sumanik wind energy



The current study has shown, using Yukon Energy's spreadsheet economic assessment model, that a 20 MW wind energy project on Mt. Sumanik is economic relative to base load diesel energy. The model used diesel fuel at $1.15 per litre but even at $0.75 per litre wind energy is more economic. The real cost of wind energy ranged from about $0.16 to about $0.19 per kWh compared to about $0.35 for diesel energy. Table 1 below provides a summary of the economic analyses.

Table 1 Summary of economic analyses

Wind Project variation	Present Value of savings relative to base load diesel
No blade heating No incentive program	46%
No blade heating With incentive program	51%
With blade heating No incentive program	49%
With blade heating With incentive program	54%

4

A 20 MW wind farm project based on using 2MW Vestas V90 wind turbines, was modelled using the WindFarmer modelling software. The estimated net energy produced by such a project is 53.82 GWh per year before allowances for icing losses. After the authors' deduction for icing losses the net estimated production was 40.4 GWh per year.

The Capital cost for the Project was estimated to be $72.119 million or about $3,606 per kW of capacity. [redacted] This figure does not include blade heating systems and no renewable energy subsidies were assumed to apply.

The authors have concluded that icing energy loss is the most serious issue affecting a possible wind project on Mt. Sumanik. Even globally, there is not the expertise or data from which to accurately assess icing related losses. Based on the data and experience available from Scandinavia and from Yukon Energy on Haeckel Hill, the authors have used an estimate of about 25% for icing losses which are concentrated in the November to January time frame.

If a full surface blade heating system were available for the turbines this would add an estimated $4 million to the capital costs of the project but would reduce the estimated net icing losses by half. Thus net annual production would increase to 47.1 GWh per year. At the projected capital cost and net energy benefit, a blade heating system would be economically beneficial.

A federal ecoENERGY for Renewable Energy program has been providing a production incentive to wind farms in Canada for a number of years. The Canadian Wind Energy Association is lobbying the federal government to provide an improved subsidy for northern and remote communities. If adopted by the federal government as proposed, such a program would provide a capital subsidy of about $200 per kW (about $4 million total) for a 20 MW project on Mt. Sumanik plus a production incentive of $0.02 per kWh. As can be seen from Table 1 above such a subsidy would improve the economics of a wind project noticeably. No territorial subsidies were assumed.

[redacted]

The operating and maintenance cost of the wind farm was estimated to be $0.043 per kWh or $43 per MWh. This is composed of $0.02 "normal" O&M cost, $0.022 for costs such as insurance, land lease and taxes, plus $0.001 per kWh for snow clearing and road maintenance.

29th of January 2009
Montreal, Québec, Canada

Georges Tadros, P.Eng
Projects Director

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1 Study Objective

The objective of the current study is to investigate the capital and operating costs of a 20 MW commercial scale wind energy project on Mt. Sumanik. Mt. Sumanik is located near Whitehorse immediately to the west of Haeckel Hill where Yukon Energy's existing two wind turbines are located.

A study based on the available data should be able to determine qualitatively whether it is worthwhile pursuing a wind energy project on Mt. Sumanik and if so to make recommendations on the next steps to be undertaken.

2 Methodologies

The authors commenced the project by reviewing the reports and data provided by Yukon Energy. The documents and data provided to the authors are described in section 3.1 below. This information was supplemented by other information and data secured by the authors including maps, wind data, research and conference papers, and manufacturers' information.

The data provided by Yukon Energy included about two years of wind resource data from Mt. Sumanik. This data was reviewed and assessed and in a process of correlation with Upper Air (radiosonde) data a full calendar year of data was developed. This incorporated corrections for the estimated effect of icing on the anemometers. More complete descriptions of this data and its development are provided in section 3.1.2 and section 5 of this report.

The capital costs for the project were developed by a combination of two methods. First, based on the authors' experience (mainly in Europe) the overall capital costs for a project of similar size by major cost centres was developed. The second was a detail up approache based on Yukon specific costs. The two methods were correlated to produce one overall cost estimate both by cost centre and by a longer list of details. Section 7.1 describes the capital costs.

Operating costs were determined by summing three components, the normal operating costs for a wind farm which were scaled up for Yukon realities, the owners' costs that would be incurred (provided by Yukon Energy) and a separate allowance for road maintenance specific to the project. These are described in section 7.4.

The projected wind turbines placement and energy produced by a 20 MW wind farm were provided by the WindFarmer modelling program which used many of the above and other inputs. Due to the limited nature of this project and the limits of the data available, a relatively simpler rather than a very detailed analysis was performed using WindFarmer. See sections 4 and 5.2 for more detail.

Project economic analyses were performed using Yukon Energy's analysis spreadsheet provided to the authors for this purpose. This spreadsheet compares a candidate project with base load diesel. Section 9 provides the detail.

2.1 Avalable documents & information

Following documents and information were provided by Yukon Energy:

- Wind data from Mt. Sumanik, January 2001 to May 2003
- Wind Energy Potential, Report #5, Boreal Alternate Energy Centre, September 1996

- Sumanik Mountain Summary Wind Analysis January 2001 to May 2003, Cathy Cottrell, July 2004
- Wind Power Generation in the Yukon, Yukon Energy Corporation, August 1995

The following information was obtained by the authors:

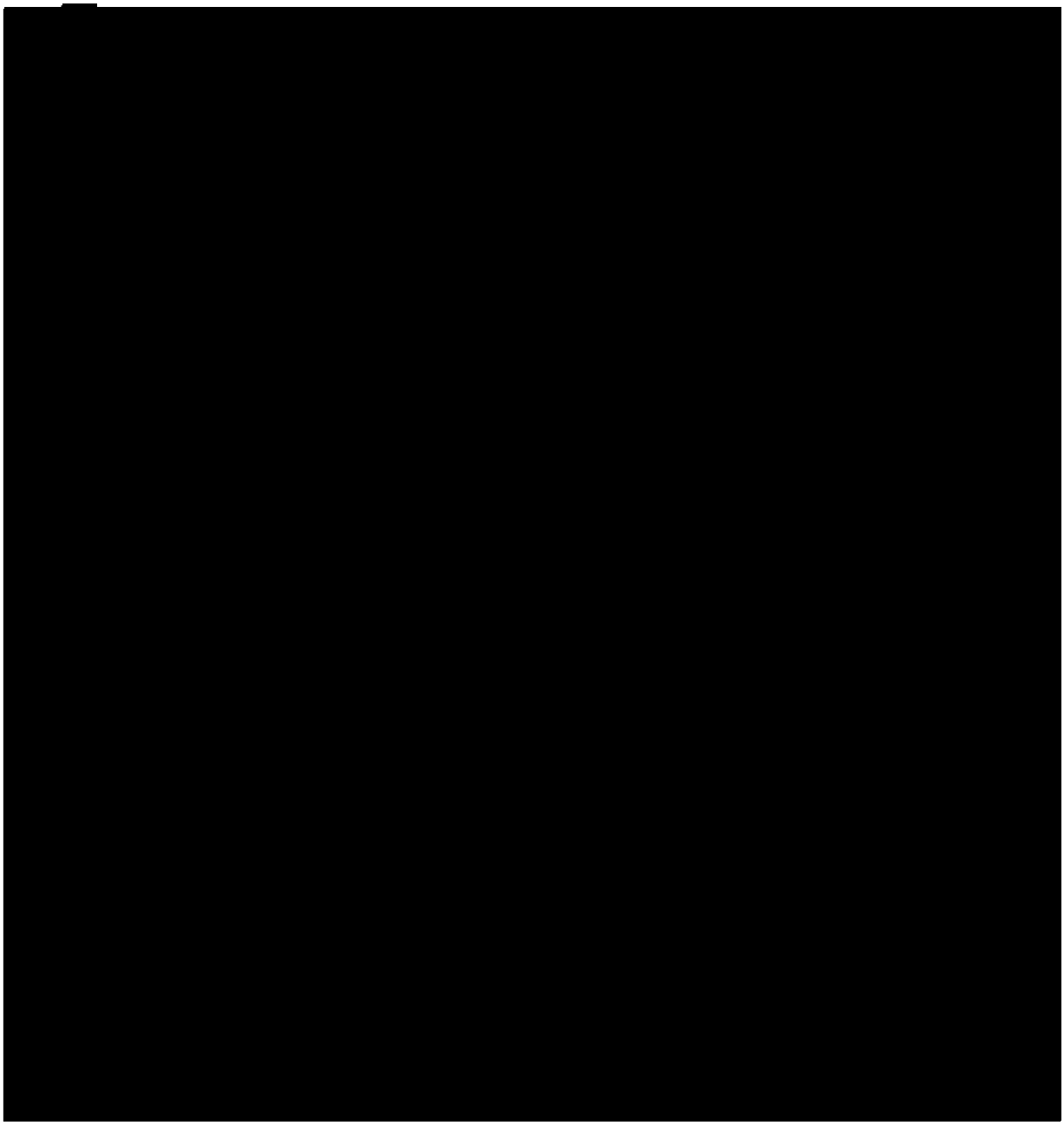


Figure [redacted]

[redacted]

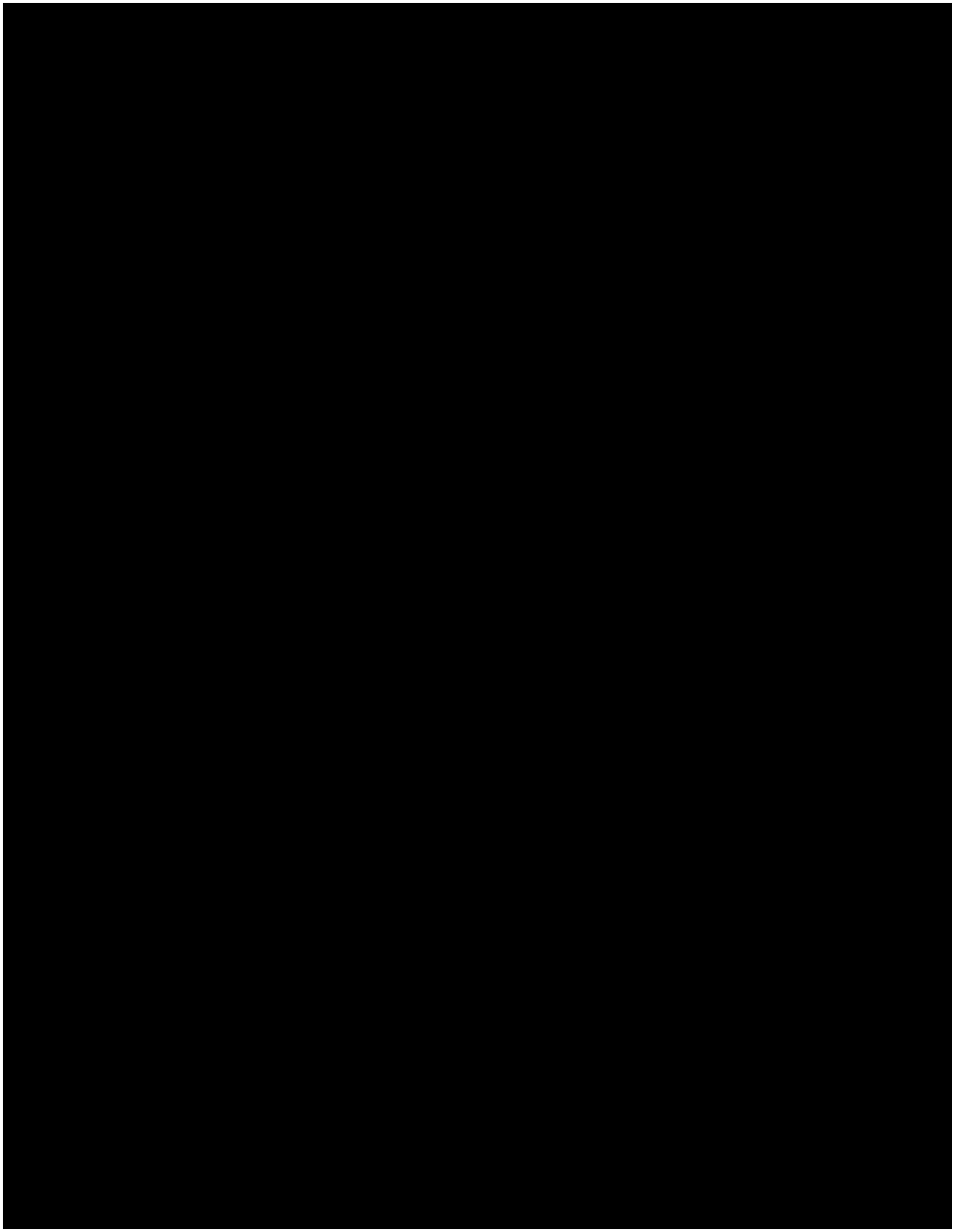
[redacted]

2.2.2 Wind data

The Mt. Sumanik Wind Resource data analyses reports provided by Yukon Energy were studied and the data were examined in detail. The authors have also examined the long term monthly data from the Whitehorse radiosonde (Upper Air) station (1955 to October 2008). The Upper Air data is obtained from a weather balloon released twice per day and have provided reliable long term data that is unaffected by rime icing. The one drawback of this data is that there are a limited number of data points – only two data points per day (every 12 hours, morning and evening); however, the long term reliable information provides a very valuable baseline. A description of the data analyses performed on the Yukon Energy data, the Upper Air data, and how the two were used together are described in the subsections below.

2.2.3 [redacted]

[redacted]



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3 The WindFarmer Program

WindFarmer is a PC based program for predicting wind climates and power production from wind turbines and wind farms. The predictions are based on wind data measured at stations in the same region. The program includes a complex terrain flow model, a roughness change model and a model for sheltering obstacles.

The data gathered by the measurement stations, also called wind climate statistics, is extrapolated vertically and horizontally. The program contains several physical models to describe the wind flow over different terrains and different sheltering obstacles. Wind Farmer is an implementation of the so-called wind atlas methodology, which is summarized on the following page.

The central point of the wind transformation model used by WindFarmer – the so-called Wind Atlas Methodology is the concept of a Regional or Generalized Wind Climate, or "Wind Atlas". This Regional Wind Climate (RWC) is the hypothetical wind climate for an ideal, completely flat terrain with uniform surface roughness, assuming the same overall atmospheric conditions as those of the measuring position.

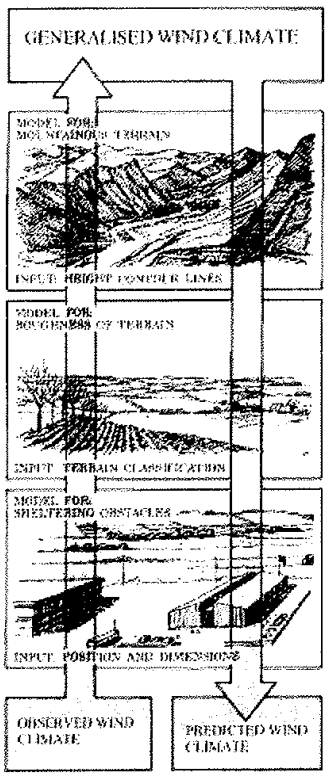
The concept of the Regional Wind Climate links the wind data from a measuring mast to the predicted wind climate and wind resources at locations of interest. Usually these locations are potential sites for a wind turbine or a wind farm.

The **WindFarmer** program is the most powerful and flexible commercially available system of its type and is an essential tool for wind farm development. Drawing on many years' expertise gained in aerodynamics and wind farm development **WindFarmer** enables users to analyze, design and optimize wind projects. **WindFarmer** calculates the energy yield of a wind farm while simultaneously including topographic and wake effects. The turbine layout can be optimized for maximum energy yield or minimum cost of energy whilst subject to natural, planning (including noise) and engineering constraints.

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Schematic presentation of WindFarmer

To deduce regional wind climate from measured wind in the actual terrain the same flow model is used, but reversely, it is done so as to remove the local terrain effects.



To deduce the wind climate at a location of interest from the regional wind climate, a flow model is used, to introduce the effect of the different terrain features:

- terrain height variations
- *terrain roughness
- *sheltering obstacles

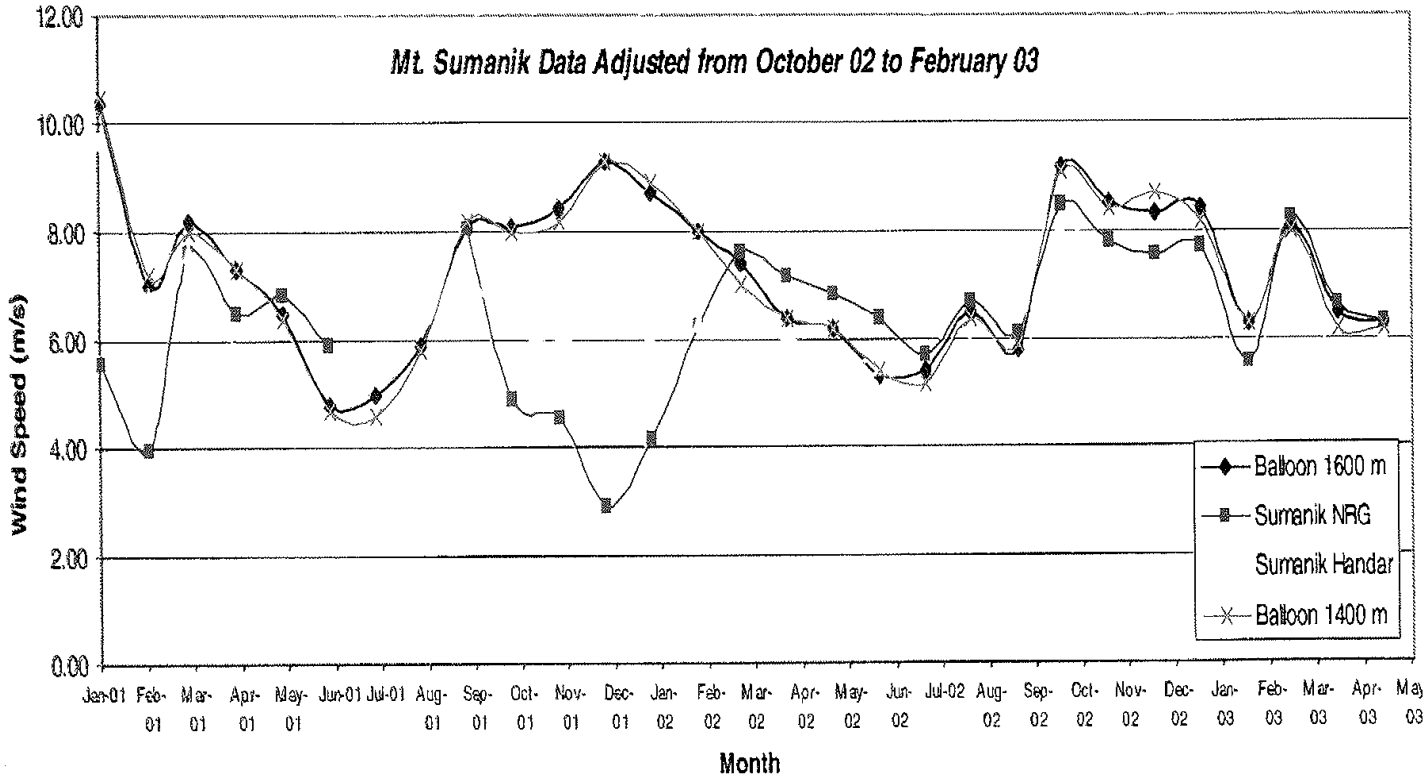
4 Wind Data and Analyses

4.1 Mt. Sumanik site data

The detailed wind data provided by Yukon Energy covered the period January 2001 to May 2003. The wind speed and direction measurements were taken at 23 meters Above Ground Level (AGL), the short mast being used to prevent icing related failures experienced with taller masts. Wind speed measurements were taken by a Handar heated ultrasonic instrument (wind speed and direction), and by an NRG Ice Free heated anemometer. Temperature and relative humidity instruments were located near ground level. Electrical energy was supplied from a large battery bank charged by wind and solar power.

The figure below graphically summarizes the wind speed data for the entire period and compares it to Upper Air (weather balloon) data. The average temperature during these years is -5.56°C.

Figure 4 Yukon Energy's Mt. Sumanik wind speed data (from Cottrell 2004)

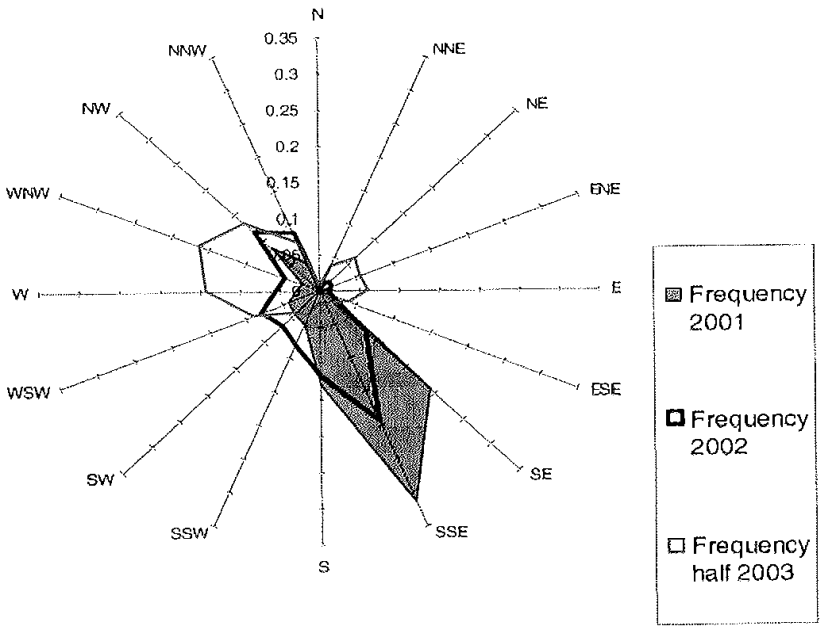


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The wind rose shows a wind blowing from the south-southeast, northwest and west. The average monthly wind roses show that from September to January southeast winds are predominant; from February to May northwest winds appear to be equal to or greater than southeast winds; and the period from June to August seems to be a transition period.

Figure 5: Sumanik Handar 425 Wind Rose
January 2001 - May 2003



4.2 Yukon Energy data

The Sumanik Mountain Summary Wind Analysis January 2001 to May 2003, report by Cathy Cottrell indicates that the most reliable period of wind resource data from Mt. Sumanik was obtained from January 2002 through May 2003. For the purposes of having a representative annual data set it was decided to use the last 12 months of this period, June 2002 through May 2003. A spreadsheet of the 10 minute average data for all of the measurements for this period was assembled from the raw data provided. This data was obtained from instruments located at about 23 meters AGL. The purpose of the relatively short tower was to reduce the risk of failure under ice loading. The data was then adjusted as described below to produce a quality controlled data set of a full year's duration.

The Cottrell report and a review of all the data indicated that the wind speed data obtained from the NRG Ice Free™ heated anemometer gave the most reliable wind speed data, so it was decided to use this as the basis for the required data set. The wind direction data was only available from a Handar heated ultrasonic wind instrument, so this data was also selected to be used for analysis. Standard deviations of both the wind speed and direction measurements which were also calculated and recorded in the original data are retained. Relative humidity measurements and temperature measurements from the project site are also deemed useful and retained. The day and time of each recorded 10 minute average data set

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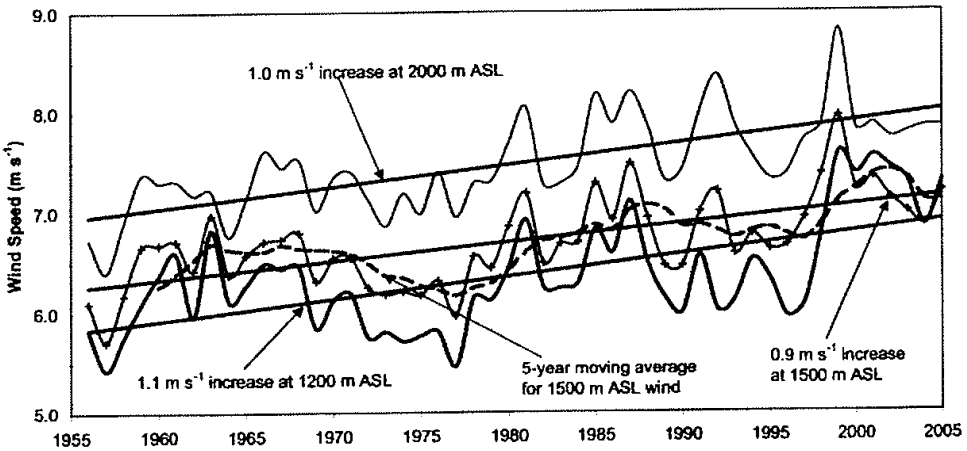
were also retained. All other parameters recorded as part of the original data set were deleted from the spreadsheet for the purposes of the Mt. Sumanik project. Additional information is added as described later. The completed wind data set was then ready for input into the WindFarmer Program.

The wind speed and direction data were often affected by rime icing during the winter months, and occasionally by other unknown problems during the summer months. Where it was obvious that the anemometers providing the wind speed was immobilized by rime ice the data were deleted, and similarly wind direction data corrupted by rime ice on the ultrasonic instrument (indicated by direction in excess of 360°) was also deleted. The relative humidity sensor also malfunctioned from time to time under high relative humidity conditions (particularly in the winter months) so this faulty data was also deleted. It should be noted that there were many times when the NRG anemometer was affected by rime ice but continued to operate at reduced speed (indicating a falsely lower wind speed) but such data was not removed as it could not always be reliably detected. Adjustments are made to this remaining winter data to correct (approximately) for such errors as described later. The obviously faulty summer data was also removed. The final quality controlled data set was thus produced.

4.3 Upper Air data

The Upper Air data from 1955 to present indicates that there is a long term slow increase in wind speed trend and that there can be fairly significant year to year variations in average wind speeds[1]. However the period from 2000 to present is very near the long term trend line. It was thus decided to use the monthly average data for the period January 2000 through October 2008 at the 1800 meter ASL (above sea level) height (closest to Mt. Sumanik at 1700 meters ASL) to calculate any necessary adjustments to the Yukon Energy data set for the purpose of running the wind energy production (WindFarmer) modelling program. The calculated annual average wind speed for this period is 7.350 m/s (meters per second). The wind speed was confirmed by the WindFarmer program.

Figure 6: Annual mean wind speed



[1] J.P. Pinard, ***Wind Climate in Yukon Mountainous Terrain***, Ph.D. Thesis University of Alberta, 2008

Figure 6 shows the time series of annual mean wind speed at three elevations (1200, 1500, and 2000 m ASL) within the Whitehorse valley. The trends at the three elevations were estimated using a linear least squares method fit to the data. A five year moving average for the 1500 m ASL elevation is shown as a dashed line.

Monthly and annual average wind speeds and temperatures were calculated as were average temperatures at the community level. The June 2002 through May 2003 Mt. Sumanik monthly data was compared to the Upper Air data for the same months and to the Upper Air monthly averages for the 2000 to 2008 time period. For the months from April through September the Mt. Sumanik site and the 1800m Upper Air data follow reasonably well with the Mt. Sumanik data showing on average a bit higher wind speed. However, in the winter the Mt. Sumanik data is noticeably below the Upper Air data. It was thus decided that the Upper Air monthly wind speeds for the months October 2002 through March 2003 would be used as the true wind speed reference. Note that while there were obvious icing effects in both September 2002 and April 2003, it was decided that the quality controlled data set was adequate for project modelling. The annual average of the monthly Mt. Sumanik site and monthly Upper Air data mix is 7.335 m/s.

4.4 Mt. Sumanik data adjusted by references to Upper Air data

There are three sets of adjustments that needed to be made to the Mt. Sumanik data. First is an adjustment for the vertical profile of the wind speed – how the wind speed increases with height above ground level. A typical a wind resource assessment tower of 50 or 60 meters in height accommodates three or more sets of anemometers to measure the wind speed at different heights to determine the rate of wind speed increase with height above ground level. Since the Mt. Sumanik data was obtained from a single set of heated instruments at 23 meters AGL, the vertical profile contained in the Upper Air data was used. The data showed that between 1500 and 1800 meters ASL (the two measuring points closest to the Mt. Sumanik summit of about 1700 meters) the rate of increase in wind speed was about 0.5% per 50 meters. So at a wind turbine hub of about 80 meters AGL the wind speed would be about 1.005 times the wind speed measured at 23 meters.

The second adjustment required is for the measured Upper Air wind speed during the June 2002 to May 2003 compared to the average for the period 2000 to 2008. In this case, the Upper Air wind speed measured from June 2002 to May 2003 was lower than the average from 2000 to 2008. The adjustment required to bring it up to that average is 2.126%. So the Mt Sumanik data also needs to be multiplied by 1.02126 to bring it up to the 2000 to 2008 average.

The combination of the first two adjustments is a multiplier of 1.026 which means that the true wind speed reference needs to be multiplied by 1.026 to yield the estimated true wind speed at 80m AGL. The final required adjustment is the amount by which the Mt. Sumanik winter (October through March) data needs to be increased to bring them up to the true wind speed (not rime ice affected) assumed to be the Upper Air monthly figures. The calculations show that during the winter months the Mt. Sumanik data needs to be multiplied by up to 1.445 (January 2003) to bring it to the true estimated wind speed at 80m AGL. These overall multipliers are outlined in Table 4. The estimated true annual average wind speed for the Mt. Sumanik site at 80m AGL is **7.528 m/s**.

In reality applying these multipliers during the winter months will not provide a true wind speed distribution as some portion of the wind speed data would not have been affected by rime icing whereas other data would have been significantly affected. However, we believe that the methods described in the previous paragraphs provide the best wind speed estimates possible in the circumstances and will provide results well within the accuracy specified in the Yukon Energy RFP.

Air density adjustments for temperature and altitude are required for the calculation of power output by wind turbines. This is adjustment is done by the WindFarmer program modelling described elsewhere in this report.

The wind energy produced by a wind farm on Mt. Sumanik appears to be well suited to provide electrical energy to the Yukon Energy WAF (Whitehorse-Aishihik-Faro) grid. There is more energy available during the winter and spring months when hydro supplies are lower and there is less wind energy available in summer months when hydro supplies are higher. The table and graph below illustrate the synergies between the WAF electrical loads and the wind energy from a 20MW wind farm (before adjustment for losses.

Table 1: WAF load patterns compared to Mt. Sumanik wind energy

Month	WAF load	20 MW wind farm
	GWh	GWh
JAN	31.20	6.76
FEB	29.59	3.75
MAR	29.45	5.83
APR	25.07	3.33
MAY	22.31	5.30
JUN	19.74	4.07
JUL	21.07	2.72
AUG	19.97	3.48
SEP	22.35	2.46
OCT	23.00	6.79
NOV	28.66	6.31
DEC	32.95	5.85

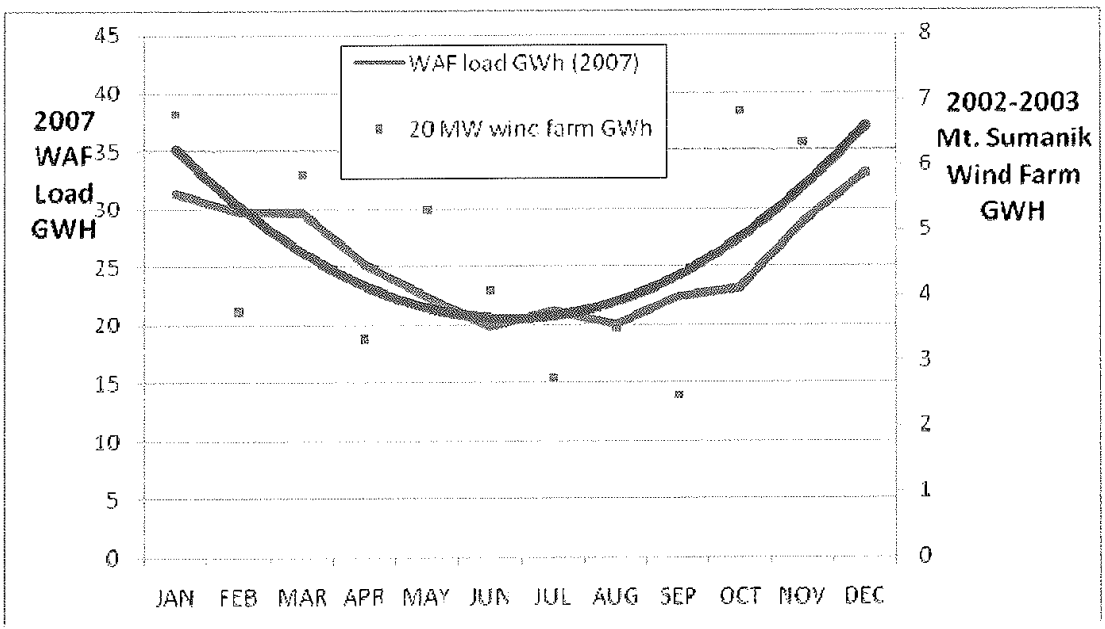


Table 2: Mt. Sumanik site and 1800m ASL Upper Air wind speeds and adjustments

(wind data is in m/s)

Month	Upper Air (UA) 1800 m	NRG Site data 23 meters AGL	Raw data for site model NRG + UA	Model at 80m multiply by 1.005 for 23 to 80 meters turbine hub height 80 m AGL	Model at 80 m c#orrected for UA period to Avg multiply by 1.02126	Overall monthly multipliers NRG to model at 80 m corrected	**2000-2008 Monthly Averages (Avg) 1800 m**
June 2002	5.387	6.890	6.890	6.924	7.072	1.026	**5.061**
July 2002	5.720	5.510	5.510	5.538	5.655	1.026	**5.594**
August 2002	6.576	6.210	6.210	6.241	6.374	1.026	**5.846**
September 2002	5.881	5.290	5.290	5.316	5.429	1.026	**7.360**
October 2002	9.366	8.230	9.366	9.413	9.613	1.168	**8.526**
November 2002	8.763	6.610	8.763	8.807	8.994	1.361	**8.487**
December 2002	8.187	6.300	8.187	8.228	8.403	1.334	**9.386**
January 2003	8.969	6.370	8.969	9.014	9.205	1.445	**9.361**
February 2003	6.667	5.700	6.667	6.700	6.843	1.200	**7.934**
March 2003	8.108	6.660	8.108	8.149	8.322	1.250	**8.263**
April 2003	6.408	6.090	6.090	6.120	6.251	1.026	**6.862**
May 2003	6.200	7.830	7.830	7.869	8.036	1.026	**6.027**
Annual Averages	**7.197**	**6.483**	**7.335**	**7.372**	**7.528**		**7.350**

NOTES: Indicates that NRG site data was used as was - assumes no measurable icing effects in data
NRG data not reliable, Upper Air wind speed data is assumed to be correct for adjusting NRG data

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4.5 Uncertainties

The above results are the findings of the authors based on the data available, and while best professional judgment was used to provide the most accurate analyses possible, the end results are still subject to uncertainty due to weaknesses in the data. This applies not only to the winter icing affected wind speed data, but also to the lack of icing data to more accurately predict what the icing related losses suffered by a wind farm on Mt. Sumanik might be.

Should Yukon Energy wish to proceed to the next phase of project development, more accurate data on the following issues would be beneficial:

- Wind speed and direction sensors that are truly ice free;
- At least three sets of reliable ice free wind speed sensors at various heights up to 60 meters or more AGL;
- Accurate measurements of relative humidity and air density;
- Definition of roughness factors and obstacles, if any, throughout the project site; and
- Measurement of icing presence, frequency, and severity for at least one complete winter season.

Although more accurate than the mesoscale models, WindFarmer is a software and extrapolates the wind resources from a given mast. Errors are inevitable.

Nothing can supplant on site measurements and their correlation to long term data, such as the Whitehorse Upper Air station or at other nearby stations.

4.6 Summary Results of WindFarmer Analyses

Based on the available data, the annual energy production information as provided by the WindFarmer program was 56,652,672 kWh. This energy production was adjusted by WindFarmer for air density variations (altitude and temperature) array losses and electrical losses. This annual production was then divided up into the months of the year based on the wind energy availability and reduced by 5% to allow for a turbine availability of 95% (lower than normal because of the challenging site). The monthly production figures were then reduced for icing losses where applicable to yield monthly production figures.

The net annual production for a 20 MW commercial wind farm, after icing losses, was estimated to be 40.4 GWh.

As an option a case of reduced icing losses was considered on the possibility that a full blade heating system might become available to the project. With icing losses cut in half the net annual production was estimated to be 47.1 GWh.

Appendix II provides the tables of detailed information for the two cases described above.

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5 Icing environments

5.1 Wind Turbines and Icing

In mountainous terrain the higher elevations are generally subject to rime or "in cloud" icing when freezing temperatures. Rime icing is caused by super humidified air, generally due to a drop in atmospheric pressure as moist air from the valleys is pushed up and over mountains by the prevailing winds. Whenever a cloud is seen covering a high hill or mountain and temperatures are below freezing, rime ice will be accumulating. The temperature data recorded at the Mt. Sumanik wind monitoring site is presented in Table 3 below. Note that the twice daily Upper Air data is obtained morning and evenings and may thus provide a slightly different temperature sampling.

Table 3 –Site and Upper Air (1800m ASL) Temperature Data in °C

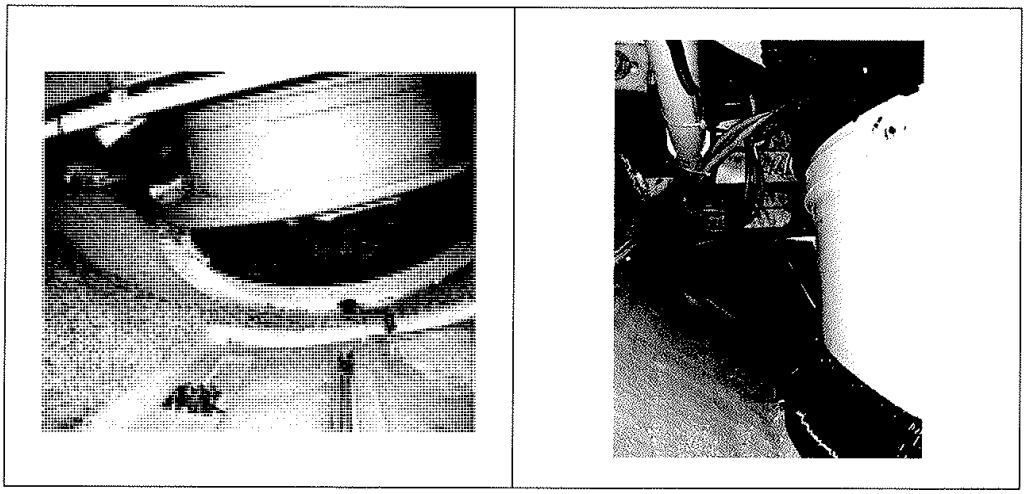
Month	Site data	Upper Air for period	Upper Air 2000 to 2008 averages
June 2002	6.73	3.8	4.54
July 2002	8.10	6.1	6.12
August 2002	5.91	4.2	5.30
September 2002	2.18	0.9	0.20
October 2002	-1.13	-1.4	-4.41
November 2002	-4.91	-4.1	-9.66
December 2002	-9.02	-7.2	-9.81
January 2003	-10.90	-8.9	-11.46
February 2003	-9.13	-9.1	-10.78
March 2003	-13.27	-13.7	-12.61
April 2003	-4.13	-6.3	-6.72
May 2003	0.29	-1.9	-1.07
Annual average	-2.411	-3.10	-4.156

Yukon Energy has experience with two wind turbines that are equipped with ice mitigation features. The first turbine installed was in 1993, a Bonus 150 kW Mark III. The second one, installed in 2000, is a Vestas 660 kW V47. Both turbines are designed to operate in temperatures down to -30°C by the use of low temperature steels, low temperature lubricants and some appropriate heating systems. Such measures are appropriate for the tower, the nacelle, the gearbox, generator, and electrical cabinets. Other ice mitigation features include fully heated wind control instruments (a must), and black ice-phobic blade coatings (very beneficial). Control algorithm changes to permit operation even under reduced power output due to icing effects have proved advantageous to the Bonus wind turbine. For various reasons it was not possible to make all the same changes on the Vestas turbine.

The authors propose that the turbines considered for the project under study be equipped with these features. An additional feature proposed is the use of brush-like "seals" between the blades and hub, and also between the hub (rotor) and the nacelle. This will discourage in ingress if ice into the hub and nacelle during icing conditions. Photos of brush-like seals used on Enercon E30 wind turbines in Antarctica are presented below.

Overhead power lines in icing environments are prone to considerable difficulty and thus, as discussed earlier, the authors propose to use underground cables in icing prone areas.

Figure 7 Photos of "brush" type of seals used in Antarctica[2]



Yukon Energy is aware of the icing challenges and the authors consider icing related energy losses as probably the most significant issue to be dealt with in a wind project on Mt. Sumanik. There is considerable literature from research work carried out in Scandinavia[3]. Researchers there have studied the rime icing losses and have produced a table of projected annual energy losses from wind turbines based on the number of days on which icing conditions occur at a site (see Table 3 below).

Table 4 Estimates of annual losses caused by icing[4]

Frequency of icing – days per year	Annual energy loss
<1	Insignificant
1 – 10	Small
10 – 30	5% - 15%
30 – 60	15% - 25%
>60	>25%

There is no doubt in the authors' minds that Mt. Sumanik would fall in the most severe category of greater than 60 days per year of icing conditions. This would suggest that annual energy losses would be 25% per year or higher without mitigation features. For this reason the authors have assumed that all of the icing mitigation features described above (heated wind instruments, black ice-phobic blade coating, turbine control algorithm modifications, and brush seals) should be used on the turbines installed on Mt.

[2] Peter Magill, Powercorp (Australia), ***Installing Large Scale Renewable Energy Systems in Antarctica***, Yukon International Wind Conference, 2003

[3] - T. Laakso et al, ***State-of-the-Art of Wind Energy in Cold Climates***, 2003
- Schoenberg, ***Two years' Experience of Three Different Turbines on the Same Site – Rodovalen – in the Middle of Sweden***,
- B. Tammelin et al, ***Wind Turbines in Icing Environment: Improvement of Tools for Siting, Certification, and Operation – NEW ICETOOLS***, Finnish Meteorological Institute, 2005

[4] B. Tammelin et al, ***Wind Energy Projects in Cold Climates***, International Energy Agency Program, 2005

Sumanik. Icing related losses were assumed to be about 25% of annual forecast production (absent icing). The losses were estimated on a monthly time step basis with the highest losses, 50%, occurring in November, December, and January.

5.2 Existing Technology

In severe icing conditions, the wind turbine rotor blades get covered with ice reducing the power production or stopping it altogether. If this situation occurs frequently enough so that annual losses are significant a blade de-icing system could be considered. Unfortunately, while some systems have been commercially available from suppliers in the past there are none currently on the market. Yukon Energy's two existing wind turbines were equipped with heating systems on the leading edges of the blades only (the leading edge being the most critical part which is exposed to enormous amounts of rime ice). Rime ice on the remainder of the blade also causes significant air drag and power losses. Leading edge heating is a partial solution, with the ideal being a de-icing system for the entire blade surface.

Full surface blade heating systems have been used with success in Scandinavia (where they were developed and commercially available for a few years from Kemijoki Arctic Technology) and authors[5] have suggested that such systems cost about 5% of the capital cost of a wind turbine (including tower) and would consume 1% to 4% of the annual energy produced.

Some wind turbine manufacturers are again considering blade de-icing systems in their research and development. At a recent conference in Sweden three manufacturers were mentioned as experimenting with blade heating systems, Enercon, WinWinD, and a private firm Kelly Aerospace working with Vestas or on a Vestas turbine. Vestas and Enercon are both active in Canada but WinWinD does not sell their turbines in North America[6].

The authors of this report have, in their economic analyses, examined the impact a blade heating system would have on the project. It was assumed that the cost of a full surface blade heating system would be $200 per kW of turbine capacity and, after allowing for power consumption, reduced icing related losses by 50%. See Appendix III for more details on blade heating systems.

Figure 8: Ice accumulation on 1/4 inch guy wire Yukon Energy photo



[5] T. Laakso and E. Peltola, ***Review on Blade Heating Technology and Future Prospects***, BOREAS VII Conference, 2005

[6] - E. Peltola et al, ***R&D and Market Review of Wind Turbines in Cold and Icing Climates***, WinterWind Conference, 2008
- E. Pederson and H Gedda, ***Wind Turbine Ice Protection System***, WinterWind Conference, 2008
- S. Plagborg (Vestas), ***Going Cold and Icy***, WinterWind Conference, 2008

6 Wind Energy Support Programs

The Canadian Federal Government expanded its initial Wind Power Production Incentive (WPPI) program in the 2005 budget to support the development of 4,000 MW of wind energy development by 2010 [Canadian Wind Energy Association, 2005]. This includes wind energy in the cold weather areas, such as Manitoba, which plans to develop 1,000 MW of wind energy by 2009 - 2014 according to the Manitoba Provincial Government, as well as Quebec Hydro with 3,500 MW of wind energy by 2012[7].

ecoENERGY for Renewable Power (successor to the WPPI program) will provide an incentive of one cent per kilowatt-hour for up to 10 years to eligible low-impact, renewable electricity projects constructed over the next four years, April 1, 2007 to March 31, 2011[8]. However the wind portion is set to be fully committed in 2009.

Wind energy projects in Canada's northern, remote and Aboriginal communities have not been able to benefit from Federal power production incentive programs for wind energy because the incentive level is not high enough to address the higher costs associated with wind energy production in the North.

In 2007, the Canadian Wind Energy Association (CanWEA) proposed to the federal government a specific program (*Remote Community Wind Incentive Program (ReCWIP)*) to help the wind energy being developed in the Northern and remote parts of Canada.

The program proposed consisted of the following elements:

- a capital incentive of $200 per installed kW for large communities and industrial projects, and a capital incentive of $900 per kW for small isolated communities; this means respectively about 5% and 10% of the installed cost for large communities and small communities.

- An incentive of 2 cents per kWh is proposed for large communities and industrial projects to reflect the higher capital and operating costs experienced in the north. For small isolated communities a production incentive of 10 cents per kWh is proposed.

The present wind incentive program 1 cent per kWh incentive represents about 15% of typical electricity generation costs in southern Canada (6 to 8 cents per kWh). Similarly, the proposed ReCWIP incentive represents about 15% of typical electricity generation costs in northern communities (40 to 150 ¢/kWh).

The document *REMOTE COMMUNITY WIND INCENTIVE PROGRAM (ReCWIP)* presented in 2007 by the Canadian Wind Energy Association explains the entire program proposed. A summary of this document is presented in appendix I. As these efforts by CanWEA were not successful in convincing the federal government to adopt this program, they have renewed their efforts by incorporating this proposal into the ecoENERGY for Renewable Power program wind power allocation. CanWEA is now actively lobbying for this expanded wind support program to be incorporated into the January 2009 federal budget.

If adopted by the federal government this program will benefit the development of wind power in Northern Canada. The wind energy will decrease the dependence of these communities on diesel, will promote an environmental energy and will help the economy of the area. Canada is working hard to be a leader in renewable energy. Projects in Northern Canada will assist in the development of wind energy in hard

[7] *Experimental study of 3-d wind turbines blades under icing conditions*, Wang, Naterer, Bibeau, University of Manitoba and University of Ontario Institute of Technology and University of Ontario Institute of Technology

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conditions such as rime icing and wind-diesel applications, and will increase our knowledge in these areas.

If the program is adopted, the possible wind project on Mt. Sumanik, could be eligible for a capital grant of about $200 per kW and a 10 year production incentive of $0.02 per kWh. In their economic analyses the authors have examined the effect of such a support program.

7 Capital and Operating Costs of the Project

To be commercially feasible, a wind farm on Mt. Sumanik should probably be in the range of 20 MW or larger to take advantage of economies of scale. Smaller projects would likely incur higher unit costs. In this section, we considered a 20 MW wind farm. The total estimated cost for such a wind farm is about $72.119 million CAD. This value corresponds approximately to a cost of $3.6 million per MW (or $3,606 per kW). The range of cost on the market right now in Europe is between $2.9 million per MW and $3.6 million per MW, while the average for larger wind farms in Canada is reported to average in the range of $1.8 to $2.2 million per MW. The following table shows how the cost is divided among the different cost centres of the projects. The capital costs outlined here capture the entire project cost from permitting and planning through to interconnection with the present power system and Yukon Energy SCADA controls.

The practical construction season on Mt. Sumanik is likely to be limited to a period from mid June (even then some snow clearing may be required) to mid September. Snow may be experienced from late August on and night frost would be encountered from about mid-August on. There will be permafrost in the bedrock on Mt. Sumanik as there was on Haeckel Hill – this created some challenges in drilling for the foundation rock anchors – the holes kept filling with water and freezing). The winds are lowest during summer (June – August) but they increase noticeably in September.

Table 5: Wind project site and off-site costs

Project Cost	Approximate Cost $CDN	Approximate Percentage
Wind turbines and related	$ 52 206 000	72%
Civil work	$ 11 156 250	15%
Electrical work	$ 6 394 500	9%
Other	$ 2 362 500	3%
Total	**$ 72 119 250**	**100%**

Table 6: Capital cost details

Conceptual project based on the use of Vestas V90 2MW wind turbines – 80 meter hub height

Item	Description	Units required	Unit cost	Total cost	Cost + 5% contingency	Comments	Project cost
1	Permitting through YESAA process	1	500 000 $	500 000 $	525 000 $	Whitehorse Designated Office level assumed, and First Nations Benefits Agreements, if necessary included	other
2	Wind turbines and towers	10	4 922 000 $	49 220 000 $	51 681 000 $	Includes 2 year service contract, unit transformers, manufacturer's SCADA system, initial spare parts, installation cost, commissioning, and testing	turbines
3	Wind turbine passive ice mitigation features	10	50 000 $	500 000 $	525 000 $	Includes blck staClean icephobic coating, heated control instruments, and brush seals around blades and hub	turbines
4	Transport from west coast port to site	10	100 000 $	1 000 000 $	1 050 000 $	Options are road transport from port ,or barge to Skagway and road to Whitehorse	other
5	Design of civil facilities	1	250 000 $	250 000 $	262 500 $	Includes roads, foundations and geotechnical	civil
6	Design of electrical facilities	1	400 000 $	400 000 $	420 000 $	Includes powerlines, and substation	electrical
7	Access - existing road upgrading, per km	5	90 000 $	450 000 $	472 500 $	Improvement of Haeckel Hill ccess road	civil
8	Access - new road, per km	11	160 000 $	1 760 000 $	1 848 000 $	New road from Haeckel Hill road to top of Mt. Sumanik and along line of turbines	civil
9	New overhead 34.5 kV powerline, per km	10	150 000 $	1 500 000 $	1 575 000 $	From McIntyre substation to valley between Haeckel Hill and Mt. Sumanik where underground cable begins, and includes a fibre optic line for communications and control	electrical
10	New underground 34.5 kV cable, per km	7	400 000 $	2 800 000 $	2 940 000 $	Includes fibre optic line for communications and control	electrical

11	Expansion to existing 138 kV to 34.5 kV McIntyre substation	1	1 250 000 $	1 250 000 $	1 312 500 $	Includes 20MVA transformer, breakers, protection, and Yukon Energy SCADA connection	electrical
12	Turbine foundation installation	10	750 000 $	7 500 000 $	7 875 000 $	Includes ground preparation, rock anchoring, forming, rea bar, and concrete	civil
13	Large crane (450+ tonne) mob and demob	1	400 000 $	400 000 $	420 000 $	From Alberta assumed	civil
14	Support crane (100 tonne) mob and demob	1	80 000 $	80 000 $	84 000 $	From Alberta assumed (could be used in Skagway to unload barge and load trucks	civil
15	Large crane turbine installation cost per turbine	10	10 000 $	100 000 $	105 000 $	Exact price to be determined during later stages	civil
16	Support crane turbine installation cost per turbine	10	4 000 $	40 000 $	42 000 $	Exact price to be determined during later stages	civil
17	Helper crane (45 tonne)	10	2 000 $	20 000 $	21 000 $	Exact price to be determined during later stages	civil
18	Yukon Energy SCADA project interface	1	140 000 $	140 000 $	147 000 $	To permit Yukon Energy control of wind turbines, located in McIntyre substation	electrical
19	On site building	1	25 000 $	25 000 $	26 250 $	Shipping container based, to include, local controls, spare part storage, and warm-up building for staff	civil
20	Nodwell or Bombardier tracked vehicle	1	250 000 $	250 000 $	262 500 $	Enclosed cab with room for tools and equipment for winter use for O&M service personnel - to speed access and avoid need to plough the road in winter	other
21	Training of O&M staff and misc costs	1	500 000 $	500 000 $	525 000 $	To include any and all costs not already included above	other
	TOTAL CAPITAL COSTS			**$68 685 000**	**$72 119 250**		

7.1 Civil works

The civil works will include the following:

- Foundation and concrete base for all turbines;
- All required road upgrading and new road, including roads within the wind farm perimeter;
- Trenching for all buried cable;
- All related equipments (such as crane rental);
- All geotechnical work and civil design; and
- A small on-site building.

7.2 [redacted]

[redacted]

7.3 Wind Turbines and related

The wind turbines and related will include the following:

- Purchase of the wind turbines (10 x Vestas V90 2MW – 80m hub height turbines assumed);
- Purchase of 80 meter towers,
- Manufacturer's SCADA system;
- Unit transformers;
- Installation, commissioning, and testing;
- Initial spare parts; and
- A two year service contract (to be evaluated in a detailed study).

7.3.1 Choice of Turbine

To take advantage of the economies of scale the wind farm should be no less than 20 MW. At the Mt. Sumanik site, it is possible to install at least 20 MW. Again for economies of scale, it is suggested the wind turbines selected for the site be in the range of 1.5 to 2 MW. In this case, Vestas and Enercon proposed different turbines that could be used in this application. The proposed turbine is the Vestas V90-2MW – 80m hub height. This decision is based upon the simulations done with various turbines with the WindFarmer software. Vestas was also chosen because it has some particular features for icing climates. This choice will have to be confirmed in the next phases of the project.

7.3.2 Vestas V90-2MW

The Vestas V90-2MW – 80m hub height is a three bladed upwind horizontal axis wind turbine designed and manufactured by Vestas specifically for the light wind regimes. Essentially, it is a V80 with a larger rotor (giving 27% more swept area than the V80), although incorporating a number of the new innovations from the V90-3MW especially in blade and tower technology.

The design follows what is now considered a contemporary design in wind turbine technology, using a doubly fed induction generator in conjunction with pitch control system to allow for variable speed operation. For a full description of the turbine please see the Vestas brochure in Appendix IV

Information on other possible turbine options is also available in Appendix IV.

7.4 Other costs

This category of costs captures various items which did not fit into any of the above categories, and include the following:

- Permitting and related costs;
- Transport of the turbines and towers to the site from a port or factory;
- A tracked vehicle for winter operations and maintenance;
- Staff training; and
- Other miscellaneous costs.

7.5 [redacted]

[redacted]

7.6 [redacted]

[redacted]

7.7 Operating Costs

Operating costs for wind farms in Europe are in the order of €0.007 per kWh or $0.0115 per kWh, and generally it is accepted that operating costs should be no more than $US0.01 per kWh in North America. However given the relatively small size of the wind farm and the relatively remote and challenging nature of the site it was decided that $0.02 per kWh would be appropriate for budgeting for a Mt. Sumanik project.

In addition to this, Yukon Energy will have insurance, land tenure, and property tax related costs. Yukon Energy estimates these at $0.022 per kWh. And finally there will be annual snow removal and road maintenance costs. The authors assumed these would be kept to a minimum, and a provision of $0.001 per kWh was made.

The overall operating cost was thus estimated to be $0.043 per kWh or $43 per MWh.

8 Economic Analyses

Economic analyses of the wind farm were performed using a spreadsheet model provided by Yukon Energy. This model requires the input of capital costs, operating costs, expected useful life of the project, annual energy produced by the project. It also includes several financial parameters relevant to Yukon Energy. The model yields a comparison between the wind energy project and a base load diesel plant that provides the same amount of energy. Yukon Energy's model uses a diesel fuel price of $1.15 per litre.

The analyses show that the wind energy project, even with no financial incentives and no blade heating systems (25% icing losses), is economic compared to the base load diesel option. Under these conditions it appears that a project would be economic even with diesel fuel costing $0.75 per litre. Based on these overall very positive results there would appear to be every justification to seriously pursue a wind generation project.

Table 6 below provides a summary of the economic analyses. Detailed information is provided in Appendix V.

Table 7: Summary of economic analyses

Wind Project variation	Present Value of savings relative to base load diesel
No blade heating No incentive program	46%
No blade heating With incentive program	51%
With blade heating No incentive program	49%
With blade heating With incentive program	54%

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9 Conclusions and Recommendations

9.1 Conclusions

This study has shown that based on all the information available and using Yukon Energy Corporation's economic analysis spreadsheet model, a wind project on Mt. Sumanik would be economic compared to base load diesel, even with diesel prices as low as $0.75 per litre.

Projected energy loss due to rime icing was by far the largest variable and relative unknown in the analyses performed by the authors.

The results of this study show that there is every reason to further pursue the possibility of a wind energy project on Mt. Sumanik.

9.2 Recommendations

The next steps towards a Wind Energy project of at least 20 MW should encompass the following:

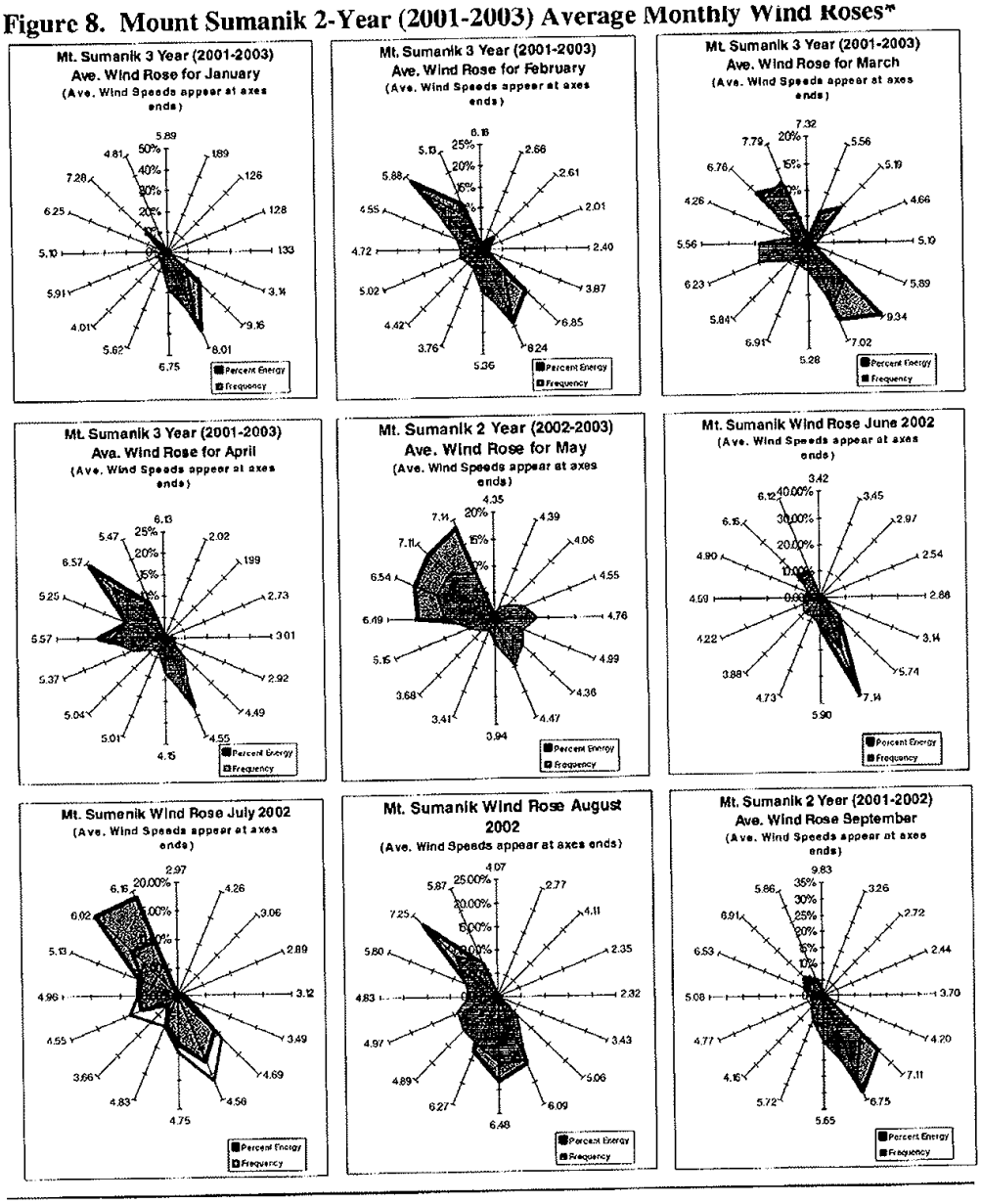
- An analysis of existing data to determine whether a wind farm on Mt. Sumanik could provide a capacity benefit to the WAF grid;
- The installation of a heavy duty engineered measurement mast at least 60 meters high that can withstand the ice loading that normal wind masts cannot withstand, and that the mast be equipped with the best heated ice free wind instruments available at least four different elevations (15, 30, 45, and 60 meters for example);
- The mast referred to above to be equipped with the latest ice detection and assessment instruments to assess the frequency, duration, and severity of icing events on Mt. Sumanik;
- The mast and its instruments to be provided with a very reliable power supply in order to obtain the highest possible quality of information;
- Discussions with various turbine and third parties involved in the development and testing of blade heating systems to try to secure access to blade heating systems for a wind project on Mt. Sumanik;
- Various planning and assessment activities that could shorten the lead time to the installation of a project, with due respect to the costs involved; and
- An investigation by Yukon Energy into the possibility of support from the Yukon Cold Climate Innovation Centre for the recommended work on Mt. Sumanik (at least the icing assessment related work).

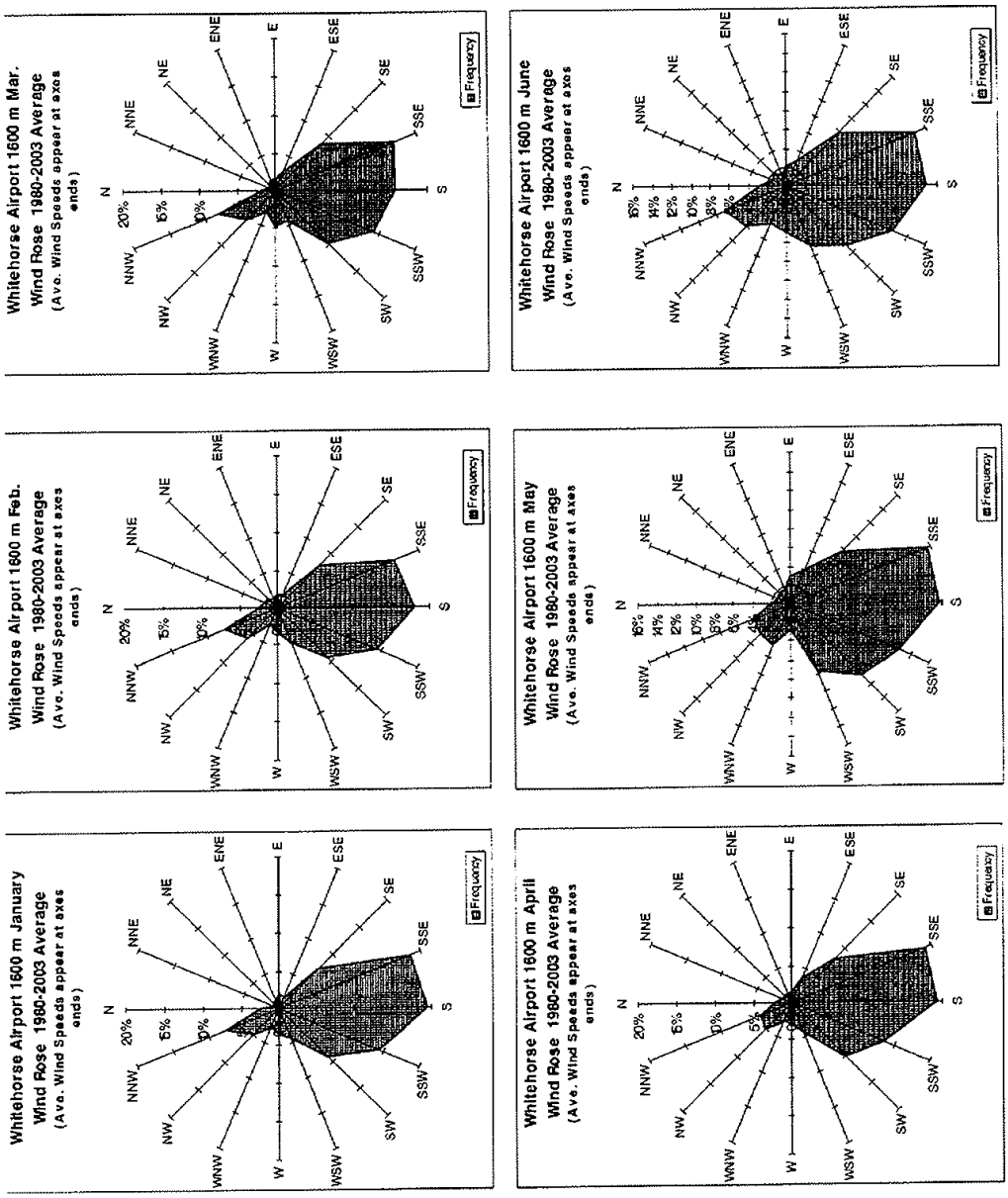
Appendix I

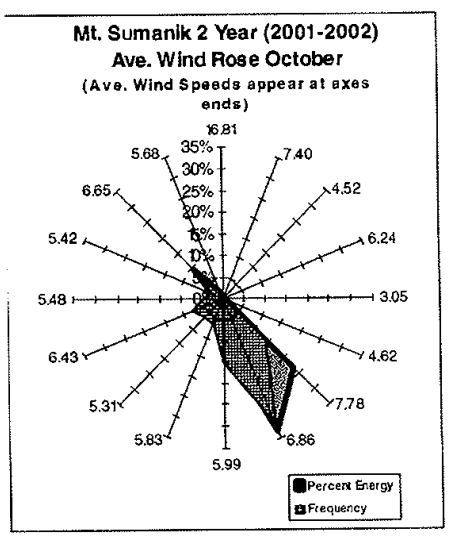
Wind Roses

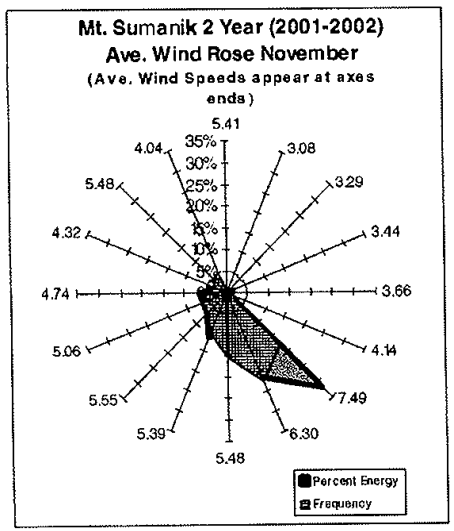
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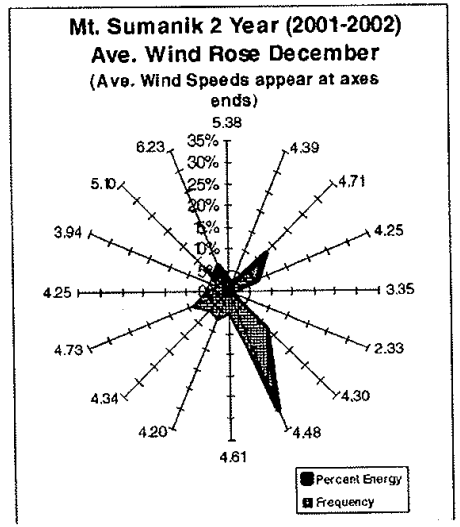
Figure 8. Mount Sumanik 2-Year (2001-2003) Average Monthly Wind Roses




Whitehorse Airport 1600 m January
Wind Rose 1980-2003 Average
(Ave. Wind Speeds appear at axes ends)
Whitehorse Airport 1600 m Feb.
Wind Rose 1980-2003 Average
(Ave. Wind Speeds appear at axes ends)
Whitehorse Airport 1600 m Mar.
Wind Rose 1980-2003 Average
(Ave. Wind Speeds appear at axes ends)
Whitehorse Airport 1600 m April
Wind Rose 1980-2003 Average
(Ave. Wind Speeds appear at axes ends)
Whitehorse Airport 1600 m May
Wind Rose 1980-2003 Average
(Ave. Wind Speeds appear at axes ends)
Whitehorse Airport 1600 m June
Wind Rose 1980-2003 Average
(Ave. Wind Speeds appear at axes ends)
N
NNE
NE
ENE
E
ESE
SE
SSE
S
SSW
SW
WSW
W
WNW
NW
NNW
20%
15%
10%
5%
Frequency







The Whitehorse Upper Air data (incorrectly labelled as airport data) for each month show a somewhat different long-term trend than site data. From 1980 to 2003, the Whitehorse balloon clearly shows a prevailing south to southeast winds throughout the year. They never show as strong a northwest component as the Sumanik data show.

Appendix II

Wind Farmer analyses

Mt. Sumanik 20 MW Wind Project Power Production No Blade Heating								
Month	Mt. Sumanik adjusted wind speed 75m AGL	Temperature monthly average	Air density at 1800m and average temperature kg/m3	Project output after deduction for array and elecrical losses (Wind Farmer)	Output after deduction for downtime of 5% (95% availability)	Projected rime icing losses %	Estimated icing losses in kWh	Net production in k/Wh
June 2002	7.072	4.544	1.023	4 068 633	3 865 201	0.00%	0	3 865 201
July 2002	5.655	6.122	1.019	2 723 259	2 587 096	0.00%	0	2 587 096
August 2002	6.374	5.300	1.021	3 480 582	3 306 552	0.00%	0	3 306 552
September 2002	5.429	0.200	1.036	2 463 481	2 340 307	10.00%	234 031	2 106 276
October 2002	9.613	-4.411	1.050	6 794 312	6 454 596	25.00%	1 613 649	4 840 947
November 2002	8.994	-9.663	1.066	6 314 612	5 998 881	50.00%	2 999 441	2 999 441
December 2002	8.403	-9.813	1.066	5 854 756	5 562 018	50.00%	2 781 009	2 781 009
January 2003	9.205	-11.456	1.071	6 761 169	6 423 110	50.00%	3 211 555	3 211 555
February 2003	6.843	-10.778	1.069	3 745 441	3 558 169	40.00%	1 423 268	2 134 902
March 2003	8.322	-12.611	1.075	5 825 011	5 533 761	15.00%	830 064	4 703 696
April 2003	6.251	-6.722	1.057	3 325 272	3 159 009	10.00%	315 901	2 843 108
May 2003	8.036	-1.067	1.040	5 296 144	5 031 337	0.00%	0	5 031 337
Annual Averages	**7.528**	**-4.156**		**56 652 672**	**53 820 038**	**~25%**	**13 408 917**	**40 411 121**

Notes
Annual output of wind project is based on Vestas V90 2 MW – 80m hub height wind turbines and WindFarmer modelling
Monthly output of wind project is based on wind energy available in each month
Capacity factor before downtime losses (but after array and electrical losses in WindFarmer) is 32.33%
Capacity factor before icing losses is 30.72%
Capacity factor after icing losses is 23.07%
Estimated icing losses are subjective professional opinion based on all the available data and available literature

Mt. Sumanik 20 MW Wind Project Power Production With Blade Heating								
Month	Mt. Sumanik adjusted wind speed 75m AGL	Temperature monthly average	Air density at 1800m and average temperature kg/m3	Project output after deduction for array and elecrical losses (Wind Farmer)	Output after deduction for downtime of 5% (95% availability)	Projected rime icing losses %	Icing losses in kWh	Net production in k/Wh
June 2002	7.072	4.544	1.023	4 068 633	3 865 201	0.00%	0	3 865 201
July 2002	5.655	6.122	1.019	2 723 259	2 587 096	0.00%	0	2 587 096
August 2002	6.374	5.300	1.021	3 480 582	3 306 552	0.00%	0	3 306 552
September 2002	5.429	0.200	1.036	2 463 481	2 340 307	5.00%	117 015	2 223 292
October 2002	9.613	-4.411	1.050	6 794 312	6 454 596	12.50%	806 825	5 647 772
November 2002	8.994	-9.663	1.066	6 314 612	5 998 881	25.00%	1 499 720	4 499 161
December 2002	8.403	-9.813	1.066	5 854 756	5 562 018	25.00%	1 390 504	4 171 513
January 2003	9.205	-11.456	1.071	6 761 169	6 423 110	25.00%	1 605 778	4 817 333
February 2003	6.843	-10.778	1.069	3 745 441	3 558 169	20.00%	711 634	2 846 535
March 2003	8.322	-12.611	1.075	5 825 011	5 533 761	7.50%	415 032	5 118 729
April 2003	6.251	-6.722	1.057	3 325 272	3 159 009	5.00%	157 950	3 001 058
May 2003	8.036	-1.067	1.040	5 296 144	5 031 337	0.00%	0	5 031 337
Annual Averages	**7.528**	**-4.156**		**56 652 672**	**53 820 038**	**~12.5%**	**6 704 459**	**47 115 580**

Notes
Annual output of wind project is based on Vestas V90 2 MW – 80m hub height wind turbines and WindFarmer modelling
Monthly output of wind project is based on wind energy available in each month
Capacity factor before downtime losses (but after array and electrical losses in WindFarmer) is 32.33%
Capacity factor before icing losses is 30.72%
Capacity factor after icing losses is 26.89%
Blade heating is projected to reduce icing related losses by 50% (net of power consumption)
Estimated icing losses are subjective professional opinion based on all the available data and available literature

Appendix III

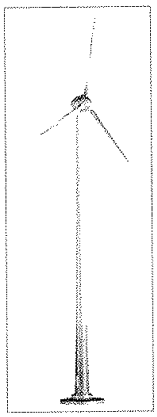
Blade heating systems

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ENERCON

Enercon has an experimental hot air (internal) blade heating system on one E40 tirbine in Switzerland. This system was installed some years ago and is not commercially available at this time. Because it has to shut down to heat the blades it is not condisered very practical and the turbine has at times not been able to restart for some time after it shut down as the heating system could not cope with severe icing. The Rotor blade heating control from Enercon procedure is the following:

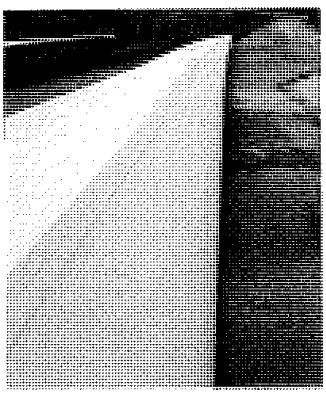
1. Ice detected
2. Wind Energy Conversion (WEC) shuts down
3. Rotor blade heating activated
4. Heating runs for a specified period of time
5. WEC starts up again automatically
6. If after startup, ice is still detected, the WEC shuts down again and the heating process restarts.



Enercon, E-44:
900 kW

Kelly Aerospace Thermal Systems

One of the companies working on a blade heating system is Kelly Aerospace Thermal Systems. This American company is working on a system designed to operate down to -40 °C, the prototype has been installed on a Vestas V90 2MW turbine in Sweden this fall and should be operational in January 2009.



Heaters installed on the ground, Sweden

As with Yukon Energy's leading edge heaters, this heating system is installed externally onto the blade and there is no blade modifications required. Also, the system is or will be adaptable to various power densities and voltages.

The prototype Vestas V90 utilizes 93 heaters, 31 per blade. Heaters are wired in series to produce large heater zones. Power is pulsed between each zone to raise its temperature and de-ice the blade: 1 – 3 deg per second rise in temperature. The V90 system utilizes 23 kW of Power. The total de-ice time is 7 to 14 minutes. With higher power densities the de-ice cycle time decreases. This system can also operate as an anti-ice system.

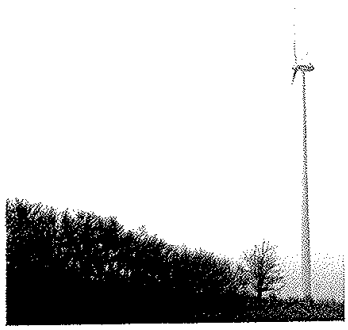
Appendix IV

Wind turbines

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Vestas

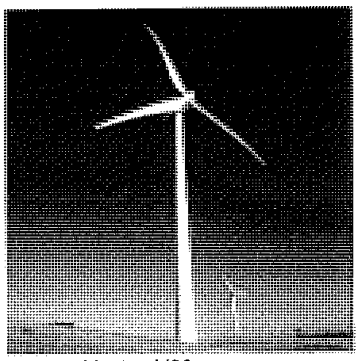
Vestas, a Denmark based company, is the world's leading supplier of wind turbines. Vestas has different wind turbines that could be used in this project. The first one, a 1.65 MW V82 wind turbine has, in its "Arctic" version already been installed at cold climate sites such as Manitoba. The V82 operates in ambient temperatures ranging from -30°C to +40°C.



This wind turbine meets the strictest standards in the wind industry. It has a simple design and it is easy to use and maintain compared to other turbines of this type. The V82 turbine is optimal for low and medium winds, as the one we encounter in Mt. Sumanik. It is optimum at wind speed of 6.5 m/s at hub height and need a wind of 3.5 m/s to start production.

For more technical specifications see Vestas V82- 1.65 MW brochure on next pages.

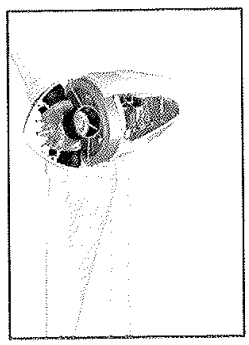
For more technical specifications see Vestas internet site at http://www.vestas.com/en/wind-power-solutions/wind-turbines/.



Vestas V80

Enercon

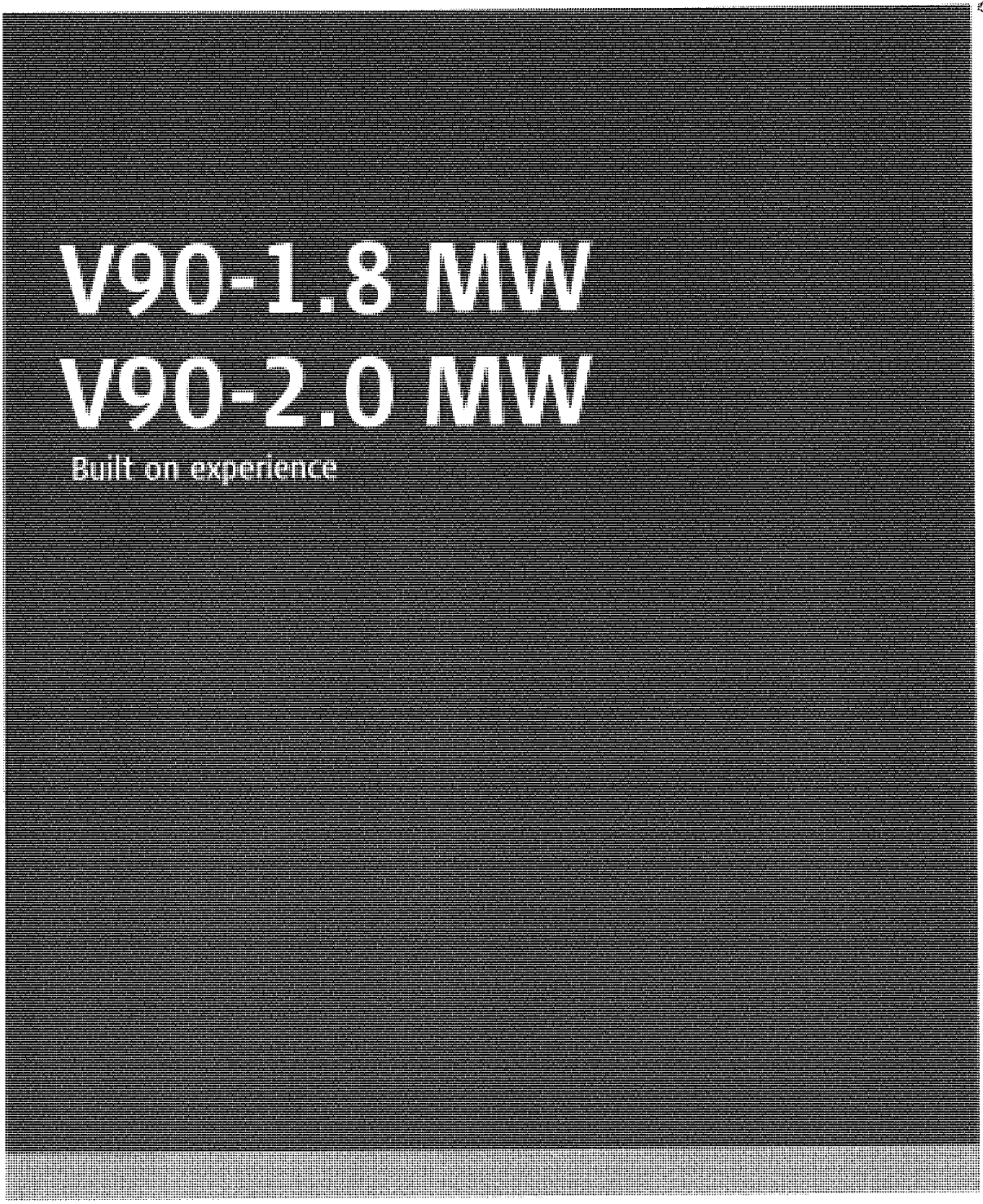
The E-82 from Enercon, another international and leading company in wind energy, is also a good choice of turbine for the present project. With a power of 2 MW and a hub height from 78 -138 m, this turbine is ideal for medium wind speeds.



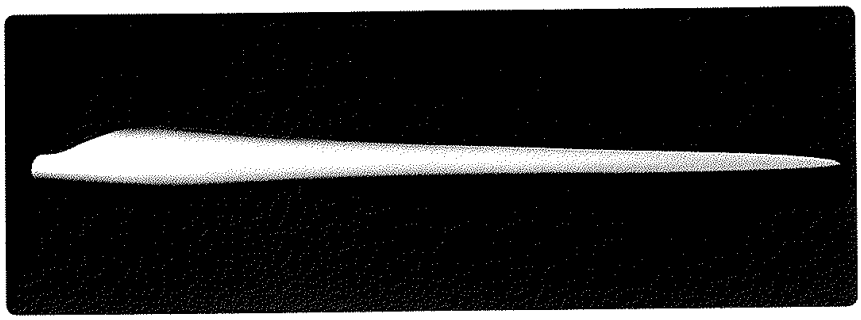
This turbine meets the IEC/NVN II standards.

For more technical specifications see Enercon E-82 at http://www.enercon.de/en/_home.htm

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Vestas®
No.1 in Modern Energy



Innovations in blade technology

Optimal efficiency

The OptiSpeed®* generators in the V90-1.8 MW and the V90-2.0 MW have been adapted from those in Vestas' highly successful V80 turbine. OptiSpeed® represents a significant advance in wind turbine efficiency as it allows the rotor speed to vary within a range of approximately 60 per cent in relation to nominal rpm. This means that with OptiSpeed®, the rotor speed can vary by as much as 30 per cent above and below synchronous speed. Its purpose is simple: to maximise energy output.

It does this by tapping the higher efficiency of slow and variable rotation, storing excess energy in rotational form and exploiting the full force of transient gusts. All told, OptiSpeed® boosts annual energy production.

As an added benefit, OptiSpeed® also reduces wear and tear on the gearbox, blades and tower on account of lower peak loading. Moreover, as turbine noise is a function of wind speed, the lower rotation speeds made possible by OptiSpeed® naturally reduce sound levels.

Finally, OptiSpeed® helps our V90s deliver better quality power to the grid, with rapid synchronisation, reduced harmonic distortion and less flicker.

3x44 metres of leading edge

Vestas blades have always been among the lightest on the market, and with the V90 turbines, we have once again raised the bar. The new blades feature several new light-weight materials, most notably carbon fibre for the load-bearing spars. Not only is carbon fibre lighter than the fibre glass used in previous blades, but its strength and rigidity have also made it possible to reduce the amount of material required. This means that even though our V90s have 27 per cent more swept area than our V80s, the longer blades actually weigh about the same.

The V90 blades also have a new profile that is aerodynamically superior to the previous generation. Vestas engineers developed this technologically advanced profile by optimising the relationship between the overall load impact on the turbine and the power generated annually. The fruit of their labours was an entirely new plane shape and a curved back edge.

The resulting airfoil improves energy production, while making the blade profile less sensitive to dirt on its leading edge and maintaining a favourable geometrical relationship between successive airfoil thicknesses. For the V90 turbine, this translates into an increase in output combined with a decrease in load transfers - as well as improvements on the bottom line.

Proven Performance

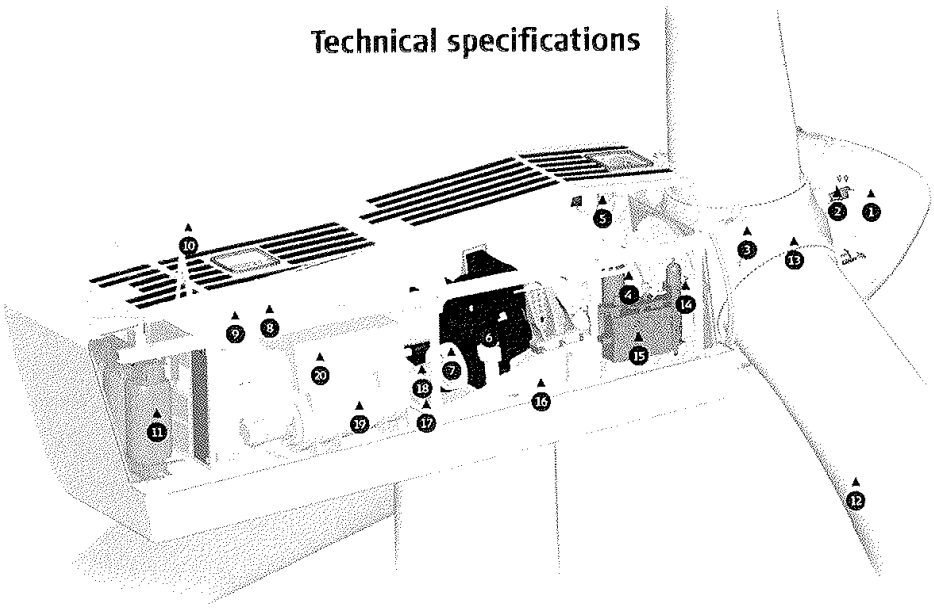
Wind power plants require substantial investments, and the process can be very complex. To assist in the evaluation and purchasing process, Vestas has identified factors that are critical to wind turbine quality: energy production, power quality and sound level.

We spend months testing and documenting these performance areas for all Vestas turbines. When we are finally satisfied, we ask an independent testing organisation to verify the results - a practice we call Proven Performance. At Vestas we do not just talk about quality. We prove it.

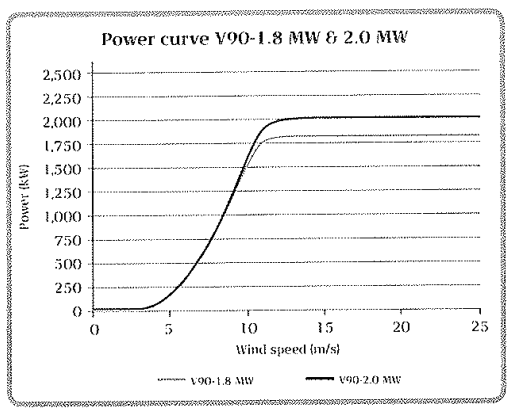
* *Vestas OptiSpeed® is not available in the USA and Canada*

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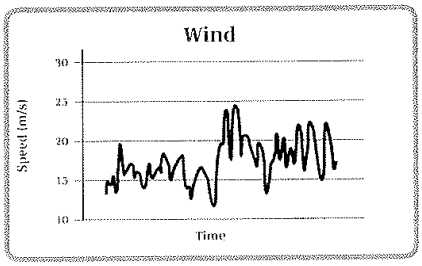
Technical specifications

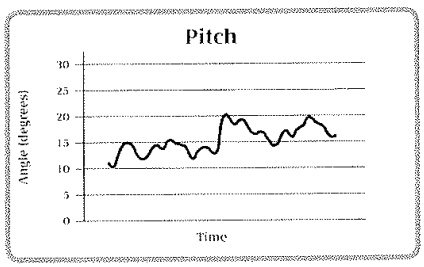


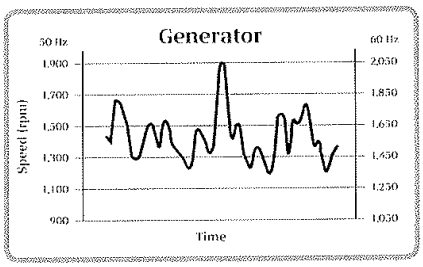
1. Hub controller
2. Pitch cylinders
3. Blade hub
4. Main shaft
5. Oil cooler
6. Gearbox
7. Mechanical disc brake
8. Service crane
9. VMP-Top controller with converter
10. Ultrasonic wind sensors
11. High voltage transformer
12. Blade
13. Blade bearing
14. Rotor lock system
15. Hydraulic unit
16. Machine foundation
17. Yaw gears
18. Composite disc coupling
19. OptiSpeed® generator
20. Air cooler for generator

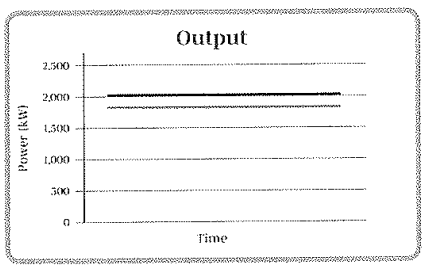


47

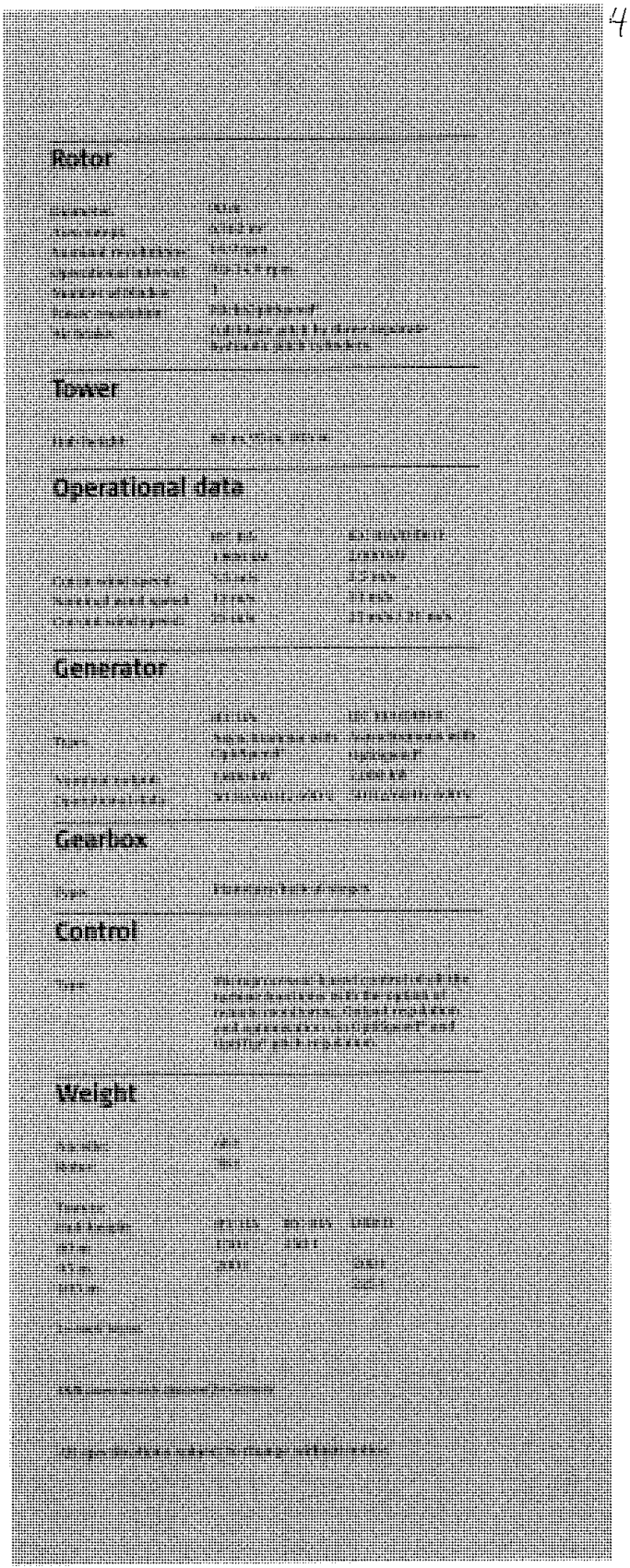




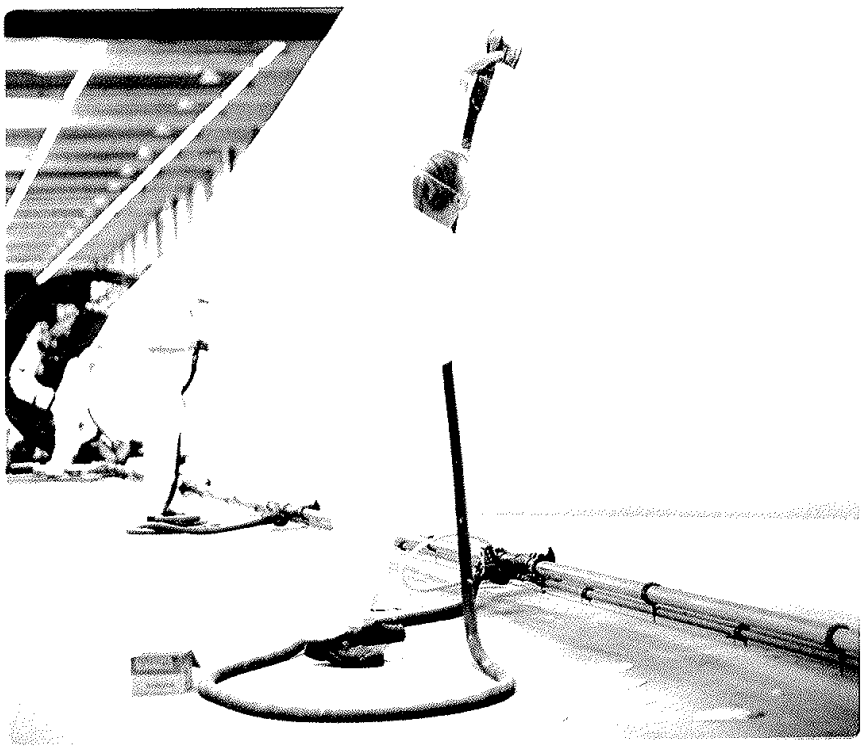




OptiSpeed® allows the rotor speed to vary within a range of approximately 60 per cent in relation to nominal rpm. Thus with OptiSpeed®, the rotor speed can vary by as much as 30 per cent above and below synchronous speed. This minimises both unwanted fluctuations in the output to the grid supply and the loads on the vital parts of the construction.



Built on experience



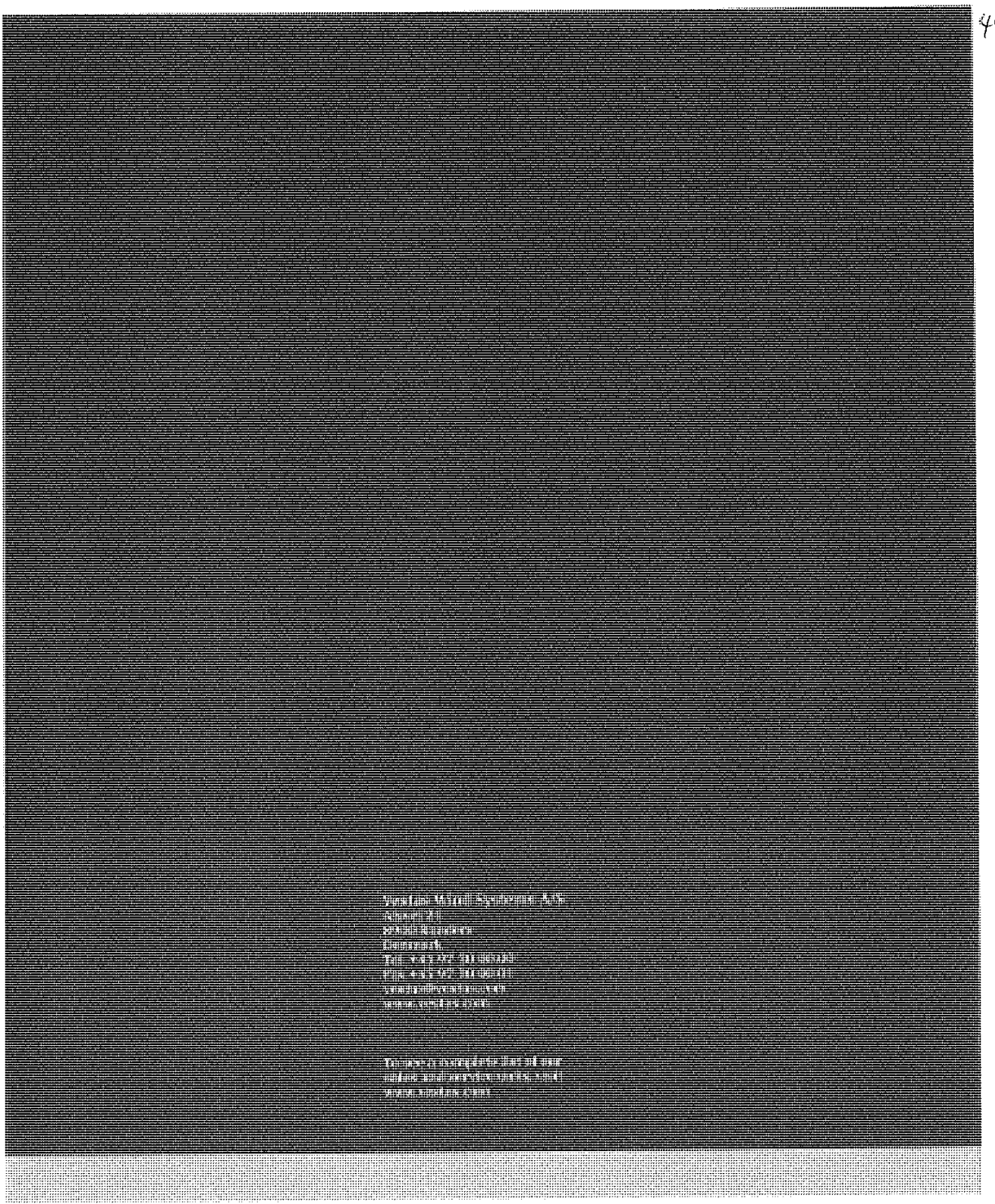
State-of-the-art wind turbines are not developed in a vacuum. To create the new V90-1.8 MW and V90-2.0 MW turbines for low and medium wind, we have drawn on the vast experience gained as the leading supplier of wind energy systems in the world. In particular, we applied successful design elements from our existing range of turbines.

We began with the nacelles of our tried and tested V80 wind turbines, which feature OptiSpeed® generators for maximum productivity. To these, we fitted the revolutionary new blades from our high-wind V90-3.0 MW. We then modified the components to ensure optimal harmonisation and to make the very most of the target conditions.

The resulting V90-1.8/2.0 MW turbines are optimised for sites with low turbulence and low and medium winds. These innovative wind turbines are so successful that they can actually generate 25 per cent more energy than the corresponding V80s.

Naturally, the new integrated turbines feature innovations of their own innovations. For instance, Vestas engineers spent two years designing a more efficient and more robust gearbox. Moreover, while the 90-metre rotor weighs approximately the same as the V80 rotor, the longer blades mean higher loads, so we also reinforced the transmission and other major components of the V90.

49



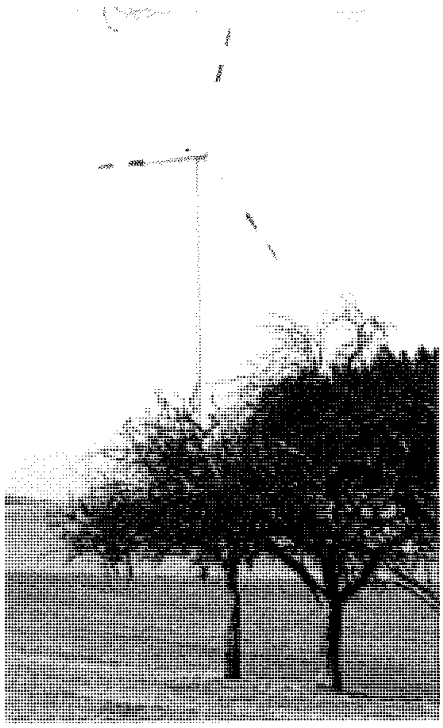
50

V82-1.65 MW
Creating more from less



Vestas

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Optimized for low and medium winds

With its large rotor and powerful generator, the V82 outperforms any turbine in its megawatt class for sites with low and medium wind conditions. Our hydraulic Active-Stall® technology ensures that the rotor gathers the maximum power from the prevailing wind, while minimizing loads and controlling output. Active-Stall® provides fail-safe protection in all conditions and, at and above its rated wind speed, maintains a steady output of 1.65 MW. With the V82, we have designed a wind turbine that offers unparalleled performance at a cost-effective price.

Low sound level

Vestas has made a concerted effort to reduce the sound level of the V82 dramatically – with audible results. The operating sound levels are among the lowest on the market, regardless of wind speed.

Excellent grid compatibility

As wind turbines capture more of the electricity market each year, they have an increasingly significant role to play in grid management. Fortunately, the V82 meets even the most stringent grid demands, and with the installation of our advanced grid compliance system, the V82 will actually help stabilize a weak grid. VestasGridSupport™ features full load and dynamic phase compensation to enhance reactive power regulation and thus keep the power factor in range. It has an uninterrupted backup power supply, too, so that auxiliary systems run at full capacity during grid disturbances. Moreover, our grid support provides continuous active and reactive power regulation to maintain voltage balance in the grid, as well as fault ride-through in the event of disturbances.

High reliability

Det Norske Veritas (DNV) has certified the V82 as meeting the strictest standards in the wind industry. It has the capacity to tune up its own generator, which helps to give it a particularly high degree of operational availability. In addition, the nacelle is based on the thoroughly tested design of previous models. To date, more than 700 wind turbines featuring this platform design have been installed on sites with conditions ranging from arctic to tropical.

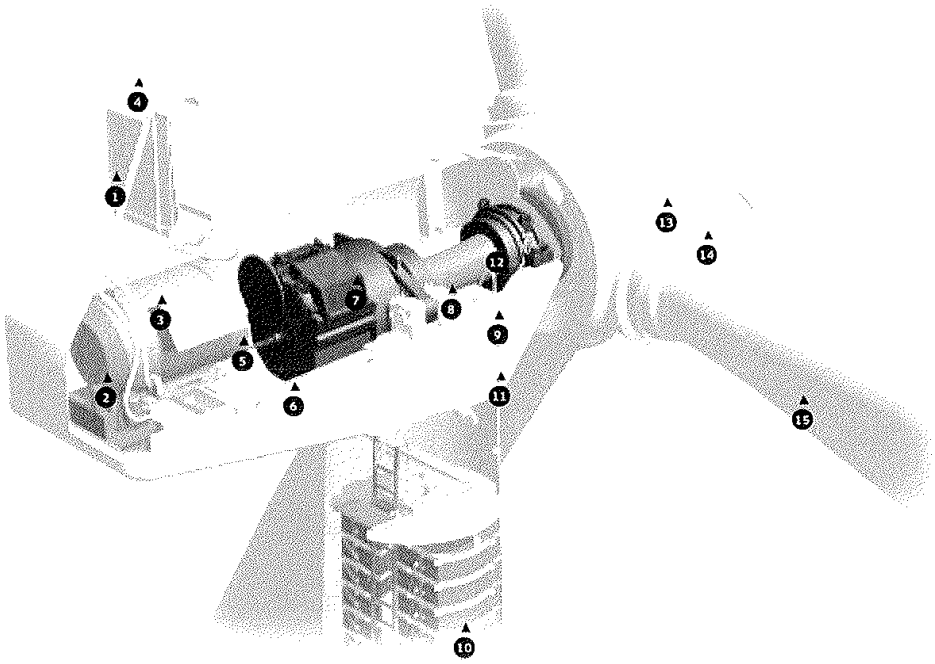
Proven performance

Wind power plants require substantial investments, and the process can be very complex. To assist in the evaluation and purchasing process, Vestas has identified four factors that are critical to wind turbine quality: energy production, operational availability, power quality and sound level.

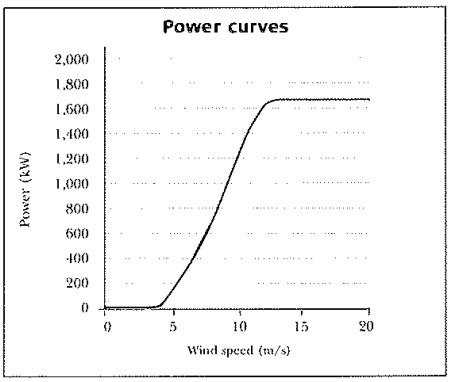
We spend months testing and documenting these performance areas for all Vestas turbines. When we are finally satisfied, we ask an independent testing organisation to verify the results – a practice we call Proven Performance. At Vestas we do not just talk about quality. We prove it.

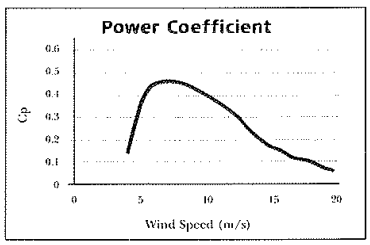
52

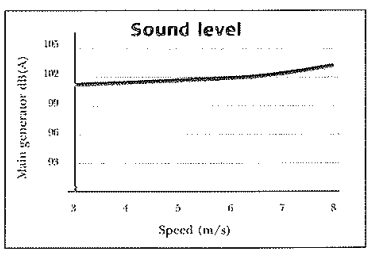
Technical specifications



1 Cooler	6 Mechanical brake	11 Machine foundation
2 Generator	7 Gearbox	12 Main bearing
3 Nacelle computer	8 Main shaft	13 Hub computer
4 Anemometer windvanes	9 Yaw gears	14 Pitch system
5 Coupling	10 Tower damper	15 Blade







Rotor

Diameter:	82 m
Area swept:	5,281 m²
Nominal revolutions:	14.4 rpm
Number of blades:	3
Power regulation:	Active-Stall®
Air brake:	Full blade pitch

Tower

Hub height (approx.): 59 m, 70 m, 80 m

Operational data

	1,650 kW
Cut-in wind speed:	3.5 m/s
Nominal wind speed:	13 m/s
Cut-out wind speed (10 minutes):	20 m/s
Cut-out wind speed (1 minute):	24 m/s
Cut-out wind speed (1 second):	32 m/s

Generator

Type:	Asynchronous generator water cooled
Nominal output:	1,650 kW
Operational data:	60 Hz 690 V

Gearbox

Type: Planetary/helical stages

Control

Type: Computer-based control of all turbine functions with the option of remote monitoring. Output regulation and optimization via Active-Stall®.

Weight (IEC IIB)

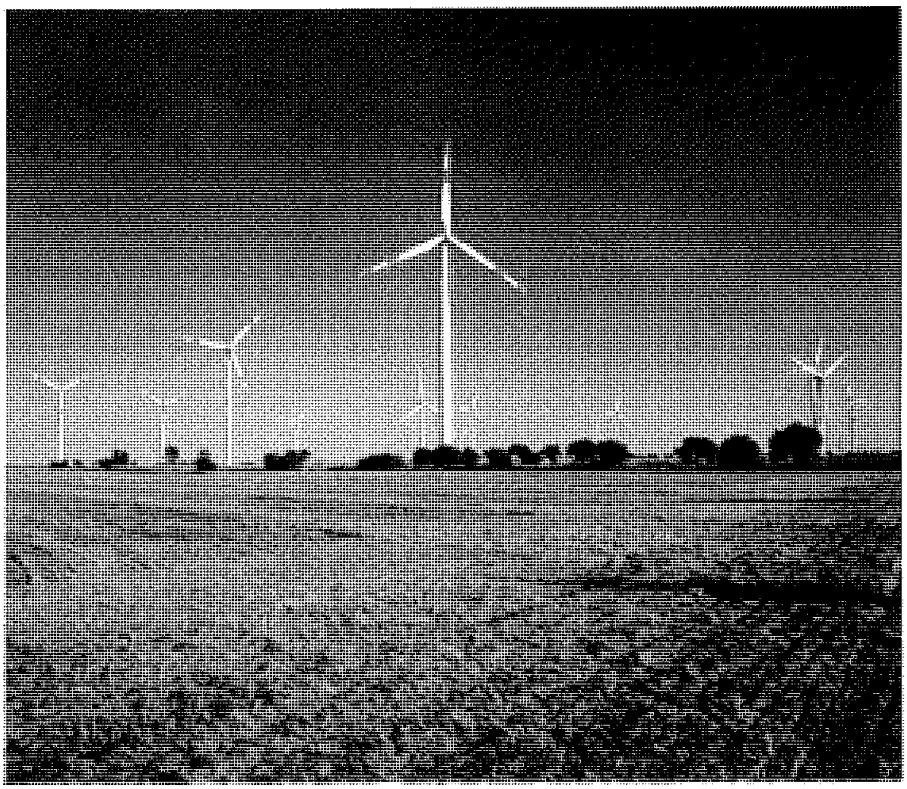
Hub height (approx.):	59 m	70 m	78 m	80 m
Tower:	72 t	105.5 t	127 t	162 t
Nacelle:	52 t	52 t	52 t	52 t
Rotor:	43 t	43 t	43 t	43 t
Total:	167 t	200.5 t	222 t	257 t

t = metric tons

All specifications subject to change without notice.

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Creating more from less



Ideally, it makes sense to generate electricity close to where it will be consumed so as to keep transmission, infrastructure and service costs low. However, since populous areas tend to have low winds and stringent requirements on sound levels, the wind industry often concentrates on coastal areas, deserted interiors and the open sea, where the wind is plentiful and sound restrictions are few.

With the V82 wind turbine, Vestas has made it easier to produce electricity close to where people live. Not only is the V82 extremely efficient in areas with low and medium winds, but it also provides lower sound levels to suit local requirements. This means that a large number of previously marginal sites can now be exploited profitably – and quietly.

The V82 is an extremely competitive turbine in its class in areas with low and medium winds. An impressive capacity factor of 41 percent at 7.5 m/s at hub height speaks for itself and enables the V82 to create more power from less

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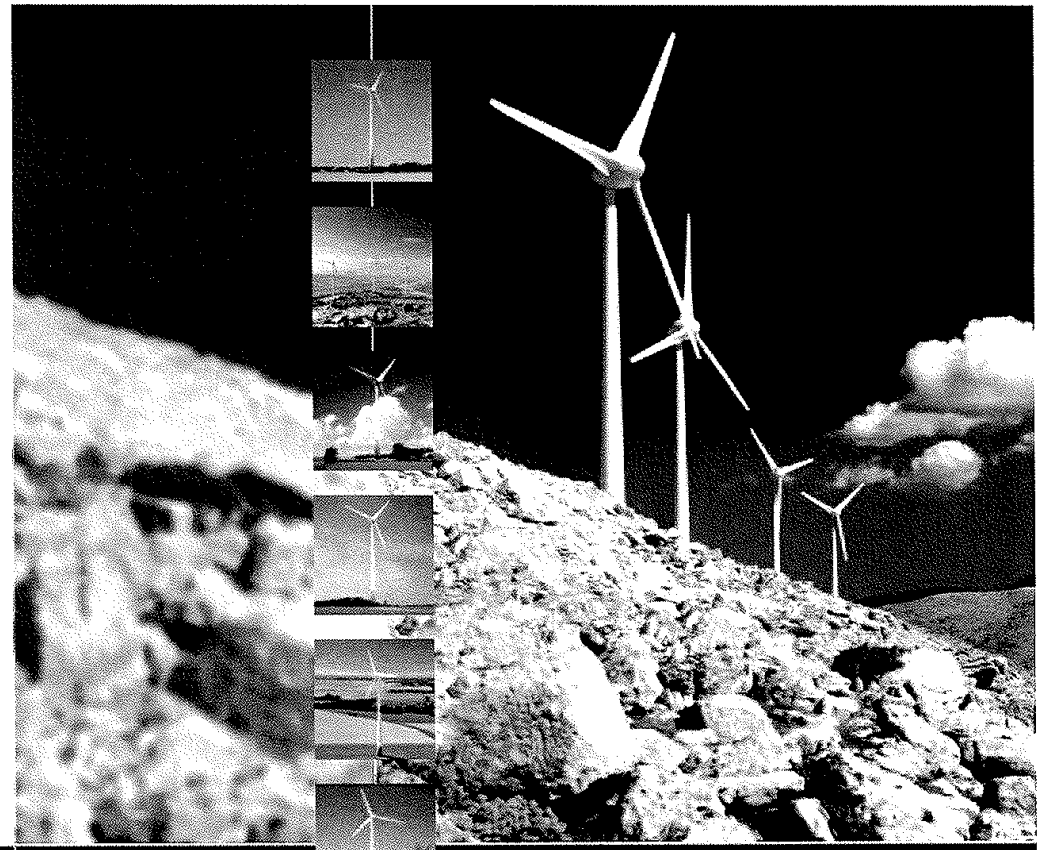
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E-33
E-44
E-48
E-53
E-70
E-82

ENERCON WIND TURBINES

PRODUCT OVERVIEW

ENERCON
ENERGY FOR THE WORLD

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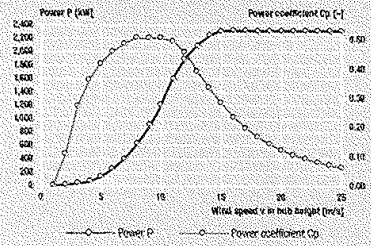
With the E-70 wind turbine ENERCON continues its longstanding reputation for reliability in the 2 MW class. Especially suitable for sites with high wind speeds, the E-70 wind turbine – with 2.3 MW rated power and numerous steel and precast concrete tower versions – is designed to ensure maximum yield in the upper power range.

TECHNICAL DATA

Rated power:	2,300 kW
Rotor diameter:	71 m
Hub height:	64 m – 113 m
Wind class (IEC):	IEC/NVN I and IEC/NVN II (depending on hub height)
Turbine concept:	Gearless, variable speed, variable pitch control
Rotor	
Type:	Upwind rotor with active pitch control
Direction of rotation:	Clockwise
Number of blades:	3
Swept area:	3,959 m²
Blade material:	Fibreglass (epoxy resin); integrated lightning protection
Rotational speed:	Variable, 6 – 21.5 rpm
Pitch control:	ENERCON blade pitch system, one independent pitching system per rotor blade with allocated emergency supply
Drive train with generator	
Hub:	Rigid
Main bearings:	Dual-row tapered/single-row cylindrical roller bearings
Generator:	ENERCON direct-drive synchronous annular generator
Grid feeding:	ENERCON converter
Braking systems:	– 3 independent blade pitch systems with emergency supply – Rotor brake – Rotor lock
Yaw control:	Active via adjustment gears, load-dependent damping
Cut-out wind speed:	28 – 34 m/s (with ENERCON storm control)
Remote monitoring:	ENERCON SCADA

Details – ENERCON Storm Control – (see last page)

CALCULATED POWER CURVE

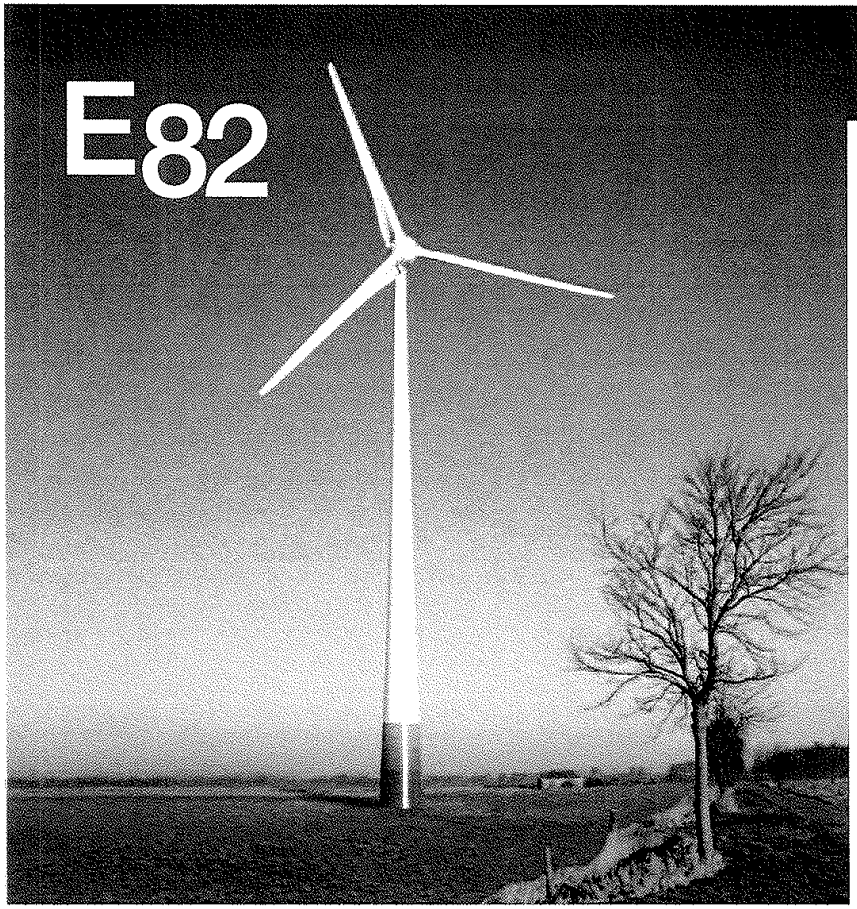


Wind [m/s]	Power P [kW]	Power coefficient Cp [-]
1	0.0	0.00
2	2.0	0.10
3	16.0	0.27
4	55.0	0.36
5	127.0	0.42
6	240.0	0.46
7	400.0	0.48
8	626.0	0.50
9	892.0	0.50
10	1,229.0	0.50
11	1,590.0	0.49
12	1,900.0	0.45
13	2,092.0	0.39
14	2,230.0	0.34
15	2,300.0	0.29
16	2,310.0	0.23
17	2,310.0	0.19
18	2,310.0	0.16
19	2,310.0	0.14
20	2,310.0	0.12
21	2,310.0	0.10
22	2,310.0	0.09
23	2,310.0	0.08
24	2,310.0	0.07
25	2,310.0	0.06

Details – ENERCON power curve – (see last page)

S7

E82



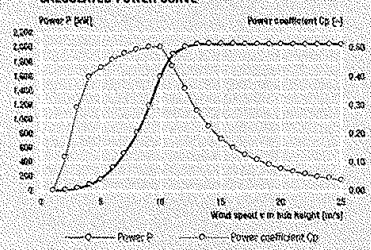
Specially designed for medium wind speeds, the ENERCON E-82 wind turbine – with the new rotor blade design and tower versions up to 138 m hub height – guarantees excellent yields in the 2 MW category, even at inland sites.

TECHNICAL DATA

Rated power:	2,000 kW
Rotor diameter:	82 m
Hub height:	78 m – 138 m
Wind class (IEC):	IEC/NVN II
Turbine concept:	Gearless, variable speed, variable pitch control
Rotor	
Type:	Upwind rotor with active pitch control
Direction of rotation:	Clockwise
Number of blades:	3
Swept area:	5,281 m²
Blade material:	Fibreglass (epoxy resin); integrated lightning protection
Rotational speed:	Variable, 6 – 19.5 rpm
Pitch control:	ENERCON blade pitch system, one independent pitching system per rotor blade with allocated emergency supply
Drive train with generator	
Hub:	Rigid
Main bearings:	Dual-row tapered/single-row cylindrical roller bearings
Generator:	ENERCON direct-drive synchronous annular generator
Grid feeding:	ENERCON converter
Braking systems:	– 3 independent blade pitch systems with emergency supply – Rotor brake – Rotor lock
Yaw control:	Active via adjustment gears, load-dependent damping
Cut-out wind speed:	28 – 34 m/s (with ENERCON storm control)
Remote monitoring:	ENERCON SCADA

Details – ENERCON Storm Control – (see last page)

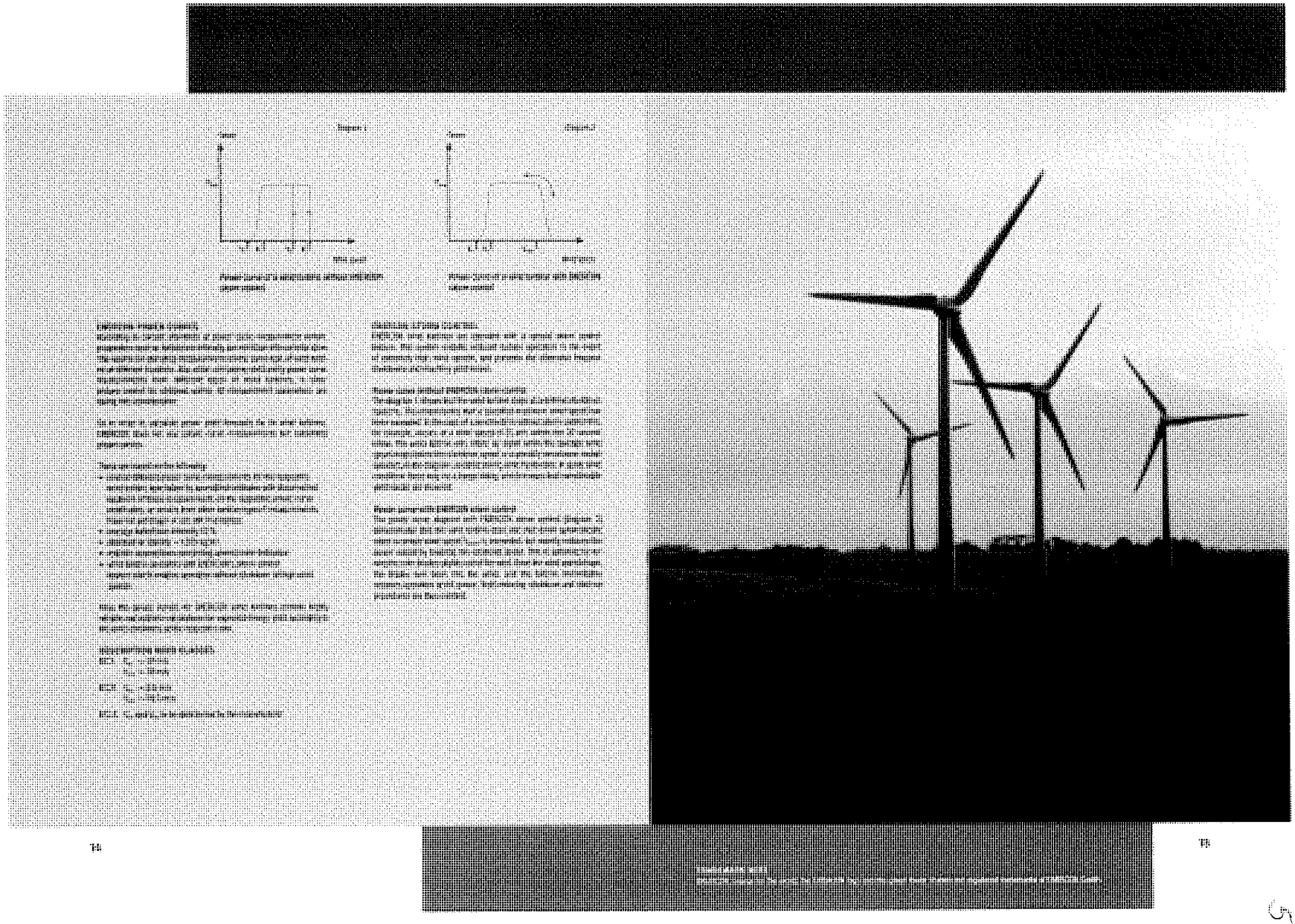
CALCULATED POWER CURVE



Wind [m/s]	Power P [kW]	Power coefficient Cp [-]
1	0.0	0.00
2	3.0	0.12
3	25.0	0.29
4	82.0	0.40
5	174.0	0.43
6	321.0	0.46
7	532.0	0.48
8	815.0	0.49
9	1,160.0	0.50
10	1,612.0	0.50
11	1,890.0	0.44
12	2,000.0	0.36
13	2,050.0	0.29
14	2,050.0	0.23
15	2,050.0	0.19
16	2,050.0	0.15
17	2,050.0	0.13
18	2,050.0	0.11
19	2,050.0	0.09
20	2,050.0	0.08
21	2,050.0	0.07
22	2,050.0	0.06
23	2,050.0	0.05
24	2,050.0	0.05
25	2,050.0	0.04

Details – ENERCON power curve – (see last page)

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Appendix V

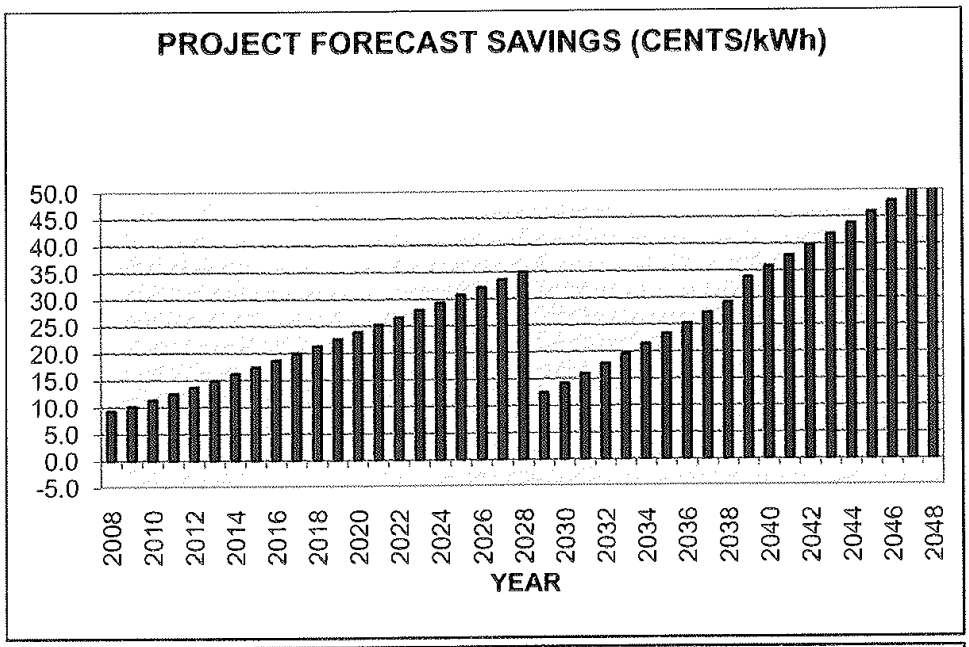
Detailed Wind Farm Economic Analyses

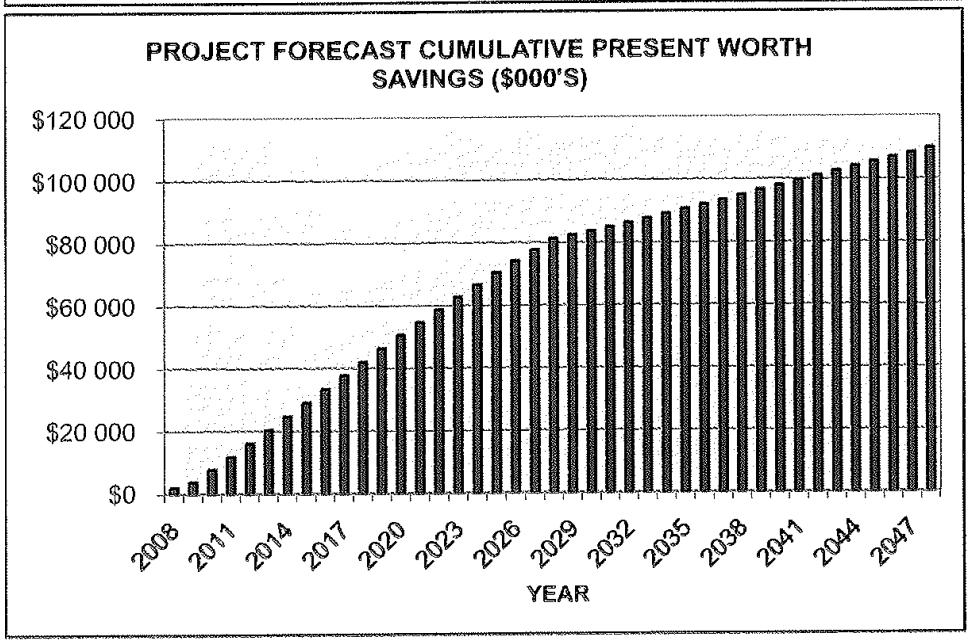
Mt SUMANIK 20 MW WIND FARM CASE 1 - NO BLADE HEATING, NO INCENTIVE PROGRAM

			WIND FARM			DIESEL DISPLACED				
Capital ($000)		2008	$72 119	20.000 MW		$7 000	7.000 MW @	$1 000 /kW		
Capital ($000)		2008	$72 119		Load	$7 000				
Energy			40.4 GW.h	(23%CF)	Max	40.4 GW.h	(66%CF)			
Fuel		2000	Load Growth		50.0	287.5 $/MWh	$1.15 /litre @	4 kW.h/litre		
O&M	(Fixed)	2000	$000/yr			15.4 $000/yr @	$2.2 /kW			
O&M	(Variable)	2000	43 $/MWh			2.0 $/MWh				
Life			20 years			30 years				
Levelized Cost of Energy										
	Nominal $	2008	24.76 cents/kW.h			45.63 cents/kW.h				
	Real $	2008	19.26 cents/kW.h			35.13 cents/kW.h				
Project PV	$	2000	130 311 $000's			240 169 $000's	PV Savings	109 858 $000's	46%	

	Mid-Year	WIND FARM						Mid-Year	DIESEL							SAVINGS			Net		
Year	Rate Base	Depr	Return	O&M	Total $000	cents/ kW.h		Rate Base	Depr	Return	O&M	Fuel	Total $000	cents/ kW.h		Net	PW to 2008	CPW	Savings c/kW.h	Annual Energy	Capacity Factor
2008	35158	1803	2531	1018	5352	26.5		3442	117	248	65	6804	7234	35.8		1882	1 882	1 882	9.3	20.20	12%
2009	68513	3606	4933	2076	10615	26.3		6767	233	487	115	13881	14717	36.4		4101	3 826	3 826	10.2	40.40	23%
2010	64907	3606	4673	2118	10397	25.7		6533	233	470	117	14159	14980	37.1		4583	3 988	7 814	11.3	40.40	23%
2011	61301	3606	4414	2160	10180	25.2		6300	233	454	120	14442	15248	37.7		5069	4 114	11 928	12.5	40.40	23%
2012	57695	3606	4154	2203	9963	24.7		6067	233	437	122	14731	15523	38.4		5560	4 210	16 138	13.8	40.40	23%
2013	54089	3606	3894	2247	9748	24.1		5833	233	420	124	15025	15803	39.1		6055	4 277	20 415	15.0	40.40	23%
2014	50483	3606	3635	2292	9533	23.6		5600	233	403	127	15326	16089	39.8		6556	4 320	24 735	16.2	40.40	23%
2015	46877	3606	3375	2338	9319	23.1		5367	233	386	129	15632	16381	40.5		7062	4 341	29 076	17.5	40.40	23%
2016	43271	3606	3116	2385	9106	22.5		5133	233	370	132	15945	16680	41.3		7574	4 343	33 419	18.7	40.40	23%
2017	39665	3606	2856	2432	8894	22.0		4900	233	353	135	16264	16985	42.0		8090	4 327	37 746	20.0	40.40	23%
2018	36060	3606	2596	2481	8683	21.5		4667	233	336	137	16589	17296	42.8		8612	4 297	42 043	21.3	40.40	23%
2019	32454	3606	2337	2531	8473	21.0		4433	233	319	140	16921	17614	43.6		9140	4 254	46 297	22.6	40.40	23%
2020	28848	3606	2077	2581	8264	20.5		4200	233	302	143	17259	17938	44.4		9674	4 200	50 497	23.9	40.40	23%
2021	25242	3606	1817	2633	8056	19.9		3967	233	286	146	17604	18269	45.2		10213	4 136	54 634	25.3	40.40	23%
2022	21636	3606	1558	2686	7849	19.4		3733	233	269	149	17957	18607	46.1		10758	4 064	58 698	26.6	40.40	23%
2023	18030	3606	1298	2739	7643	18.9		3500	233	252	152	18316	18953	46.9		11309	3 986	62 684	28.0	40.40	23%
2024	14424	3606	1039	2794	7439	18.4		3267	233	235	155	18682	19305	47.8		11867	3 901	66 585	29.4	40.40	23%
2025	10818	3606	779	2850	7235	17.9		3033	233	218	158	19056	19665	48.7		12430	3 812	70 397	30.8	40.40	23%
2026	7212	3606	519	2907	7032	17.4		2800	233	202	161	19437	20033	49.6		13000	3 719	74 117	32.2	40.40	23%
2027	3606	3606	260	2965	6831	16.9		2567	233	185	164	19825	20408	50.5		13577	3 623	77 740	33.6	40.40	23%
2028	0	3606	0	3025	6630	16.4		2333	233	168	167	20222	20791	51.5		14160	3 525	81 265	35.1	40.40	23%
2029	107165	5358	7716	3085	16159	40.0		2100	233	151	171	20626	21182	52.4		5023	1 166	82 431	12.4	40.40	23%
2030	101807	5358	7330	3147	15835	39.2		1867	233	134	174	21039	21581	53.4		5746	1 245	83 676	14.2	40.40	23%
2031	96449	5358	6944	3210	15512	38.4		1633	233	118	178	21460	21988	54.4		6476	1 309	84 985	16.0	40.40	23%
2032	91090	5358	6559	3274	15191	37.6		1400	233	101	181	21889	22404	55.5		7214	1 360	86 345	17.9	40.40	23%
2033	85732	5358	6173	3339	14870	36.8		1167	233	84	185	22327	22829	56.5		7959	1 400	87 744	19.7	40.40	23%
2034	80374	5358	5787	3406	14551	36.0		933	233	67	189	22773	23262	57.6		8711	1 429	89 173	21.6	40.40	23%
2035	75016	5358	5401	3474	14234	35.2		700	233	50	192	23229	23705	58.7		9471	1 449	90 622	23.4	40.40	23%
2036	69657	5358	5015	3544	13917	34.4		467	233	34	196	23693	24156	59.8		10239	1 462	92 084	25.3	40.40	23%
2037	64299	5358	4630	3615	13602	33.7		233	233	17	200	24167	24617	60.9		11015	1 467	93 551	27.3	40.40	23%
2038	58941	5358	4244	3687	13289	32.9		0	233	0	204	24651	25088	62.1		11799	1 466	95 016	29.2	40.40	23%
2039	53583	5358	3858	3761	12977	32.1		12680	423	913	208	25144	26687	66.1		13711	1 589	96 605	33.9	40.40	23%
2040	48224	5358	3472	3836	12666	31.4		12257	423	882	212	25646	27164	67.2		14498	1 567	98 172	35.9	40.40	23%
2041	42866	5358	3086	3913	12357	30.6		11834	423	852	217	26159	27651	68.4		15294	1 542	99 714	37.9	40.40	23%
2042	37508	5358	2701	3991	12050	29.8		11412	423	822	221	26682	28148	69.7		16098	1 514	101 228	39.8	40.40	23%
2043	32150	5358	2315	4071	11744	29.1		10989	423	791	225	27216	28655	70.9		16912	1 484	102 712	41.9	40.40	23%
2044	26791	5358	1929	4152	11439	28.3		10566	423	761	230	27760	29174	72.2		17735	1 451	104 163	43.9	40.40	23%
2045	21433	5358	1543	4235	11136	27.6		10144	423	730	235	28316	29703	73.5		18567	1 418	105 581	46.0	40.40	23%
2046	16075	5358	1157	4320	10835	26.8		9721	423	700	239	28882	30244	74.9		19408	1 382	106 963	48.0	40.40	23%
2047	10717	5358	772	4406	10536	26.1		9298	423	669	244	29460	30796	76.2		20260	1 346	108 309	50.1	40.40	23%
2048	901	1803	65	4494	6362	15.7		8876	423	639	249	30049	31359	77.6		24997	1 549	109 858	61.9	40.40	23%
PV		51309	44540	34462	130311	$194			3204	4643	1908	230414	240169	$358		109858	111 740			526	

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PROJECT FORECAST SAVINGS (CENTS/kWh)
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
YEAR


PROJECT FORECAST CUMULATIVE PRESENT WORTH SAVINGS ($000'S)
$120 000
$100 000
$80 000
$60 000
$40 000
$20 000
$0
2008
2011
2014
2017
2020
2023
2026
2029
2032
2035
2038
2041
2044
2047
YEAR

Mt SUMANIK 20 MW WIND FARM CASE 2 - NO BLADE HEATING, WITH INCENTIVE PROGRAM

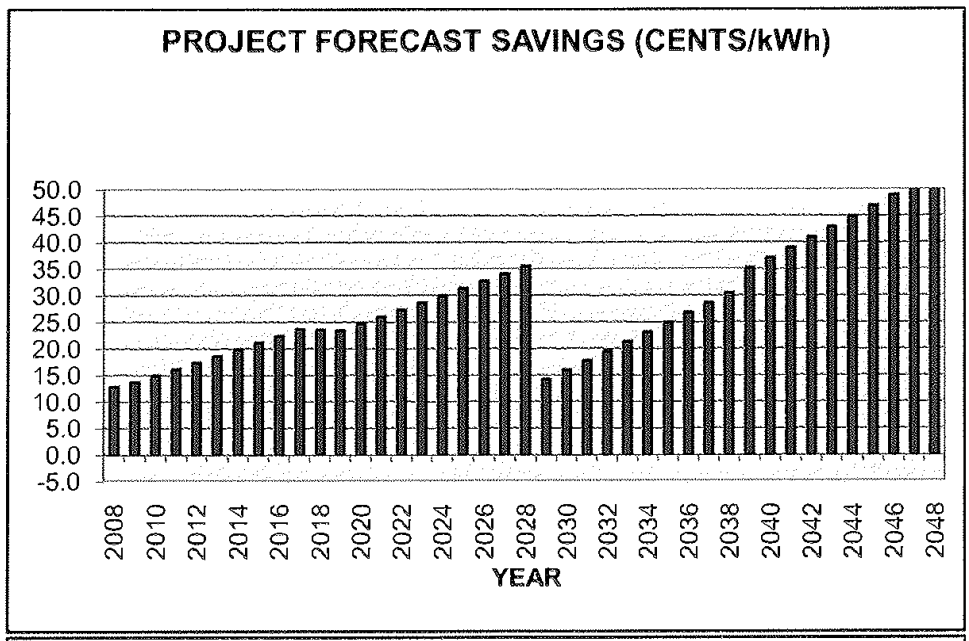
		WIND FARM				DIESEL DISPLACED				
Capital ($000)		**2008**	**$68 119**	**20.000** MW		$7 000	**7.000** MW @	$1 000 /kW		
Capital ($000)		**2008**	$68 119		Load	$7 000				
Energy			**40.4** GW.h	(23%CF)	Max	40.4 GW.h	(66%CF)			
Fuel		2000	Load Growth		50.0	287.5 $/MWh	**$1.15** /litre @	**4** kW.h/litre		
O&M	(Fixed)	2000	$000/yr			**15.4** $000/yr @	**$2.2** /kW			
O&M	(Variable)	2000	**43** $/MWh			**2.0** $/MWh				
Life			**20** years			**30** years				
Levelized Cost of Energy										
	Nominal $	2008	22.42 cents/kW.h			45.63 cents/kW.h				
	Real $	2008	17.42 cents/kW.h			35.13 cents/kW.h				
Project PV	$	2000	118 007 $000's			240 169 $000's	PV Savings	122 162 $000's	51%	

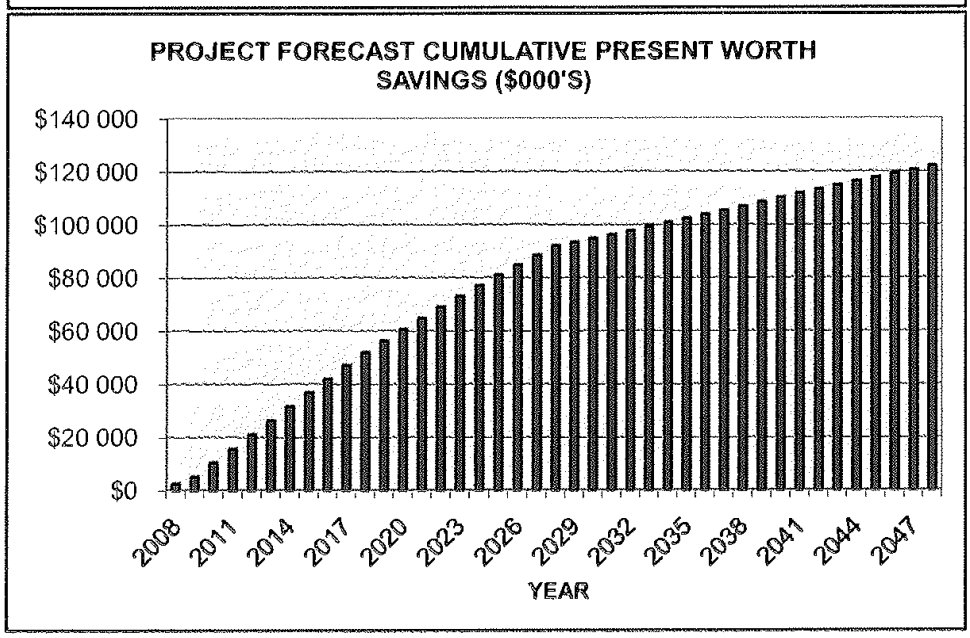
Cost of Capital	7.20%		
Discount Rate	7.20%		
Inflation Rate	2.00%		
Real discount rate	5.10%		
Fuel Inflation rate	2.00%		
Rate of Return	Ratio	Rate	
Debt	60%	6.00%	3.60%
Equity	40%	9.00%	3.60%
Total	100%		7.20%

	WIND FARM						DIESEL						SAVINGS					
Year	Mid-Year Rate Base	Depr	Return	O&M	Total $000	cents/ kW.h	Mid-Year Rate Base	Depr	Return	O&M	Fuel	Total $000	cents/ kW.h	Net	PW to 2008	CPW		Net Savings c/kW.h	Annual Energy	Capacity Factor
2008	33208	1703	2391	544	4638	23.0	3442	117	248	65	6804	7234	35.8	2596	2 596	2 596		12.9	20.20	12%
2009	64713	3406	4659	1110	9176	22.7	6767	233	487	115	13881	14717	36.4	5541	5 169	5 169	1	13.7	40.40	23%
2010	61307	3406	4414	1133	8953	22.2	6533	233	470	117	14159	14980	37.1	6027	5 244	10 413	2	14.9	40.40	23%
2011	57901	3406	4169	1155	8730	21.6	6300	233	454	120	14442	15248	37.7	6518	5 291	15 704	3	16.1	40.40	23%
2012	54495	3406	3924	1178	8508	21.1	6067	233	437	122	14731	15523	38.4	7015	5 312	21 016	4	17.4	40.40	23%
2013	51089	3406	3678	1202	8286	20.5	5833	233	420	124	15025	15803	39.1	7517	5 309	26 325	5	18.6	40.40	23%
2014	47683	3406	3433	1226	8065	20.0	5600	233	403	127	15326	16089	39.8	8024	5 287	31 612	6	19.9	40.40	23%
2015	44277	3406	3188	1251	7845	19.4	5367	233	386	129	15632	16381	40.5	8537	5 247	36 860	7	21.1	40.40	23%
2016	40871	3406	2943	1276	7624	18.9	5133	233	370	132	15945	16680	41.3	9056	5 192	42 052	8	22.4	40.40	23%
2017	37465	3406	2698	1301	7405	18.3	4900	233	353	135	16264	16985	42.0	9580	5 124	47 176	9	23.7	40.40	23%
2018	34060	3406	2452	1904	7762	19.2	4667	233	336	137	16589	17296	42.8	9533	4 757	51 933	10	23.6	40.40	23%
2019	30654	3406	2207	2531	8144	20.2	4433	233	319	140	16921	17614	43.6	9470	4 408	56 340	11	23.4	40.40	23%
2020	27248	3406	1962	2581	7949	19.7	4200	233	302	143	17259	17938	44.4	9989	4 337	60 677	12	24.7	40.40	23%
2021	23842	3406	1717	2633	7756	19.2	3967	233	286	146	17604	18269	45.2	10514	4 258	64 935	13	26.0	40.40	23%
2022	20436	3406	1471	2686	7563	18.7	3733	233	269	149	17957	18607	46.1	11044	4 173	69 108	14	27.3	40.40	23%
2023	17030	3406	1226	2739	7371	18.2	3500	233	252	152	18316	18953	46.9	11581	4 082	73 190	15	28.7	40.40	23%
2024	13624	3406	981	2794	7181	17.8	3267	233	235	155	18682	19305	47.8	12124	3 986	77 176	16	30.0	40.40	23%
2025	10218	3406	736	2850	6992	17.3	3033	233	218	158	19056	19665	48.7	12674	3 887	81 062	17	31.4	40.40	23%
2026	6812	3406	490	2907	6803	16.8	2800	233	202	161	19437	20033	49.6	13229	3 785	84 847	18	32.7	40.40	23%
2027	3406	3406	245	2965	6616	16.4	2567	233	185	164	19825	20408	50.5	13791	3 681	88 528	19	34.1	40.40	23%
2028	0	3406	0	3025	6430	15.9	2333	233	168	167	20222	20791	51.5	14360	3 575	92 102	20	35.5	40.40	23%
2029	101221	5061	7288	3085	15434	38.2	2100	233	151	171	20626	21182	52.4	5748	1 335	93 437	21	14.2	40.40	23%
2030	96160	5061	6924	3147	15131	37.5	1867	233	134	174	21039	21581	53.4	6450	1 397	94 834	22	16.0	40.40	23%
2031	91099	5061	6559	3210	14830	36.7	1633	233	118	178	21460	21988	54.4	7159	1 447	96 281	23	17.7	40.40	23%
2032	86038	5061	6195	3274	14530	36.0	1400	233	101	181	21889	22404	55.5	7875	1 484	97 765	24	19.5	40.40	23%
2033	80977	5061	5830	3339	14231	35.2	1167	233	84	185	22327	22829	56.5	8598	1 512	99 277	25	21.3	40.40	23%
2034	75916	5061	5466	3406	13933	34.5	933	233	67	189	22773	23262	57.6	9329	1 530	100 808	26	23.1	40.40	23%
2035	70855	5061	5102	3474	13637	33.8	700	233	50	192	23229	23705	58.7	10068	1 541	102 348	27	24.9	40.40	23%
2036	65794	5061	4737	3544	13342	33.0	467	233	34	196	23693	24156	59.8	10815	1 544	103 892	28	26.8	40.40	23%
2037	60733	5061	4373	3615	13048	32.3	233	233	17	200	24167	24617	60.9	11569	1 540	105 432	29	28.6	40.40	23%
2038	55672	5061	4008	3687	12756	31.6	0	233	0	204	24651	25088	62.1	12332	1 532	106 964	30	30.5	40.40	23%
2039	50611	5061	3644	3761	12466	30.9	12680	423	913	208	25144	26687	66.1	14222	1 648	108 612	31	35.2	40.40	23%
2040	45550	5061	3280	3836	12176	30.1	12257	423	882	212	25646	27164	67.2	14988	1 620	110 232	32	37.1	40.40	23%
2041	40489	5061	2915	3913	11889	29.4	11834	423	852	217	26159	27651	68.4	15762	1 589	111 821	33	39.0	40.40	23%
2042	35427	5061	2551	3991	11603	28.7	11412	423	822	221	26682	28148	69.7	16545	1 556	113 377	34	41.0	40.40	23%
2043	30366	5061	2186	4071	11318	28.0	10989	423	791	225	27216	28655	70.9	17337	1 521	114 898	35	42.9	40.40	23%
2044	25305	5061	1822	4152	11035	27.3	10566	423	761	230	27760	29174	72.2	18139	1 485	116 383	36	44.9	40.40	23%
2045	20244	5061	1458	4235	10754	26.6	10144	423	730	235	28316	29703	73.5	18950	1 447	117 830	37	46.9	40.40	23%
2046	15183	5061	1093	4320	10474	25.9	9721	423	700	239	28882	30244	74.9	19770	1 408	119 238	38	48.9	40.40	23%
2047	10122	5061	729	4406	10196	25.2	9298	423	669	244	29460	30796	76.2	20600	1 369	120 606	39	51.0	40.40	23%
2048	851	1703	61	4494	6259	15.5	8876	423	639	249	30049	31359	77.6	25101	1 556	122 162	40	62.1	40.40	23%
PV		48463	42069	27474	118007	$176		3204	4643	1908	230414	240169	$358	122162	124 758				526	

63

64


PROJECT FORECAST SAVINGS (CENTS/kWh)
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
2008
2010
2012
2014
2016
2018
2020
2022
2024
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2046
2048
YEAR

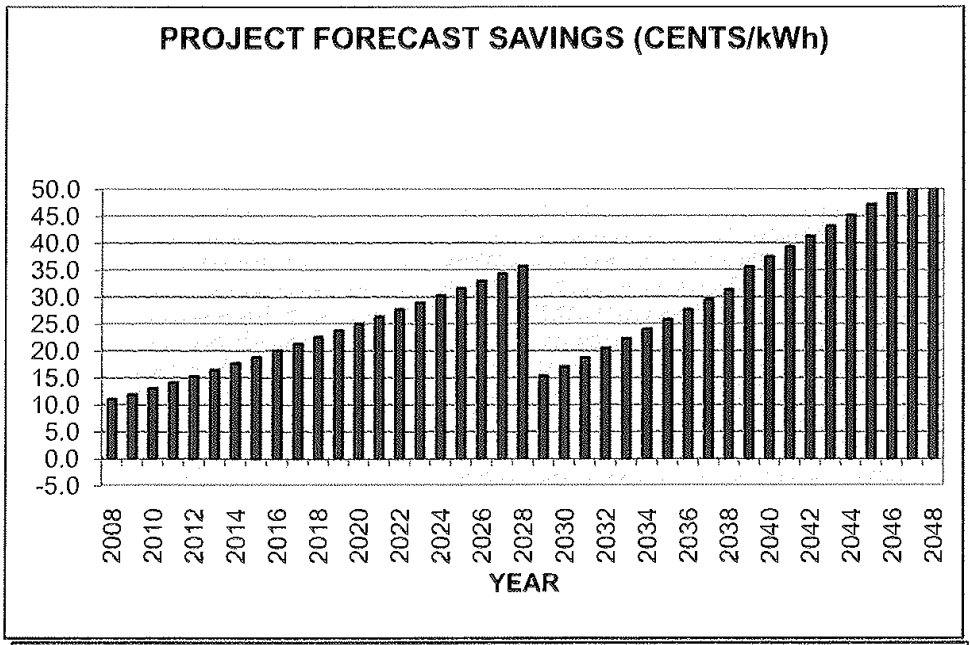

PROJECT FORECAST CUMULATIVE PRESENT WORTH SAVINGS ($000'S)
$140 000
$120 000
$100 000
$80 000
$60 000
$40 000
$20 000
$0
2008
2011
2014
2017
2020
2023
2026
2029
2032
2035
2038
2041
2044
2047
YEAR

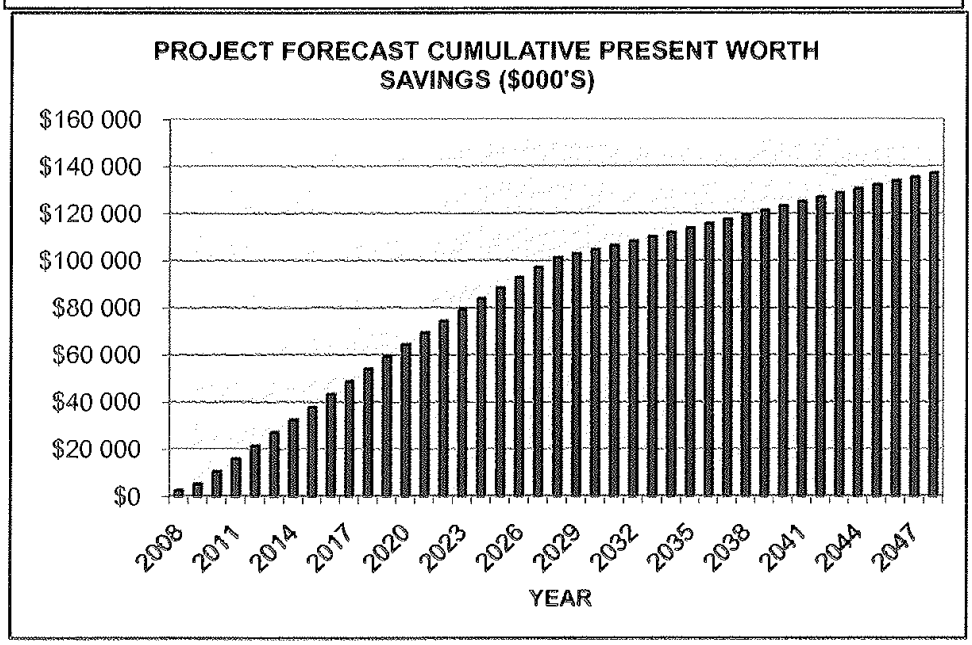
Mt SUMANIK 20 MW WIND FARM CASE 3 - WITH BLADE HEATING, NO INCENTIVE PROGRAM

		WIND FARM				DIESEL DISPLACED					
Capital ($000)		2008	$76 119	20.000 MW		$7 000	7.000 MW @	$1 000 /kW			
Capital ($000)		2008	$76 119		Load	$7 000					
Energy			47.1 GW.h	(27%CF)	Max	47.1 GW.h	(77%CF)				
Fuel		2000	Load Growth		50.0	287.5 $/MWh	$1.15 /litre @	4 kW.h/litre			
O&M	(Fixed)	2000	$000/yr			15.4 $000/yr @	$2.2 /kW				
O&M	(Variable)	2000	43 $/MWh			2.0 $/MWh					
Life			20 years			30 years					
Levelized Cost of Energy											
	Nominal $	2008	23.03 cents/kW.h			45.41 cents/kW.h					
	Real $	2008	17.92 cents/kW.h			34.96 cents/kW.h					
Project PV	$	2000	141 342 $000's			278 647 $000's	PV Savings	137 305 $000's	49%		

Cost of Capital	7.20%		
Discount Rate	7.20%		
Inflation Rate	2.00%		
Real discount rate	5.10%		
Fuel Inflation rate	2.00%		
Rate of Return	Ratio	Rate	
Debt	60%	6.00%	3.60%
Equity	40%	9.00%	3.60%
Total	100%		7.20%

	Mid-Year WIND FARM						Mid-Year DIESEL						SAVINGS			Net		
Year	Rate Base	Depr	Return	O&M	Total $000	cents/ kW.h	Rate Base	Depr	Return	O&M	Fuel	Total $000	cents/ kW.h	Net	PW to 2008	CPW	Savings c/kW.h	Annual Energy	Capacity Factor
2008	37108	1903	2672	1186	5761	24.5	3442	117	248	73	7933	8371	35.5	2609	2 609	2 609	11.1	23.55	13%
2009	72313	3806	5207	2420	11433	24.3	6767	233	487	131	16183	17035	36.2	5602	5 225	5 225	11.9	47.10	27%
2010	68507	3806	4933	2469	11207	23.8	6533	233	470	134	16507	17344	36.8	6137	5 340	10 566	13.0	47.10	27%
2011	64701	3806	4658	2518	10983	23.3	6300	233	454	136	16837	17660	37.5	6677	5 420	15 986	14.2	47.10	27%
2012	60895	3806	4384	2569	10759	22.8	6067	233	437	139	17174	17983	38.2	7224	5 470	21 456	15.3	47.10	27%
2013	57089	3806	4110	2620	10536	22.4	5833	233	420	142	17517	18312	38.9	7776	5 493	26 948	16.5	47.10	27%
2014	53283	3806	3836	2672	10315	21.9	5600	233	403	145	17867	18649	39.6	8334	5 491	32 440	17.7	47.10	27%
2015	49477	3806	3562	2726	10094	21.4	5367	233	386	148	18225	18992	40.3	8898	5 469	37 909	18.9	47.10	27%
2016	45671	3806	3288	2780	9875	21.0	5133	233	370	150	18589	19343	41.1	9468	5 429	43 338	20.1	47.10	27%
2017	41865	3806	3014	2836	9656	20.5	4900	233	353	153	18961	19701	41.8	10044	5 372	48 710	21.3	47.10	27%
2018	38060	3806	2740	2893	9439	20.0	4667	233	336	157	19340	20066	42.6	10627	5 302	54 012	22.6	47.10	27%
2019	34254	3806	2466	2950	9223	19.6	4433	233	319	160	19727	20439	43.4	11217	5 221	59 233	23.8	47.10	27%
2020	30448	3806	2192	3009	9008	19.1	4200	233	302	163	20122	20820	44.2	11813	5 129	64 362	25.1	47.10	27%
2021	26642	3806	1918	3070	8794	18.7	3967	233	286	166	20524	21209	45.0	12415	5 028	69 390	26.4	47.10	27%
2022	22836	3806	1644	3131	8581	18.2	3733	233	269	169	20934	21606	45.9	13025	4 921	74 311	27.7	47.10	27%
2023	19030	3806	1370	3194	8370	17.8	3500	233	252	173	21353	22011	46.7	13642	4 808	79 119	29.0	47.10	27%
2024	15224	3806	1096	3258	8160	17.3	3267	233	235	176	21780	22425	47.6	14265	4 690	83 809	30.3	47.10	27%
2025	11418	3806	822	3323	7951	16.9	3033	233	218	180	22216	22847	48.5	14897	4 569	88 377	31.6	47.10	27%
2026	7612	3806	548	3389	7743	16.4	2800	233	202	183	22660	23279	49.4	15535	4 444	92 822	33.0	47.10	27%
2027	3806	3806	274	3457	7537	16.0	2567	233	185	187	23113	23719	50.4	16182	4 318	97 140	34.4	47.10	27%
2028	0	3806	0	3526	7332	15.6	2333	233	168	191	23576	24168	51.3	16836	4 191	101 331	35.7	47.10	27%
2029	113109	5655	8144	3597	17396	36.9	2100	233	151	195	24047	24626	52.3	7230	1 679	103 010	15.4	47.10	27%
2030	107453	5655	7737	3669	17061	36.2	1867	233	134	199	24528	25094	53.3	8034	1 740	104 751	17.1	47.10	27%
2031	101798	5655	7329	3742	16727	35.5	1633	233	118	202	25019	25572	54.3	8845	1 787	106 538	18.8	47.10	27%
2032	96143	5655	6922	3817	16394	34.8	1400	233	101	207	25519	26060	55.3	9665	1 822	108 360	20.5	47.10	27%
2033	90487	5655	6515	3893	16064	34.1	1167	233	84	211	26029	26557	56.4	10494	1 845	110 205	22.3	47.10	27%
2034	84832	5655	6108	3971	15734	33.4	933	233	67	215	26550	27065	57.5	11331	1 859	112 064	24.1	47.10	27%
2035	79176	5655	5701	4050	15407	32.7	700	233	50	219	27081	27584	58.6	12177	1 863	113 927	25.9	47.10	27%
2036	73521	5655	5293	4131	15080	32.0	467	233	34	224	27623	28113	59.7	13033	1 860	115 788	27.7	47.10	27%
2037	67865	5655	4886	4214	14756	31.3	233	233	17	228	28175	28653	60.8	13897	1 850	117 638	29.5	47.10	27%
2038	62210	5655	4479	4298	14433	30.6	0	233	0	233	28739	29205	62.0	14772	1 835	119 473	31.4	47.10	27%
2039	56554	5655	4072	4384	14112	30.0	12680	423	913	237	29313	30886	65.6	16775	1 944	121 417	35.6	47.10	27%
2040	50899	5655	3665	4472	13792	29.3	12257	423	882	242	29900	31447	66.8	17655	1 908	123 325	37.5	47.10	27%
2041	45244	5655	3258	4561	13474	28.6	11834	423	852	247	30498	32019	68.0	18545	1 870	125 195	39.4	47.10	27%
2042	39588	5655	2850	4653	13158	27.9	11412	423	822	252	31108	32604	69.2	19445	1 829	127 023	41.3	47.10	27%
2043	33933	5655	2443	4746	12844	27.3	10989	423	791	257	31730	33200	70.5	20356	1 786	128 809	43.2	47.10	27%
2044	28277	5655	2036	4841	12532	26.6	10566	423	761	262	32364	33810	71.8	21278	1 741	130 551	45.2	47.10	27%
2045	22622	5655	1629	4937	12222	25.9	10144	423	730	267	33012	34432	73.1	22210	1 696	132 247	47.2	47.10	27%
2046	16966	5655	1222	5036	11913	25.3	9721	423	700	273	33672	35067	74.5	23154	1 649	133 896	49.2	47.10	27%
2047	11311	5655	814	5137	11607	24.6	9298	423	669	278	34345	35715	75.8	24109	1 602	135 497	51.2	47.10	27%
2048	951	1903	69	5240	7211	15.3	8876	423	639	284	35032	36377	77.2	29166	1 808	137 305	61.9	47.10	27%
PV		54155	47010	40177	141342	$181		3204	4643	2174	268626	278647	$356	137305	139 914			614	


PROJECT FORECAST SAVINGS (CENTS/kWh)
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
2008
2010
2012
2014
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YEAR

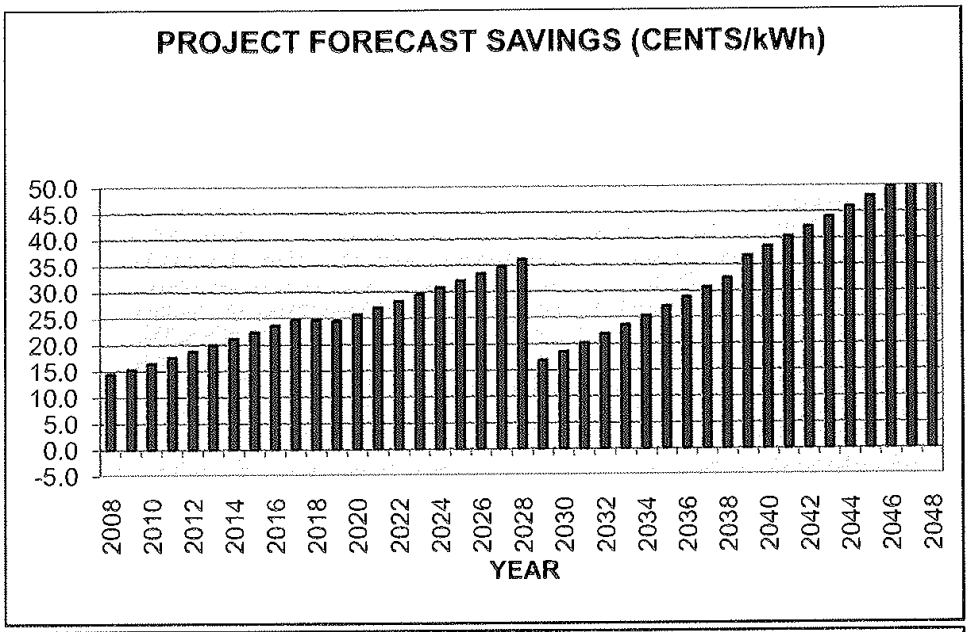

PROJECT FORECAST CUMULATIVE PRESENT WORTH SAVINGS ($000'S)
$160 000
$140 000
$120 000
$100 000
$80 000
$60 000
$40 000
$20 000
$0
2008
2011
2014
2017
2020
2023
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2044
2047
YEAR

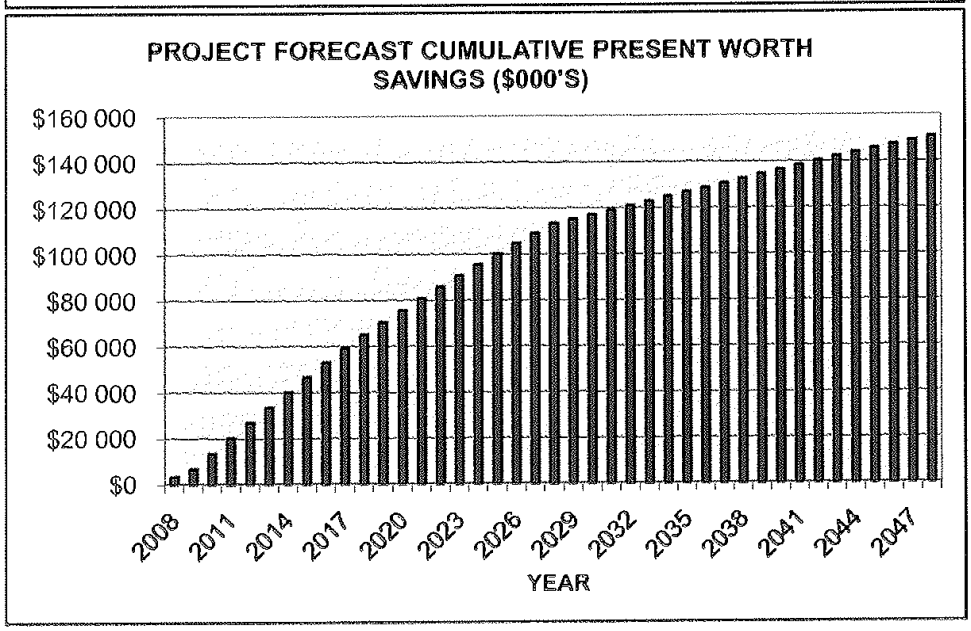
Mt SUMANIK 20 MW WIND FARM CASE 4 - WITH BLADE HEATING, WITH INCENTIVE PROGRAM

		WIND FARM				DIESEL DISPLACED				
Capital ($000)		2008	$72 119	20.000 MW		$7 000	7.000 MW @	$1 000 /kW		
Capital ($000)		2008	$72 119		Load	$7 000				
Energy			47.1 GW.h	(27%CF)	Max	47.1 GW.h	(77%CF)			
Fuel		2000	Load Growth		50.0	287.5 $/MWh	$1.15 /litre @	4 kW.h/litre		
O&M	(Fixed)	2000	$000/yr			15.4 $000/yr @	$2.2 /kW			
O&M	(Variable)	2000	43 $/MWh			2.0 $/MWh				
Life			20 years			30 years				
Levelized Cost of Energy										
	Nominal $	2008	20.84 cents/kW.h			45.41 cents/kW.h				
	Real $	2008	16.18 cents/kW.h			34.96 cents/kW.h				
Project PV	$	2000	127 879 $000's			278 647 $000's	PV Savings	150 767 $000's	54%	

	Mid-Year	WIND FARM						Mid-Year	DIESEL							SAVINGS			Net		
Year	Rate Base	Depr	Return	O&M	Total $000	cents/ kW.h		Rate Base	Depr	Return	O&M	Fuel	Total $000	cents/ kW.h		Net	PW to 2008	CPW	Savings c/kW.h	Annual Energy	Capacity Factor
2008	35158	1803	2531	635	4969	21.1		3442	117	248	73	7933	8371	35.5		3402	3 402	3 402	14.4	23.55	13%
2009	68513	3606	4933	1295	9834	20.9		6767	233	487	131	16183	17035	36.2		7201	6 717	6 717	15.3	47.10	27%
2010	64907	3606	4673	1321	9600	20.4		6533	233	470	134	16507	17344	36.8		7744	6 739	13 456	16.4	47.10	27%
2011	61301	3606	4414	1347	9367	19.9		6300	233	454	136	16837	17660	37.5		8293	6 732	20 188	17.6	47.10	27%
2012	57695	3606	4154	1374	9134	19.4		6067	233	437	139	17174	17983	38.2		8849	6 700	26 889	18.8	47.10	27%
2013	54089	3606	3894	1401	8902	18.9		5833	233	420	142	17517	18312	38.9		9410	6 647	33 536	20.0	47.10	27%
2014	50483	3606	3635	1429	8670	18.4		5600	233	403	145	17867	18649	39.6		9978	6 575	40 111	21.2	47.10	27%
2015	46877	3606	3375	1458	8439	17.9		5367	233	386	148	18225	18992	40.3		10553	6 486	46 597	22.4	47.10	27%
2016	43271	3606	3116	1487	8209	17.4		5133	233	370	150	18589	19343	41.1		11134	6 384	52 981	23.6	47.10	27%
2017	39665	3606	2856	1517	7979	16.9		4900	233	353	153	18961	19701	41.8		11722	6 270	59 251	24.9	47.10	27%
2018	36060	3606	2596	2220	8422	17.9		4667	233	336	157	19340	20066	42.6		11644	5 810	65 061	24.7	47.10	27%
2019	32454	3606	2337	2950	8893	18.9		4433	233	319	160	19727	20439	43.4		11546	5 374	70 435	24.5	47.10	27%
2020	28848	3606	2077	3009	8692	18.5		4200	233	302	163	20122	20820	44.2		12128	5 266	75 700	25.7	47.10	27%
2021	25242	3606	1817	3070	8493	18.0		3967	233	286	166	20524	21209	45.0		12716	5 150	80 850	27.0	47.10	27%
2022	21636	3606	1558	3131	8295	17.6		3733	233	269	169	20934	21606	45.9		13311	5 029	85 880	28.3	47.10	27%
2023	18030	3606	1298	3194	8098	17.2		3500	233	252	173	21353	22011	46.7		13914	4 904	90 783	29.5	47.10	27%
2024	14424	3606	1039	3258	7902	16.8		3267	233	235	176	21780	22425	47.6		14523	4 775	95 558	30.8	47.10	27%
2025	10818	3606	779	3323	7708	16.4		3033	233	218	180	22216	22847	48.5		15140	4 643	100 201	32.1	47.10	27%
2026	7212	3606	519	3389	7514	16.0		2800	233	202	183	22660	23279	49.4		15764	4 510	104 711	33.5	47.10	27%
2027	3606	3606	260	3457	7323	15.5		2567	233	185	187	23113	23719	50.4		16396	4 376	109 086	34.8	47.10	27%
2028	0	3606	0	3526	7132	15.1		2333	233	168	191	23576	24168	51.3		17036	4 241	113 327	36.2	47.10	27%
2029	107165	5358	7716	3597	16671	35.4		2100	233	151	195	24047	24626	52.3		7956	1 847	115 175	16.9	47.10	27%
2030	101807	5358	7330	3669	16357	34.7		1867	233	134	199	24528	25094	53.3		8737	1 893	117 068	18.6	47.10	27%
2031	96449	5358	6944	3742	16044	34.1		1633	233	118	202	25019	25572	54.3		9528	1 925	118 993	20.2	47.10	27%
2032	91090	5358	6559	3817	15734	33.4		1400	233	101	207	25519	26060	55.3		10326	1 947	120 940	21.9	47.10	27%
2033	85732	5358	6173	3893	15424	32.7		1167	233	84	211	26029	26557	56.4		11133	1 958	122 897	23.6	47.10	27%
2034	80374	5358	5787	3971	15116	32.1		933	233	67	215	26550	27065	57.5		11949	1 960	124 857	25.4	47.10	27%
2035	75016	5358	5401	4050	14810	31.4		700	233	50	219	27081	27584	58.6		12774	1 955	126 812	27.1	47.10	27%
2036	69657	5358	5015	4131	14505	30.8		467	233	34	224	27623	28113	59.7		13608	1 942	128 754	28.9	47.10	27%
2037	64299	5358	4630	4214	14202	30.2		233	233	17	228	28175	28653	60.8		14451	1 924	130 679	30.7	47.10	27%
2038	58941	5358	4244	4298	13900	29.5		0	233	0	233	28739	29205	62.0		15304	1 901	132 580	32.5	47.10	27%
2039	53583	5358	3858	4384	13600	28.9		12680	423	913	237	29313	30886	65.6		17286	2 003	134 583	36.7	47.10	27%
2040	48224	5358	3472	4472	13302	28.2		12257	423	882	242	29900	31447	66.8		18144	1 961	136 544	38.5	47.10	27%
2041	42866	5358	3086	4561	13006	27.6		11834	423	852	247	30498	32019	68.0		19013	1 917	138 461	40.4	47.10	27%
2042	37508	5358	2701	4653	12711	27.0		11412	423	822	252	31108	32604	69.2		19892	1 871	140 332	42.2	47.10	27%
2043	32150	5358	2315	4746	12419	26.4		10989	423	791	257	31730	33200	70.5		20782	1 823	142 155	44.1	47.10	27%
2044	26791	5358	1929	4841	12128	25.7		10566	423	761	262	32364	33810	71.8		21682	1 775	143 929	46.0	47.10	27%
2045	21433	5358	1543	4937	11839	25.1		10144	423	730	267	33012	34432	73.1		22593	1 725	145 654	48.0	47.10	27%
2046	16075	5358	1157	5036	11552	24.5		9721	423	700	273	33672	35067	74.5		23515	1 675	147 329	49.9	47.10	27%
2047	10717	5358	772	5137	11267	23.9		9298	423	669	278	34345	35715	75.8		24449	1 624	148 953	51.9	47.10	27%
2048	901	1803	65	5240	7107	15.1		8876	423	639	284	35032	36377	77.2		29270	1 814	150 767	62.1	47.10	27%
PV		51309	44540	32031	127879	$164			3204	4643	2174	268626	278647	$356		150767	154 169			614	

Cost of Capital	7.20%		
Discount Rate	7.20%		
Inflation Rate	2.00%		
Real discount rate	5.10%		
Fuel Inflation rate	2.00%		
Rate of Return	Ratio	Rate	
Debt	60%	6.00%	3.60%
Equity	40%	9.00%	3.60%
Total	100%		7.20%


PROJECT FORECAST SAVINGS (CENTS/kWh)
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
2008
2010
2012
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2034
2036
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2040
2042
2044
2046
2048
YEAR


PROJECT FORECAST CUMULATIVE PRESENT WORTH SAVINGS ($000'S)
$160 000
$140 000
$120 000
$100 000
$80 000
$60 000
$40 000
$20 000
$0
2008
2011
2014
2017
2020
2023
2026
2029
2032
2035
2038
2041
2044
2047
YEAR

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CANADIAN WIND ENERGY ASSOCIATION | ASSOCIATION CANADIENNE DE L'ÉNERGIE ÉOLIENNE

A Proposal to Expand and Extend the Federal Government's Successful ecoENERGY Renewable Power Program in the 2009 Federal Budget

- The federal government's major renewable power initiative, the extremely successful ecoENERGY for Renewable Power Program (eRPP), is projected to have allocated all of its funding early in the 2009-2010 fiscal year, well before the program's scheduled end date of March 31, 2011. **While the federal government states that renewable energy is a key part of its environmental and energy strategy, there is currently no commitment to expand or extend the eRPP.**
- **The Canadian Wind Energy Association (CanWEA) is calling on the federal government to expand and extend the eRPP in the 2009 federal budget to support the deployment of an additional 8,000 MW of new renewable energy development in Canada by March 31, 2014. Such action is required because:**
  - **An end to the eRPP will make Canada an even less competitive destination for rapidly growing global wind energy project / manufacturing investment** (US federal incentives are more than twice the value of the eRPP)
  - **Greenhouse gas offsets are not a substitute for the eRPP, and would provide significantly less value than the eRPP in virtually all of Canada**
  - **The eRPP was designed to help "close the cost gap" between wind energy and conventional energy sources and the current economic circumstances facing the industry indicate that the eRPP is still required for this purpose.**
- **Expanding / extending the eRPP is a fiscally responsible measure in a time of economic challenges.** Program costs start small and ramp up over time - $15 million in 2009-2010, $45 million in 2010-2011, and $126 million in 2011-2012. Over the 15 year life of the program, the average additional cost would be $187 million/year.
- **Expanding / extending the eRPP will be an important stimulus for private sector investment in new electricity infrastructure.** Over the next five years, a federal investment of just over $600 million will facilitate $6 billion of new private sector investment as well as the creation of 8,000 new Canadian jobs.
- **Expanding / extending the eRPP is essential if the federal government is to meet its commitment that 90 percent of Canadian electricity needs are to be provided by non-emitting sources by 2020** as wind energy, unlike most other clean technologies, can be built quickly and significantly in this time frame.

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The Expansion and Extension of the eRPP is Critical for Wind Energy in Canada

The Federal Government announced the eRPP in January 2007 to support the deployment of approximately 4,000 MW of new low-impact, renewable electricity projects by March 31, 2011. As of August 2008, almost 10,000 MW of renewable energy projects had registered for the program and contribution agreements had already been signed for almost 1,000 MW of new renewable energy facilities. **According to Natural Resources Canada, all of the funding associated with this successful program is expected to be fully allocated before the end of the 2009-2010 fiscal year, and potentially by as early as March 31, 2009. In other words, the program will meet its objectives almost two full years ahead of schedule.**

Projects that are to be commissioned in the 2009-2011 period are now unlikely to be able to receive support from the program, and if this support is not forthcoming, the economic viability of such projects will be at risk.

The eRPP has played a fundamental role in stimulating the deployment of wind energy in Canada by providing a production incentive (1 cent / kwh produced for 10 years) that helps to close the gap between the cost of wind energy and the cost of conventional electricity generation – encouraging provincial governments and utilities to actively seek out wind energy. Between 2002 and 2007, Canada's installed wind energy capacity grew from 322 MW to 1,846 MW, and we expect to be close to 2,600 MW by the end of 2008.

Expanding the eRPP beyond 2008 is critical to maintain and accelerate this impressive growth in Canada's wind energy industry and to maximize the economic and environmental benefits that result for Canada. There are several reasons for this:

- **More than $1 trillion is projected to be invested in new wind energy capacity globally between 2008 and 2020.**[1] The wind energy industry is a global industry and investors will seek to invest in countries that provide the highest rate of return. For Canada, the major competing investment destination is the United States. Over the last four years, the United States has installed more than 18,000 MW of new wind energy capacity – only natural gas fired electricity generation has installed more capacity in that time period. **An important driver for wind energy development in the United States is a Federal Production Tax Credit that provides investors**

[1] Global installed wind energy capacity increased from 31,000 MW in 2002 to more than 94,000 MW in 2007. This is projected to increase to 240,000 MW by 2012 and more than 500,000 MW by 2020.

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with a tax credit of 2.1 cents/kWh produced for the first 10 years of production – more than twice the value provided by the eRPP. This tax credit was recently extended until the end of 2009 and President-Elect Obama has made a commitment to extend it until 2014. An end to the eRPP at this time will significantly weaken Canada's ability to compete for global wind energy investment and will drive investment to the United States and other markets at the expense of Canada.

- Wind turbine and component manufacturers also operate in a global marketplace and are seeking to invest in stable markets with steady growth. While Canada has seen the establishment of a small number of manufacturing facilities over the last few years (e.g., towers, blades, nacelle shells, nacelle assembly), Canada is not yet a competitive investment destination. **The United States alone has seen the announcement or construction of 41 new or expanded wind energy manufacturing facilities in the last 18 months, representing $1 billion in investment and 9,000 jobs. An end to the eRPP will make the Canadian market less attractive to investment at a time when manufacturers are actively seeking to make new investments in an effort to catch up to the rapidly growing global demand for wind turbines.**

- While wind energy provides numerous environmental benefits for Canada (no greenhouse gas emissions, air or water pollution, or toxic, hazardous or nuclear wastes), the value of these benefits and associated health care cost savings are still not recognized in electricity markets. The Federal Government's Regulatory Framework for Air Emissions has the potential to provide value for one environmental benefit of wind energy by putting a price on greenhouse gas emissions. Environment Canada estimates, however, that that the market price for carbon dioxide under the Regulatory Framework will not reach $30/tonne until 2014, despite the fact that the world's only major functioning carbon market (in Europe) already has prices at this level. **An end to the eRPP before the establishment of a free and functional carbon market in Canada is clearly premature and will not allow wind energy to get full value for its greenhouse gas emission reduction benefits.**

- **While a fully functioning carbon market will provide some future support for wind energy development in Canada**, it is important to note that it will not provide value for the other environmental attributes of wind energy and that **the incentive provided will vary significantly among different regions of Canada because of the different greenhouse gas intensities of electricity generation in those**

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regions.[2] Europe, the global leader on wind energy, is using both a carbon market and a separate and distinct renewable energy policy (that requires 20% of all energy used in Europe - a higher percentage of electricity - to come from renewable energy sources by 2020) to drive future wind energy development. **An end to the eRPP would represent the termination of the federal government's key policy to support renewable energy in electricity generation.**

- While increased costs of inputs like steel have increased the costs of all forms of electricity generation, wind energy faces a unique challenge. It is extremely capital intensive – wind turbines account for 70-80 percent of total wind energy project costs – **and a global shortage of wind turbines, due to the strong global demand for wind energy**, has resulted in additional and significant cost increases. In fact, the installed cost of a wind energy project has increased from about $1,700/kW in 2003 to more than $2,500/kW today. Although investments in new manufacturing facilities are expected to bring supply and demand into balance within the next five years and stabilize costs, we are seeing a short-term impact on the relative cost competitiveness of wind energy as well as more marginal returns for wind energy projects as electricity prices increase more slowly than project costs. **The eRPP was designed to help "close the cost gap" between wind energy and conventional energy sources and the current economic circumstances facing the industry indicate that the eRPP is still required for this purpose.**

- **Provincial governments and utilities are now planning for a future that would see a minimum of 12,000 MW of wind energy capacity installed in Canada by 2016.** By narrowing the cost gap between wind energy and conventional sources of electricity, the eRPP has played a critical role in encouraging such planning at the provincial level by enhancing wind energy's cost competitiveness. **An end to the eRPP at this time will result in provinces reducing the role of wind energy in their future electricity generation.**

- Many major greenhouse gas emitters are looking to use greenhouse gas offsets created through wind energy projects to help them meet their regulated greenhouse gas emission reduction commitments under the Federal Regulatory Framework on Air Emissions. **An end to the eRPP will decrease the number of wind energy**

[2] CanWEA estimates that a $15 / tonne price on carbon dioxide will result in GHG offset values for wind energy projects of $0.0098 / kwh in Alberta, $0.0054 / kwh in Ontario, $0.0033 / kwh in Quebec, and $0.0015 / kwh in British Columbia – all less than the current incentive provide by the eRPP.

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projects built in Canada and reduce the quantity of greenhouse gas offsets made available to companies required to reduce their emissions.

Failure to extend and expand the eRPP will slow the growth of wind energy in Canada and reduce our share of rapidly expanding global investment in wind energy by making Canada's wind energy market a less attractive destination for wind energy investment.

The Benefits of Wind Energy Deployment in Canada

Canada's electricity system faces a number of sustainability challenges and wind energy has a critical role to play in making our electricity system more reliable, affordable, economically viable, socially acceptable and environmentally sound.

- **Wind energy will help stabilize and moderate electricity price increases over the next decade.** With support from the eRPP, good wind energy sites have already demonstrated that they can be cost-competitive with some conventional generation sources such as natural gas. Over the next decade, however, wind energy will become much more cost-competitive with all sources of generation. Wind energy costs are expected to stabilize or decline over the next decade while the costs of all other forms of generation are expected to increase. For example, fossil-fuel fired electricity costs will increase with the imposition of a price on carbon emissions.

- **Wind energy is bringing new investment and new jobs to Canada and the eRPP was designed as an industrial development program**. In 2007, it is estimated that Canada's wind energy industry contributed $900 million to Canada's GDP and employed more than 4,000 Canadians. Every 10 MW of new installed wind energy capacity represents more than $25 million of investment, of which anywhere between 30% and 60% remains in Canada, as well as 15 person-years of employment in wind farm construction and 1 job in wind farm operation and maintenance. Increased manufacture of wind turbines and components has the potential to create significantly more employment benefits for Canada.

- **Wind energy provides substantial benefits for Canada's rural communities, helping them to diversify their economies and stabilize their tax bases**. In addition to investment and jobs, it is estimated that wind energy projects currently pay more than $5 million a year to rural landowners who lease their land for the placement of wind turbines. In many rural communities, where no other form of

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industrial activity is present, wind energy is also making a very substantial contribution to the municipal tax base.

- **Wind energy has an essential role to play in helping Canada "Turn the Corner" in fighting climate change by 2020.** In that time period, Canada has few options for limiting greenhouse gas emissions in the electricity sector: (a) energy efficiency improvements, (b) renewable energy, and (c) fuel switching from coal to natural gas. Nuclear power plants cannot be built in this timeframe and clean coal / carbon capture and storage technologies are unlikely to have moved much beyond pilot projects by 2020.

Supporting Wind Energy Deployment in Remote Communities

Canada has roughly 300 northern and remote communities, including many Aboriginal communities, with a total population of about 200,000 people. These areas are isolated from the national grid and typically draw their electricity from diesel generator sets that are expensive ($1.50 per kWh), cause a great deal of pollution (local air contaminants and greenhouse gases), and bring few economic or capacity-development benefits to the community. Wind energy is an excellent alternative for these situations.

A 1 cent per kWh incentive, however, will not adequately cover the relatively higher costs and risks of wind generation in these isolated areas. As a result, CanWEA would like to see $61 million of the proposed expansion to the eRPP set aside to provide capital grants and a production incentive appropriate to the North that would support the deployment of 34 wind projects in remote communities and ensure that the eRPP is available to all regions of Canada. **These projects would have a total capacity of 55 MW and would meet roughly 10% of all electricity demand in remote communities, therefore eliminating the need for almost 300 million litres of imported diesel fuel.**

Wind energy represents a tremendous opportunity for Canada. With one of the world's best wind resources, a strong hydro-electric base that can facilitate higher levels of wind energy integration, a manufacturing sector that has the skill sets required to service wind energy markets and a huge potential export market south of the border, we have the potential to compete for global wind energy investment. Maximizing our potential for success, however, requires an expansion and extension of the ecoENERGY for Renewable Power Program.

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TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS requests YEC inform the YUB and Intervenors what follow up work has been done since the *Wind Assessment Feasibility Study Final Report* dated January 2009.

ANSWER:

(a)

Since 2009, Yukon Energy has commissioned two feasibility studies to assess the viability of building a 20 MW wind farm at Ferry Hill, near Stewart Crossing, and a 10 MW or 20 MW wind farm on Mt Sumanik, near Whitehorse.

Yukon Energy also commissioned third-party consultants (Natural Power Consultants and MG Renewables Consulting) to complete regional mesoscale wind mapping throughout the Yukon Territory. In 2011, a wind monitoring tower was built on Ferry Hill to collect data to confirm the potential power benefit that could be achieved at the site.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like to know whether an analysis of existing data to determine whether a wind farm on Mt. Sumanik could provide a capacity benefit to the WAF grid has been done.

ANSWER:

(a)

Please see response to YCS-YEC-1-2. Yukon Energy commissioned a third-party consultant to update a feasibility study for the construction of a 10 MW or 20 MW wind farm on Mt Sumanik.

With regard to capacity, please see YCS-YEC-1-8 with regard to capacity benefits (5 MW) if developed in conjunction with DRUPS (diesel rotary uninterruptible power supply).

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like to know whether the installation of a heavy duty engineered measurement mast at least 60 metres high that can withstand the ice loading that normal wind masts cannot withstand, and that the mast be equipped with the best heated ice free wind instruments available at least four different elevations (15, 30. 45, and 60 metres for example), and that the mast be equipped with the latest ice detection and assessment instruments to assess the frequency, duration, and severity of icing events on Mt. Sumanik, has been done.

ANSWER:

(a)

The installation of ice and wind monitoring instruments at Mt Sumanik has not been completed at this time. A wind monitoring tower was constructed on Ferry Hill to collect data at that site. At a future date if determined to be warranted, Yukon Energy could re-locate its wind monitoring tower currently at Ferry Hill to collect data at Mt Sumanik.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like to know whether discussions with various turbine manufacturers and third parties involved in the development and testing of blade heating systems to try to secure access to blade heating systems for a wind project on Mt. Sumanik has been done.

ANSWER:

(a)

Yukon Energy approached turbine manufacturers directly, and via third-party consultants working on behalf of the Corporation, to inquire about blade heating and related systems to prevent ice formation.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like to know whether various planning and assessment activities that could shorten the lead time to the installation of the project, with due respect of the costs involved, have been done.

ANSWER:

(a)

To reduce project expense and risk, prior to investing material time and financial resources to complete baseline data collection and related activities to support a regulatory submission, Yukon Energy must better understand the wind resource potential at the preferred sites. As such, efforts are currently directed toward completing Phase 1: Project definition of the Corporation's Project Planning & Development framework.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like to know whether an investigation by YEC into the possibility of support from the Yukon Cold Climate Innovation Centre for the recommended work on Mt. Sumanik (at least the icing assessment related work) has been done.

ANSWER:

(a)

Yukon Energy has approached the Yukon Cold Climate Innovation Centre for other renewable energy initiatives. Yukon Energy expects to seek support from the Yukon Cold Climate Innovation Centre once the wind resource is confirmed and Yukon Energy is ready to move forward within the project planning and development framework.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) If the answers to questions 3 to 7 are no, YCS would like to know why, considering the conclusion of the study is that a wind project on Mt. Sumanik would be economic relative to base load diesel (even with diesel prices as low as $0.75 per litre), that the wind resources during the entire year on Mt. Sumanik match the electrical load, and that there is every reason to further pursue a wind project on Mt. Sumanik (especially due to its proximity to the predicted large load of new residential/commercial development in Whitehorse and the predominance of electrical heat).

ANSWER:

(a)

Yukon Energy has fully recognized the need to assess the wind potential in the Yukon to determine whether, and when, it is a viable resource option to meet near-term or longer term grid requirements, given the range of options available to meet these requirements.

Yukon Energy's assessments to date have confirmed at a preliminary level potential 20-21 MW alternatives at two sites (Ferry Hill and Mount Sumanik), as well as a potential smaller scale "first stage" alternative (10 MW) that could potentially be pursued at each of these sites. To reduce project expense and risk, prior to investing material time and financial resources to complete baseline data collection and related activities to support a regulatory submission, Yukon Energy has recognized that it must better understand the wind resource potential at these sites. Based on preliminary assessments, and the expectation that only one such site at best can be accommodated on the grid during the current 20-year planning period, Yukon Energy has focused its current ongoing wind monitoring work at Ferry Hill. As such, efforts are currently directed at further wind monitoring at the Ferry Hill site in order to move forward on Phase 1: Project definition of the Corporation’s Project Planning & Development framework. Please see response to

YUB-YEC-1-40(b) for more information on YEC's development phases for feasibility study projects.

In summary, over the past 3 years, the Corporation has invested material resources to better understand the potential for wind. Yukon Energy is committed to further investigate wind resource at Ferry Hill. In combination with wind monitoring at the site, the Corporation is investigating other ancillary systems (e.g. diesel rotary uninterruptible power system) that would be required with the development of a large wind farm to ensure grid stability and reliability in instances where generation is suspended as a result of wind lulls. These ancillary systems, once included in the overall project cost, contribute to a material increase in cost of energy for wind energy that nonetheless, at some potential grid loads, remains less than the cost of diesel generation but higher than other energy generation options.

An overview of Yukon Energy's current assessments of the Ferry Hill wind resource potential, and how this matches with grid diesel displacement forecast over a year and the life of a wind project, is provided below.

Overview of Current Wind Potential Assessments

Subsequent to the 2011 Wind Feasibility Study, Yukon Energy engaged in a resource planning process which led to the development of the draft 2011 20-Year Resource Plan: 2011-2030. This resource planning process relied upon costs and other information referenced in the 2011 Wind Feasibility Study for development of a wind resource in Yukon. The cost effectiveness of development of a wind resource in Yukon was assessed based on information available at the time and considered diesel displacement opportunities and project benefits under various forecast load scenarios.

The results of this resource planning process are summarized in the 2011 20-Year Resource Plan: 2011-2030 Overview provided as an attachment to YECL-YEC-1-18.

As discussed at the Energy Charrette, wind is generally assessed to be not reliable as to delivery of power (not add to peaking capacity, not storable, needs added costs to provide related storage, medium cost (Full Utilization LCOE at 15+ cents/kW.h), not flexible (capital intensive option, not dispatchable, high costs per net kW.h of useful energy when minimal diesel to displace), but relatively low on regulatory risk as to approvals, and high on environmentally responsibility (renewable energy option with very

low GHG emissions). For a 20-21 MW wind project on the Yukon grid, it is estimated that Yukon Energy would likely also require a new diesel rotary uninterruptible power supply (DRUPS) units (estimated cost of $2 million per MW).

The 2011 Resource Plan summarizes YEC's current assessment of a 21 MW wind farm at Ferry Hill, assuming 14 GE 1.5 MWxle wind turbines; gross annual energy capability estimated at 68.70 GW.h before losses, and 55.60 GW.h after all losses (includes 9% downtime, icing losses averaging 7.8%, and other losses – average capacity factor approximates 30.2%). Initial wind monitoring indicates higher useful wind energy generation in winter months than in summer months. Capital costs (2010$) are estimated at $83.42 million ($3.97 million per MW) before consideration of spinning reserve or other added energy storage requirements (see below), including 10% contingency and provision for turbine de-icing system, transmission/substation improvements (with transmission connection to Stewart Crossing south substation), development and permitting, engineering/construction management at 12% and owner's costs at 7%). Annual operating costs (2010$) estimated at $2.1 million (about $38/MW.h). Financial analysis assumes a 25 year life. In assessing a 20-21MW wind site on the Yukon grid, $10 million is added to the capital cost to provide for a minimum 5 MW of DRUPS to ensure adequate spinning reserve to integrate the site on the grid.

If the Yukon grid was able to use all of the Ferry Hill wind generation to displace diesel generation over the life of the project, this resource option would be economic based on the above preliminary cost assessments, i.e., the average levelized cost of energy (LCOE) for this wind resource over its assumed 25 year life, based on full use of all its generation to displace diesel and the above cost estimates, is 14.8 cents/kWh in 2010$. This LCOE at full utilization of the wind resource is well below the expected equivalent cost of diesel fuel and O&M (assumed at 28 cents per kWh in 2010$ in the 2011 Resource Plan).

However, the 2011 Resource Plan reviews the impact of the isolated Yukon grid where generation that cannot be used to meet Yukon grid loads is effectively "spilled" (as occurs with surplus hydro generation on this grid) and has no value.

In the context of the Yukon grid, new wind generation derives economic value by displacing diesel generation that would otherwise be required (based on long term average hydro generation estimated at the forecast grid loads). To be potentially attractive, 21 MW of new wind generation at Ferry Hill would require major new loads on

the grid – for the purpose of the following analysis, Scenario A loads as presented in the 2011 Resource Plan are adopted (assumes connection of Victoria Gold mine load by 2015, the assumed time when the wind generation commences service).

Even when the new mine loads are on the grid during the 2015-19 time period, the figure below (from the Overview, Figure 5-3) demonstrates that the 21 MW wind generation would not be fully utilized to displace diesel generation under Scenario A loads (even when DSM/SSE is excluded). This reflects the combined impact of seasonal (weekly) loads, seasonal (weekly) hydro generation under long term average conditions, and seasonal (weekly) average wind generation.

- Annual available wind generation assumed at 55.8 GW.h from the 21 MW facility.

- 34.8 GW.h directly displaces diesel (focused during winter months when over 95% of diesel generation would otherwise occur).

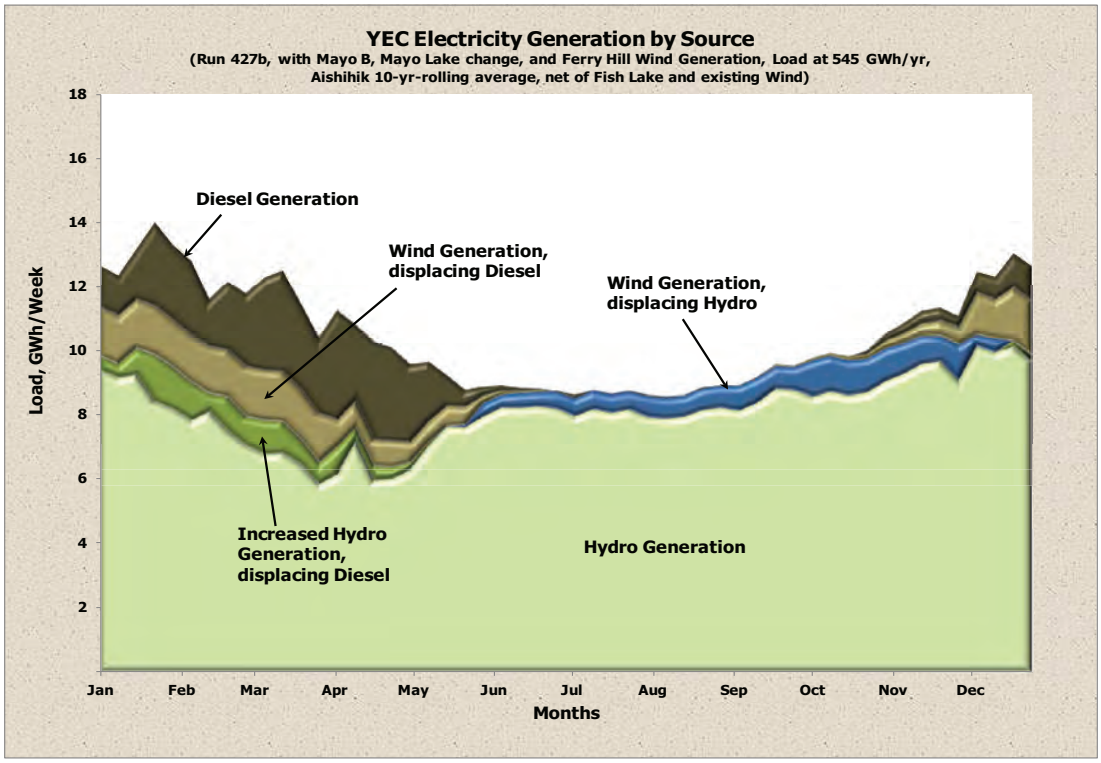
- The balance of the wind generation would "displace" hydro generation; 14.6 GWh of the displaced hydro (typically during summer months) would be forecast to enhance hydro storage that would then be used to displace diesel during winter months - the remaining 6.6 GW.h would be forecast to have no value in displacing diesel at this Scenario A load.

- In total 49.2 GW.h of forecast wind generation would be forecast to displace diesel during these years at the Scenario A forecast grid load.

- 52 GW.h of diesel energy generation requirements would remain on the grid under this assumed load and scale of wind generation (assumed Mayo Lake enhanced storage is in place, but excludes any DSM/SSE).

- Unlike diesel, the 21 MW of new wind generation is dependent at all times on wind availability and therefore does not contribute to grid reliable capacity requirements, i.e., diesel or other new reliable capacity is needed during these years at this load o address diesel unit retirements plus added capacity requirements from growth. Only the 5 MW DRUPS contributes towards the projected 12.8 to about 27 MW of new reliable capacity required during this time period with this assumed grid load (Table 5-1 in Overview).

YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) with 21 MW Wind Project Displacing Diesel and Displacing Hydro at Scenario A 2015-16 Load Without DSM/SSE



Grid Generation at 545 GW/h load* (GW.	Without Wind Project	With 21 MW Wind Project	Change
Grid Load	545.0	545.0	
Grid Generation			
Hydro*	443.9	437.3	(6.6)
Diesel	101.1	51.9	(49.2)
Wind*	-	55.8	55.8
Total	545.0	545.0	

Breakdown of Wind Generation Impacts (GW.h/yr)	
Directly Displacing Diesel	34.6
Directly Displacing Hydro	
Stored Hydro Displacing Diesel	14.6
Spilled Hydro (not required)**	6.6
Total Wind Project Generation	55.8
Total Displaced Diesel = 34.6 + 14.6 = 49.2 GW.h	

* Existing Wind and Fish Lake generation not included.

**This figure provides an example that illustrates impacts this supply option would have on the existing generation system; This does not suggest YEC would operate the system in a manner that results in hydro being displaced by other forms of more costly generation

The economic benefits of the 21 MW wind resource are also affected by the forecast grid loads (and related diesel generation otherwise forecast to be required) over the assumed 21 year life of the wind resource.

The following figure (Figure 6-4 from the Overview) demonstrates over a 25 year life how full utilization generation for this wind resource varies from forecast net diesel displaced with Scenario A loads with maximum potential DSM/SSE as assumed in the 2011 Resource Plan (highlights the impact of assumed all mines shutdown after 2020 when

the wind resource has no flexibility to limit its ongoing generation or costs). Based on the diesel displacement in this figure with the assumed grid load, the estimated LCOE (2010$) for the 21 MW wind project increases to 40.0 cents per kW,h of diesel displaced, i.e. the resource over its life is more costly than diesel at the assumed 28 cents/kWh LCOE for fuel and O&M costs.

Wind Project: Displacing Diesel and Hydro at Scenario A Load with DSM/SSE (current forecast mine life, no mine loads after 2021)

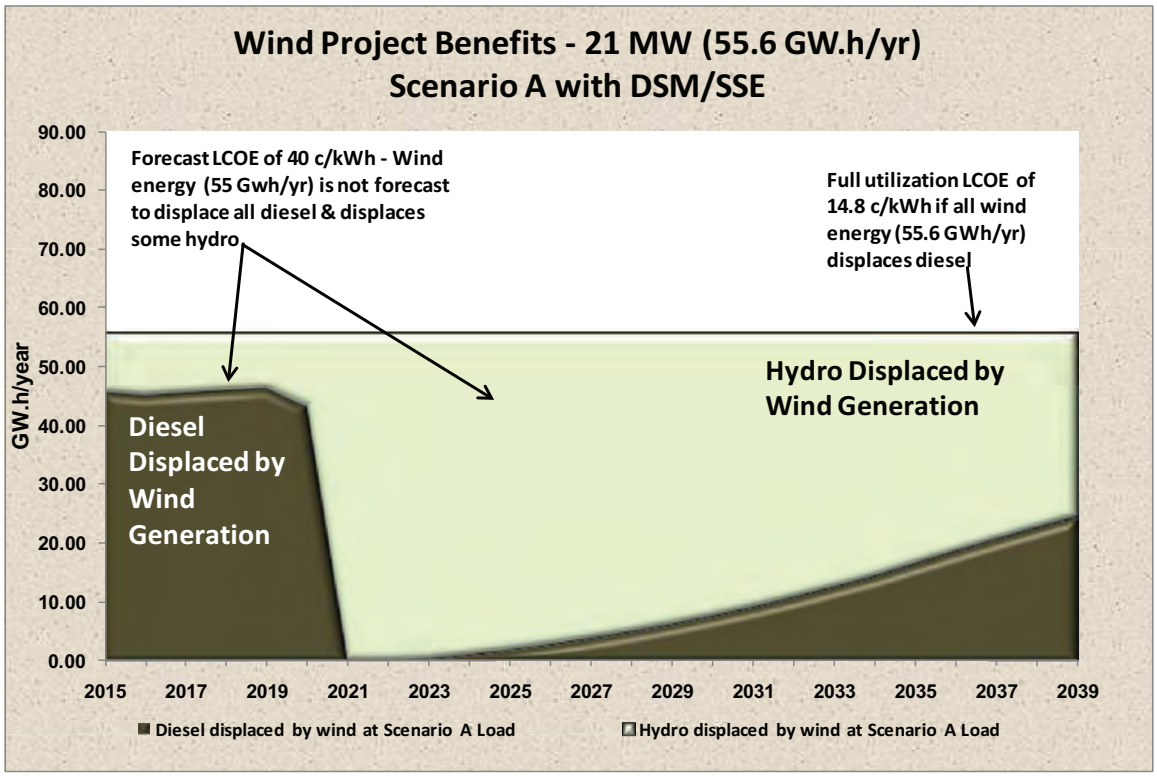


Table 8-1 and Table 8-2 in the Resource Plan Overview document provide an overview assessment of wind compared to other potential resource options and indicate as follows with regard to development of a 21 MW wind project (including 5 MW of DRUPS) to provide annual energy capability of 56 GWh with 5 MW of reliable peak winter capacity:

- Based on Scenario A with assumed DSM/SSE grid loads as defined in the Resource Plan annual costs (based on cents/ kWh of forecast diesel displaced) for the years 2015-2019 range between 26 and 29 c/kWh, i.e., slightly less than diesel fuel and O&M costs at 29-31 cents per kW.h, but higher than costs

estimated for Marsh Lake Storage (15-16 c/kW.h), Gladstone Diversion (14 c/kW.h) or LNG (17 c/kW.h).

- Based on Scenario A and Scenario B grid loads with assumed DSM/SSE as defined in the Resource Plan, LCOE (2010$) over the life of the project (based on cents/kWh of forecast diesel displaced) is more expensive than diesel, e.g., at 36.5 to 40 cents/kWh for Scenarios B and A respectively. This outcome reflects the impact of assumed mine load shut down after 2020 as well as assumed ongoing DSM/SSE; for example:
  - If Scenario A grid loads with DSM/SSE forecast for 2019 are extended to 2030, the LCOE (2010$) for wind drops to 21.3 c/kW.h; and
  - If Scenario A loads are assumed without any DSM/SSE to reduce future diesel generation, the LCOE (2010$) for wind drops to 19.6 c/kW.h.

- The 2011 Resource Plan analysis highlights the impacts on wind project economics of Yukon's isolated grid, limited loads, and variable hydro generation (both seasonal and annual variability). In contrast to forecast LCOE that take into account Yukon-specific grid conditions, a full utilization LCOE (of the type typically adopted in resource-specific feasibility studies) for a 21 MW wind project at Ferry Hill drops to 14.8 c/kW.h (2010$).

The 2011 Resource Plan Overview recommends that current Ferry Hill wind monitoring be completed in order to have this project shelf-ready to pursue through regulatory submissions and other development activity at such time as grid loads and other relevant conditions indicate that this project would be cost-effective to implement. It is also recommended that YEC continue to examine for initial development the feasibility of smaller wind projects in the range of 10 MW to meet suitable grid loads.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like to know why the existing wind turbines on Haeckel Hill are not running in the winter in order to gain experience dealing with rime icing in preparation for a wind project and to develop expertise with blade heating systems.

ANSWER:

(a)

The Haeckel Hill wind turbines run in the winter when they are available to run (i.e. not out-of-service due to a forced outage).

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like to know what work is ongoing with the wind turbines on Haeckel Hill?

ANSWER:

(a)

WW1 is at or near the end of life at 20 years. An assessment is planned for 2012 to determine the go forward options. The factors to be assessed include parts availability, support, constant Rime icing versus heating repair costs, safety concerns, site access and the required remedial action cost considerations. Scheduled Preventative Maintenance is continuing on an ongoing basis. A PLC card issue continues to be diagnosed for cause and requires repair.

WW2 is scheduled for Preventative Maintenance on an annual basis. Blade heat repairs and site access, especially in the winter months, continue to be issues.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide a detailed breakdown of costs by task and by consultant for expenditures over $50,000 for the $4.83 million spent on the Marsh Lake Winter Storage Enhancement Project.

ANSWER:

(a)

Please see response to YUB-YEC-1-42(i) for the expense forecast to end of 2011 of approximately $3.23 million spent on the Marsh Lake Winter Storage Enhancement project to date.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide a detailed breakdown of costs by task and by consultant for expenditures over $50,000 for the $4.394 million spent on the Gladstone Diversion project.

ANSWER:

(a)

Please see response to YUB-YEC-1-43(d) for spending forecast to end of 2011 of $3.7 million spent on the Gladstone Diversion project to date.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide a detailed breakdown of costs by task and by consultant for expenditures over $50,000 for the $2.231 million spent on the Atlin Enhanced Storage project.

ANSWER:

(a)

Please see YUB-YEC-1-44(a) for spending forecast to end of 2011 of $2.23 million spent on the Atlin Enhanced Storage project to date.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide a detailed breakdown of costs by task and by consultant for expenditures over $50,000 for the $2.1 million spent on the Mayo Lake drawdown project.

ANSWER:

(a)

Please see response to YUB-YEC-1-45(b) for spending forecast to end of 2011 of $1.43 million spent on the Mayo Lake drawdown project to date.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide a detailed breakdown of costs by task and by consultant for expenditures over $50,000 for the $3.746 million and $0.735 million spent on DSM.

ANSWER:

(a)

Please see response to YUB-YEC-1-46(d) for spending forecast to end of 2011 of $1.01 million spent on DSM project to date, prior to offsetting contributions of $0.735 million (see Page 5-41 of Application for breakdown of contributions). Forecast spending over the test years is $2.709 million.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide a detailed breakdown of costs by task and by consultant for expenditures over $50,000 for the $1.853 million and $0.225 million spent on Waste-To-Energy/Biomass.

ANSWER:

(a)

The $1.853 million relates to costs to the end of 2011 plus total forecast spending to the end of 2013. The $0.225 million is contributions from CANNOR (half applied in 2011 and balance in 2012).

Please see Table 1 below for a breakdown of expenditures to end of 2011 over $50,000 by task by Consultant for Waste-To-Energy/Biomass. The difference between the total expense noted below and the $0.741 million spending to end of 2011 noted in the Application is due to consultant and other costs < $50,000.

Please see Tables 2 and 3 below for a breakdown of forecast expenditures in 2012 and 2013.

Table 1:
Total Expense at 2011 Year End by Contractor by Task for Waste-to-Energy/Biomass

Vendor	Description of Services	Total to 2011 Year End
Morrison Hershfield Limited	Waste to energy prefeasibility study: Business case analysis. Technical memorandum #1 - Feedstock Analysis. Technical Memorandum #2 - Review of WTES's Design Basis Memorandum	209,184
Morrison Hershfield Limited	Waste to Energy Updated Design Basis and Business Case Analysis	98,503
Morrison Hershfield Limited	Preliminary Yukon Biomass Energy Evaluation	39,740
Lesley Cabott Consulting	Waste to Energy and Biomass project and contract management, Waste to Energy and Biomass Workshops	102,574
Waste to Energy Canada	Waste to Energy Canada Design Basis Memorandum. Prefeasibility study with cBOS technology	100,000
YEC - Owners Costs		129,031
Total Expense > $50,000		**679,033**

Table 2:

Total Forecast 2012 Expense by Contractor by Task for Waste-to-Energy/Biomass

Vendor	Task	2012 Fcst
Morrison Hershfield Limited	Completion of Waste to Energy Business Case Analysis. Biogas Prefeasibility report	154,016
Morrison Hershfield Limited	Bioenergy in Yukon: Issues and Opportunities report. Funding application for NRCan,	35,000
Morrison Hershfield Limited	Defining scope of work for a Front End Engineering Design Study and NRCan funding submission	55,000
Lesley Cabott Consulting		16,510
Bio-mass Feed Study	Overall cost of feed study - (to be tendered)	850,000
NRCan	Contribution towards Feed Study	(500,000)
Renewable Energy Committee	Contribution towards Feed Study	(88,000)
Yukon Cold Climate Innovation C	Contribution towards Feed Study	(76,000)
YEC - Owners Costs		165,974
Forecast 2012 Expenditures		**612,500**

Table 3:

Total Forecast 2013 Expense

by Contractor by Task for Waste-to-Energy/Biomass

Vendor	Task	2013 Fcst
To be Tendered	Detailed Design and submit Environmental Assessment	365,000
YEC - Owners Costs		135,000
Forecast 2013		**500,000**

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide a detailed breakdown of costs by task and by consultant for expenditures over $50,000 for the $1.030 million and $0.530 million spent on District Heating.

ANSWER:

(a)

Total forecast spending on District Heating is $1.030 million, with $0.07 million in 2011, $0.46 million in 2012 and $0.50 million in 2013. Spending in 2011 and 2012 is forecast to be offset by contributions of $0.53 million as described at page 5-49 of the Application.

Please see Table 1 below for a breakdown of expenditures to end of 2011 by task by Consultant for District Heating. Please see Tables 2 and 3 below for a breakdown of forecast expenditures in 2012 and 2013.

Table 1:
Total Expense to 2011 Year End
by Contractor by Task for District Heating

Vendor	Description of Services over $50,000	2011 Year End Expense
FVB Energy Inc.	District Energy Feasibility Study	13,687
Lesley Cabott Consulting	District Energy Project Management	49,407
City of Whitehorse		3,000
YEC - Owner Costs		4,355
Total		**70,449**

Table 2:

Total 2012 Forecast Expense by Contractor by Task for District Heating

Vendor	Description of Services over $50,000	2012 Fcst
FVB Energy Inc.	District Energy Feasibility Study/Business Case	303,519
Lesley Cabott Consulting	District Energy Project Management	2,860
Morrison Hershfield	District Energy Project Management & Biomass Feedstock Feasibility	85,719
YEC - Owner Costs		67,902
Total		**460,000**

Table 3:

Total 2013 Forecast Expense by contractor by task for District Heating

Vendor	Description of Services over $50,000	2013 Fcst
To be Tendered	District Energy Detailed Design	400,000
Morrison Hershfield		40,000
YEC - Owner Costs		60,000
Total		**500,000**

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide a detailed breakdown of costs by task and by consultant for expenditures over $50,000 for the LNG project $1.669 million.

ANSWER:

(a)

Please see response to YUB-YEC-1-49 for a summary of current information that YEC can provide on LNG.

Expenses to the end of 2011 are as noted in Table 1 below:

Table 1:
LNG Expenses to 2011 Year End, by Consultant by Task

Vendor	Description	2011 Year End
Casino Mining Corporation	Joint Feasibility Study	33,344
Davis LLP	Legal	4,637
Intergroup Consultants Ltd.	Economic analysis and support	56,697
KGS Group		13,953
Lesley Cabott Consulting		1,332
YEC - Owner Costs		58,941
Total Expense		**168,905**

A detailed breakdown of LNG expense for each test year is not available at this time. None of the LNG costs are expected to be included in rates or revenue requirements during the test years (2012 or 2013).

TOPIC:

REFERENCE:

PREAMBLE:

Page 5-5 mentions another potential hydro project under consideration and feasibility – Hoole. "Other Feasibility projects undertaken to enhance the compliment of renewable generation projects in Yukon [including Marsh, Gladstone, Atlin, Hoole]."

QUESTION:

a) YCS would like YEC to provide the feasibility study on the Hoole hydro project. If YEC is unwilling or feels it is unable to share this study, then please describe the project (location, generation capacity, cost, etc) in as much detail as possible.

ANSWER:

(a)

There is no modern feasibility study on Hoole options.

As noted in the 2006 Resource Plan, the Hoole Canyon potential hydro site is located along the Pelly River, 30 km south-east of Ross River. An initial concept for development includes the construction of a control structure on the main stem of the Pelly River with upstream storage. The project would have an installed capacity of 40 MW with an average annual energy generation estimated at 275 GWh/yr. The capital investment is estimated at $460 million (2009) and would include all phases of project development. This site is among a number of large hydro options that have been previously identified. No decisions have been made on potential future large hydro sites.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

YCS would like YEC to please provide a detailed breakdown of the costs by task and by consultant for expenditures over $50,000 for the feasibility studies on the Hoole hydro project.

ANSWER:

(a)

Please see response to YUB-YEC-1-51(c) which provides a cost breakdown for Large Hydro expenditures.

TOPIC:

REFERENCE:

PREAMBLE:

In YEC's presentation from the YEC 2012-2013 GRA workshop on May 30, slide 43 speaks to LNG. It reads: "It is expected that this project will meet reasonable assurance before the end of 2012, and that costs to date (and ongoing costs) will be included in construction WIP as the project is developed." In YEC's GRA documents it speaks to money spent on LNG: "$1.7 million for LNG (assumed transfer to fixed assets in the end of 2013 with $1 million additional spending as fixed assets project in 2013)."

QUESTION:

a) YCS would like YEC to please explain why the non-renewable LNG option is taking precedence over other alternatives, demonstrated by these stated assumptions that this project will proceed?

ANSWER:

(a)
"Reasonable assurance" simply explains how YEC expects to capitalize deferred cost projects that have reached a certain stage - it does not signify a final decision to construct an asset. Under YEC's accounting rules, the Application sets out an expectation that some form of LNG development will meet this "reasonable assurance" test for accounting treatment purposes before the end of 2012. Whether this will in fact occur remains to be seen. If this does not occur, YEC's forecast costs for LNG planning after 2012 will likely also be curtailed. Please see response to YUB-YEC-1-49 for a summary of current information that YEC can provide on LNG, including review of the above statement included in the GRA.

As noted in the Application, Yukon Energy is also continuing to work on renewable energy options, including the Marsh Lake and the Gladstone hydro enhancement projects, wind and a small wood biomass pilot project.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide details of what commitments it has made, contracts it has entered into, and feasibility studies it has undertaken, regarding LNG.

ANSWER:

(a)

Please see response to YUB-YEC-1-49 for a summary of current information that YEC can provide on LNG.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide and explain the criteria for the Reasonable Assurance Test for proposed projects.

ANSWER:

(a)

Please see the Planning Cost Accounting Policy provided as Attachment 5.1 to the Application.

Reasonable assurance is generally consistent with Yukon Energy's commitment to proceed with a specific project. This would be consistent with the following specific types of activities:

- A decision by YEC to define a specific project location, approach, technology;
- Prepare and file a YESAB Project Proposal;
- Enter into substantive negotiations with First Nations or other project partners;
- Preparation of engineering designs and tender materials; and
- Arrangement of project financing where needed.

Recent experience with CSTP and Mayo B has indicated "Commitment to Proceed" or "Reasonable Assurance" at time of a decision to prepare a YESAB filing.

Please also see CW-YEC-1-33 and YUB-YEC-1-39.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide the updated 2006 Resource Plan.

ANSWER:

(a)

Please see response to YECL-YEC-1-18 for Overview of 20-year Resource Plan: 2011-2030.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS would like YEC to please provide an update on the IPP and Net Metering policy (policies), a timeframe for when it (they) will go into effect, and anticipated demand that will be met or offset through IPP and Net Metering in the test years and beyond.

ANSWER:

(a)

Please see response to LE-YEC-1-13.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) YCS commends YEC and the working group on their work to date on DSM planning. We look forward to an ambitious plan to reduce consumption and waste. Please explain how much demand YEC intends to meet through efficiency and conservation in the test years.

ANSWER:

(a)

DSM savings (in terms of reduced forecast sales) are not forecast in Tab 2 sales forecasts as some lead time is required before energy savings can be translated into electrical energy available (with the amount of lead time required expected to vary by initiative). Typical DSM programs are implemented over a three to five year period at which time they are usually evaluated and modified based on the results of that evaluation.

Please also see LE-YEC-1-12.

Yukon Electrical Company Limited
(YECL)

TOPIC: **OIC 2012/68**

REFERENCE: **YEC April 2012 Phase I, Introduction to Application, Page 1**

PREAMBLE:

Pursuant to the OIC 2012/68 direction, the Board must ensure until the end of 2013.

QUESTION:

a) Please discuss YEC's view of Board Order 2010–13 and the requirement to produce a joint YECL / YEC Phase II Cost of Service Study within 6 months of the expiry of OIC 2008/149 and what impact OIC 2012/68 has on Board Order 2010-13 and OIC 2008/149.

ANSWER:

(a)

In Order 2010-13 the Board provided a series of directives related to the Cost of Service Study as filed by the Companies noting that it "[did] not accept the COS study as filed by the Companies", "an updated COS study approved by the Board is essential to establishing a future rate restructuring process" and directed the Companies to "file a joint COS study within six months of the expiry of OIC 2008/149" that "incorporate[s] all findings and directions of the decision."

The requirement in Order 2010-13 to produce a joint COS within six months of the expiry of OIC 2008/149 was previously understood to require this COS by June 30, 2013, based on the fact that OIC 2008/149 was stated to expire on December 31, 2012.

The latest direction in OIC 2012/68 effectively requires that, among other matters, the provisions of OIC 2008/149 as regards rate changes for all classes of retail customers are extended by one year to December 31, 2013. YEC's understanding is that material rate design changes that would result in rebalancing of rates between different customer classes cannot now be undertaken until 2014 at the earliest, and that the direction in Order 2010-13 to produce a joint COS within six months of the expiry of OIC 2008/149 is extended by one year to June 30, 2014.

TOPIC: **Table 2.1 Summary of Customers, Energy Sales and Revenues**

REFERENCE: **YEC April, 2012 Phase I, Section 2, Page 2-17, Table 2**

PREAMBLE:

Yukon Electrical wishes to further understand the Sales Forecast contained in Table 2.1.

QUESTION:

a) Please provide an updated Table 2.1 with the 2011 Actual values.

ANSWER:

(a)

Please see updated Table 2.1 below with 2011 actual values. Note the 2011 actual sales and revenues are the same as 2011 preliminary numbers filed in 2012/13 GRA Application.

Updated Table 2.1 to the YEC's 2012/13 GRA Application

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

Line No.	Description	2009 Approved	2009 Actual	2010 Actual	2011 Actual	Forecast 2012	Forecast 2013
1	**Residential**						
2	Customers	1,432	1,457	1,472	1,515	1,526	1,536
3	Sales in MWh	11,183	11,676	11,386	12,710	12,325	12,408
4	MWh sales per customer	7.8	8.0	7.7	8.4	8.1	8.1
5	Revenue ($000s)	1,335	1,386	1,359	1,694	1,803	1,815
6	Cents per KWh	11.9	11.9	11.9	13.3	14.6	14.6
7	**General Service**						
8	Customers	457	442	455	464	460	467
9	Sales in MWh	19,543	19,672	22,719	21,305	21,693	22,620
10	MWh sales per customer	42.8	44.5	50.0	45.9	47.1	48.5
11	Revenue ($000s)	2,637	2,696	2,942	3,218	3,582	3,735
12	Cents per KWh	13.5	13.7	12.9	15.1	16.5	16.5
13	**Industrial**						
14	Sales in MWh	29,023	29,355	30,255	43,259	52,309	62,364
15	Revenue ($000s)	3,203	3,190	3,311	4,599	6,179	7,383
16	Cents per KWh	11.0	10.9	10.9	10.6	11.8	11.8
17	**Street lights**						
18	Sales in MWh	278	496	283	283	279	279
19	Revenue ($000s)	71	60	74	82	88	88
20	Cents per KWh	25.6	12.1	26.3	29.0	31.6	31.6
21	**Space lights**						
22	Sales in MWh	15	26	14	14	15	15
23	Revenue ($000s)	3	3	3	3	4	4
24	Cents per KWh	21.5	12.0	21.7	24.0	26.8	26.8
25	**Total Company - Firm Retail & Ind.**						
26	Customers	1,889	1,899	1,927	1,979	1,986	2,003
27	Sales in MWh	60,042	61,225	64,658	77,571	86,621	97,685
28	Revenue ($000s)	7,249	7,335	7,689	9,596	11,656	13,025
29	Cents per KWh	12.1	12.0	11.9	12.4	13.5	13.3
30	**Wholesale sales**						
31	Sales in MWh	267,747	267,229	276,345	290,541	296,000	298,228
32	Revenue ($000s)	18,314	18,279	18,902	21,940	24,562	24,747
33	Cents per KWh	6.8	6.8	6.8	7.6	8.3	8.3
34	**Total Company - Firm**						
35	Sales in MWh	327,789	328,455	341,003	368,112	382,621	395,913
36	Revenue ($000s)	25,563	25,613	26,591	31,535	36,218	37,772
37	Cents per KWh	7.8	7.8	7.8	8.6	9.5	9.5
38	**Secondary**						
39	Sales in MWh	7,584	17,384	10,489	552	0	0
40	Revenue ($000s)	470	1,066	644	46	0	0
41	Cents per KWh	6.2	6.1	6.1	8.3	0.0	0.0
42	**Total Company**						
43	Sales in MWh	**335,373**	**345,839**	**351,492**	**368,665**	**382,621**	**395,913**
44	Revenue ($000s)	**26,033**	**26,679**	**27,234**	**31,581**	**36,218**	**37,772**
45	Cents per KWh	**7.8**	**7.7**	**7.7**	**8.6**	**9.5**	**9.5**

Note:
1. Excludes revenues from Rider J and other revenues.

TOPIC: **Wholesale Sales Forecast**

REFERENCE: **Footnote 7, Page 2-4, "Unit #1 failed in March 2010…, this unit expected to be back in service January 2013".**

Footnote 8 Page 2-4, "Variations in the annual generation at Yukon Electrical's Fish Lake hydro plant can have an impact on Yukon Energy's wholesale sales. In 2011, the actual wholesales to Yukon Electrical were 290.5 GW.h, 5.14% higher than 2010 actual wholesales because of (a) unavailability of hydro generation from Unit 1 of Fish Lake hydro generation plant (added 4.35 GW.h to the 2011 sales) and (b) colder than normal weather (HDD analysis showed that the temperature in Whitehorse was colder in 2011 than the 10-year average and that the estimated impact added 1 GW.h to the 2011 sales). The average annual growth rate of 2.26% was applied to the adjusted 2011 wholesales of 285.1 GW.h (290.5 GW.h - 4.35 GW.h – 1 GW.h =285.1 GW.h) and 4.35 GW.h for Unit 1 of Fish Lake plant added back to wholesales forecast in 2012 as commencing of this unit is now expected to be in the beginning of 2013."

PREAMBLE:

Yukon Electrical is seeking more information on Wholesale forecast calculation.

QUESTION:

a) Please explain and provide all backup (in Excel format) for the calculation of normalized values which result in the decrease of 1 GW.h HDD for 2011 sales.

b) Footnote 7, Page 2-4 of the Application indicates that Unit # 1 (Fish Lake) failed in March 2010 and is expected back in service 2013. Please explain how Fish Lake # 1 impacts the Wholesales forecast. In particular, please explain why the annual load growth rate applied to the 2011 Wholesale load forecast is net of Fish Lake (supply).

ANSWER:

(a)

Please see YECL-YEC-1-3(a) Attachment 1 for HDD adjustment analysis.

Heating Degree Days (HDD) analysis showed that the temperature in Whitehorse was colder in 2011 than the 10-year average. HDD for 7 winter months (Jan-Apr, Oct-Dec) showed approximately 66 higher HDD in 2011 compared to 10-year average (columns B and C in Table 1 of Attachment 1)[1].

For the analysis the correlation function has been used based on:

- Monthly generation numbers derived from hourly generation data (column A in Table 1 of Attachment 1), and

- 2011 HDD analysis, based on Environment Canada hourly temperature database for Whitehorse (column B in Table 1 of Attachment 1).

The analysis indicated a relationship of 15.399 MW.h generation per HDD. This number was then adjusted for line losses at 8.7% to yield approximately 14.2 MW.h sales to HDD. The difference between the 10-year average HDD and the actual HDD for 2011 was checked and 2011 sales were adjusted for this normalization to get estimated MW.h sales that arose due to the colder 2011 temperatures. The calculation in column F in Table 1 of Attachment 1 showed that the estimated impact of the colder temperature added approximately 1 GW.h to the 2011 sales.

(b)

YEC's understanding is that when the hydro generation is not available from YECL's Fish Lake hydro plant YECL's power purchase increases to cover that unavailable generation. This was demonstrated when Fish Lake generation decreased in 2010 and 2011.

[1] Based on 2002-2011 Environment Canada hourly temperature database for Whitehorse.

The average annual growth rate of 2.26% was applied to the adjusted 2011 wholesales, net of reduced Fish Lake generation and average HDD (i.e., so as to represent a more typical YECL purchase power forecast when Fish Lake is operating normally and temperature is normal), to determine a base forecast for 2012 wholesales. The 2012 forecast uses this "base" value plus and adjustment for extra sales to replace lower Fish Lake generation in 2012. For 2013 wholesales, Fish Lake was assumed to be in operation for the full year.

It is acknowledged that the growth rate could be applied to YECL generation requirements prior to Fish Lake generation being deducted - however, this adjustment would not materially change the test year forecasts. Applying the annual growth rate for wholesales with hydro generation of 4.35 GW.h for Unit 1 of Fish Lake would result approximately 0.1 GW.h higher wholesale forecast for 2012.

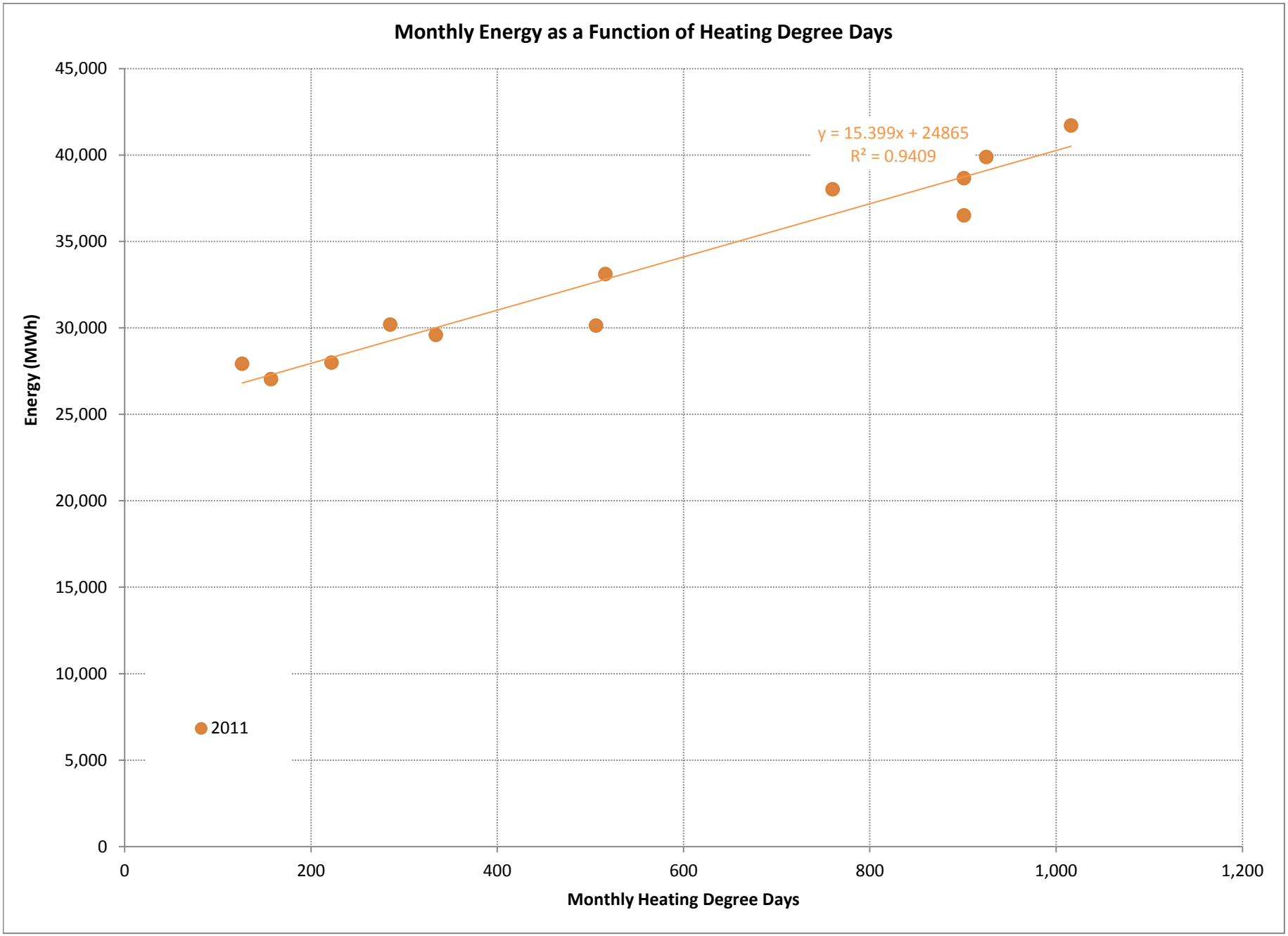

Monthly Energy as a Function of Heating Degree Days
y = 15.399x + 24865
R² = 0.9409
Energy (MWh)
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
0
200
400
600
800
1,000
1,200
Monthly Heating Degree Days
2011

Table 1. Adjustments for Heating Degree Days.

Year	Month	Monthly Generation	2011 Heating Degree Days	10-year average Heating Degree Days	Deviation from 10-yr average (Jan-Apr, Oct-Dec)	Estimated MW.h Sales to Heating Degree Day correlation [1]	Deviation from 10-yr average
		MW.h	HDD	HDD	HDD	MW.h	MW.h
		A	B	C	D=B-C	E	F=D*E
2011	Jan	41,707	1,016	1,054	-38	14.2	-538
	Feb	36,508	901	833	68	14.2	963
	Mar	38,660	901	812	89	14.2	1,261
	Apr	30,135	506	510	-4	14.2	-57
	May	30,191	285	305			
	Jun	27,036	157	156			
	Jul	27,925	126	110			
	Aug	27,994	222	171			
	Sep	29,595	334	330			
	Oct	33,114	516	522	-6	14.2	-85
	Nov	39,884	925	795	130	14.2	1,842
	Dec	38,019	760	933	-173	14.2	-2,451
Total		400,766	6,649	6,531			935
						Rounded	1,000

Note:
1. Please see figure in previous tab. Adjusted to line losses at 8.7%.

TOPIC: **Wholesale Sales Forecast**

REFERENCE: **Footnote 9 Page 2-4, "The average annual increase of 2.26% was determined based on an average of the WAF average growth rate (2.18%) and 2.34% (reflecting Whitehorse residual use growth). The WAF average growth rate of 2.18% per year for 2001-2010 was calculated by excluding Pelly Crossing sales starting late 2008 (0.275 GW.h in 2008, 2.584 GW.h in 2009 and 2.691 GW.h in 2010) and including Faro site dewatering sales after Faro mine closure charged as "Industrial" prior to 2005. The Whitehorse residential use growth rate of 2.34% per year was calculated based on City of Whitehorse population for the 2001-2010 period (averaging 1.8% per year based on Yukon Bureau of Statistics, Annual Reports - 2001-2008, Monthly Reports of Dec. 2009 and 2010) and the weather normalized average annual increase in residential usage per customer (0.52% per year based on Weather normalized UPC data for 2001-2007 as filed in Yukon Electrical 2008-2009 GRA; 2008-2010 data as provided by Yukon Electrical)."**

PREAMBLE:

Yukon Electrical is seeking more information on forecasting calculations.

QUESTION:

a) Footnote 9 Page 2-4 of the Application indicates, "…WAF average growth rate (2.18%) and 2.34% (reflecting Whitehorse residual use growth…". Please explain what is meant by residual growth.

b) Regarding the average annual increase, please explain why an average growth rate was used instead of a weighted average growth rate, considering that Whitehorse comprises a substantial proportion of the usage on the Yukon grid.

c) Please provide detailed calculations (in Excel format) for Grid growth.

d) To calculate average growth on the Grid, please explain why the period 2001 to 2010 was used instead of the period 2002 to 2011 and what the average growth would have been had the 2002 to 2011 period been used.

ANSWER:

(a)

There was a typographical error in the Application. The statement should read, "…WAF average growth rate (2.18%) and 2.34% (reflecting Whitehorse residential use growth…"

(b)

As indicated in Footnote 9 Page 2-4 of the Application, the average annual increase of 2.26% was calculated by averaging WAF average growth rate (2.18%) and Whitehorse residential use growth rate (2.34%). This calculation reflects Whitehorse's share of the usage on the Yukon grid as follows:

- The calculation directly assigns 50% of weight directly to the Whitehorse residential use growth rate of 2.34% in the average annual increase determination; and

- In addition, historical Whitehorse sales growth is also factored into (and makes up the largest percentage of) the WAF average growth rate of 2.18%.

(c)

Please see Attachment 1 to this response for the requested information.

(d)

The average annual increase of 2.26% was developed in preparation of 2011 Resource Plan Update and 2010 was the latest for which the actual sales were available. Therefore the period from 2001 to 2010 was used in the calculation.

The Corporation did not attempt to calculate the average growth rate for the 2002 to 2011 period, which will also require 2011 actual weather normalized UPC information from YECL.

Attachment 1 to YECL-YEC-1-4 (c)
Non-Industrial Load Forecast Growth Rates (WAF System)

Line No	Rate of Population Increase	Source	Annual Average Increase in Whitehorse Residential UPC (2001-2010)[2]	Potential Growth Rates for Non-Industrial Loads
	A		B	C=(1+A)*(1+B)-1
1	1.81%	Historical City of Whitehorse Population Increase (average annual increase 2001-2010)[1]	0.52%	2.34%
2=(1+3)/2	Medium Annual Load Increase			2.26%
3		Yukon WAF Average Annual Increase in Consumption (2001-2010, incl. Fish Lake)[3]		2.18%

Notes:

1. Yukon Bureau of Statistics, Annual Reports - 2001-2008, Monthly Reports of Dec. 2009 and 2010.
2. Weather normalized UPC data for 2001-2007 as filed in YECL 2008-2009 GRA; 2008-2010 data as provided by YECL.
3. Growth rate calculated excluding Pelly Crossing sales;
   Includes Faro site dewatering sales after Faro Mine closure charged as "Industrial" prior to 2005.

Population of Whitehorse

Date	Population of Whitehorse
2001	22,476
2002	22,192
2003	22,213
2004	22,795
2005	23,267
2006	23,751
2007	24,124
2008	24,969
2009	25,690
2010	26,418
Average Annual increase	1.81%

Notes:

1. Yukon Bureau of Statistics, Annual Reports - 2001-2008, Monthly Reports of Dec. 2009 and 2010.

WAF Sales

Date	Total WAF Non-industrial Sales including Fish Lake
	GW.h
2001	235.94
2002	238.16
2003	243.69
2004	250.14
2005	253.51
2006	267.37
2007	271.28
2008	278.46
2009	281.18
2010	286.47
Average Annual increase	2.18%

Notes:

1. Growth rate calculated excluding Pelly Crossing sales;
Includes Faro site dewatering sales after Faro Mine closure charged as "Industrial" prior to 2005.

Whitehorse Residential Usage Per Customer

Date	Annual weather normalized UPC
	MW.h
2001	10.27
2002	10.38
2003	10.37
2004	10.52
2005	10.59
2006	10.51
2007	10.47
2008	10.47
2009	10.86
2010	10.76
Average Annual increase	0.52%

Notes:

1. Weather normalized UPC data for 2001-2007 as filed in YECL 2008-2009 GRA; 2008-2010 data as provided by YECL.

TOPIC: **Table 2.2 Summary of Energy Balance, Losses, Peak and Load Factor**

REFERENCE: **YEC April 2012 Phase I, Section 2, Page 2-18, Table 2.2**

PREAMBLE:

Yukon Electrical wishes to further understand the Losses contained in Table 2.2.

QUESTION:

a) Please provide the actual system losses for 2011.

b) Please provide information on the change in system losses after the addition of the new generation capacity (Mayo B hydro generation and Aishihik Third turbine) and the WAF/MD systems integration. Please provide the increase/decrease in system losses due to this change.

c) If losses are expected to be lower (Section 2.3, Page 2-10, footnote 24), why were the expected system efficiencies not accounted for in forecasting the losses for 2012 and 2013?

d) Please provide the proportion of system energy losses in 2012 and 2013 that are due to the addition of station services in the hydro units and transmission lines.

ANSWER:

(a)

The actual losses for 2011 were at 32.1 GW.h or 8.7% of total sales.

(b), (c) and **(d)**

Yukon Energy does not have actual information on the change in losses that arise due to each specified factor. This is because (a) most of the changes noted have not been in service for a year as yet, and (b) it is very difficult after-the-fact to disentangle the effects of any single system change on the overall losses for the system. In preparing the load

forecast for 2012 and 2013, YEC did run a detailed electrical model to confirm that compared to the situation prior to CSTP II and Mayo B, where remote loads such as Minto or Pelly Crossing could see transmission losses alone equal to 7% using supply from Aishihik, transmission losses using power from Mayo B would yield much lower percentages (1.8%). These lower losses will be somewhat offset by new base losses (charging current) and new station service loads.

Without specific data on the compounding effects of the various changes, the most reasonable basis to estimate losses for the test years was to continue the most recent actual experience.

TOPIC: **Table 2.2 Summary of Energy Balance, Losses, Peak and Load Factor**

REFERENCE: **YEC April 2012 Phase I, Section 2, Page 2-18, Table 2.2**

PREAMBLE:

Yukon Electrical wishes to further understand the Load Factors associated with Table 2.2.

QUESTION:

a) Please reproduce Table 2.2 to include Load Factor values with respect to Sales volumes.

ANSWER:

(a)

Load Factors values are calculated based on system peak numbers (i.e., total generation and not sales). As there is no system peak associated with system sales volumes, Load Factor values cannot be calculated with respect to sales volumes.

In order to be responsive, an updated Table 2.2 is provided below with added annual Load Factors based on total generation and peak demand.

Table 2.2
YECL-YEC-1-6

Yukon Energy Corporation
Summary of Energy Balance, Losses, Peak and Load Factor

Line No.	Description	2009 Approved	2009 Actual	2010 Actual	Preliminary 2011 [3]	Existing Forecast 2012 [5]	Proposed Forecast 2012 [1,4]	Existing Forecast 2013 [5]	Proposed Forecast 2013 [2,4]
	Sales and Losses								
1	Total Energy Sales	335,373	345,839	351,492	368,665	382,621	382,621	395,913	395,913
2	Losses - MWh	28,359	28,007	30,764	32,101	33,288	33,288	34,444	34,444
3	Losses - %	8.5%	8.1%	8.8%	8.7%	8.7%	8.7%	8.7%	8.7%
4	Total Generation	363,732	373,846	382,255	400,766	415,909	415,909	430,357	430,357
	Source - MWh								
	Hydro Generation								
5	Whitehorse	228,573	223,775	233,806	231,501	232,207	229,245	232,231	230,124
6	Aishihik	103,110	118,680	111,710	132,340	121,661	120,109	130,037	128,857
7	Mayo	30,613	28,507	31,528	20,588	59,533	58,774	60,977	60,424
8	Total Hydro	362,296	370,962	377,044	384,429	413,402	408,128	423,244	419,405
9	**Wind Turbine**	491	238	85	402	239	239	238	238
	Diesel Generation								
10	Whitehorse	0	1,722	2,417	6,571	1,142	3,878	3,462	5,510
11	Faro	550	413	272	1,654	323	1,142	980	1,622
12	Dawson	395	509	2,404	7,170	802	2,522	2,432	3,583
13	Mayo	0	1	34	539				
14	Total Diesel	945	2,645	5,127	15,935	2,268	7,542	6,875	10,714
	Source - %								
15	**Hydro Generation**	99.6%	99.2%	98.6%	95.9%	99.4%	98.1%	98.3%	97.5%
16	**Diesel Generation**	0.3%	0.7%	1.3%	4.0%	0.5%	1.8%	1.6%	2.5%
17	**Wind Generation**	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
	Peak - MW								
	Integrated System	N/A	N/A	N/A	76.9	80.1	80.1	81.1	81.1
18	**WAF**	62	60.9	67.3	N/A	N/A	N/A	N/A	N/A
19	**MD**		5.1	6.9	N/A	N/A	N/A	N/A	N/A
20	**Load Factor[6]**		65%	58%	60%	59%	59%	61%	61%

Notes;

1 Hydro generation at 101% of long-term average at 404.18 GW.h (diesel at 66% of requirement based on long-term average hydro).
2 Hydro generation at 101.8% of long-term average at 411.95 GW.h (diesel at 59% of requirement based on long-term average hydro).
3 Diesel generation in 2011 includes requirements related to generation capital projects at Aishihik and Mayo hydro generating plants.
4 Diesel generation forecasts include diesel fuel required for maintenance.
5 Diesel generation forecasts under the "Existing" assumption (i.e., without a GRA) are calculated based on 2009 approved efficiency and fuel price.
1 6 Load Factor is calculated based on annual generation and peak demand numbers.

TOPIC: **Table 2.1 and Table 2.2 Energy Sales**

REFERENCE: **YEC April 2012 Phase I, Section 2, Pages 2-17 and 2-18, Tables 2.1 and 2.2**

PREAMBLE:

Yukon Electrical wishes to further understand the Energy Sales associated with Tables 2.1 and 2.2.

QUESTION:

a) Did YEC use the billed or earned method for determining the Energy Sales Forecast for residential, general service, industrial and wholesale customer classes. Please explain the rationale for using the method YEC chose.

ANSWER:

(a)

The forecast is prepared relying on both load data and, where relevant, customer input.

For Residential and General Service forecast energy sales YEC was developed based on actual load data, which relied upon billing data as recorded by ATCO CIS without any adjustments for the partial billing period in one month that gets billed as part of the following month. YEC uses this method as the information is already available for use in the forecast and does not require additional administrative time and cost, and in any event direct YEC retail sales to non-industrial customers make up a small percentage of YEC's total sales.

For actual data on the industrial and purchase power accounts, YEC works with month end metered data that does not require adjustment for partial billing periods.

For the industrial sales forecast YEC relied upon the representations of the customers regarding the level of sales expected for the forecasted years.

For wholesale forecast please see responses to YECL-YEC-1-3 and YECL-YEC-1-15(c) and (d).

TOPIC: **Increased Baseload Diesel Generation to Meet Load Growth**

REFERENCE: **Table 2.1 (with additional calculations, below)**

		2009 Actual	2010 Actual	Prelim 2011	Forecast 2012	Forecast 2013
	Total Company					
1	Sales in MWh	345,838	351,491	368,664	382,621	395,914
2	MWh Growth Over Previous Year		5,653	17,173	13,957	13,293
	Industrial					
3	Sales in MWh	29,355	30,255	43,259	52,309	62,364
	% growth over previous year		**103%**	**143%**	**121%**	**119%**
4	MWh Growth Over Previous Year		900	13,004	9,050	10,055
5 = 4 / 2	**% of Total Growth**		**16%**	**76%**	**65%**	**76%**
	Non-Industrial					
6 = 1 - 3	Sales in MWh	316,483	321,236	325,405	330,312	333,550
	% growth over previous year		**102%**	**101%**	**102%**	**101%**
7	MWh Growth Over Previous Year		4,753	4,169	4,907	3,238
8 = 7 / 2	**% of Total Growth**		**84%**	**24%**	**35%**	**24%**

Lines 16-17 page 1-6: "Industrial load growth to data continues to bring higher revenues that tend to more than offset any related incremental costs."

Lines 4-5 page 2-2: "Industrial load growth to date has continued to bring higher revenues that tend to more than offset any related incremental costs."

PREAMBLE:

Yukon Electrical wishes to further understand the impact of the growth in Industrial load on other Retail customers.

QUESTION:

a) Please explain what costs are included in the incremental costs which the industrial load growth tends to offset? Please provide the corresponding analysis which supports the findings that revenues from industrial load growth is offsetting the incremental costs associated with such growth.

b) From line 5 in the table above, Industrial load growth accounts for the majority of forecast load growth in the test years. Please provide what proportion of increased diesel costs is caused by industrial customers.

c) Please provide how YEC interprets its obligation to serve Industrial customers, given the increased diesel costs associated with such customers. Please discuss any capacity or energy restrictions which YEC adheres to regarding oncoming Industrial customers, relative to existing hydro energy and capacity.

d) If YEC does not adhere to any capacity or energy restrictions, please explain why it does not.

ANSWER:

(a)

Please see the response to YUB-YEC-1-2(a).

(b)

Please see response to LE-YEC-1-38 and 39. Changes in diesel generation are not caused by any one customer or class of customers.

(c) and **(d)**

Please see the response to LE-YEC-1-37 to 40. As discussed in this response, the obligation to serve applies to all relevant customers and classes of customers.

YEC is not aware of any basis under normal regulatory principles to impose any capacity or energy restrictions on new industrial or wholesale customer loads based on existing hydro capacity and energy capability and expected increases in diesel generation requirements. To date, in connecting major industrial loads to the grid there have been no new loads that have required Yukon Energy to consider such possible energy or capacity restrictions.

YEC's ongoing resource planning, however, addresses in each instance the implications of such new loads regarding impacts on diesel generation and on system capacity

planning requirements, as well as consideration of the range of options to supply resulting future grid loads in a cost effective, reliable, flexible and environmentally responsible manner.

TOPIC: **Yukon Energy Firm Retail Sales**

REFERENCE: **Section 2.2.3.2: General Service Sales and Table 2.1**

PREAMBLE:

The 2013 forecast indicates a 3.15% average annual increase in Yukon Energy's general service sales.

QUESTION:

a) Please confirm that that the average annual increase in Yukon Energy's general service sales should be 3.55%, instead of 3.15% as stated above.

b) Please explain what the impacts of this error are on the other aspects of YEC's Application.

ANSWER:

(a) and **(b)**

Confirmed. Yukon Energy's general service sales forecast average annual increase is 3.55% in 2013 over 2009 actual. This is a typographical error and does not affect forecast sales or impact any other area of the Application.

TOPIC: **Yukon Energy Firm Retail Sales**

REFERENCE: **Section 2.2.3.1: Residential Sales and Table 2.1**

PREAMBLE:

Firm residential retail sales have grown from 11,676 MW.h in 2009 (actual) to 12,325 MW.h in 2012 (forecast) and 12,408 MW.h in 2013 (forecast). The average annual growth rate is 1.5% in 2013 (forecast) compared to 2009 (actual). This reflects ongoing modest growth in the number of customers and the average use per customer over the previous three years.

QUESTION:

a) Per Table 2.1 of the Application, please confirm that while the number of Residential customers has somewhat increased, the average annual consumption of such customers dropped from 8.0 MW.h/customer in 2009 actual to 7.7 MW.h/customer in 2010 actual. Please elaborate as to whether this would be considered as modest growth.

b) Please provide whether actual sales were normalized (i.e. weather-adjusted). If not, please provide the normalized sales and explain how they compare.

c) Please comment on the appropriateness of using 3 years of history as a trend predictor for forecasting purposes.

ANSWER:

(a)

The average annual consumption per YEC's residential customers decreased from 8.0 MW.h/customer in 2009 actual to 7.7 MW.h/customer in 2010 actual; however, it increased to 8.4 MW.h/customer in 2011 as shown in Table 2.1 of the GRA Application. The annual average increase in number of customers in 2011 over 2009 was 1.9%, annual average increase in usage per customer in 2011 over 2009 was 2.3%.

(b)

The sales shown in Table 2.1 of the GRA Application are not weather normalized. Weather normalized retail sales for YEC residential customers have not been developed, and the requested analysis cannot be provided at this time.

(c)

The 3 year period is simply an average value since the last GRA, for information purposes. It is not used for forecasting. For information on YEC's approach to retail load forecasting, please see CW-YEC-1-12(a).

TOPIC: **Yukon Energy Firm Retail Sales**

REFERENCE: **Section 2.3.1: Integrated Grid Hydro Generation, Page 2-11**

PREAMBLE:

The new integrated grid, including the new Mayo Hydro Enhancement Project (Mayo B) and Aishihik Third Turbine hydro unit, has 92 MW of installed YEC hydro generation, of which approximately 72 MW can be relied upon for the winter peak. The Integrated System typically operates with Whitehorse Hydro as first-on generation (outside of wind and Fish Lake) as a largely run-of-river plant. Mayo and Aishihik are used to supplement this run-of-river generation to achieve the required output.

QUESTION:

a) Please provide the monthly capacity of the hydro generating units used in the reliability and capacity requirement model, Loss of Load Expectation (LOLE).

b) Please provide the monthly energy generation produced by the hydro generating units for the last 3 years, 2009-2011, and forecast for the test years 2012 and 2013.

c) Please provide the monthly energy generation produced by the diesel generating units for the last 3 years, 2009-2011, and forecast for the test years, 2012 and 2013.

ANSWER:

(a)

Loss of Load Expectation (LOLE) analysis is prepared based on MW capacity of the YEC's hydro generation units that can be relied upon for the winter peak as shown in Table 1 below. No monthly LOLE capacity requirement analysis has been undertaken.

Table 1:
YEC's Current installed Hydro Generation Units

Hydro GS	Unit	MCR, MW	Total MW	Winter MW
A	B	C	D	E
Whitehorse	WH1	5.8	40	24
	WH2	5.8		
	WH3	8.4		
	WH4	20		
Aishihik	AH1	15	37	37
	AH2	15		
	AH3	7		
Mayo	MH1	2.6	15.4	11
	MH2	2.8		
	MH3	5		
	MH4	5		
Total		92.4	92.4	72

(b)

Please see Table 2 below for YEC's 2009-2011 actual and 2012-2013 forecast monthly hydro generation in GW.h.

Table 2:

YEC's 2009-2011 Actual and 2012-2013 Forecast Monthly Hydro Generation

Year	Month	Hydro Generation (GW.h)			
		Whitehorse	Aishihik	Mayo	Total
2009	JAN	18.8	16.3	2.8	37.9
	FEB	17.2	17.4	2.6	37.2
	MAR	14.1	15.8	2.7	32.5
	APR	13.3	14.2	2.2	29.7
	MAY	14.4	11.6	2.3	28.3
	JUN	18.5	4.0	2.1	24.6
	JUL	21.3	2.0	2.2	25.5
	AUG	22.0	1.1	2.2	25.3
	SEP	22.9	2.1	1.8	26.9
	OCT	21.7	5.8	2.1	29.6
	NOV	21.4	11.5	2.6	35.5
	DEC	18.4	16.9	2.8	38.1
	Total	**223.8**	**118.7**	**28.5**	**371.0**
2010	JAN	18.0	15.5	2.8	36.3
	FEB	17.6	15.3	2.7	35.5
	MAR	15.3	15.0	2.5	32.8
	APR	13.0	14.7	2.0	29.6
	MAY	13.9	12.9	2.3	29.2
	JUN	21.6	1.4	2.3	25.4
	JUL	22.7	1.2	2.4	26.4
	AUG	22.4	3.0	2.1	27.6
	SEP	23.4	1.8	2.5	27.6
	OCT	23.2	3.0	2.7	28.8
	NOV	23.6	9.7	4.0	37.3
	DEC	19.0	18.3	3.1	40.4
	Total	**233.8**	**111.7**	**31.5**	**377.0**
2011	JAN	19.8	16.6	2.9	39.3
	FEB	16.1	16.1	2.9	35.1
	MAR	13.7	19.2	2.6	35.5
	APR	12.1	14.7	1.6	28.4
	MAY	13.8	12.8	2.8	29.4
	JUN	22.3	1.8	2.0	26.0
	JUL	23.9	3.8	0.0	27.6
	AUG	19.1	8.4	0.0	27.4
	SEP	24.2	4.8	0.0	29.1
	OCT	25.2	4.4	0.0	29.5
	NOV	22.8	14.7	1.6	39.1
	DEC	18.6	15.2	4.1	37.9
	Total	**231.5**	**132.3**	**20.6**	**384.4**

Table 2:
YEC's 2009-2011 Actual and 2012-2013 Forecast Monthly Hydro Generation
(continued)

Year	Month	Hydro Generation (GW.h)			
		Whitehorse	Aishihik	Mayo	Total
2012	JAN	19.0	16.1	5.1	40.3
	FEB	16.5	13.9	5.1	35.6
	MAR	15.5	15.3	5.4	36.2
	APR	13.0	13.2	5.1	31.3
	MAY	15.2	11.4	4.6	31.1
	JUN	21.3	2.9	4.8	28.9
	JUL	22.9	3.2	4.1	30.2
	AUG	23.7	1.0	4.4	29.1
	SEP	22.6	5.0	4.2	31.8
	OCT	20.3	7.9	5.5	33.6
	NOV	19.4	14.4	5.2	39.0
	DEC	19.9	15.8	5.2	40.9
	Total	**229.2**	**120.1**	**58.8**	**408.1**
2013	JAN	18.7	17.1	5.4	41.1
	FEB	16.9	14.0	5.0	35.9
	MAR	13.9	17.9	5.0	36.8
	APR	15.2	12.3	4.8	32.3
	MAY	14.5	13.5	4.2	32.2
	JUN	21.7	3.0	5.2	29.9
	JUL	22.1	3.9	5.8	31.7
	AUG	23.0	3.7	3.9	30.6
	SEP	23.9	4.6	4.6	33.1
	OCT	21.0	8.0	6.0	35.1
	NOV	19.4	15.2	5.2	39.8
	DEC	19.9	15.8	5.2	40.9
	Total	**230.1**	**128.9**	**60.4**	**419.4**

Note: 2012 and 2013 hydro generation forecasts per Table 2.2 of Application, i.e., hydro generation in 2012 at 101.0% of long term average of 404.18 GW.h (diesel at approximately 66% of LTA), and hydro generation in 2013 at 101.8% of long-term average of 411.95 GW.h (diesel at approximately 59% of LTA).

(c)

Please see the response to YECL-YEC-1-17 Attachment 1.

TOPIC: **Reliable Capacity Requirement and Generation Key Performance Indicators (KPIs)**

REFERENCE: **Section 2.4 and Appendix 6.1**

PREAMBLE:

Yukon Electric wishes to further understand the reliable capacity requirement and generation KPIs in Appendix 6.1.

QUESTION:

a) Section 2.4 discusses the adequacy of meeting the capacity requirement based on the LOLE criterion. Please provide the system reserve margin and how it compares to the actual operating system reserve observed in the past 3 years, prior to the test years, 2009-2011.

b) Respecting the generation KPIs in Appendix 6.1, please provide the operational performance indicators for such KPIs (Capacity Factor, Unit Availability, Operating Factor, & Forced Outage) broken down by each generating unit.

c) In addition to the generation KPIs provided in Appendix 6.1, please include the installed or commissioned year, maximum capacity rating (MCR) and emergency capacity rating (ECR). ECR is defined as the capacity above the MCR.

d) Please discuss and quantify in terms of load (demand and energy) if any of these generating units were operated in an ECR situation in the last 3 years, prior to the test years, 2009-2011.

ANSWER:

(a)

Yukon Energy does not use a “system reserve margin”. As indicated in Tab 2, Section 2.4, a two-part capacity planning criteria adopted by Yukon Energy for the WAF and MD systems in the 2006 Resource Plan.

(b)

Please see Attachments 1 through 3 to this response for operational performance indicators for KPIs (Capacity Factor, Unit Availability, Operating Factor & Forced Outage) broken down by each generating unit for 2009-2011 actual years.

(c)

Attachment 1 to this response provides the YEC Generation Inventory. This provides installed or commissioned year and maximum capacity rating (MCR). However, it is noted that YEC does not have an Emergency Capacity Rating (ECR) for the generation units. YEC does not have an ECR for generation units and ECR is not a YEC operating practice for the following reasons:

- Hydro Units cannot be run above the MCR; and

- YEC does not run the diesel units above the MCR due to the fact that diesel units are connected to the grid and YEC runs spinning reserve whenever they are run.

(d)

Please see (c) above. YEC generating units are not run generating units above the MCR and as such these units were not run above the MCR in the last three years.

2009 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
Type: Hydro								
Location: AISHIHIK								
Model: Dom.Eng. - Francis								
AH1	15.000	60,400.0	131,400.0	116,625.0	51.79%	88.76%	77.24%	0.08%
AH2	15.000	58,282.0	131,400.0	125,025.0	46.62%	95.15%	75.98%	1.91%
Summary - Dom.Eng. - Francis		118,682.0	262,800.0	241,650.0	49.20%	91.95%	76.61%	0.99%
Location: MAYO								
Model: Dom.Eng. - Francis								
MH1	2.600	11,650.6	22,776.0	22,432.8	51.94%	98.49%	98.46%	0.43%
MH2	2.600	16,856.8	24,528.0	24,497.2	68.81%	99.87%	98.63%	0.03%
Summary - Dom.Eng. - Francis		28,507.4	47,304.0	46,930.0	60.37%	99.18%	98.54%	0.23%
Location: WHITEHORSE								
Model: C.A.C. - Propeller								
WH3	8.500	24,727.6	74,460.0	71,706.0	34.48%	96.30%	45.14%	0.03%
Summary - C.A.C. - Propeller		24,727.6	74,460.0	71,706.0	34.48%	96.30%	45.14%	0.03%
Model: Dom. Eng. - Propeller								
WH4	20.500	140,930.2	179,580.0	166,316.5	84.74%	92.61%	90.75%	0.17%
Summary - Dom. Eng. - Propeller		140,930.2	179,580.0	166,316.5	84.74%	92.61%	90.75%	0.17%
Model: K.M.W. - Kaplan								
WH1	5.800	28,371.1	50,808.0	46,336.2	61.23%	91.20%	80.99%	0.72%
WH2	5.800	29,746.1	50,808.0	47,734.0	62.32%	93.95%	82.41%	0.24%
Summary - K.M.W. - Kaplan		58,117.2	101,616.0	94,070.2	61.77%	92.57%	81.70%	0.48%
Summary - Hydro		370,964.4	665,760.0	620,672.7	57.74%	94.54%	81.20%	0.45%

2009 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
Type: Diesel								
Location: DAWSON								
Model: Caterpillar - 3512								
DD1	0.800	52.3	7,008.0	5,533.6	0.95%	78.96%	1.06%	0.00%
Summary - Caterpillar - 3512		52.3	7,008.0	5,533.6	0.95%	78.96%	1.06%	0.00%
Model: Caterpillar - 3516								
DD2	1.000	80.4	8,760.0	8,760.0	0.92%	100.00%	1.13%	0.00%
Summary - Caterpillar - 3516		80.4	8,760.0	8,760.0	0.92%	100.00%	1.13%	0.00%
Model: Caterpillar - 3516 TA								
DD3	1.000	124.4	8,760.0	8,760.0	1.42%	100.00%	2.32%	0.00%
Summary - Caterpillar - 3516 TA		124.4	8,760.0	8,760.0	1.42%	100.00%	2.32%	0.00%
Model: Caterpillar - 3606								
DD5	1.500	236.2	13,140.0	13,032.0	1.81%	99.18%	2.98%	0.23%
Summary - Caterpillar - 3606		236.2	13,140.0	13,032.0	1.81%	99.18%	2.98%	0.23%
Location: FARO								
Model: Caterpillar - 3516								
FD3	0.850	9.0	7,446.0	3,304.8	0.27%	44.38%	0.07%	55.62%
FD5	1.200	4.4	10,512.0	9,416.4	0.05%	89.58%	0.10%	0.00%
Summary - Caterpillar - 3516		13.4	17,958.0	12,721.2	0.16%	66.98%	0.09%	27.81%
Model: Caterpillar - 3612								
FD7	3.000	399.8	26,280.0	26,247.0	1.52%	99.87%	3.71%	0.06%
Summary - Caterpillar - 3612		399.8	26,280.0	26,247.0	1.52%	99.87%	3.71%	0.06%
Location: MAYO								
Model: Caterpillar - 3516								
MD1	0.850	0.6	7,446.0	7,446.0	0.01%	100.00%	0.03%	0.00%
MD2	0.850	0.5	7,446.0	7,446.0	0.01%	100.00%	0.03%	0.00%
YM1	1.400	15.4	12,264.0	12,264.0	0.13%	100.00%	0.07%	0.00%
Summary - Caterpillar - 3516		16.5	27,156.0	27,156.0	0.05%	100.00%	0.05%	0.00%
Location: WHITEHORSE								

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2009 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
Type: Diesel								
Location: WHITEHORSE								
Model: Caterpillar - 3612								
WD7	3.200	672.0	28,032.0	28,025.6	2.40%	99.98%	3.42%	0.02%
Summary - Caterpillar - 3612		672.0	28,032.0	28,025.6	2.40%	99.98%	3.42%	0.02%
Model: EMD - 20C								
WD4	2.500	103.0	21,900.0	21,900.0	0.47%	100.00%	0.76%	0.00%
WD5	2.500	119.1	21,900.0	19,402.5	0.61%	88.60%	0.80%	0.02%
WD6	2.500	372.1	21,900.0	21,900.0	1.70%	100.00%	2.87%	0.00%
Summary - EMD - 20C		594.2	65,700.0	63,202.5	0.93%	96.20%	1.48%	0.01%
Model: Mirlees - KV12								
WD1	3.500	33.6	30,660.0	30,660.0	0.11%	100.00%	0.14%	0.00%
Summary - Mirlees - KV12		33.6	30,660.0	30,660.0	0.11%	100.00%	0.14%	0.00%
Model: Mirlees - KV16								
WD2	4.500	187.9	39,420.0	39,420.0	0.48%	100.00%	0.58%	0.00%
WD3	4.500	127.4	39,420.0	8,451.0	1.51%	21.44%	0.43%	25.40%
Summary - Mirlees - KV16		315.4	78,840.0	47,871.0	0.99%	60.72%	0.51%	12.70%
Summary - Diesel		2,538.2	312,294.0	271,968.9	0.84%	89.53%	1.21%	4.79%

2009 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
YEC Summary -		373,502.6	978,054.0	892,641.6	19.05%	91.13%	26.80%	3.40%

Definitions

MCR: Maximum continuous rating

Actual Generation: Amount of real power (energy) that the generating unit produced for the period. (this # comes from month end reports)

Available Generation: Amount of generation the unit would have produced if it was run at full load for the entire year (based on MCR multiplied by number of hours in period)

Capacity Factor: Actual energy produced divided by the amount of energy that the unit had the potential to produce.

Unit Availability: Number of hours the generator is available for production divided by the total hours in the period. (this factor is displayed in a percentile).

Operating Factor: The hours the generator was on line divided by the total hours in the period.(displayed in a percentile).

Forced Outage: Unplanned outage or breakdown that removes the unit from service.

2010 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
Type: Hydro								
Location: AISHIHIK								
Model: Dom.Eng. - Francis								
AH1	15.000	55,600.0	131,040.0	125,280.0	44.38%	95.62%	69.05%	0.05%
AH2	15.000	56,410.0	131,400.0	128,445.0	43.92%	97.75%	70.45%	0.00%
Summary - Dom.Eng. - Francis		112,010.0	262,440.0	253,725.0	44.15%	96.68%	69.75%	0.02%
Location: MAYO								
Model: Dom.Eng. - Francis								
MH1	2.600	13,869.9	22,776.0	22,014.2	63.00%	96.66%	95.88%	1.69%
MH2	2.600	16,651.6	24,408.0	24,038.4	69.27%	98.49%	98.38%	0.00%
Summary - Dom.Eng. - Francis		30,521.5	47,184.0	46,052.6	66.14%	97.57%	97.13%	0.84%
Location: WHITEHORSE								
Model: C.A.C. - Propeller								
WH3	8.500	30,135.7	73,200.0	69,290.0	43.49%	94.75%	54.06%	0.00%
Summary - C.A.C. - Propeller		30,135.7	73,200.0	69,290.0	43.49%	94.75%	54.06%	0.00%
Model: Dom. Eng. - Propeller								
WH4	20.500	142,756.2	179,580.0	161,519.5	88.38%	89.94%	86.69%	1.34%
Summary - Dom. Eng. - Propeller		142,756.2	179,580.0	161,519.5	88.38%	89.94%	86.69%	1.34%
Model: K.M.W. - Kaplan								
WH1	5.800	30,686.1	50,808.0	48,952.0	62.69%	96.35%	89.32%	0.00%
WH2	5.800	30,179.9	50,808.0	48,928.8	61.68%	96.30%	86.61%	0.00%
Summary - K.M.W. - Kaplan		60,866.0	101,616.0	97,880.8	62.18%	96.32%	87.96%	0.00%
Summary - Hydro		376,289.3	664,020.0	628,467.9	59.60%	95.73%	81.30%	0.38%

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2010 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
Type: Diesel								
Location: DAWSON								
Model: Caterpillar - 3512								
DD1	0.800	349.0	7,008.0	7,002.4	4.98%	99.92%	8.40%	0.00%
Summary - Caterpillar - 3512		349.0	7,008.0	7,002.4	4.98%	99.92%	8.40%	0.00%
Model: Caterpillar - 3516								
DD2	1.000	551.5	8,760.0	8,759.0	6.30%	99.99%	9.68%	0.00%
Summary - Caterpillar - 3516		551.5	8,760.0	8,759.0	6.30%	99.99%	9.68%	0.00%
Model: Caterpillar - 3516 TA								
DD3	1.000	623.1	8,760.0	8,105.0	7.69%	92.52%	10.51%	2.17%
Summary - Caterpillar - 3516 TA		623.1	8,760.0	8,105.0	7.69%	92.52%	10.51%	2.17%
Model: Caterpillar - 3606								
DD5	1.500	807.0	13,140.0	12,447.0	6.48%	94.73%	9.58%	0.00%
Summary - Caterpillar - 3606		807.0	13,140.0	12,447.0	6.48%	94.73%	9.58%	0.00%
Location: FARO								
Model: Caterpillar - 3516								
FD3	0.850	6.1	7,446.0	7,145.1	0.09%	95.96%	0.14%	3.85%
FD5	1.200	13.0	10,512.0	10,507.2	0.12%	99.95%	0.14%	0.00%
Summary - Caterpillar - 3516		19.1	17,958.0	17,652.3	0.10%	97.96%	0.14%	1.92%
Model: Caterpillar - 3612								
FD7	3.000	178.9	26,280.0	26,025.0	0.69%	99.03%	1.22%	0.00%
Summary - Caterpillar - 3612		178.9	26,280.0	26,025.0	0.69%	99.03%	1.22%	0.00%
Model: Mirlees - KV12								
FD1		73.8	37,520.0	15,355.0	0.48%	35.06%	0.41%	0.00%
Summary - Mirlees - KV12		73.8	37,520.0	15,355.0	0.48%	35.06%	0.41%	0.00%
Location: MAYO								

2010 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
Type: Diesel								
Location: MAYO								
Model: Caterpillar - 3516								
MD1	0.850	16.8	7,446.0	7,157.9	0.24%	96.13%	0.51%	0.02%
MD2	0.850	17.1	7,446.0	7,444.3	0.23%	99.98%	0.50%	0.00%
YM1	1.400	73.9	12,264.0	12,264.0	0.60%	100.00%	0.23%	0.00%
Summary - Caterpillar - 3516		107.9	27,156.0	26,866.2	0.36%	98.70%	0.41%	0.01%
Location: WHITEHORSE								
Model: Caterpillar - 3612								
WD7	3.200	1,340.6	28,032.0	27,024.0	4.96%	96.40%	6.40%	0.07%
Summary - Caterpillar - 3612		1,340.6	28,032.0	27,024.0	4.96%	96.40%	6.40%	0.07%
Model: EMD - 20C								
WD4	2.500	252.1	21,900.0	20,772.5	1.21%	94.85%	1.43%	0.00%
WD5	2.500	293.6	21,900.0	20,835.0	1.41%	95.14%	1.66%	0.00%
WD6	2.500	557.5	21,900.0	20,645.0	2.70%	94.27%	3.31%	0.00%
Summary - EMD - 20C		1,103.2	65,700.0	62,252.5	1.77%	94.75%	2.13%	0.00%
Model: Mirlees - KV12								
WD1	3.500	0.0	30,660.0	29,967.0	0.00%	97.74%	0.00%	0.00%
Summary - Mirlees - KV12		0.0	30,660.0	29,967.0	0.00%	97.74%	0.00%	0.00%
Model: Mirlees - KV16								
WD2	4.500	15.1	39,420.0	39,163.5	0.04%	99.35%	0.02%	0.00%
WD3	4.500	4.3	39,420.0	10,566.0	0.04%	26.80%	0.08%	9.19%
Summary - Mirlees - KV16		19.4	78,840.0	49,729.5	0.04%	63.08%	0.05%	4.59%
Summary - Diesel		5,173.6	349,814.0	291,184.9	2.13%	89.88%	3.01%	0.85%

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2010 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
YEC Summary -		381,462.9	1,013,834.0	919,652.8	19.81%	91.68%	27.10%	0.71%

Definitions

MCR: Maximum continuous rating

Actual Generation: Amount of real power (energy) that the generating unit produced for the period. (this # comes from month end reports)

Available Generation: Amount of generation the unit would have produced if it was run at full load for the entire year (based on MCR multiplied by number of hours in period)

Capacity Factor: Actual energy produced divided by the amount of energy that the unit had the potential to produce.

Unit Availability: Number of hours the generator is available for production divided by the total hours in the period. (this factor is displayed in a percentile).

Operating Factor: The hours the generator was on line divided by the total hours in the period.(displayed in a percentile).

Forced Outage: Unplanned outage or breakdown that removes the unit from service.

2011 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
Type: Hydro								
Location: AISHIHIK								
Model: Dom.Eng. - Francis								
AH1	15.000	69,215.8	130,393.0	118,618.0	58.35%	91.04%	83.80%	0.06%
AH2	15.000	61,104.5	131,385.0	118,725.0	51.47%	90.36%	72.53%	0.02%
Summary - Dom.Eng. - Francis		130,320.3	261,778.0	237,343.0	54.91%	90.70%	78.17%	0.04%
Model: TDPS - TD172								
AH3		1,510.0	11,416.0	4,864.0	31.04%	6.94%	5.50%	0.00%
Summary - TDPS - TD172		1,510.0	11,416.0	4,864.0	31.04%	6.94%	5.50%	0.00%
Location: MAYO								
Model: Dom.Eng. - Francis								
MH1	2.600	8,790.3	22,773.4	13,439.4	65.41%	59.01%	50.72%	0.00%
MH2	2.600	10,316.0	22,773.4	13,527.8	76.26%	59.40%	56.44%	0.00%
Summary - Dom.Eng. - Francis		19,106.3	45,546.8	26,967.2	70.83%	59.21%	53.58%	0.00%
Model: HLA743-WJ-115								
MBH1		0.8	7,339.1	3,049.5	0.03%	6.66%	2.23%	2.19%
MBH2		0.6	7,339.1	3,974.1	0.02%	8.63%	1.64%	0.00%
Summary - HLA743-WJ-115		1.4	14,678.1	7,023.6	0.02%	7.64%	1.94%	1.10%
Location: WHITEHORSE								
Model: C.A.C. - Propeller								
WH3	8.500	39,136.7	70,979.5	69,391.0	56.40%	96.62%	58.10%	0.00%
Summary - C.A.C. - Propeller		39,136.7	70,979.5	69,391.0	56.40%	96.62%	58.10%	0.00%
Model: Dom. Eng. - Propeller								
WH4	20.500	133,272.5	179,559.5	171,605.5	77.66%	95.57%	82.67%	0.17%
Summary - Dom. Eng. - Propeller		133,272.5	179,559.5	171,605.5	77.66%	95.57%	82.67%	0.17%
Model: K.M.W. - Kaplan								
WH1	5.800	27,374.9	50,802.2	47,966.0	57.07%	94.42%	78.83%	0.00%
WH2	5.800	29,169.6	50,802.2	49,537.8	58.88%	97.51%	86.43%	0.00%
Summary - K.M.W. - Kaplan		56,544.4	101,604.4	97,503.8	57.98%	95.96%	82.63%	0.00%
Summary - Hydro		379,891.7	685,562.3	614,698.1	48.42%	64.20%	52.63%	0.22%

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2011 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
Type: Diesel								
Location: DAWSON								
Model: Caterpillar - 3512								
DD1	0.800	992.1	7,007.2	7,003.2	14.17%	99.94%	22.67%	0.01%
Summary - Caterpillar - 3512		992.1	7,007.2	7,003.2	14.17%	99.94%	22.67%	0.01%
Model: Caterpillar - 3516								
DD2	1.000	1,635.9	8,759.0	8,580.0	19.07%	97.96%	26.82%	0.00%
Summary - Caterpillar - 3516		1,635.9	8,759.0	8,580.0	19.07%	97.96%	26.82%	0.00%
Model: Caterpillar - 3516 TA								
DD3	1.000	1,297.5	8,759.0	8,742.0	14.84%	99.81%	21.36%	0.00%
Summary - Caterpillar - 3516 TA		1,297.5	8,759.0	8,742.0	14.84%	99.81%	21.36%	0.00%
Model: Caterpillar - 3606								
DD5	1.500	3,332.9	13,138.5	13,057.5	25.52%	99.38%	35.23%	0.22%
Summary - Caterpillar - 3606		3,332.9	13,138.5	13,057.5	25.52%	99.38%	35.23%	0.22%
Location: FARO								
Model: Caterpillar - 3516								
FD3	0.850	88.0	7,445.2	7,445.2	1.18%	100.00%	1.46%	0.00%
FD5	1.200	40.1	10,510.8	9,636.0	0.42%	91.68%	0.22%	8.32%
Summary - Caterpillar - 3516		128.1	17,956.0	17,081.2	0.80%	95.84%	0.84%	4.16%
Model: Caterpillar - 3612								
FD7	3.000	1,082.6	26,277.0	25,272.0	4.28%	96.18%	6.51%	0.00%
Summary - Caterpillar - 3612		1,082.6	26,277.0	25,272.0	4.28%	96.18%	6.51%	0.00%
Model: Mirlees - KV12								
FD1		64.0	43,795.0	40,360.0	0.16%	92.16%	0.65%	2.18%
Summary - Mirlees - KV12		64.0	43,795.0	40,360.0	0.16%	92.16%	0.65%	2.18%
Location: MAYO								

2011 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
Type: Diesel								
Location: MAYO								
Model: Caterpillar - 3516								
MD1	0.850	253.3	7,445.2	6,956.4	3.64%	93.44%	4.30%	6.56%
MD2	0.850	216.4	7,445.2	7,263.3	2.98%	97.56%	3.40%	2.44%
YM1	1.400	51.0	12,262.6	12,262.6	0.42%	100.00%	3.05%	0.00%
Summary - Caterpillar - 3516		520.7	27,152.9	26,482.3	2.35%	97.00%	3.58%	3.00%
Location: WHITEHORSE								
Model: Caterpillar - 3612								
WD7	3.200	2,262.2	28,028.8	24,579.2	9.20%	87.69%	12.91%	9.50%
Summary - Caterpillar - 3612		2,262.2	28,028.8	24,579.2	9.20%	87.69%	12.91%	9.50%
Model: EMD - 20C								
WD4	2.500	800.3	21,897.5	21,407.5	3.74%	97.76%	4.52%	1.47%
WD5	2.500	1,196.3	21,897.5	21,600.0	5.54%	98.64%	5.73%	0.00%
WD6	2.500	759.3	21,897.5	16,497.5	4.60%	75.34%	6.11%	24.19%
Summary - EMD - 20C		2,755.9	65,692.5	59,505.0	4.63%	90.58%	5.45%	8.56%
Model: Mirlees - KV12								
WD1	3.500	191.0	30,656.5	30,656.5	0.62%	100.00%	0.88%	0.00%
Summary - Mirlees - KV12		191.0	30,656.5	30,656.5	0.62%	100.00%	0.88%	0.00%
Model: Mirlees - KV16								
WD2	4.500	131.2	39,415.5	39,294.0	0.33%	99.69%	0.55%	0.31%
WD3	4.500	16.3	39,415.5	38,448.0	0.04%	97.55%	0.19%	0.00%
Summary - Mirlees - KV16		147.5	78,831.0	77,742.0	0.19%	98.62%	0.37%	0.15%
Summary - Diesel		14,410.5	356,053.4	339,060.8	6.15%	95.82%	8.70%	3.07%

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2011 Generation Key Performance Indicators

Note: Definitions on back page

UNIT ID	UNIT MCR (MW)	ACTUAL GEN (MWHr)	POTENTIAL GEN (MWHr)	AVAILABLE GEN (MWHr)	CAPACITY FACTOR (%)	UNIT AVAIL (%)	OPERATING FACTOR (%)	FORCED OUTAGE (%)
YEC Summary -		394,302.3	1,041,615.7	953,758.9	22.18%	83.83%	25.36%	1.99%

Definitions

MCR: Maximum continuous rating

Actual Generation: Amount of real power (energy) that the generating unit produced for the period. (this # comes from month end reports)

Available Generation: Amount of generation the unit would have produced if it was run at full load for the entire year (based on MCR multiplied by number of hours in period)

Capacity Factor: Actual energy produced divided by the amount of energy that the unit had the potential to produce.

Unit Availability: Number of hours the generator is available for production divided by the total hours in the period. (this factor is displayed in a percentile).

Operating Factor: The hours the generator was on line divided by the total hours in the period.(displayed in a percentile).

Forced Outage: Unplanned outage or breakdown that removes the unit from service.

YEC Generation Inventory

LOCATION	UNIT NO.	PRIME MOVER TYPE	NAME PLATE CAPACITY	MCR RATING (kW)	GEN. RATING (KVA)	GEN. VOLTAGE (V)	IN-SERVICE DATE	PLANNED RETIREMENT DATE
Aishihik	Total			37,000				
	AH1	hydro	15,600	15,000	19,200	13,800	1975	N/A
	AH2	hydro	15,600	15,000	17,000	13,800	1975	N/A
	AH3	hydro	7,200	7,000	8,250	13,800	2011	N/A
Faro	Total			8,850				
	FD1	diesel	5,150	4,000	6,000	12000/6900	1970	2021
	FD3	diesel	1,000	850	1,250	4,160	1989	2019
	FD5	diesel	1,400	1,200	1,800	4,160	1990	2020
	FD7	diesel	3,000	2,800	3,750	4,160	1992	2027
Dawson	Total			3,960				
	DD1	diesel	800	720	1,000	2400/4160	1988	2018
	DD2	diesel	1,000	920	1,250	4,160	1987	2017
	DD3	diesel	1,000	920	1,288	4,160	1990	2020
	DD5	diesel	1,500	1,400	1,875	4,160	1996	2031
Mayo	Total			17,100				
	MD1	diesel	1,000	850	1,250	4,160	1989	2019
	MD2	diesel	1,000	850	1,250	4,160	1989	2019
	MH1	hydro	2,620	2,600	2,550	6,900	1957	N/A
	MH2	hydro	2,840	2,800	2,550	6,900	1951	N/A
	MBH1	hydro	5,693	5,000	5,693	6,900	2011	N/A
	MBH2	hydro	5,693	5,000	5,693	6,900	2011	N/A
Whitehorse	Total			62,500				
	WH1	hydro	5,800	5,800	5,800	6,900	1958	N/A
	WH2	hydro	5,800	5,800	5,800	6,900	1958	N/A
	WH3	hydro	8,400	8,400	8,400	6,900	1969	N/A
	WH4	hydro	20,000	20,000	2,360	6,900	1984	N/A
	WD1	diesel	3,920	3,500	4,250	6,900	1968	2014
	WD2	diesel	5,150	4,500	6,000	6,900	1968	2015
	WD3	diesel	5,150	4,500	6,000	6,900	1970	2021
	WD4	diesel	2,500	2,250	3,000	4,160	1975	2025
	WD5	diesel	2,500	2,250	3,000	4,160	1975	2025
	WD6	diesel	2,700	2,500	3,125	4,160	1990	2025
	WD7	diesel	3,300	3,000	4,125	4,160	1991	2026
Haeckel Hill	Total			810				
	WW1	wind		150			1993	2018
	WW2	wind		660			2000	2025
Mobile Diesels	Total			1,610				
	YM1	diesel	1,400	1,300		4,160	1990	2015
	YM2	diesel	150	150	150	347/600	1999	2024
	YM3	diesel	125	125		277/480		
	YM4	diesel	35	35		277/480		

TOPIC: **Table 2.2 Summary of Energy Balance, Losses, Peak and Load Factor**

REFERENCE: **YEC April 2012 Phase I, Section 2, Page 2-18, Table 2**

PREAMBLE:

Yukon Electric seeks better understanding of the numbers presented in Table 2.2.

QUESTION:

a) Please provide a numerical analysis (in Excel format) as well as reasons for the increase of the loss percentage from 8.1% to 8.8% from 2009 actual to 2010 actual.

b) Please explain the reason for the 85 MW.h drop in wind generation in 2010 actual from the 238 MW.h produced in 2009 actual.

ANSWER:

(a)

Please see Attachment 1 for the requested information.

The attachment also includes numbers for 2008 to show that the losses in 2009 were lower than the other actual years. The line losses for 2008, 2010 and 2011 are within 8.7%-8.9% range.

Losses can be affected by a number of factors, including timing of meter reads, changes to system configuration, unmetered use (such as some utility station service loads), outages, weather conditions, etc. Typically, line losses that stay within a reasonable band over a number of years, with limited outliers, and do not indicate any trend to higher or lower levels are considered stable and reasonable.

(b)

YEC could not work on WW1 in 2010 due to the access ladder being decommissioned (damage) to the nacelle. Access to the nacelle is crucial to assess and make repairs.

Issues related to the turbines during this timeframe have been:

- WW1 - This unit is approaching its end of life, with multiple component failures (hydraulic and electrical). An assessment will be complete this year to determine if the planned retirement date of 2013 is required.

- WW1 – Has very limited vendor support and parts availability.

- WW1 and WW2 - Rime ice continues to be problematic at this site, which in conjunction with the blade heat issues continues to be the cause of this units shut down.

- WW1 and WW2 - Surplus hydro in summer months reduce the priority for repairs to the wind turbines and inaccessibility during the winter months to work at the site is limited due to weather (wind and temperature) conditions.

YEC 2008-2011 Actual Sales, Generation and Losses

Year	Total YEC, Sales vs Generation to determine Losses						
	Sales	**Losses**		**Generation (Kwh)**			
	KWh	**KWh**	**%**	**Total Generation**	**Hydro**	**Diesel**	**Wind**
2008	315,784,130	28,057,255	8.9%	343,841,385	341,742,046	1,662,449	436,890
2009	345,838,959	28,006,592	8.1%	373,845,551	370,962,385	2,644,943	238,223
2010	351,491,832	30,763,607	8.8%	382,255,439	377,043,572	5,127,227	84,640
2011	368,664,529	32,101,417	8.7%	400,765,946	384,429,008	15,934,849	402,089

TOPIC: **Diesel Contingency Fund (DCF)**

REFERENCE: **Appendix 3.2**

PREAMBLE:

Yukon Electrical wishes to further understand the mechanics of the DCF.

QUESTION:

a) Please explain how changes in YEC Diesel fuel volumes that result from changes in YEC customer load, as opposed to water availability, impact the Diesel Contingency Fund (DCF). If there is no impact to the DCF, please explain what happens with these changes in diesel volumes.

b) Please explain how the Diesel Contingency Fund (DCF) impacts, or is impacted by, the Energy Reconciliation Adjustment in Rate Schedule 42.

c) Please explain if the mechanics of the DCF have changed from the previous methodology. Please itemize all changes.

ANSWER:

(a)

Changes in YEC diesel fuel volumes that result from changes in YEC customer load, as opposed to water or hydro generation availability, do not result in any payment into or out of the DCF. At the grid loads forecast for the current GRA, such changes will adjust the diesel generation levels expected with long term average hydro generation.

At any adjusted level of grid load, diesel generation that varies from expected diesel generation (i.e., diesel generation variances that are due to changes in water availability) will impact the DCF. Such changes in diesel volume driven by the wholesale customer load variation will be recovered (refunded) through the Energy Reconciliation Adjustment (ERA). YEC bears the risk for such changes in diesel volume driven by the retail and industrial customer load variations, which will be reflected in the YEC's Income Statement.

(b)

The DCF and the ERA in Rate Schedule 42 do not impact each other. The DCF is applied first, to "normalize" the annual diesel to a consistent percentage of the long-term average. The ERA is only applied subsequent to the DCF to analyze YECL loads as compared to generation at the relevant GRA long-term average index.

(c)

Yes.

Under the proposed approach, the mechanics of the DCF have changed from the previous methodology. Please see Attachment 3.2 which summarizes all changes.

Please refer to Appendix 3.2 and Attachment 3.2 of the Application and the response to YUB-YEC-1-30(b) for further details of the proposed changes in DCF mechanics.

TOPIC: **Rate Schedule 42 - Energy Reconciliation Adjustment (ERA)**

REFERENCE: **Lines 1-4 Page 4-12, "To the extent that actual wholesale purchases fall short or exceed forecast wholesale purchases, an adjustment to the YECL bills will be made at a rate equal to the Hydro zone incremental cost of diesel of 32.74 cents per kW.h as approved by the Board in Order 2010-13."**

Line 1-10s Pages 4-13, "Charges to YECL will be adjusted on a monthly basis to reconcile actual wholesale purchases to Yukon Energy's most recent test year forecast purchases during the months when Yukon Energy diesel generation cost is modified by such variances in wholesale purchases. To the extent that actual wholesale purchases fall short or exceed Yukon Energy's most recent test year forecast wholesale purchases, an adjustment to the YECL bills will be made based on the variance in diesel generation costs incurred by Yukon Energy as a direct result of actual wholesale purchases falling short or exceeding forecast wholesale purchases. Such adjustments for shortfalls in actual wholesale purchases will be limited to minus 10% of the forecast wholesale purchases in any period."

PREAMBLE:

Yukon Electrical wishes to further understand the charges associated with the ERA.

QUESTION:

a) Please explain the calculations that will be used to determine diesel generation costs incurred by Yukon Energy as a direct result of actual wholesale sales to YECL.

b) Please provide detailed sample calculations (in Excel format) of the mechanism described in b) above. Please include any assumptions made for this calculation.

c) Please provide a monthly breakdown of Wholesale sales forecasted in 2012 and 2013 in Table 2.1 of the Application.

d) Please explain how YEC derived the monthly forecast amounts (in Excel format).

ANSWER:

(a) and **(b)**

The quote provided indicates that "…diesel generation costs incurred by Yukon Energy as a direct result of actual wholesale sales falling short or exceeding forecast wholesale purchases" will be adjusted. In short, it is only the variance from GRA forecast levels that will be adjusted, not the entire wholesale sales to YECL.

The diesel generation costs incurred due to the variance in YECL's purchases will be determined as follows:

i. The expected incremental wholesale generation required to be served by diesel under long-term average hydro conditions will be determined in any time period as follows:
    a. The change in expected diesel (at long term average hydro generation, adjusted to reflect the percentage of such long term average that is included in rates approved by the Board) that is recorded for the period regarding the variance in YEC's overall grid generation from GRA approved forecasts, stated as a percentage of the variance in YEC's overall grid generation from GRA approved forecasts; and
    b. The application of the percentage as determined in (a) to the variance in YECL's wholesale purchases from GRA approved forecasts during the same period.

ii. The per kW.h difference between the YEC incremental diesel cost and incremental rate revenue (approved wholesale rate and rider rate revenue) will be applied to the diesel generation amount calculated in step (i).

ERA determinations will initially be estimated on a monthly basis, but will be subject to true up and final determination on an annual calendar year basis.

Please see the attachment provided in the response to YUB-YEC-1-30(b) for detailed sample calculations.

(c) and **(d)**

As requested, this response addresses how the YEC annual forecast for wholesale sales were divided into monthly values. For the derivation of the YEC annual wholesale forecast, please see YECL-YEC-1-3.

Please see YUB-YECL-1-15 (c-d) Attachment 1 for a monthly breakdown of Wholesale sales forecast in 2012 and 2013 in Table 2.1 of the Application, as well as for the details of derivation of the monthly forecast.

For derivation of the monthly sales forecast, YEC reviews YECL's monthly forecast and compares it to the actual monthly sales of the past year to determine the reasonableness of the monthly distribution of sales based on the actual trend. YEC's monthly sales forecast is then derived by splitting the annual forecast sales in accordance with this review and comparison subject to adjustments where required.

Monthly forecast amounts for 2012 were estimated by splitting the 2012 annual forecast consistent with 2011 actual monthly sales trend. Actual 2011 December sales were considered unusually low for this year and as such forecast sales for December 2012 were adjusted upwards based on the review of YECL's forecast for this month and 2010 actual sales for December.

The 2013 monthly wholesale forecast is based on the 2013 annual forecast prorated by the 2012 monthly sales forecast.

YEC`s Wholesale Forecast for 2012 and 2013, GW.h

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
YECL, forecast for 2012	34.0	25.8	27.4	21.6	21.5	19.2	20.0	18.8	21.7	21.9	26.6	30.5	289.1
2010 Actual Sales	26.6	26.0	23.5	21.1	20.3	18.7	18.8	19.8	20.2	21.9	27.2	32.2	276.3
2011 Actual Sales	31.0	27.2	28.1	21.6	21.6	19.2	19.8	19.3	21.3	23.5	29.4	28.5	290.5
YECL forecast vs. 2011 Actual	3.0	-1.4	-0.7	-0.0	-0.0	-0.0	0.2	-0.4	0.3	-1.5	-2.8	2.0	-1.5
YEC 2012 Wholesale forecast	31.0	27.0	28.5	22.0	21.9	19.6	20.2	19.6	21.6	23.8	29.8	31.3	296.0
YEC 2013 Wholesale forecast	31.2	27.2	28.7	22.2	22.1	19.7	20.3	19.7	21.8	23.9	30.0	31.5	298.2

	2012	2013
Past 12 months	290.5	296.0
Estimate due to FL #1 out of service	-4.4	-4.4
Adjust 2011 to 10 yr Avg HDD	-1.0	
Base Sales	285.2	291.6
Growth at 2.26%	291.6	298.2
Add FL #1 back	4.4	
2012 Wholesale Forecast	296.0	298.2

TOPIC: **DCF & ERA**

REFERENCE: **Appendix 3.2, Rate Schedule 42, Table 3.2-1 and Table 3.2-1**

PREAMBLE:

YECL wishes to better understand the mechanics with the proposed DCF and ERA.

QUESTION:

a) The table below shows 6 possible scenarios that may arise as a result of the variations in hydro generation availability and Wholesale sales to YECL. For each scenario, please calculate the impact on the Diesel Contingency Fund (DCF) and the Energy Reconciliation Adjustment (ERA). Please provide (in Excel format) formulas and all supporting details and assumptions for the calculations.

Scenario	Hydro Generation (GW.h)[1]	Hydro Generation Increase/(Decrease) (GW.h)	Actual versus Forecast variance in YECL Wholesale Sales (GW.h)
1	419.4	+5	+2
2	419.4	+5	-2
3	419.4	-5	+2
4	419.4	-5	-2
5	419.4	0	+2
6	419.4	0	-2

1) Hydro Generation (GWh) is the 2013 forecast amount per Line 8, Table 2.2 of the Application.

ANSWER:

(a)

Please see Attachment 1 to this response for the requested calculation. Also see YUB-YEC-1-30(b) for further descriptions and scenarios.

Scenario descriptions:

Scenario #1: Actual Hydro Generation Higher by 5 GW.h; Actual Wholesale Sales Higher by 2 GW.h
Scenario #2: Actual Hydro Generation Higher by 5 GW.h; Actual Wholesale Sales Lower by 2 GW.h
Scenario #3: Actual Hydro Generation Lower by 5 GW.h; Actual Wholesale Sales Higher by 2 GW.h
Scenario #4: Actual Hydro Generation Lower by 5 GW.h; Actual Wholesale Sales Lower by 2 GW.h
Scenario #5: Hydro Generation at GRA Forecast; Actual Wholesale Sales Higher by 2 GW.h
Scenario #6: Hydro Generation at GRA Forecast; Actual Wholesale Sales Lower by 2 GW.h

		Scenarios					
	GRA	**Scenario #1** High Water High Sales	**Scenario #2** High Water Low Sales	**Scenario #3** Low Water High Sales	**Scenario #4** Low Water Low Sales	**Scenario #5** Normal Water High Sales	**Scenario #6** Normal Water Low Sales
Retail and Industrial (MW.h)	97,685	97,685	97,685	97,685	97,685	97,685	97,685
Wholesale (MW.h)	298,228	300,228	296,228	300,228	296,228	300,228	296,228
Total Sales (MW.h)	395,913	397,913	393,913	397,913	393,913	397,913	393,913
Losses (MW.h)	34,444	34,618	34,270	34,618	34,270	34,618	34,270
Total Generation (MW.h)	430,357	432,531	428,183	432,531	428,183	432,531	428,183
Hydro (MW.h)	419,405	424,405	424,405	414,405	414,405	419,405	419,405
Diesel (MW.h)	10,714	7,888	3,540	17,888	13,540	12,888	8,540
Wind (MW.h)	238	238	238	238	238	238	238
Total Generation (MW.h)	430,357	432,531	428,183	432,531	428,183	432,531	428,183
Diesel MW.h	10,714	7,888	3,540	17,888	13,540	12,888	8,540
Proposed ERA Determination & related DCF determinations							
In Base Rates Excluding ERA MW.h (YEC's Income Statement)	10,714	10,772	10,651	10,772	10,651	10,772	10,651
Charged/credited via ERA (MW.h)	0	661	-725	661	-725	661	-725
Total in Rates	10,714	11,432	9,927	11,432	9,927	11,432	9,927
Charged/credited via DCF (MW.h)	0	-3,544	-6,387	6,456	3,613	1,456	-1,387
Total Diesel	10,714	7,888	3,540	17,888	13,540	12,888	8,540

DCF Formulaic Approach Operation Sample for 2013 Scenarios

Variable cost of diesel calculation

Line No				Notes
L1	Fuel Price	28.68	kW.h	DCF diesel price as forecast in GRA for 2013 (average for YEC grid)
L2	Variable O&M cost	3.000	kW.h	2009 GRA approved
L3=L1+L2	Variable cost of diesel	**31.681**	cents/kW.h	

Calculation of Diesel Cost to Charge (Refund) DCF

GRA Load

L4	2013 GRA Forecast Load (YEC grid load excluding Fish Lake generation)	430,357	MW.h	Table 2.2 of GRA
L5	Grid Load for DCF (2013 GRA Forecast Load net of Wind Generation)	430,119	MW.h	Table 2.2 of GRA (wind generation at 238 MW.h)
L6	Expected Base Diesel Generation at 430 GW.h	18,100	MW.h	Derived from Table 3.2-2 of GRA
L7=(L5-430 GW.h)x56%	Expected Incremental Diesel Generation at 119 MW.h above 430 GW.h	67	MW.h	56% of Grid Load between 430 GW.h and 435 GW.h is diesel - Derived from Table 3.2-2 of GRA
L8=L6+L7	Total Expected Diesel Generation	18,167	MW.h	
L9=L8x59%	Expected Diesel Generation in Rates	10,714	MW.h	GRA proposes to include in rates 59% of Expected Diesel Generation - see Table 2.2

Scenario #1: Actual Hydro Generation Higher by 5 GW.h; Actual Wholesale Sales Higher by 2 GW.h

	Assumptions			
	Hydro	424,405		
	Diesel	7,888		
	Wind	238		
L10	Total Actual YEC Supply	432,531	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	432,293	MW.h	Scenario load of 432.531 GW.h less 238 MW.h
L12	Expected Base Diesel Generation at 430 GW.h	18,100	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-430 GW.h)x56%	Expected Incremental Diesel Generation at 2,293 MW.h	1,284	MW.h	56% of Grid Load between 430 GW.h and 435 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	19,384	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	11,432	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	7,888	MW.h	As per scenario assumptions
L17=L16-L15	Diesel Generation to be Included in DCF	-3,544	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF	($1,122,794)		

Scenario #2: Actual Hydro Generation Higher by 5 GW.h; Actual Wholesale Sales Lower by 2 GW.h

Assumptions

	Hydro	424,405		
	Diesel	3,540		
	Wind	238		
L10	Total Actual YEC Supply	428,183	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	427,945	MW.h	Scenario load of 428.183 GW.h less 238 MW.h
L12	Expected Base Diesel Generation at 425 GW.h	15,300	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-425 GW.h)x52%	Expected Incremental Diesel Generation at 2,945 MW.h	1,531	MW.h	52% of Load between 425 GW.h and 430 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	16,831	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	9,927	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	3,540	MW.h	As per scenario assumptions
L17=L16-L15	Diesel Generation to be Included in DCF	-6,387	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF	($2,023,317)		

Scenario #3: Actual Hydro Generation Lower by 5 GW.h; Actual Wholesale Sales Higher by 2 GW.h

Assumtpions	Hydro	414,405		
	Diesel	17,888		
	Wind	238		
L10	Total Actual YEC Supply	432,531	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	432,293	MW.h	Scenario load of 432.531 GW.h less 238 MW.h
L12	Expected Base Diesel Generation at 430 GW.h	18,100	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-430 GW.h)x56%	Expected Incremental Diesel Generation at 2,293 MW.h	1,284	MW.h	56% of Load between 430 GW.h and 435 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	19,384	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	11,432	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	17,888	MW.h	As per scenario assumptions
L17=L16-L15	Diesel Generation to be Included in DCF	6,456	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF	$2,045,297		

Scenario #4: Actual Hydro Generation Lower by 5 GW.h; Actual Wholesale Sales Lower by 2 GW.h

Assumtpions	Hydro	414,405		
	Diesel	13,540		
	Wind	238		
L10	Total Actual YEC Supply	428,183	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	427,945	MW.h	Scenario load of 428.183 GW.h less 238 MW.h
L12	Expected Base Diesel Generation at 425 GW.h	15,300	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-425 GW.h)x52%	Expected Incremental Diesel Generation at 2,945 MW.h	1,531	MW.h	52% of Load between 425 GW.h and 430 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	16,831	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	9,927	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	13,540	MW.h	As per scenario assumptions
L17=L16-L15	Diesel Generation to be Included in DCF	3,613	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF	$1,144,774		

Scenario #5: Hydro Generation at GRA Forecast; Actual Wholesale Sales Higher by 2 GW.h

Assumtpions	Hydro	419,405	
	Diesel	12,888	
	Wind	238	
L10	Total Actual YEC Supply	432,531	MW.h

L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	432,293	MW.h	Scenario load of 432.531 GW.h less 238 MW.h
L12	Expected Base Diesel Generation at 430 GW.h	18,100	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-430 GW.h)x56%	Expected Incremental Diesel Generation at 2,293 MW.h	1,284	MW.h	56% of Load between 430 GW.h and 435 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	19,384	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	11,432	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	12,888	MW.h	As per scenario assumptions
L17=L16-L15	Diesel Generation to be Included in DCF	1,456	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF	$461,251		

Scenario #6: Hydro Generation at GRA Forecast; Actual Wholesale Sales Lower by 2 GW.h

Assumtpions	Hydro	419,405		
	Diesel	8,540		
	Wind	238		
L10	Total Actual YEC Supply	428,183	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	427,945	MW.h	Scenario load of 428.183 GW.h less 238 MW.h
L12	Expected Base Diesel Generation at 425 GW.h	15,300	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-425 GW.h)x52%	Expected Incremental Diesel Generation at 2,945 MW.h	1,531	MW.h	52% of Load between 425 GW.h and 430 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	16,831	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	9,927	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	8,540	MW.h	As per scenario assumptions
L17=L16-L15	Diesel Generation to be Included in DCF	-1,387	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF	($439,272)		

Scenario descriptions:

Scenario #1: Actual Hydro Generation Higher by 5 GW.h; Actual Wholesale Sales Higher by 2 GW.h
Scenario #2: Actual Hydro Generation Higher by 5 GW.h; Actual Wholesale Sales Lower by 2 GW.h
Scenario #3: Actual Hydro Generation Lower by 5 GW.h; Actual Wholesale Sales Higher by 2 GW.h
Scenario #4: Actual Hydro Generation Lower by 5 GW.h; Actual Wholesale Sales Lower by 2 GW.h
Scenario #5: Hydro Generation at GRA Forecast; Actual Wholesale Sales Higher by 2 GW.h
Scenario #6: Hydro Generation at GRA Forecast; Actual Wholesale Sales Lower by 2 GW.h

Inputs

		Scenarios					
	GRA	**Scenario #1** High Water High Sales	**Scenario #2** High Water Low Sales	**Scenario #3** Low Water High Sales	**Scenario #4** Low Water Low Sales	**Scenario #5** Normal Water High Sales	**Scenario #6** Normal Water Low Sales
Retail and Industrial (MW.h)	97,685	97,685	97,685	97,685	97,685	97,685	97,685
Wholesale (MW.h)	298,228	300,228	296,228	300,228	296,228	300,228	296,228
Total Sales (MW.h)	395,913	397,913	393,913	397,913	393,913	397,913	393,913
Losses (MW.h)	34,444	34,618	34,270	34,618	34,270	34,618	34,270
Total Generation (MW.h)	430,357	432,531	428,183	432,531	428,183	432,531	428,183
Change from GRA Forecast							
Retail and Industrial (MW.h)		0	0	0	0	0	0
Wholesale (MW.h)		2,000	-2,000	2,000	-2,000	2,000	-2,000
Total Sales (MW.h)		2,000	-2,000	2,000	-2,000	2,000	-2,000
Losses (MW.h)		174	-174	174	-174	174	-174
Total Generation (MW.h)		2,174	-2,174	2,174	-2,174	2,174	-2,174
Hydro (MW.h)	419,405	424,405	424,405	414,405	414,405	419,405	419,405
Diesel (MW.h)	10,714	7,888	3,540	17,888	13,540	12,888	8,540
Wind (MW.h)	238	238	238	238	238	238	238
Total Generation (MW.h)	430,357	432,531	428,183	432,531	428,183	432,531	428,183
Diesel MW.h	10,714	7,888	3,540	17,888	13,540	12,888	8,540
less: DCF	0	-3,544	-6,387	6,456	3,613	1,456	-1,387
In Base Rates MW.h (YEC's Income Statement)	10,714	11,432	9,927	11,432	9,927	11,432	9,927
Incremental Diesel in Base Rates (MW.h)		718	-788	718	-788	718	-788
Incremental Diesel in Base Rates (% of Total Gen'n Change)		33%	36%	33%	36%	33%	36%

Proposed ERA Approach

Proposed 2013 Wholesale Rate	8.298	cents/kW.h	current wholesale rate (Appendix 4.1)
Average proposed rider revenue per kW.h	2.088	cents/kW.h	89.23% of non-industrial rider revenue of $6.98 million (Table 4.2)
ERA Rate Calculation:			
Fuel Price	28.681	kW.h	DCF diesel price as forecast in GRA for 2013 (average for YEC grid)

Variable O&M cost	3.000	kW.h	2009 GRA approved
ERA rate (var cost of diesel)	**31.681**	cents/kW.h	

The **Energy Reconciliation Adjustment** is calculated as follows:

a) **sales below GRA forecast**: no adjustment for sales more than 10% below GRA forecast

b) **sales above GRA forecast:** all sales in excess of GRA forecast are subject to the adjustment

		Scenarios						
	GRA	**Scenario #1** High Water High Sales	**Scenario #2** High Water Low Sales	**Scenario #3** Low Water High Sales	**Scenario #4** Low Water Low Sales	**Scenario #5** Normal Water High Sales	**Scenario #6** Normal Water Low Sales	
Incremental Wholesale Sales (MW.h)	0	2,000	-2,000	2,000	-2,000	2,000	-2,000	
Incremental Wholesale Related Generation (MW.h)	0	2,174	-2,174	2,174	-2,174	2,174	-2,174	at 8.7% losses (Table 2.2 of GRA)
Incremental Diesel Generation Subject to ERA Charge (MW.h)	0	718	-788	718	-788	718	-788	
Incremental Wholesale Sales Subject to ERA Credit (MW.h)	0	661	-725	661	-725	661	-725	sales equivalent of diesel gen.
Amount paid under normal ongoing billing ($000s)	$ 24,747	$ 24,913	$ 24,581	$ 24,913	$ 24,581	$ 24,913	$ 24,581	
ERA Adjustment to be Paid (Refunded) ($000s)	$ -	$ 159	($174)	$ 159	($174)	$ 159	($174)	
Total Amount Paid after ERA	$ 24,747	$ 25,072	$ 24,407	$ 25,072	$ 24,407	$ 25,072	$ 24,407	

Note:

Calculations are to be done on a monthly basis, however in practice the adjustment and calculations would be addressed periodically (and made final based on a year-end reconciliation processes).

TOPIC: **Fuel and Purchased Power**

REFERENCE: **Table 2.2 page 2-18, Table 3.2 page 3-5**

PREAMBLE:

Yukon Electrical wishes to understand amounts arrived at for Fuel and Purchased Power.

QUESTION:

a) Please supply all data (in Excel format), actual 2009 to forecast 2013, to support the amounts used for Total Diesel MW.h, Line 14 in Table 2.2.

b) Please provide diesel fuel prices, actual 2009 to forecast 2013, to support fuel cost calculations in Table 3.2. Additionally, please provide the source of the diesel price forecasts for the 2012 and 2013 test years.

c) Please provide fuel efficiency rates, actual 2009 to forecast 2013, to support the cost calculations in Table 3.2. Please provide the source of the forecasts for the 2012 and 2013 test years.

ANSWER:

(a) through **(c)**

Please see Attachment 1 to this response for the requested information.

2012/13 GRA fuel prices are based on contract fuel prices effective February 1, 2012 as provided by North 60 Petro Ltd., a diesel fuel supplier for YEC.

Fuel efficiency forecasts for 2012 and 2013 are based on 2011 full year forecast (FYF) average fuel efficiency rates at the time of preparation of forecasts. Please note that the fuel efficiency rates for 2011 in Attachment 1 are actuals for 2011 and as such they are different than 2011 FYF fuel efficiency rates. Please see the Table 1 below for comparison 2011 FYF and actuals and Table 2 for calculation of 2011 FYF fuel efficiency.

Table 1:
Average Annual Fuel Efficiency Rates for 2011

	2011 FYF	2011 Actual
Whitehorse	3.77	3.78
Faro	3.83	3.77
Dawson	3.72	3.72
Mayo	3.37	3.35

Table 2:
Calculation of Average Annual Fuel Efficiency Rates for 2011 FYF

	2011 FYF		
	Diesel Generation (MW.h)	Fuel Consumption (thousand litres)	Fuel Efficiency
Whitehorse	6,535.3	1,732.4	3.77
Faro	1,648.0	430.4	3.83
Dawson	7,558.8	2,033.8	3.72
Mayo	533.0	158.3	3.37

Diesel Generation, Fuel Expense and Fuel Efficiency for 2009

2009 ACTUAL	FUEL EXPENSE LITRES												
Fuel Expense Litres	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	8,431	1,303	218	9,940	9,494	2,504	3,667	54,886	393	21,047	3,933	204	116,020
Mayo	0	163	51	0	0	137	0	0	306	141	0	0	798
Dawson	20,867	8,100	1,471	-1,295	205	625	6,675	2,390	78,793	18,332	650	990	137,803
Whitehorse	178,858	24,284	452	3,312	31,656	0	66,690	1,475	21,183	480	15,920	117,150	461,460
Total	208,156	33,850	2,192	11,957	41,355	3,266	77,032	58,751	100,675	40,000	20,503	118,344	716,081

2009 ACTUAL	DIESEL GENERATION (KW.h)												
Diesel Generation (KW.h)	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	36,540	8,400	2,520	31,920	31,290	7,140	9,660	193,620	2,100	78,960	7,980	3,150	413,280
Mayo	0	0	0	0	0	420	0	0	693	0	0	0	1,113
Dawson	76,555	30,681	388	148	1,234	1,087	27,315	5,580	288,420	75,974	373	916	508,671
Whitehorse	664,339	96,304	0	2,880	124,921	0	238,215	4,520	83,453	6,900	57,324	443,023	1,721,879
Total	777,434	135,385	2,908	34,948	157,445	8,647	275,190	203,720	374,666	161,834	65,677	447,089	2,644,943

2009 ACTUAL	FUEL EXPENSE DOLLARS												
Fuel Expense Dollars	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	7,358	1,081	181	8,249	7,879	2,020	2,958	43,722	313	12,596	3,141	163	89,660
Mayo	0	102	32	0	0	86	0	0	190	87	0	0	497
Dawson	20,287	7,875	1,430	-1,169	184	566	6,011	2,152	70,872	16,036	569	866	125,679
Whitehorse	144,232	19,403	359	2,553	24,206	0	52,030	1,135	16,636	377	12,508	86,574	360,013
Total	171,877	28,461	2,001	9,633	32,268	2,671	60,998	47,009	88,012	29,097	16,218	87,603	575,849

2009 ACTUAL	CENTS/LITER												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	87.28	82.99	82.99	82.99	82.99	80.65	80.65	79.66	79.66	59.85	79.86	79.86	**77.28**
Mayo	0.00	62.56	62.55	0.00	0.00	62.56	0.00	0.00	62.23	62.04	0.00	0.00	**62.34**
Dawson	97.22	97.22	97.22	90.26	89.61	90.50	90.05	90.05	89.95	87.48	87.48	87.48	**91.20**
Whitehorse	80.64	79.90	79.32	77.07	76.47	0.00	78.02	76.95	78.53	78.61	78.57	73.90	**78.02**
Total	82.57	84.08	91.31	80.56	78.03	81.78	79.19	80.01	87.42	72.74	79.10	74.02	**80.42**

2009 ACTUAL	EFFICIENCY												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	4.33	6.45	11.56	3.21	3.30	2.85	2.63	3.53	5.34	3.75	2.03	15.44	3.56
Mayo	0.00	0.00	0.00	0.00	0.00	3.07	0.00	0.00	2.26	0.00	0.00	0.00	1.39
Dawson	3.67	3.79	0.26	-0.11	6.02	1.74	4.09	2.33	3.66	4.14	0.57	0.93	3.69
Whitehorse	3.71	3.97	0.00	0.87	3.95	0.00	3.57	3.06	3.94	14.38	3.60	3.78	3.73
Total	3.73	4.00	1.33	2.92	3.81	2.65	3.57	3.47	3.72	4.05	3.20	3.78	3.69

Total Diesel Generation (Table 2.2)	2,644,943
Total Fuel Expense	575,849
Diesel Fuel Costs for Capital Work Orders	-84,930
Diesel Fuel Price Variance booked during year	123,054
Difference (heating fuel or coding issues)	8,432
Total Fuel Expense	622,406
Total Fuel Expense in Table 3.2	622,406
Difference	0

Diesel Generation, Fuel Expense and Fuel Efficiency for 2010

2010 ACTUAL	FUEL EXPENSE LITRES												
Fuel Expense Litres	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	877	2,229	3,403	-4,220	868	4,286	7,972	4,503	0	35,225	9,310	26,411	90,864
Mayo	73	242	0	0	0	0	3,429	1,138	2,320	413	9	1,724	9,348
Dawson	7,471	1,469	970	48,432	2,000	1,500	2,000	126,131	22,743	1,267	128,709	326,104	668,796
Whitehorse	37,186	11,281	0	0	6,598	4,548	66,162	61,618	10,231	38,548	11,072	413,353	660,597
Total	45,607	15,221	4,373	44,212	9,466	10,334	79,563	193,390	35,294	75,453	149,100	767,592	1,429,605

2010 ACTUAL	DIESEL GENERATION (KW.h)												
Diesel Generation (KW.h)	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	5,460	3,780	10,500	6,930	7,352	12,515	8,236	2,520	0	74,670	39,236	100,590	271,789
Mayo	0	672	0	0	48	0	10,185	3,780	10,920	840	0	7,560	34,005
Dawson	27,500	3,168	558	198,842	7,419	2,941	4,871	471,886	74,586	708	479,163	1,132,497	2,404,139
Whitehorse	139,840	34,253	0	1,020	11,256	10,680	268,156	233,120	33,182	94,681	33,718	1,557,388	2,417,294
Total	172,800	41,873	11,058	206,792	26,075	26,136	291,448	711,306	118,688	170,899	552,117	2,798,035	5,127,227

2010 ACTUAL	FUEL EXPENSE DOLLARS												
Fuel Expense Dollars	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	700	1,780	2,718	-3,381	720	3,474	6,462	3,683	0	29,984	7,985	22,972	77,096
Mayo	45	151	0	0	0	0	2,134	708	1,444	315	7	1,314	6,117
Dawson	6,561	1,290	852	43,303	1,359	1,358	1,801	113,581	20,208	1,126	118,620	309,649	619,706
Whitehorse	30,918	9,379	0	0	5,485	3,781	55,268	51,471	8,546	32,200	9,676	369,248	575,973
Total	38,224	12,600	3,569	39,922	7,564	8,612	65,664	169,443	30,198	63,625	136,288	703,183	1,278,893

2010 ACTUAL	CENTS/LITER												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	79.86	79.86	79.86	80.12	82.90	81.04	81.05	81.78	0.00	85.12	85.77	86.98	**84.85**
Mayo	62.22	62.23	0.00	0.00	0.00	0.00	62.23	62.22	62.23	76.23	76.22	76.23	**65.44**
Dawson	87.82	87.82	87.79	89.41	67.95	90.50	90.05	90.05	88.85	88.85	92.16	94.95	**92.66**
Whitehorse	83.14	83.14	0.00	0.00	83.14	83.14	83.53	83.53	83.54	83.53	87.39	89.33	**87.19**
Total	83.81	82.78	81.62	90.30	79.91	83.34	82.53	87.62	85.56	84.32	91.41	91.61	**89.46**

2010 ACTUAL	EFFICIENCY												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	6.23	1.70	3.09	-1.64	8.47	2.92	1.03	0.56	0.00	2.12	4.21	3.81	2.99
Mayo	0.00	2.78	0.00	0.00	0.00	0.00	2.97	3.32	4.71	2.03	0.00	4.39	3.64
Dawson	3.68	2.16	0.58	4.11	3.71	1.96	2.44	3.74	3.28	0.56	3.72	3.47	3.59
Whitehorse	3.76	3.04	0.00	0.00	1.71	2.35	4.05	3.78	3.24	2.46	3.05	3.77	3.66
Total	3.79	2.75	2.53	4.68	2.75	2.53	3.66	3.68	3.36	2.26	3.70	3.65	3.59

Total Diesel Generation (Table 2.2)	5,127,227
Total Fuel Expense	1,278,893
Diesel Fuel Costs for Capital Work Orders	-229,559
Diesel Fuel Price Variance booked during	111,348
Difference (heating fuel or coding issues)	-16,158
Total Fuel Expense	1,144,523
Total Fuel Expense in Table 3.2	1,144,523
Difference	0

Diesel Generation, Fuel Expense and Fuel Efficiency for 2011

2011 ACTUAL	FUEL EXPENSE LITRES												
Fuel Expense Litres	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	38,042	33,964	37,370	6,184	3,262	65,248	840	449	52,816	166,191	26,030	7,969	438,365
Mayo	0	38	200	44,695	9,941	5,110	1,688	43,808	10,540	42,304	0	2,359	160,683
Dawson	320,245	155,887	354,553	370,850	151,943	85,535	73,046	30,500	13,321	241,302	116,327	15,473	1,928,982
Whitehorse	245,082	158,664	451,846	28,081	46,406	127,898	67,984	67,717	62,940	422,639	53,147	4,953	1,737,357
Total	603,369	348,553	843,969	449,810	211,552	283,791	143,558	142,474	139,617	872,436	195,504	30,754	4,265,387

2011 ACTUAL	DIESEL GENERATION (KW.h)												
Diesel Generation (KW.h)	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	145,320	87,576	105,420	27,853	8,244	254,100	3,150	840	50,190	853,800	111,530	6,300	1,654,323
Mayo	0	0	420	174,510	37,380	14,490	6,510	99,750	39,900	160,020	0	6,090	539,070
Dawson	1,281,792	754,311	1,330,021	1,423,903	590,192	132,456	94,355	111,975	52,187	912,234	429,216	57,826	7,170,468
Whitehorse	940,369	582,235	1,710,095	92,902	177,913	623,709	138,796	243,250	247,733	1,583,657	194,689	35,640	6,570,988
Total	2,367,481	1,424,122	3,145,956	1,719,168	813,729	1,024,755	242,811	455,815	390,010	3,509,711	735,435	105,856	15,934,849

2011 ACTUAL	FUEL EXPENSE DOLLARS												
Fuel Expense Dollars	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	34,239	31,266	36,957	6,230	3,286	68,446	881	471	56,091	180,427	28,335	9,183	455,813
Mayo	0	29	152	42,621	10,116	5,200	1,729	44,602	10,731	46,767	0	2,608	164,555
Dawson	308,400	156,392	378,475	404,994	168,003	77,409	65,778	27,465	15,369	275,714	119,694	18,663	2,016,357
Whitehorse	221,234	147,443	452,003	28,268	47,344	131,319	71,121	68,380	63,954	434,900	55,043	5,143	1,726,151
Total	563,873	335,131	867,587	482,113	228,749	282,374	139,509	140,918	146,145	937,808	203,072	35,597	4,362,876

2011 ACTUAL	CENTS/LITER												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	90.00	92.06	98.89	100.74	100.74	104.90	104.90	104.90	106.20	108.57	108.86	115.23	**103.98**
Mayo	0.00	76.24	76.23	95.36	101.76	101.76	102.44	101.81	101.81	110.55	0.00	110.55	**102.41**
Dawson	96.30	100.32	106.75	109.21	110.57	90.50	90.05	90.05	115.38	114.26	102.89	120.61	**104.53**
Whitehorse	90.27	92.93	100.03	100.66	102.02	102.67	104.61	100.98	101.61	102.90	103.57	103.84	**99.36**
Total	93.45	96.15	102.80	107.18	108.13	99.50	97.18	98.91	104.68	107.49	103.87	115.75	**102.29**

2011 ACTUAL	EFFICIENCY												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	3.82	2.58	2.82	4.50	2.53	3.89	3.75	1.87	0.95	5.14	4.28	0.79	3.77
Mayo	0.00	0.00	2.10	3.90	3.76	2.84	3.86	2.28	3.79	3.78	0.00	2.58	3.35
Dawson	4.00	4.84	3.75	3.84	3.88	1.55	1.29	3.67	3.92	3.78	3.69	3.74	3.72
Whitehorse	3.84	3.67	3.78	3.31	3.83	4.88	2.04	3.59	3.94	3.75	3.66	7.20	3.78
Total	3.92	4.09	3.73	3.82	3.85	3.61	1.69	3.20	2.79	4.02	3.76	3.44	3.74

Total Diesel Generation (Table 2.2)	15,934,849
Total Fuel Expense	4,362,876
Diesel Fuel Costs for Capital Work Orders	-1,372,223
Diesel Fuel Price Variance booked during	-249,579
Difference (heating fuel or coding issues)	-32,831
Total Fuel Expense	2,708,243
Total Fuel Expense in Table 3.2	2,708,243
Difference	0

Diesel Generation, Fuel Expense and Fuel Efficiency Forecast for 2012

2012 Forecast	FUEL EXPENSE LITRES												
Fuel Expense Litres	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	51,737	51,737	83,198	0	0	0	3,952	3,952	0	0	51,737	51,737	298,051
Mayo	0	0	0	0	0	0	0	0	0	0	0	0	0
Dawson	117,661	117,661	189,209	0	0	0	8,988	8,988	0	0	117,661	117,661	677,829
Whitehorse	178,559	178,559	287,139	0	0	0	13,641	13,641	0	0	178,626	178,626	1,028,791
Total	347,957	347,957	559,546	0	0	0	26,582	26,581	0	0	348,024	348,024	2,004,671

2012 Forecast	DIESEL GENERATION (KW.h)												
Diesel Generation (KW.h)	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	198,153	198,153	318,648	0	0	0	15,138	15,138	0	0	198,153	198,153	1,141,535
Mayo													0
Dawson	437,698	437,698	703,857	0	0	0	33,437	33,437	0	0	437,698	437,698	2,521,525
Whitehorse	673,169	673,168	1,082,515	0	0	0	51,425	51,425	0	0	673,419	673,419	3,878,541
Total	1,309,020	1,309,020	2,105,020	0	0	0	100,000	100,000	0	0	1,309,270	1,309,270	7,541,600

2012 Forecast	FUEL EXPENSE DOLLARS												
Fuel Expense Dollars	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	56,316	56,316	90,561	0	0	0	4,302	4,302	0	0	56,316	56,316	324,428
Mayo	0	0	0	0	0	0	0	0	0	0	0	0	0
Dawson	131,404	131,404	211,309	0	0	0	10,038	10,038	0	0	131,404	131,404	757,000
Whitehorse	187,719	187,719	301,869	0	0	0	14,340	14,340	0	0	187,789	187,789	1,081,568
Total	375,439	375,439	603,739	0	0	0	28,681	28,681	0	0	375,509	375,509	2,162,996

2012 Forecast	CENTS/LITER												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	**108.85**
Mayo	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	**0.00**
Dawson	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	**111.68**
Whitehorse	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	**105.13**
Total	107.90	107.90	107.90	0.00	0.00	0.00	107.90	107.90	0.00	0.00	107.90	107.90	**107.90**

2012 Forecast	EFFICIENCY												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83
Mayo	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	NA
Dawson	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72
Whitehorse	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77
Total	3.76	3.76	3.76	0.00	0.00	0.00	3.76	3.76	0.00	0.00	3.76	3.76	3.76

Total Diesel Generation (Table 2.2)	7,541,600
Total Fuel Expense Forecast	2,162,996
Total Fuel Expense Forecast in Table 3.2	2,162,996
Difference	0

Diesel Generation, Fuel Expense and Fuel Efficiency Forecast for 2013

2013 Forecast	FUEL EXPENSE LITRES												
Fuel Expense Litres	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	75,136	75,136	115,016	0	0	0	3,952	3,952	0	0	75,136	75,136	423,465
Mayo	0	0	0	0	0	0	0	0	0	0	0	0	0
Dawson	170,875	170,875	261,569	0	0	0	8,988	8,988	0	0	170,875	170,875	963,047
Whitehorse	259,316	259,317	396,951	0	0	0	13,641	13,641	0	0	259,341	259,341	1,461,548
Total	505,328	505,328	773,535	0	0	0	26,582	26,581	0	0	505,353	505,353	2,848,061

2013 Forecast	DIESEL GENERATION (KW.h)												
Diesel Generation (KW.h)	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	287,772	287,772	440,509	0	0	0	15,138	15,137	0	0	287,772	287,772	1,621,872
Mayo													0
Dawson	635,656	635,656	973,037	0	0	0	33,437	33,437	0	0	635,656	635,656	3,582,536
Whitehorse	977,623	977,623	1,496,505	0	0	0	51,426	51,425	0	0	977,717	977,717	5,510,036
Total	1,901,051	1,901,052	2,910,051	0	0	0	100,000	100,000	0	0	1,901,145	1,901,145	10,714,444

2013 Forecast	FUEL EXPENSE DOLLARS												
Fuel Expense Dollars	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	81,786	81,786	125,194	0	0	0	4,302	4,302	0	0	81,786	81,786	460,942
Mayo	0	0	0	0	0	0	0	0	0	0	0	0	0
Dawson	190,834	190,834	292,120	0	0	0	10,038	10,038	0	0	190,834	190,834	1,075,531
Whitehorse	272,619	272,619	417,315	0	0	0	14,340	14,340	0	0	272,646	272,646	1,536,526
Total	545,239	545,239	834,629	0	0	0	28,681	28,681	0	0	545,265	545,265	3,072,999

2013 Forecast	CENTS/LITER												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	108.85	**108.85**
Mayo	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	109.66	**0.00**
Dawson	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	111.68	**111.68**
Whitehorse	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	105.13	**105.13**
Total	107.90	107.90	107.90	0.00	0.00	0.00	107.90	107.90	0.00	0.00	107.90	107.90	**107.90**

2013 Forecast	EFFICIENCY												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Faro	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83
Mayo	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	NA
Dawson	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72
Whitehorse	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77
Total	3.76	3.76	3.76	0.00	0.00	0.00	3.76	3.76	0.00	0.00	3.76	3.76	3.76

Total Diesel Generation (Table 2.2)	10,714,444
Total Fuel Expense Forecast	3,072,999
Total Fuel Expense Forecast in Table 3.2	3,072,999
Difference	0

TOPIC: **2.0 YUKON ENERGY SYSTEM SALES AND GENERATION**

REFERENCE: **Lines 20-24 Page 2-1, "For example, 2011 resource planning forecast grid non-industrial growth at 2.26%/year, which was higher than the 1.85%/year forecast in the 2006 Resource Plan; furthermore, growth is presently tending to exceed the 2011 resource planning forecast. This growth reflects overall Yukon economic expansion plus other factors such as an apparent increase in reliance on electric heat."**

PREAMBLE:

Yukon Electrical is interested to know about the latest resource plan.

QUESTION:

a) Has the resource plan been updated? If so, please provide the resource plan. If not, please advise when the next resource plan is forecasted to be prepared.

ANSWER:

(a)

Yes. A copy of the Overview of the 20-Year Resource Plan: 2011-2030 is provided as Attachment 1 to this response. A summary and the more comprehensive Overview of a draft of Yukon Energy's latest 20-year resource plan is available as follows on Yukon Energy's web site.

http://www.yukonenergy.ca/news/releases/archive/117/

Dates for the public meetings to get Yukoners' feedback on the draft plan can be found on this page:

http://www.yukonenergy.ca/about/business/resourceplans/

Copies of the full draft 2011 Resource Plan and related materials will be provided on Yukon Energy's web site as soon as these are available.



YUKON ENERGY CORPORATION

OVERVIEW OF 20-YEAR RESOURCE PLAN: 2011-2030

July 2012

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INTRODUCTION

Yukon Energy's 2011 Resource Plan addresses generation and transmission priorities in Yukon for the 20-year planning period (2011-2030), focusing on:

- Resource options for implementation over the first five years (2011-2015); and
- Planning activities for implementation during the first five years to protect longer-term legacy resource development options for potential start of construction before or after 2021.

The 2011 Resource Plan updates the review of overall planning priorities and options as last provided in the 2006 Resource Plan. It was drafted in late 2011 based on then available information. Overall load forecasts and analysis of specific project options are subject to ongoing updates. As reviewed in the 2006 Resource Plan, several additional planning stages are required beyond the Resource Plan prior to any Yukon Energy decision to proceed with construction for any preferred project[1].

The Overview summarizes the 2011 Resource Plan document. Where relevant, the Overview also notes more recent information that may modify the earlier analysis.

Background on 2011 Resource Plan Process

The first activity Yukon Energy undertook preparing this latest 20-year resource plan was to seek input from First Nations and other governments, stakeholders and the public through meetings, workshops and a three-day energy planning charette held in March 2011.

The charette brought together Yukoners from all walks of life along with nationally and intentionally-recognized energy experts. Information and knowledge was shared and the participants provided a great deal of input in terms of what Yukon's energy future should look like.

Dr Mark Jaccard led off the proceedings by clarifying his experience regarding energy planning and urged participants to thoughtfully consider all of the choices available and to examine the alternatives from the point of view that all options have impacts and risks and all require trade-offs.

[1] Subsequent planning stages include: the final feasibility assessment, costing, design and contract arrangements (and related tendering to obtain final estimated costs); consultation with First Nations and others; all required external reviews, approvals and agreements (includes where relevant YESAB, DFO, YWB and other regulatory authorities as required, as well as seeking YUB review of near-term projects over $3 million).

Dr. Jaccard also talked to the gathering about how we determine and provide affordable energy:

- What role energy has in economic development;
- Future demand and supply; and
- The need to examine multiple objectives.

Along with providing a list of potential energy options that required further investigation and analysis, the charrette participants also helped Yukon Energy formulate four principles around which to base future energy decisions. They include:

- Reliability;
- Affordability;
- Flexibility; and
- Environmental Responsibility.

With these four principles as the lens through which all possible energy options were considered, Yukon Energy prepared later in 2011 a draft of a new 20-year resource plan that is summarized in this Overview for Yukoners to review.

Yukon Energy recognizes that the 2011 Resource Plan, as with its predecessor, is a living document that continues to evolve.

Yukon Energy has continued in fall 2011 and 2012 to date, for example, to hold workshops to examine in more detail specific resource options, including waste to energy, biomass, liquefied natural gas, and energy conservation. As noted in this Overview, new load forecast scenarios have also been developed since the draft 2011 Resource Plan to reflect updated information.

Yukon Energy will continue to use the draft 2011 Resource Plan to frame priorities and options for ongoing new assessments and analysis, without going back to amend or revise the draft as prepared in 2011.

All papers, reports, presentations and records from the energy charrette and workshops have been made available to the public on Yukon Energy's web site.

Outline of Overview

The Overview summarizes the 2011 Resource Plan as follows:

- Current Challenges and Opportunities;
- Background on Yukon Power System;
- Future Yukon Power Requirements – Overview;
- Range of Resource Supply Options;
- Yukon Utilities – Default Diesel Portfolio Requirements;
- Near-Term Resource Options to Default Diesel;
- Longer-Term Resource Options to Default Diesel; and
- Summary Conclusions & Recommended Plans.

The Overview summarizes the 2011 Resource Plan as drafted in late 2011. Where relevant, the Overview also notes more recent information that may modify the earlier analysis. Updated load forecasts that Yukon Energy is currently using, for example, are provided in the Appendix A. Ongoing examination of specific resource options continues, using updated information and analysis as required.

Yukon Energy will review the Overview and draft 2011 Resource Plan with the public, and report on the results of this review, including any resulting adjustments to recommended plans for ongoing priority attention.

1.0 CURRENT CHALLENGES AND OPPORTUNITIES

Unprecedented growth is expected in Yukon-wide electricity requirements over the next decade, creating new generation challenges:

- **Near-Term Challenges** – To move quickly to meet new grid energy requirements emerging today with options that cost materially less than diesel generation while continuing the planning needed to develop longer-term Yukon power resources.
- **Longer-Term Opportunities** – Development as soon as feasible in future of hydro and other Yukon power resources to supply growing Yukon loads with reduced costs and emissions.

The 2011 Resource Plan assesses resource options in the context of current forecasts for overall Yukon energy and capacity requirements (i.e., off-grid as well as on-grid for all major power loads), agreed upon resource planning principles[2], and the assumption that Yukon Energy is proceeding with a robust and aggressive Demand Side Management/Supply Side Enhancement (DSM/SSE) program in response to Yukon Utilities Board Directives, government policy considerations and stakeholder comments.

Key challenges related to new generation requirements in Yukon include:

- **Higher Costs** – Higher costs to secure safe and reliable new resource supplies from utility operations on or off the grid will increase rates throughout Yukon. Electricity prices in Yukon today are relatively low due to legacy hydro. On Yukon's isolated grid, planning and capital costs are borne by ratepayers (no opportunity to 'overbuild' and sell to another market).
- **Higher Greenhouse Gas ("GHG") Emissions** – Higher GHG emissions from increased electricity generation in Yukon on and off the grid (including utility and non-utility operations) will challenge Yukon's ability to secure overall GHG emission reductions.
- **Flexibility Required** – The isolation of Yukon's electrical system requires flexibility to address a wide range of challenges, including: seasonal variations in loads and existing hydro generation; annual changes in grid hydro generation due to varying water conditions; development and/or shut down of major mine loads; and potential changes in competitive generation option costs due to new resource supplies becoming available (e.g., development of accessible natural gas in Yukon).

[2] The four key planning principles agreed to by the March 2011 Energy Charrette participants are reliability, affordability, flexibility and environmental responsibility.

2.0 BACKGROUND ON YUKON POWER SYSTEM

Yukon's centres continue to have residential and commercial electric rates that are lower than other northern centres in Canada, reflecting extensive reliance on low cost legacy hydro generation.

Figure 2-1 provides a map of existing power infrastructure, active and potential mine developments, the potential Alaska Highway Pipeline, and future power supply options in Yukon over the planning period. Areas within a 50 km boundary from the current and potential future electric grids are identified (based on the current southern highway structure).

Current and committed generation capacity in Yukon includes approximately 138 MW of installed generation on the integrated grid (approximately 92 MW YEC hydro, 0.8 MW YEC wind, 37 MW YEC diesel, 1.3 MW YECL hydro, and 6.8 MW of YECL diesel) and 8.4 MW of diesel generation in five separate off-grid diesel-served communities supplied by YECL (5.3 MW in Watson Lake, 2.0 MW in three Small Diesel zone communities along the Alaska Highway, and 1.1 MW in Old Crow).

The current integrated Yukon grid reflects material Yukon Energy developments since the 2006 Resource Plan, including completion in 2011 of the Carmacks-Stewart Transmission Project to connect the Whitehorse-Aishihik-Faro (WAF) grid and the Mayo-Dawson (MD) grid, expansion of Mayo hydro capacity from 5 to 15 MW (Mayo B project), and the 7 MW enhancement of the Aishihik hydro facility. As a result of substantial federal and Yukon funding contributions, in 2012 these new grid power assets are already yielding ratepayer cost savings due to displacement of otherwise required costly diesel generation.

Grid capacity planning is required to not exceed a Loss of Load Expectation (LOLE) of 2 hours per year and, for non-industrial loads, to provide capacity adequate to accommodate loss of the system's largest generating or transmission-related generation resource (the "N-1" standard). Current capacity planning also provides for sufficient winter peak capacity reserve to accommodate loss of the Aishihik transmission line connection to Whitehorse.

Off-grid mine development has recently commenced at the Wolverine mine located south east of Ross River. The 2011 Resource Plan highlights many other potential off-grid mine developments over the next decade (locations for these projects are noted on Figure 2-1).

Figure 2-1: Existing Yukon Power Infrastructure, Potential Supply Options, and Active & Potential Mine Loads

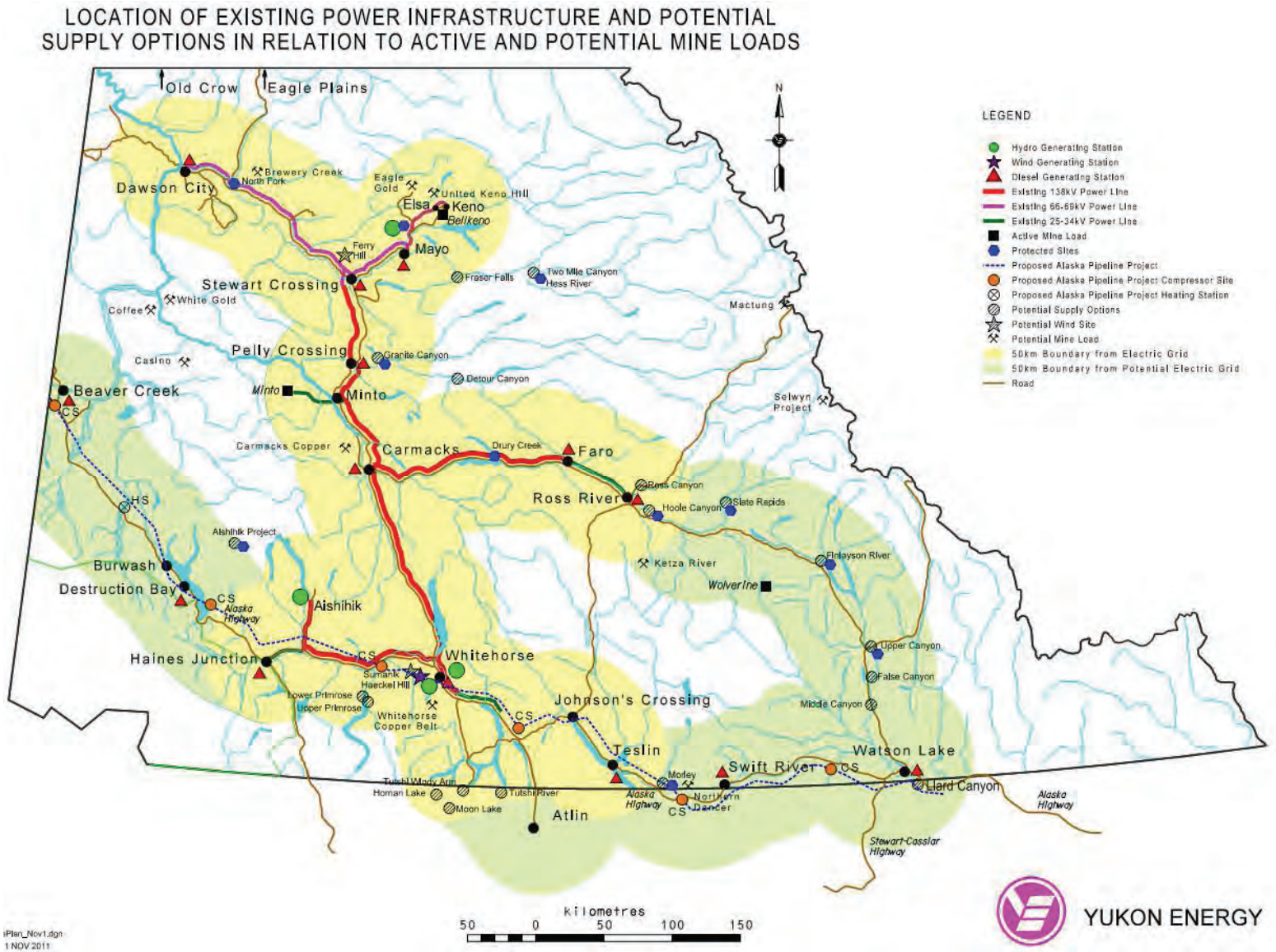
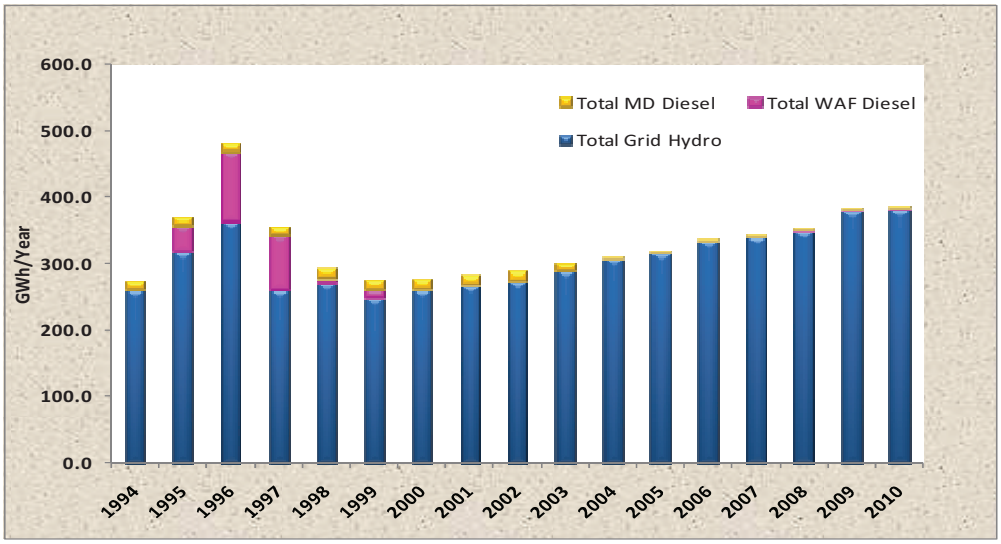


Figure 2-2 reviews historical power generation (1995-2010) by source for the WAF and MD grids. The following load changes are highlighted over this period:

- WAF – Faro mine closure in 1998 (82-100 GW.h/yr diesel immediately before shut down; no material diesel needed after shut down, except for low water year of 1999).
- WAF – Load growth since 1998 to the point that diesel generation starting to be needed again (impacts of non-industrial load growth plus recent Minto mine connection).
- Mayo Dawson – Grid expansion (15 GW.h/yr diesel reduction) – now connected to WAF.

Figure 2-2: Yukon Grid Generation – 1995-2010 (GW.h/year)

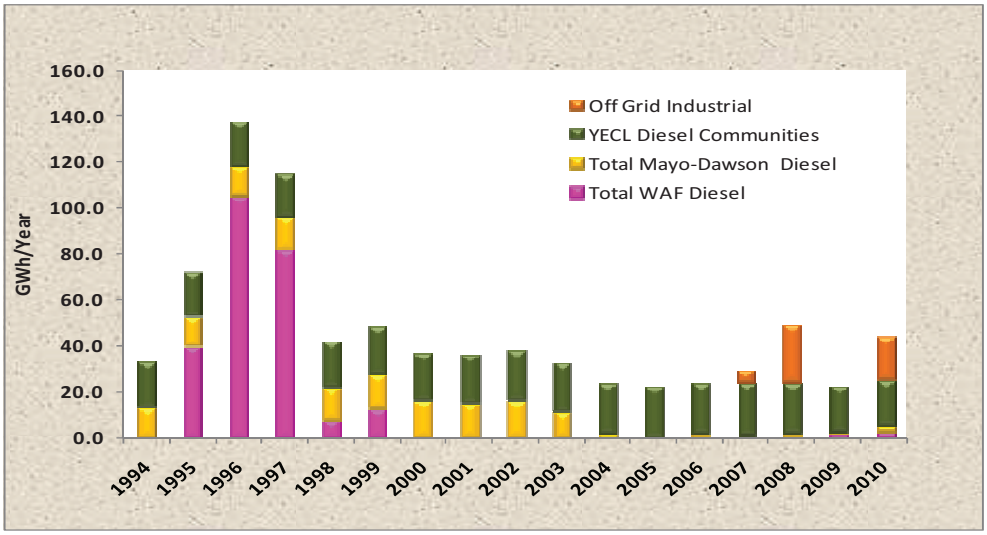


Grid Generation by Source (GW.h/year)	1995	1996	1997	1998	2000	2003	2005	2009	2010
Total Grid Hydro & Wind (Incl Fish Lake)	317.5	362.3	259.6	270.3	259.5	288.3	315.5	379.3	380.5
Total WAF Diesel	39.5	104.6	81.8	7.2	0.7	0.3	0.1	2.1	2.7
Total Mayo Dawson Diesel	12.9	13.6	14.0	14.6	15.3	11.1	0.5	0.5	2.4
Total WAF & MD Diesel	52.4	118.1	95.9	21.8	16.0	11.4	0.6	2.6	5.1
Total WAF & MD Generation	**369.9**	**480.4**	**355.5**	**292.1**	**275.5**	**299.6**	**316.1**	**381.9**	**385.6**

Figure 2-3 reviews historical (1995-2010) annual diesel generation and GHG emissions for the grid and off-grid loads. The following load changes are highlighted over this period:

- After closure of the Faro mine in 1998, off-grid communities accounted for almost all of the Yukon diesel generation.
- Off-grid Diesel Communities – YECL communities today at about 20 GW.h/yr (approximately 70.5% in Watson Lake).
- Off-grid Industrial – No off-grid mine loads until Wolverine in 2010 (19 GW.h that year).

Figure 2-3: Yukon Grid & Off-Grid Diesel Generation – 1995-2010 (GW.h/year)



Diesel Generation (GW.h/year)	1995	1996	1997	1998	2000	2005	2008	2009	2010
Total WAF Diesel Generation	39.5	104.6	81.8	7.2	0.7	0.1	1.2	2.1	2.7
Total MD Diesel Generation	12.9	13.6	14.0	14.6	15.3	0.5	0.4	0.5	2.4
Off Grid YECL Diesel Communities	20.0	19.2	19.1	20.0	21.0	21.8	22.1	19.8	19.8
Off-Grid Industrial	0	0	0	0	0	0	25	0	19
Total Yukon Diesel Generation	**72.4**	**137.4**	**114.9**	**41.8**	**37.0**	**22.4**	**48.7**	**22.4**	**43.9**

*OffGrid Indusrial sales in 2007 and 2008 relate to estimates (not actuals) for Minto mine prior to interconnection with WAF grid.

GHG Emissions (tonnes/year)	1995	1996	1997	1998	2000	2005	2008	2009	2010
GHGs WAF	27,668	73,189	57,283	5,039	510	80	850	1,495	1,882
GHG's Mayo Dawson	8,996	9,489	9,833	10,222	10,708	326	314	357	1,707
GHG's Off Grid Communities & Industrial	14,020	13,472	13,337	14,009	14,674	15,265	15,446	13,827	27,137
Total Yukon GHG's	**50,684**	**96,150**	**80,453**	**29,271**	**25,892**	**15,671**	**16,609**	**15,679**	**30,726**

3.0 FUTURE YUKON POWER REQUIREMENTS – OVERVIEW

Overall, forecast Yukon power requirements highlight the extent to which off-grid mine loads are expected to grow and dwarf grid loads within the next 5 to 10 years. To the extent this occurs, a fundamental shift will occur in Yukon power generation – affecting near-term opportunities for new fuel or other resource supply development options, ongoing Yukon GHG emissions, and potential options for future grid expansion concurrent with development of new longer-term legacy supply options in Yukon.

Figure 3-1 shows potential off-grid mine loads over a longer-term 40 year period (2011-2050) as projected in the 2011 Resource Plan. These off-grid mine loads are forecast to grow rapidly, surpassing grid loads as soon as the 2015-2020 time period, potentially exceeding 1,500 GW.h/year by 2020, and potentially continuing at over 1,300 GW.h/year for more than 20 years (beyond 2040) for new mines such as Casino, Selwyn and Northern Dancer. Off-grid projects are currently expected to rely upon diesel or LNG resource supply options for on-site power generation.

Figure 3-1 also shows over this same 40-year period (2011-2050) the existing Yukon grid system capability to supply potential grid loads as projected in the 2011 Resource Plan. Highlights from this figure include:

- Non-industrial grid load is projected in the 2011 Resource Plan to grow after 2010 at an annual rate of 2.26% based on recent trends[3].
- Grid connected mine loads are assumed in the 2011 Resource Plan to include Minto and Alexco (which are currently connected to the grid) plus Whitehorse Copper Tailings (assumed to be connected in 2013), Victoria Gold (assumed in the 2011 planning to be connected in late 2013) and Carmacks Copper (assumed in the 2011 planning to be connected in late 2014)[4].

[3] The 2011 Resource Plan forecasts were prepared using 2010 actual results and do not reflect current YEC forecasts for 2012 and 2013 based on more recent information. Based on current forecasts through 2013 and 2.26% annual growth thereafter (and grid loss now assumed at 8.7%), grid non-industrial loads would be about 7.7 GW.h/yr higher in 2015 than projected in the earlier 2011 Resource Plan (with similar increases for subsequent years). See Appendix A to this Overview for current load forecasts.

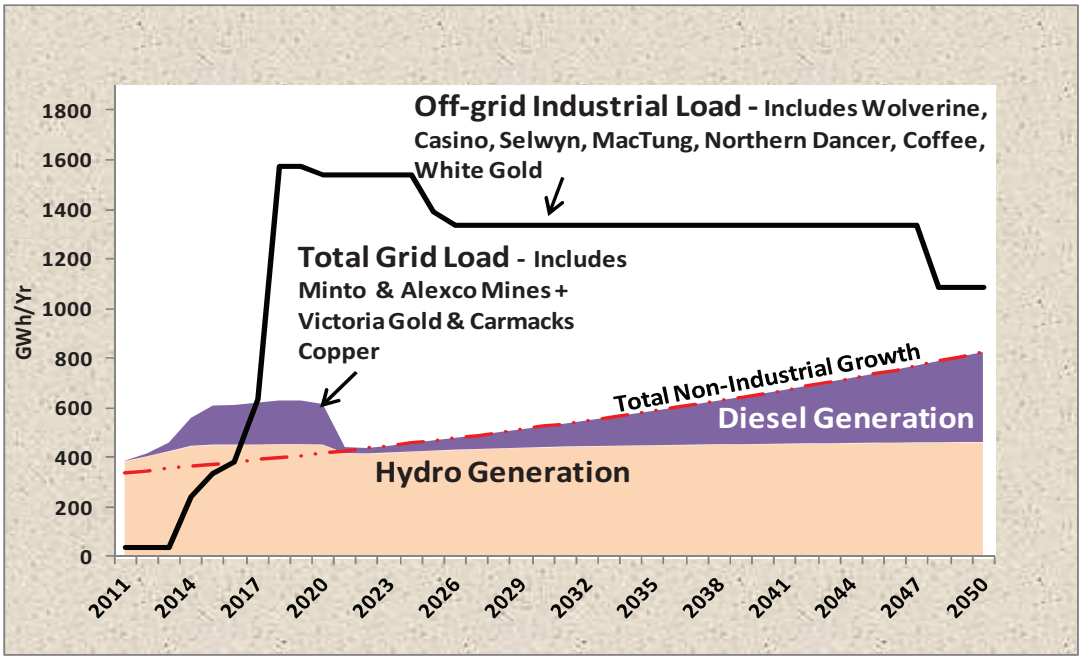
[4] Changes in expected grid mine load forecasts since the 2011 Resource Plan forecasts were prepared include: Minto load growth occurring later in 2012; somewhat lower Alexco loads and higher Whitehorse Copper Tailings mine loads by 2014; delay in connection of Victoria Gold load until start of 2015 and expectation that this load will peak in summer and extend for a longer life than the seven years assumed earlier. No specific timing is currently forecast for Carmacks Copper mine connection to the grid, although the mine's developer (Copper North Mining Corp.) has recently announced (April 26, 2012) plans to submit a proposal to YESAB in Q3, 2012 based on design changes for the plans for development and closure of the project, and expects to submit plans for the Quartz Mining Licence amendment, revised Closure Plan, and a new Water Use Licence application immediately thereafter. Other potential future mine connections to the grid include Brewery Creek (potentially starting in 2013), Rau Gold and Ketza River.

- Forecast grid diesel generation reflects the extent to which forecast grid loads exceed long-term average generation from existing and committed grid hydro and wind generation[5].
    - Assuming no new resource supply developments, forecast grid diesel generation requirements exceed 150 GW.h/yr (2015-2020) with Victoria Gold and Carmacks Copper.
    - Grid mine loads are forecast in Figure 3-1 to stop by the early 2020s; thereafter, ongoing diesel growth reflects only non-industrial growth; in light of this impact, the 2011 Resource Plan tests the sensitivity of new resource options to different potential extensions of related grid diesel requirements to 2025 and 2030.

The 2011 Resource Plan forecasts as highlighted in Figure 3-1 were used in the initial 2011 analysis, as summarized in this Overview, to provide the initial assessment of overall options and priorities. However, expected grid mine loads continue to evolve. Mine and non-industrial grid load forecasts have been updated for the 2012/2013 Yukon Energy General Rate Application filed in April 2012 - and based on this information, updated near-term grid load forecasts have been prepared (see Appendix A to this Overview). These updates assist in ongoing near-term planning for specific new resource project options.

[5] In these assessments, long-term average annual generation capability is assumed for existing hydro and wind resources (annual hydro generation capability is adjusted as required to reflect higher capability at higher annual grid load levels).

Figure 3-1: Existing System Capability to Supply Potential Grid Load & Potential Off-Grid Mine Loads: 2011-2050[6] Excludes DSM/SSE - 2011 Resource Plan



***Scenario B - Base Case Load Forecast with Victoria Gold, Carmacks Copper & WHCT**

	2011*	2015	2020	2025	2030	2035	2040	2045	2050
Grid Load/Hydro Supply Gap**	2	158	163	40	83	138	204	278	364
(Forecast Diesel Generation-GW.h/yr)									
Potential Off Grid Mines	37	332	1,538	1,390	1,338	1,338	1,338	1,338	1,088
(Forecast Diesel or LNG*** GW.h/yr)									
Total Yukon Diesel or LNG Generation (GWh/yr)	39	490	1,701	1,430	1,421	1,476	1,541	1,616	1,451
Total Potential GHG's (tonnes)	**26,962**	**343,073**	**864,118**	**674,435**	**667,793**	**706,413**	**752,282**	**804,481**	**689,306**

* 2011 diesel generation is based on long term forecast (not actuals)

** Assumes connection of Carmacks Copper and Victoria Gold to grid

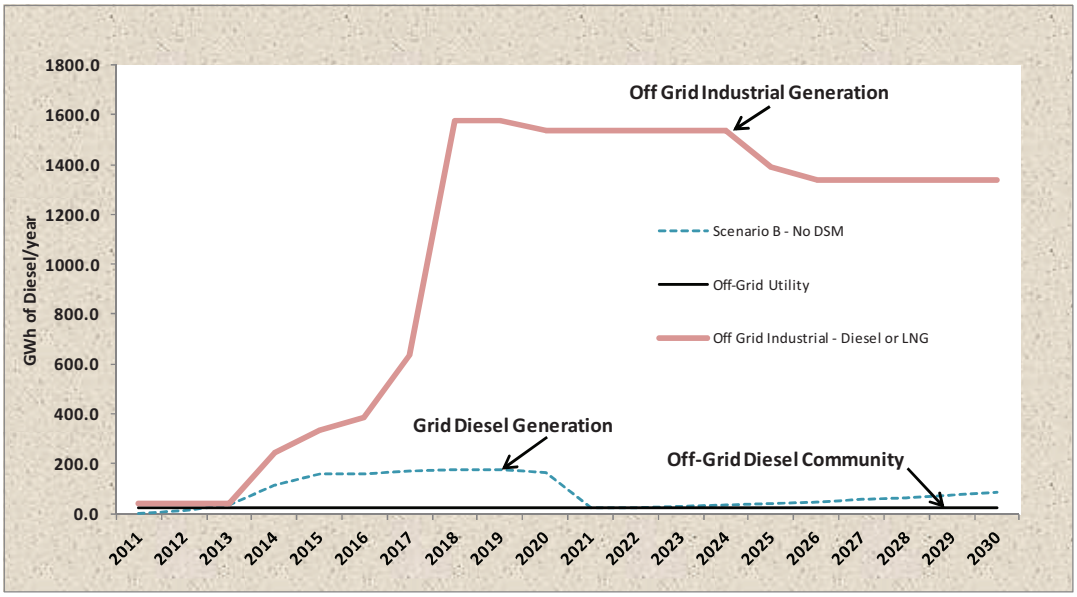
***Assumes Casino develops using LNG with combined cycel power generation & other off grid mines develop using diesel

Figure 3-2 shows non-renewable generation during the 20-year planning period (2011-2030) for all grid and off-grid loads (forecast off-grid diesel community generation and potential off-grid mine diesel) with an accompanying table showing related GHG emissions. The figure and table further highlight the extent to which potential off-grid mine diesel or LNG generation could dwarf grid diesel generation by as soon as 2018-2019.

[6] Potential Alaska Highway Pipeline Project compressor station power loads not included in the above figure could potentially add 1,470 GW.h/year of additional equivalent energy requirements (six compressor stations). Forecasts prepared in 2011 noted that this could occur by approximately 2020/21 and be sustained over 25 years in the event that GHG emissions initiatives support electrification initiatives. Ongoing events in 2012 suggest that this project may be materially delayed.

As noted above, forecast grid diesel generation reflects the extent to which forecast grid loads exceed long-term average generation from existing and committed grid hydro and wind generation. Absent DSM/SSE and new mine loads connected to the grid after forecast mine loads end, Figure 3-2 indicates that on-grid diesel generation is forecast to grow from being minimal in 2011 to 40 GW.h by 2025, i.e., almost twice as large as the off-grid diesel community generation. Continuation of recent non-industrial grid load growth is forecast (without DSM/SSE) to result in 83 GW.h of grid diesel generation by 2030.

Figure 3-2: Total Yukon Non-Renewable Generation (Grid & Off-Grid): 2011-2030
Excludes DSM/SSE - 2011 Resource Plan



Diesel* Energy Requirement	2011	2015	2020	2025	2030
Grid Diesel (YEC - Scenario B-no DSM/SSE)					
Diesel Generation (GW.h)	1.5	158.1	163.3	40.3	82.8
GHG Emissions (tonnes)	1,062	110,673	114,304	28,220	57,979
Off Grid Diesel Communities (YECL)					
Diesel Generation (GW.h)	19.9	20.4	20.9	21.5	22.1
GHG Emissions (tonnes)	13,936	14,247	14,644	15,053	15,473
Potential Off Grid Mine Diesel* (GWh)					
Diesel Generation (GW.h)	37.0	332.0	1,537.8	1,389.8	1,337.8
GHG Emissions (tonnes)	25,900	232,400	749,814	646,214	609,814
Total Yukon					
Diesel Generation (GW.h)	58.4	510.5	1,722.0	1,451.6	1,442.7
GHG Emissions (tonnes)	40,898	357,320	878,763	689,487	683,266

* Includes LNG for Casino mine

4.0 RANGE OF RESOURCE SUPPLY OPTIONS

The 2011 Resource Plan identifies and assesses near-term (i.e., can be committed before 2015) as well as longer-term (i.e., can start construction before 2021) resource options in Yukon. Table 4-1 provides an overview of resource options considered at Yukon Energy's March 2011 Charrette.

- **Near-term options** are identified, i.e., potentially available to start construction before 2015. In addition to diesel and DSM/SSE, these include the following resource options:
    - Hydro enhancements – Limited potential added supply from Mayo Lake storage[7], Marsh Lake storage, Aishihik licencing, Gladstone Diversion (cannot meet timing for short-term).
    - Thermal-Biomass – Wood biomass has potentially large supplies, relative to near-term needs (10 to 25 MW); municipal waste-to-energy (WTE) for up to 2.2 MW.
    - Thermal-LNG – Liquid natural gas (LNG) from BC gas source (potentially unlimited supply relative to Yukon needs over the planning period).
    - Wind – Ferry Hill or Mount Sumanik opportunities (up to 21 MW and about 56 GW.h/yr)
- **Longer-term options** are screened into the "hydro" greenfield site options potentially available to start construction by 2021 versus "other" options that require information, technology or other external action to be considered potentially available before 2021.
    - Longer-term hydro – Subject to adequate connected loads being committed and adequate ongoing resource planning being carried out prior to 2015, includes up to 70 GW.h/yr of small hydro (<10 MW) at 20-23 c/kW.h, over 2,070 GW.h/yr of medium hydro (11-60 MW) at less than 15 c/kW.h, and over 4,700 GW.h of large hydro (>60 MW) at less than 15 c/kW.h.
    - Other longer-term – Includes geothermal (needs exploration), nuclear (needs cost-effective proven technology, permitting experience), solar (needs cost-effective proven technology for Yukon market conditions), pipeline/natural gas (needs commitments by others re: Alaska Highway Pipeline [plans first gas by 2020, full gas by 2021], and/or potential Eagle Plain gas development), and grid connect to BC or Alaska (needs commitments by others).
- **Yukon Energy's resource planning principles** are also used to characterize at a high level each option as regards reliability, affordability, flexibility and environmental responsibility.

[7] The 2011 Resource Plan assumes that Mayo Lake Storage (1 metre of added bottom storage) is approved prior to assessing new resource options. The earliest in service for this project is currently estimated to be after winter 2013/14.

Table 4-1: Range of Resource Supply Options & Initial High Level Characterization

		RELIABILITY Reliable winter peak capacity, & reliable development (timing & cost)	AFFORDABILITY c/kW.h ($2010) if fully utilized	FLEXIBILITY Ratepayer cost risks re Mine Load Reductions	ENVIRONMENTAL RESPONSIBILITY Env. impact mitigation - reduction of GHG Emissions
NEAR-TERM potentially available start to construction before end of 2014 (available no later than 2017)	DSM/SSE	MEDIUM - depends on uptake and type of DSM/SSE	HIGH - <10 c/kW.h	MEDIUM – reasonably flexible; curtailable as/when needed	HIGH
	Diesel – existing default option	HIGH - low cost peaking & reserve capacity on system; low regulatory risk	LOW- approx. 30 c/kW.h	HIGH – low capital cost; save fuel & operating cost when load not there (summer/mine shutdown)	LOW- higher GHG & emissions than any other option
	Hydro Enhancements	MEDIUM – reliable winter energy but high regulatory risk	HIGH <10 c/kW.h	MEDIUM – reasonable flexible; - winter storage; long-term value	HIGH
	Thermal - Biomass (incl. waste)	HIGH - baseload energy & capacity (no development planning to date)	MEDIUM - approx 15 c/kW.h; Scalability issues	LOW – not flexible – high capital cost; intended for yr-round energy supply	HIGH
	Thermal - Liquid Natural Gas (LNG)	HIGH - peaking & reserve capacity; low regulatory risk	MEDIUM/HIGH – < 15 c/kW.h	HIGH - low capital cost; save fuel & operating cost when load not there (summer/mine shutdown)	MEDIUM – 30% to 50% lower GHG emissions than diesel
	Wind	LOW – not add reliable peaking/ reserve capacity; not dispatchable; but low regulatory risk	MEDIUM – approx 15 c/kW.h; includes storage	LOW – not flexible – high capital cost & not dispatchable	HIGH
LONG-TERM HYDRO (greenfield) potentially available to start construction before 2021	Small Hydro (< 10 MW)	MEDIUM – reasonably reliable; medium regulatory risk	LOW to MEDIUM(15 to> 20 c/kW.h)	LOW – not flexible; high capital costs req's sustained demand (30+ yrs)	MEDIUM- HIGH – minimal emissions; large footprint
	Medium Hydro (11 to 60 MW)	MEDIUM – reasonably reliable; high regulatory risk	LOW to MEDIUM (10 to 20 c/kW.h)	LOW – not flexible; high capital costs req's sustained demand (30+ yrs)	MEDIUM- HIGH – minimal emissions; large footprint
	Large Hydro (> 60 MW)	MEDIUM – reasonably reliable; high regulatory risk	HIGH – 5 to 11 c/kW.h	LOW – not flexible; high capital costs req's sustained demand (30+ yrs)	MEDIUM – HIGH – minimal emissions; large footprint
OTHER LONG-TERM (require information, technology or other external action to be considered potentially available before 2021)	Geothermal (exploration)	HIGH re: energy & capacity LOW re: development risk as depends on successful exploration	HIGH - low cost to build and operate LOW– high exploration costs	LOW – not flexible; high capital cost req's sustained demand; Not dispatchable	HIGH – minimal emissions/ footprint
	Nuclear	HIGH – baseload energy & capacity	UNKNOWN	LOW – capital intensive; req's sustained demand;	LOW-MEDIUM – low emissions; nuclear-specific env. issues
	Solar	LOW - not dispatchable, dependant on sun availability	LOW - high cost at this time 20 to 60 c/kW.h & req storage	LOW - capital intensive; req's sustained demand;	HIGH
	Pipeline/ Nat gas	HIGH - provides peaking & reserve capacity; low reg. risk	MEDIUM to HIGH (high cost to establish)	HIGH - low capital cost; save fuel & operating costs when no loads	MEDIUM - lower GHG emissions than diesel
	Grid Connection (B.C. or Alaska)	MEDIUM-HIGH	LOW – high cost to provide	LOW - capital intensive; may enhance greatly flexibility in Yukon	MEDIUM-HIGH – offers clean energy options

Note: "Affordability" in this table is assessed assuming adequate load to fully utilize the resource, e.g., greenfield large hydro lifecycle costs of 5 to 11 cents/kW.h assume full use of the resource throughout a 65 year life. In practice, project feasibility for each option depends on forecast lifecycle costs (LCOE) based on forecast utilization of the option over its life.

5.0 YUKON UTILITIES – DEFAULT DIESEL PORTFOLIO REQUIREMENTS

The 2011 Resource Plan grid load forecasts indicate that the major near-term challenge is to reduce costs and GHG emissions by displacing diesel energy generation that would otherwise be required between 2014 and 2021. Higher costs for default diesel generated by Yukon Energy and Yukon Electrical will affect rates for utility customers throughout Yukon due to integrated and equalized rate setting directives to the Yukon Utilities Board.

Diesel is currently the "default" generation resource option in Yukon, i.e., diesel is the reliable, established and available supply option against which other new supply options must be assessed. The Default Diesel Portfolio option retains established diesel generation capacity on and off the grid (with unit replacements as required), and assumes new capacity is supplied only through new diesel units as required at relatively low capital costs. In effect, this option assumes that all forecast grid electrical energy and capacity requirements beyond those that can be supplied by currently existing or committed hydro and wind generation are reliably and flexibly met through diesel generation.

After an overview of overall default diesel portfolio costs and GHG emissions, Section 5 reviews load forecast scenarios for grid diesel generation requirements for energy and capacity. Key features of the Yukon grid default diesel use are then reviewed which drive flexibility requirements and ability to utilize new resources effectively, i.e., grid seasonality in diesel generation and annual variability in diesel generation due to annual changes in hydro generation. The sensitivity of grid diesel energy forecasts to a range of possible mine connection loads is outlined, and future off-grid diesel generation is also reviewed for utility communities and mines.

Default Diesel Portfolio Costs & GHG Emissions

The concerns raised by the Default Diesel Portfolio option are high costs and high GHG emissions, each of which derive from the use of diesel fuel[8].

Forecast grid generation accounts for a small portion of total GHG emissions forecast for the Yukon power generation sector[9]. This is the situation today (2011) and is forecast to remain the likely reality throughout the 20-year forecast period. Over the next several years prior to 2020, off-grid industrial load and related emissions are forecast to increase dramatically, effectively dwarfing on-grid load and GHG

[8] Costs are also required to replace all existing diesel capacity (and to provide added capacity as needed) during the planning period. However, with regard to meeting these capacity planning requirements, diesel is a low cost option with minimal site-related environmental impact concerns.

[9] See Figure 3-2 shows total Yukon non-renewable generation (grid and off-grid) GHG emissions during the planning period under each grid load scenario without DSM/SSE; the figure includes off-grid utility communities and existing plus potential off-grid industrial (mines).

emissions. Addressing the GHG emission challenge related to off-grid loads also raises new power planning considerations well beyond those addressed in the 2006 Resource Plan. The potential near-term surge in off-grid mine development, however, also raises the opportunity to examine new renewable resource development options for commitment prior to 2021 to expand the grid and help to supply power requirements for major new industrial developments.

Grid Diesel Requirements Load Scenarios with and without DSM/SSE - Energy

Each grid load scenario provides projections with no DSM/SSE and also with DSM/SSE that is assumed to secure a 67% reduction in annual non-industrial grid load growth each year starting in 2013[10].

Forecast utility grid (integrated WAF and MD grids) diesel energy generation requirements for the 2011 Resource Plan (GW.h and incremental energy costs/year) are provided in Figure 5-1 for the following three grid scenarios focused on near-term (i.e., to 2015) mine load connection prospects[11,12]. Existing diesel capacity on the grid is more than adequate to supply forecast energy requirements under each of these near-term load scenarios.

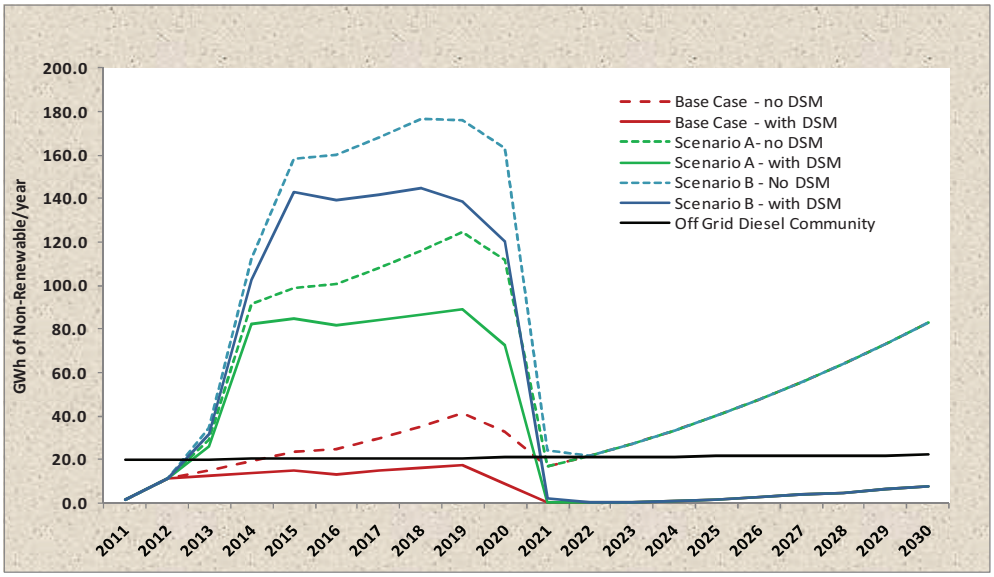
- **Base Case** – Includes non-industrial loads growing at recent rates (2.26%/year) and current connected mines (Minto and Alexco – forecasts assume these mines remain on the grid until around 2020).
- **Scenario A** – Adds Victoria Gold mine to the grid Base Case in late 2013 (based on then available information, forecast assumes on grid for about 7 years, i.e. until end of 2020).
- **Scenario B** – Adds the potential Carmacks Copper mine and Whitehorse Copper Tailings mine to the grid Scenario A (based on then available information, forecasts assume on grid until 2021).

[10] This range of potential diesel generation requirements is used to test the sensitivity of new supply options to potential DSM/SSE program impacts (DSM/SSE costs and programs are being addressed later in 2012 after completion of current studies and program development). DSM is also being addressed with industrial customers and is anticipated to provide some load reductions beyond those shown (potentially in the order of 10% of grid mine loads). Pending completion of current DSM/SSE studies, the 2011 Resource Plan assumes that DSM/SSE programs incur an average annual cost equal to 7.5c/kW.h (2010$) of assumed energy load reduction.

[11] Figure 5-1 also shows forecast off-grid utility diesel generation requirements. Forecast diesel generation fuel and O&M costs reflect approved 2009 incremental diesel generation costs by rate zone escalated at inflation (2% per year) after 2010. Incremental grid diesel generation costs for fuel and O&M (2010$) are assumed at 28c/kW.h (escalated at general inflation assumed at 2%/year), reflecting YEC's approved 2009 GRA fuel prices (e.g., 96 cents per litre at Whitehorse) and a 50/50 average of estimated costs for existing and new units (range of unit efficiencies and O&M cost). Diesel fuel prices in 2011 were generally higher than the approved 2009 fuel prices; however, based on October 2011 NYMEX futures, future diesel prices would be slightly lower than assumed in the Resource Plan (NYMEX futures based prices about 3% lower in 2012, 5% lower by 2015 and 6% lower by 2018).

[12] All loads (including mine loads) as forecast in 2011 based on then available information. Changes since the 2011 Resource Plan was prepared include: Minto load growth occurring later in 2012; somewhat lower Alexco loads and higher Whitehorse Copper Tailings mine loads by 2014; delay in connection of Victoria Gold load until start of 2015 and expectation that this load will peak in summer and extend for a longer life than the seven years assumed earlier. See Appendix A to this Overview for updates.

Figure 5-1: Diesel Energy Requirements (Grid & Off-Grid Utility)
Resource Plan Scenarios 2011 Resource Plan[1]



Diesel Energy Requirement	2011	2015	2020	2025	2030
Base Case (GWh)					
with DSM/SSE	1.5	15.2	8.7	1.8	7.5
without DSM/SSE	1.5	23.7	32.5	40.3	82.8
Scenario A (GWh)					
with DSM/SSE	1.5	84.9	72.5	1.8	7.5
without DSM/SSE	1.5	98.9	112.0	40.3	82.8
Scenario B (GWh)					
with DSM/SSE	1.5	142.9	120.6	1.8	7.5
without DSM/SSE	1.5	158.1	163.3	40.3	82.8
Off Grid Diesel Community (GWh)	19.9	20.4	20.9	21.5	22.1
Diesel Energy Cost (Fuel & O&M)					
Base Case ($ millions)					
with DSM/SSE	0.4	4.7	3.0	0.7	3.1
without DSM/SSE	0.4	7.3	11.1	15.2	34.5
Scenario A ($ millions)					
with DSM/SSE	0.4	26.3	24.8	0.7	3.1
without DSM/SSE	0.4	30.6	38.3	15.2	34.5
Scenario B ($ millions)					
with DSM/SSE	0.4	44.2	41.2	0.7	3.1
without DSM/SSE	0.4	48.9	55.8	15.2	34.5
Off Grid Community ($ millions)	5.9	6.6	7.5	8.6	9.9

[1.] See Appendix A to this Overview for current updated diesel energy and other forecasts prepared since the 2011 Resource Plan.

Under each of the above grid scenarios, a robust and successful DSM/SSE program would see minimal diesel generation (and consequently minimal diesel cost impacts and diesel displacement opportunities) after shut down of connected mine loads (i.e., with assumed DSM/SSE and Scenario A or B assumed mine closures after 2020, there is less than 10 GW.h of required diesel generation annually over the period from 2021 to 2030). In contrast, no DSM/SSE program (or unsuccessful DSM/SSE programming over the period) would see much greater rate impacts and diesel displacement opportunities after 2020 (i.e., between 22 GW.h to 83 GW.h per year (2022-2030) under all "no DSM/SSE" scenarios that assume closure of connected mines after 2020-2021).

Grid Season Generation – Impacts on Diesel Generation

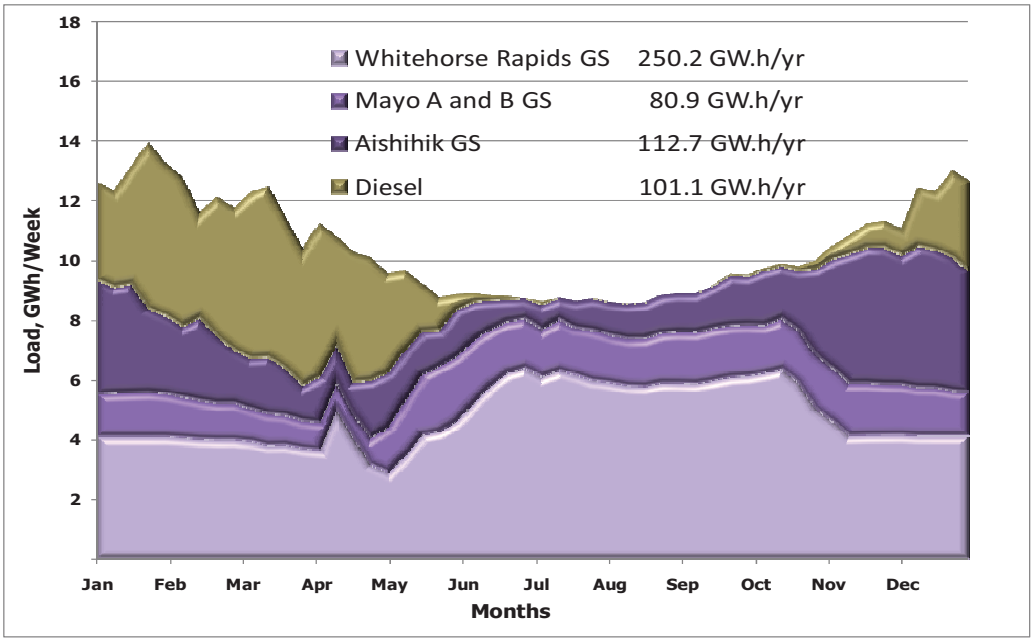
Diesel generation on the Yukon grid occurs in winter. As reviewed in Figure 5-2, with Scenario A 2015-2016 load and no DSM/SSE, 69% of annual near-term diesel generation forecast under average water conditions occurs in four winter months (December to March), and only 2% occurs in the five summer/fall months (June to October). Concentration of forecast diesel generation outside the summer/fall remains a key feature of the Yukon grid under a wide range of load and water conditions.

This concentration of grid diesel generation outside the summer/fall months reflects two factors: seasonal variation in grid loads (which are higher in winter than in summer) and seasonal variation in grid hydro generation for existing and committed facilities (hydro generation typically is higher in summer and fall as compared to winter/spring months). The seasonal concentration of grid diesel generation also reflects a key feature of Default Diesel, i.e., its flexibility to be utilized only when needed, reflecting both the technology (i.e., portable/storable fuel that is readily available) and its relatively low capital cost.

In contrast, Figure 5-3 shows seasonal generation at the Scenario A 2015-2016 load with a new 21 MW of wind generation providing 56 GW.h/year with year-round operation (reflects maximum near-term potential wind development at Ferry Hill). In an average water year, 88% of this new wind is used to displace diesel generation (this result is sensitive to assumed grid load and scale of wind generation):

- 49 GW.h of diesel displaced (70% directly displaced in winter, 30% through use of incremental stored hydro due to impact of wind's summer generation);
- 52 GW.h of diesel energy generation requirements remain on the grid under the assumed load and scale of wind capacity; and
- Unlike diesel, the 21 MW of new wind generation is dependent at all times on wind availability and therefore does not contribute to grid reliable capacity requirements (i.e., diesel or other new reliable capacity is needed to address diesel unit retirements plus added capacity requirements from growth).

Figure 5-2: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) at Scenario A 2015-16 Load without DSM/SSE Grid Load Net of Fish Lake and Wind

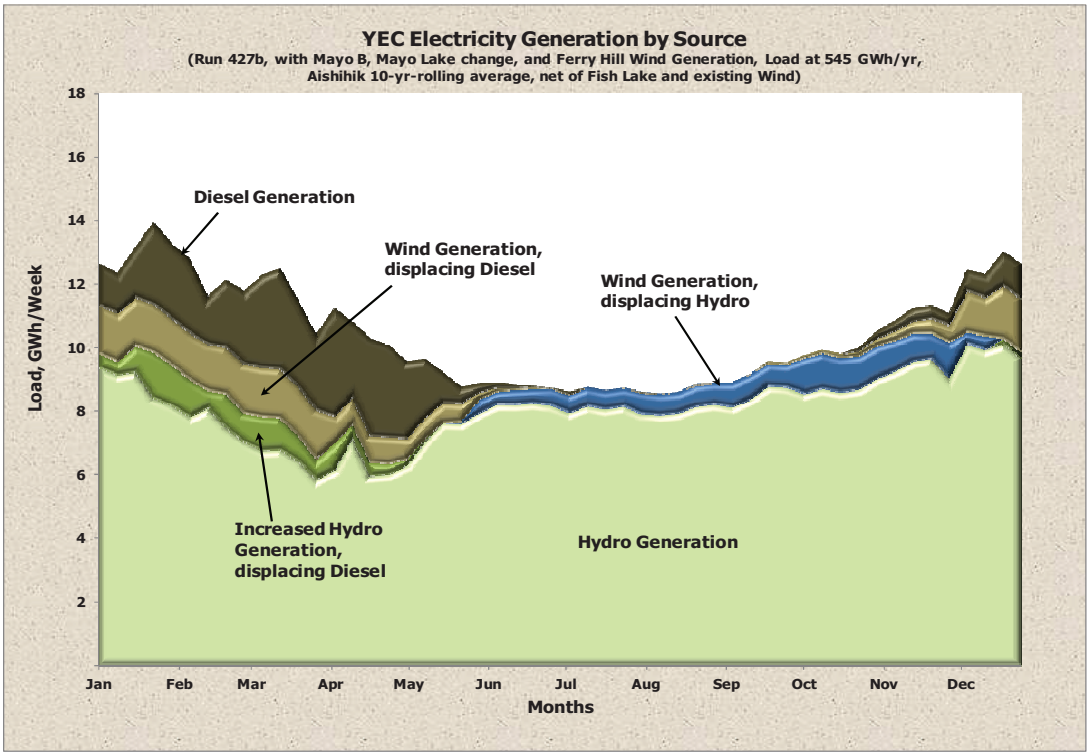


GW.h	Jan-Mar	April	May	June-Oct	Nov	Dec	Annual
	Wks 1-13	Wks 14-17	Wks 18-22	Wks 23-44	Wks 45-48	Wks 49-52	
Diesel Generation	59.9	17.2	9.1	1.9	3.2	9.8	101.1
	59%	*17%*	*9%*	*2%*	*3%*	*10%*	*100%*
Hydro Generation	100.5	25.3	37.1	199.0	41.3	40.6	443.9
	23%	*6%*	*8%*	*45%*	*9%*	*9%*	*100%*
Total Generation	160.4	42.5	46.2	201.0	44.5	50.4	545.0
	29%	*8%*	*8%*	*37%*	*8%*	*9%*	*100%*

Notes: Weekly grid generation by source in Figure 5-2 from January to December is based on long-term average water flows and the Scenario A grid 2015-2016 load without DSM/SSE (assumes yet-to-be approved Mayo Lake project with amended licence for one metre of enhanced bottom storage):

- Seasonal loads (peak in winter and are lowest in summer).
- Current hydro generation supply (tends to peak in summer/fall, constrained in winter/spring).
- Diesel energy generation for average year is concentrated in winter months (60% in four months of December to March), and only 2% in five summer/fall months (June to October).
- Diesel energy generation forecast for average year at 101 GW.h (reflects impact of potential load growth by 2015/16, i.e., much lower grid diesel generation today based on average year).
- Diesel provides critical reliable grid capacity requirements to meet peak winter loads and reserve when hydro capacity can be constrained on the current grid, e.g., reliable winter hydro capacity approximates 24 MW at Whitehorse (out of 40 MW installed) and 11 MW at Mayo (out of 15 MW installed).

Figure 5-3: YEC Grid Electricity Seasonal Generation by Source: Mean Flows (average of all water years) with 21 MW Wind Project Displacing Diesel and Displacing Hydro at Scenario A 2015-16 Load Without DSM/SSE



Grid Generation at 545 GW/h load* (GW.	Without Wind Project	With 21 MW Wind Project	Change
Grid Load	545.0	545.0	
Grid Generation			
Hydro*	443.9	437.3	(6.6)
Diesel	101.1	51.9	(49.2)
Wind*	-	55.8	55.8
Total	545.0	545.0	

Breakdown of Wind Generation Impacts (GW.h/yr)	
Directly Displacing Diesel	34.6
Directly Displacing Hydro	
Stored Hydro Displacing Diesel	14.6
Spilled Hydro (not required)**	6.6
Total Wind Project Generation	55.8

* Existing Wind and Fish Lake generation not included.

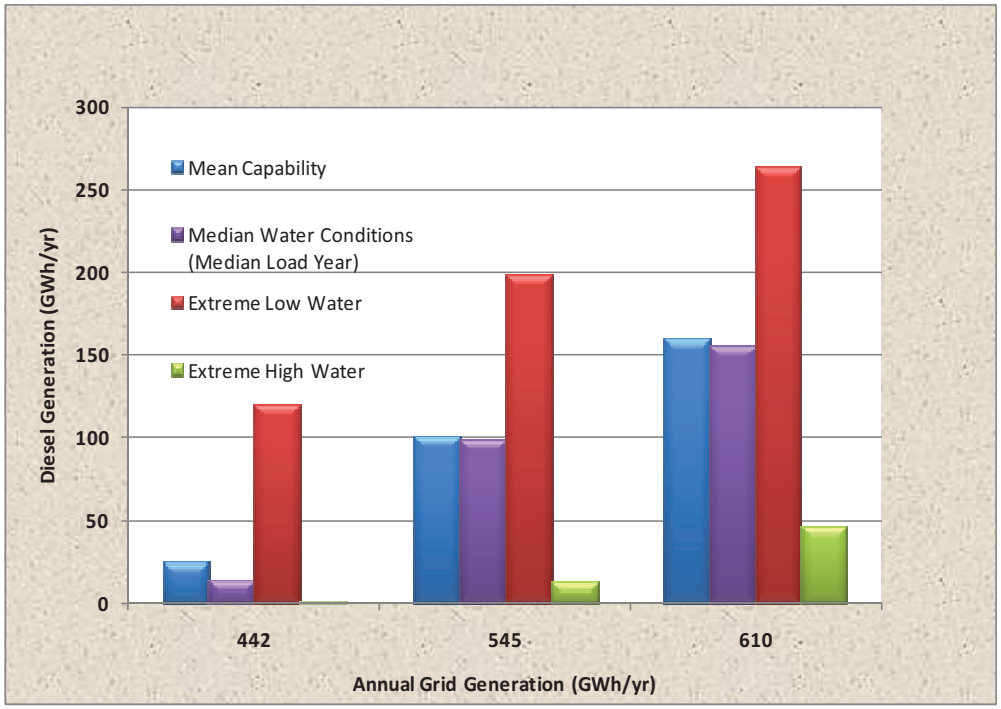
Total Displaced Diesel = 34.6 + 14.6 = 49.2 GW.h

**This figure provides an example that illustrates impacts this supply option would have on the existing generation system;
This does not suggest YEC would operate the system in a manner that results in hydro being displaced by other forms of more costly generation

Annual Diesel Variability Due to Annual Hydro Generation Fluctuations

Figure 5-4 demonstrates the high variability that exists on the current Yukon grid regarding annual diesel generation requirements at any assumed grid load level. By way of example, at the Scenario A 2015-2016 load without DSM/SSE assumed in Figures 5-2 and 5-3, diesel generation can potentially range in any year from 13 to 199 GW.h/year, depending on water flow impacts on grid hydro generation.

Figure 5-4: YEC Annual Grid Diesel Generation Variability at Different 2015-2016 Grid Loads (GW.h/yr)



Annual Diesel Generation (GW.h/yr)	Annual Grid Load (GW.h/yr)		
	442	545	610
Mean Capability	24.6	101.1	160.2
Median Water Conditions (Median Load Year)	13.6	98.6	155.7
Extreme Low Water	119.7	198.8	263.8
Extreme High Water	0.1	13.0	46.2

Notes:

- The range of annual grid loads reflects approximate forecast 2015-16 loads ranging from Base Case (442 GW.h - no new mines) to Scenario A (545 GW.h – connect Victoria Gold) and Scenario B (610 GW.h – connect Victoria Gold, Carmacks Copper and Whitehorse Copper Tailings).
- An "extreme" or "median" year reflects one year out of 364 cases (28 water years and 13 load years). "Averaged load year" (which not shown above) is average annual value for a water year calculated over all 13 load years. For the 545 GW.h/year grid load, the extreme low water diesel generation for Averaged Water Year would require 166.7 GW.h/year diesel generation (reflects 1996 water year of record), and the extreme high water diesel generation for Averaged Water Year would require 34.1 GW.h/year diesel generation (reflects 1992 water year of record).

Range of Possible Connected Mine Loads

The 2011 Resource Plan recognizes that a wide range of possible variations in connected mine loads may occur over the 20-year planning period, including delays in connection of specific loads, extensions in the

life of any connected loads, earlier-than-expected mine shutdowns, new connections not currently forecast and expansions or contractions in connected loads.

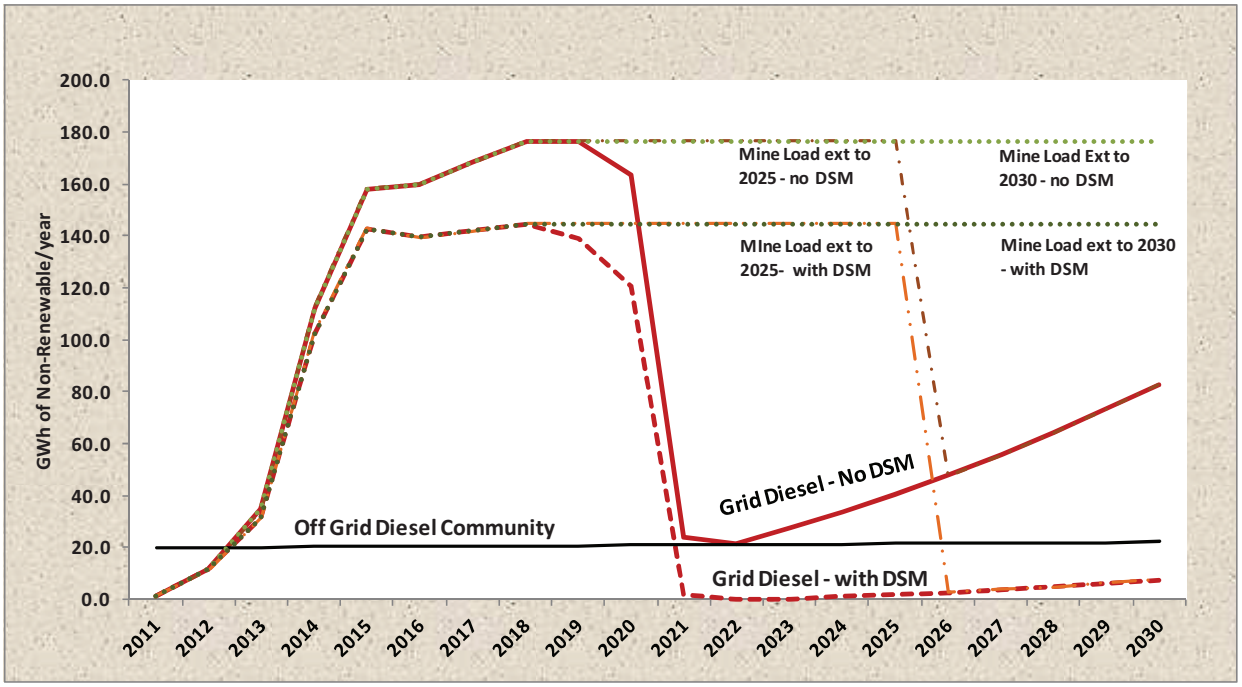
- Beyond looking at a range of near-term mine connections (e.g., Base Case, Scenario A and Scenario B loads), resource option sensitivity for displacing grid diesel generation is also tested for different potential extensions of connected mine loads beyond the 2020 date after which the forecasts show shut down of connected mine loads (sensitivity is tested separately as shown in Figure 5-5 for extensions of related grid diesel requirements to 2025 and 2030).

- The potential for connection to the grid of material new off-grid mine loads (beyond those included in Scenario A and B) has been forecast to be very limited:

    - Off-grid industrial diesel or other fossil fuel power generation at the Wolverine mine (37 GW.h/year) already exceeds utility diesel generation (grid and off-grid). This load is over 270 km from the grid, and connection was never considered to be a practical option given this distance and an expected 10 year mine life.
    - There are currently only a limited number of potential new mine opportunities located within 50-100 km of the 69-138 kV grid (e.g., potentially Brewery Creek, Rau Gold, and Ketza River); although none of these mine loads were included in the 2011 grid load forecasts, the developer of the Brewer Creek mine (Predator Mining Group Inc.) informed YEC that it would like to discuss connection to the grid potentially as soon as mid 2013 with a load of approximately 3.7 MW.

- Opportunities exist in the longer-term (i.e., commitments prior to 2021) to connect to the grid one or more of the major new off-grid mine loads that are driving potential off-grid diesel/LNG generation on a multi-decade basis as shown earlier in Figure 3-1. However, as noted, these mine loads are not being planned on the basis of any grid connection – and any potential grid connection in future will be contingent on new larger-scale renewable resources being developed that can supply a major share of the new off-grid power requirements on a timely and cost-effective basis. Looking at the largest of these potential off-grid mine loads (Casino), this opportunity translates into the challenge of developing new renewable resource options within the next decade that are less costly than the LNG (or natural gas fuelled generation if pipeline or Eagle Plain gas becomes available) that is currently planned to supply this load.

Figure 5-5: Diesel Energy Requirements - Sensitivity Tests re: Mine Load Extensions



Forecast Grid Diesel Requirements - Capacity

In addition to supplying energy requirements, diesel generating units are important for meeting grid capacity planning requirements, i.e., the required capacity to meet firm winter peak load requirements with adequate reserve. As reviewed in Table 5-1, over the 20-year planning period all of Yukon Energy's existing diesel generation capacity (37 MW) is forecast to be replaced due to expected retirements. The following highlights are noted from Table 5-1:

- There are no forecast new grid capacity requirements in 2011 under any of the resource planning scenarios.
- By 2015, with DSM/SSE, there is no new grid capacity required under the Base Case scenario, and between 9.6 MW to 17.6 MW of new capacity required under Scenario A and Scenario B loads respectively (at a diesel capacity replacement cost of approximately $15.7 million to $28.7 million)[13].
- By 2020, with DSM/SSE, 8.8 MW of new grid capacity is required under the Base Case scenario (at a diesel capacity replacement cost of $15.8 million). New capacity required under Scenario A

[13] Cumulative diesel capacity spending to date after 2010 to meet capacity planning requirements (escalated dollars – assumed cost of $1.5 million/MW [$2010]).

and Scenario B loads is 17.9 MW and 25.9 MW respectively (at a diesel capacity replacement cost of $30.6 million to meet Scenario A loads and $43.6 million to meet Scenario B loads).

- By 2025, with DSM/SSE, under all scenarios 27.6 MW of new capacity is required at a diesel capacity replacement cost of between $47.0 million and $52.1 million.
- By 2030, with DSM/SSE, under all scenarios 37.1 MW of new capacity is required at a diesel capacity replacement cost of between $67.0 million and $72.1 million.

Table 5-1: New Diesel Grid Capacity Requirements for Resource Plan Scenarios: 2011-30*

	2011	2015	2020	2025	2030
New Diesel Capacity Requirement (MW)					
With DSM/SSE					
N-1	0.0	0.0	8.8	27.6	37.1
Base Case	0.0	0.0	8.8	27.6	37.1
Scenario A	0.0	9.6	17.9	27.6	37.1
Scenario B	0.0	17.6	25.9	27.6	37.1
Without DSM/SSE					
N-1	0.0	2.8	18.0	43.5	60.4
Base Case	0.0	2.8	18.0	43.5	60.4
Scenario A	0.0	12.8	27.1	43.5	60.4
Scenario B	0.0	20.8	35.1	43.5	60.4
Diesel Capacity Additions ($Millions)[1]					
With DSM/SSE					
Base Case	0.0	0.0	15.8	52.1	72.1
Scenario A	0.0	15.7	30.6	50.0	70.0
Scenario B	0.0	28.7	43.6	47.0	67.0
Without DSM/SSE					
Base Case	0.0	4.7	31.7	81.0	116.9
Scenario A	0.0	21.0	46.4	78.8	114.7
Scenario B	0.0	34.0	59.4	76.3	112.2

1. Cumulative diesel capacity spending to date after 2010 to meet capacity planning requirements (escalated dollars - assumed cost of $1.5 million/MW [$2010]).

*See Appendix A to this Overview for current updated diesel grid capacity requirement forecasts prepared since the 2011 Resource Plan.

Forecast timing for new diesel capacity will be affected by diesel unit retirements and new capacity requirements during the 2013-2020 period related to different load scenarios[14]. This 2011 Resource Plan analysis assumes that the 25 km line L172 between Takhini and Whitehorse is appropriately reinforced within the next few years so as to provide no line constraint, i.e., absent such reinforcement, additional capacity would be required in Whitehorse.

Off-Grid Utility Diesel Generation Requirements

Off-grid utility community diesel energy power generation requirements are forecast to grow very slowly based on recent trends for the diesel rate zone communities served by Yukon Electrical (Watson Lake, three small diesel communities, and Old Crow). Off-grid utility community diesel generation exceeds grid diesel generation under the Base Case forecast with DSM/SSE. Off-grid utility community diesel capacity requirements are not addressed at this time.

Potential Off-Grid Mine Diesel Requirements

Potential off-grid mine diesel/LNG energy generation forecasts indicate that unprecedented potential off-grid industrial power load growth before 2020 could easily dwarf current projected utility gird and off-grid diesel generation (see earlier Figure 3-1). Current forecasts indicate that industrial off-grid diesel and/or LNG power generation could potentially exceed 330 GWh/year by 2015 and 1,545 GW.h/year by 2020, and remain above 1,300 GW.h per year beyond the planning period (2030); by comparison, total grid load served by hydro, wind and diesel generation as projected in 2020 under Scenario B with no DSM/SSE is 614 GW.h/year, i.e., about 36% of the potential off-grid industrial generation by that date.

The larger potential off-grid longer-life mines which constitute most of the potential projected off-grid industrial load over the planning period (e.g., Casino, Selwyn, Mactung and Northern Dancer) are not currently considering connection to the Yukon grid in order to meet load requirements. The largest of these potential industrial loads (Casino project) is planning to use LNG at costs well below the cost of diesel, and Northern Dancer is also looking at the LNG option.

[14] Forecast new default diesel capacity requirements by year on the grid for each load scenario reflect forecast peak loads under the grid load scenarios, forecast generation unit retirements, and Yukon Energy's grid capacity planning requirements to meet peak winter loads. During the 2015-2020 period connected mine loads as assumed in Scenarios A and B of the 2011 Resource Plan are expected to be sufficient potentially to affect capacity planning requirements (under updated assessments, this is assumed to occur under the Loss of Load Expectation [LOLE] planning requirements when industrial loads exceed 13 MW), while in other years the N-1 requirement (currently loss of the Whitehorse transmission connection to the Aishihik hydro plant) based on non-industrial loads is expected to determine new default diesel capacity requirements.

6.0 NEAR-TERM RESOURCE OPTIONS TO DEFAULT DIESEL

Portfolio options examine the extent to which alternative resource combinations could effectively reduce grid diesel generation under different forecast load scenarios. Diesel generation is assumed to be retained in each portfolio to supply all generation requirements not supplied by other resources.

Near-Term Resource Options to Default Diesel

Non-diesel resource options potentially available for in service by late 2014 that were selected for near-term portfolios include Marsh Lake Storage (6.4 GW.h/year potential), Wood Biomass Thermal (15 MW)[15], Waste to Energy (WTE) Thermal (2.2 MW)[16], Wind (21 MW)[17], and Liquid Natural Gas (LNG)[18]. In contrast, Gladstone Diversion (36.6 GW.h/year potential) likely cannot be committed before 2016 at the earliest, but could potentially constitute a resource for in-service by late 2017.

Each of these near-term options were assessed in the 2011 Resource Plan based on then available information – recognizing that further feasibility work is required in each case to confirm costs and supply capabilities, and also to determine whether or not the option is feasible to be committed by the dates currently assumed.

- LNG and Wood biomass are options where sourcing fuel supply remained a significant issue at the time of the 2011 Resource Plan analysis, and it was recognized that further pre-feasibility analysis is required prior to relying on either of these options for near-term supply[19]. Ongoing work by YEC is focusing on confirming least-cost options whereby LNG supplies can be secured as required by late 2014[20].

- Feasibility information for Marsh Lake Storage and Gladstone Diversion confirms the relatively low cost offered by each of these hydro enhancement options – however, each of these hydro

[15] Resource Plan analysis determined that any larger scale Wood Biomass plant would be more costly under forecast grid loads (the plant scale exceeds forecast grid requirements for a thermal plant running throughout the year). In contrast, a 10 MW plant might merit review under lower Scenario A loads. Wood Biomass plants smaller than 10 MW (e.g., 3 MW) are being examined as possible pilot projects (see Section 8 of this Overview).

[16] The 2.2 MW scale was assessed to be an optimum scale based on projected available municipal solid waste (MSW) resource supplies and potential access to low cost wood biomass "waste" supplies to supplement MSW supplies.

[17] A smaller 10.5 MW option was examined, but was slightly less cost-effective at forecast loads than the 21 MW option (the latter option reflected estimated wind resource that could be developed at Ferry Hill).

[18] LNG capacity is adapted as required to the specific assumed load forecast (assumes BC based LNG supply not limited).

[19] It was assumed that LNG and wood biomass options could likely be committed before 2015 if selected for development, subject to sufficient studies and planning being carried out in a timely manner to resolve various feedstock supply issues. The 2011 Resource Plan (Section 6.1) reviewed recent studies that YEC has participated in with the developer of the Casino mine project to confirm the feasibility of near-term LNG supply chain options to Yukon from Kitimat or Fort Nelson, B.C.

[20] See YEC web site for: (a) January 2012 LNG Workshop background paper and presentations; (b) December 2011 Biomass background study and presentations.

projects is subject to material timing uncertainties related to regulatory and permitting processes, and further Yukon Energy planning work on Gladstone Diversion is also subject to securing local First Nation support for the project. Gladstone Diversion is examined as potentially being in-service by late 2017 (it is expected that this option cannot be committed before 2015 – the assessment examined the potential impact of securing this option by the end of 2017).

- Feasibility information is also available for Wind and WTE options – however, further feasibility work is required on each of these projects before commitments could be made to proceed with permitting activities[21].

Energy and Capacity Supply Capabilities

Overall, only a few of the available non-diesel resource options offer large scale energy generation supply potential relative to forecast Yukon diesel generation loads. Figure 6-1 highlights the gross energy supply capabilities of the near-term options relative to each of the forecast 2015-2019 grid diesel requirement load scenarios with and without DSM/SSE (the table below this figure reviews reliable capacity capabilities and capital costs for each resource supply option):

- **LNG** – LNG supply is the only option that can potentially displace all diesel energy loads as well as all new diesel capacity requirements at any near-term load.

- **15 MW Wood Biomass** – Gross energy capability of a 15 MW wood biomass option exceeds all but Scenario B diesel energy loads; however, after seasonal diesel requirements and annual hydro variability impacts are considered, this option's net energy displacement of diesel is much lower than the gross energy capability, e.g., assuming Scenario A with DSM/SSE, net energy diesel displacement approximates only 72 GW.h of the 119.6 GW.h annual gross energy. This option can displace only a portion of new diesel capacity requirements (at this scale of plant, the only identified potentially feasible locations are either in Whitehorse or in the Minto burn area).

- **Other Near-Term Options** – Gross energy capability of other near-term options only displace portions of Scenario A diesel requirements, and net energy capability to displace diesel is lower than gross capability, e.g., approximately 80% to 88% of WTE or Wind gross generation displaces diesel with Scenario A load; minimal contributions from Marsh Lake hydro and WTE; wind provides minimal capacity contribution.

In summary, LNG can provide flexible amounts of supply up to any load levels likely to be required and Wood Biomass can also provide relatively large amounts of annual generation (119.6 GW.h/year for a 15

[21] See YEC web site for October 2011 Waste to Energy Workshop background study and presentations.

MW plant, of which 72 GW.h would displace diesel generation under Scenario A loads with DSM/SSE)[22]. In contrast, maximum potential levels of annual generation are limited from Marsh Lake (6.4 GW.h/year), 2.2 MW WTE (17.1 GW.h/year), Gladstone Diversion (36.6 GW.h/year), and Wind (55.6 GW.h/year).

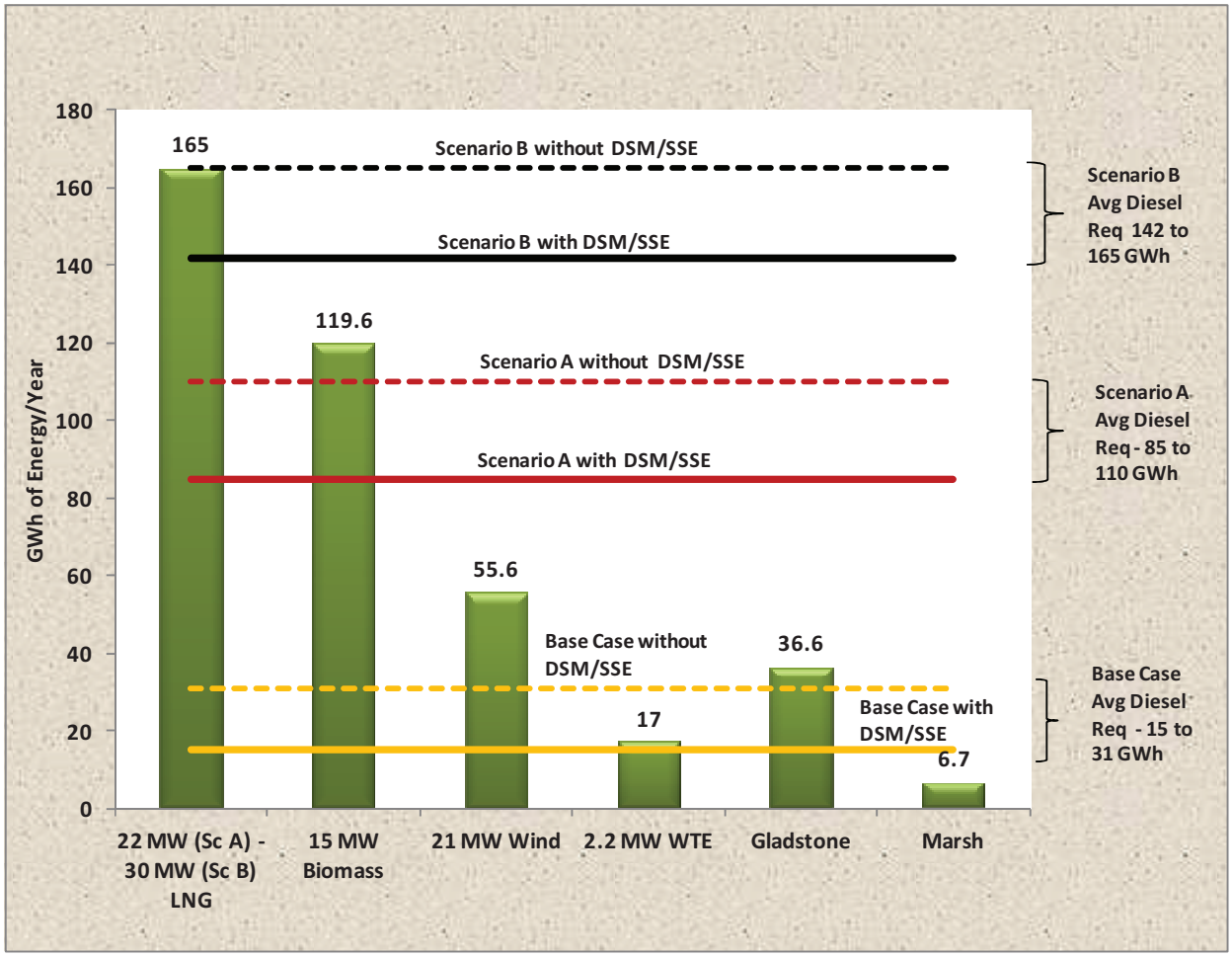
Ongoing studies are defining the economic potential for DSM and SSE as well as specific programs and costs. Pending completion of these studies, the 2011 Resource Plan assumes that a specific level of DSM/SSE will be implemented starting in 2013 for non-industrial grid loads[23] and tests the sensitivity of all non-diesel supply options to these potential DSM/SSE impacts. In summary, notwithstanding the materially higher diesel displacement opportunities and higher Default Diesel Portfolio costs with no DSM/SSE, comparative feasibility assessments of the different resource portfolio options under load scenarios with DSM/SSE were not generally changed by consideration of load scenarios with no DSM/SSE[24]. Accordingly, the following summary overview analysis of resource and portfolio options typically focuses solely on review of load scenarios with DSM/SSE.

[22] Studies suggest that a 25 MW plant scale located in Whitehorse might also be feasible, with annual generation approaching 200 GW.h/year; however, under Scenario A loads with DSM/SSE, less than 15% of the annual biomass energy over the project life would displace diesel generation (even during the 2015-19 period with mine loads connected, less than 100 GW.h/yr of the wood biomass generation would be used to displace diesel generation).

[23] Although the timing and level of future DSM/SSE remains uncertain, preliminary study results suggest that future DSM/SSE load reduction impacts over the period to 2030 may be within 50-75% of DSM/SSE assumed in the 2011 Resource Plan.

[24] Higher loads assuming no DSM/SSE tend to improve cost savings for all non-diesel portfolio options when compared with the Default Diesel Portfolio, and reduce somewhat the penalties faced by non-flexible options such as Wind when grid loads drop due to mine closures. Portfolios that include Gladstone Diversion tend in particular to show improved (lower) present value costs over the planning period with higher loads assuming no DSM/SSE. However, the overall cost ranking of LNG Transition Portfolio Options relative to Minimum GHG Portfolio Options or the Default Diesel Portfolio is not materially changed without DSM/SSE.

Figure 6-1: Gross Energy Supply Capabilities by Near-Term Option (GW.h/yr During 2015-2019) – Compared to Diesel Requirements by Load Scenario with and without DSM/SSE (Net Energy Displacement of Diesel may be less than Gross Energy)



Notes: Reliable Capacity capability (up to 37 MW new grid capacity needed by 2030 with Scenario A load with DSM/SSE):

- **Diesel, LNG** – Each can provide all of the firm capacity required (capital cost of $1.5 million/MW assumed; for LNG cost of $1.8 million/MW for combined cycle).
- **Wood Biomass** - Option assumes 15 MW of firm capacity (capital cost of $5.7 million/MW).
- **Waste-to-Energy (WTE)** - 2.2 MW of firm capacity (capital cost of $17.7 million/MW).
- **21 MW Wind** – Wind generation does not provide any reliable capacity; the option includes 5 MW of DRUPS (diesel rotary uninterruptible power) to enhance reliability, and this adds 5 MW to reliable capacity. Wind option capital cost of $3.6 million/MW for 26 MW (wind & DRUPS).
- **Gladstone and Marsh** – Gladstone Diversion hydro adds minimal or no reliable capacity (due to Aishihik Transmission line vulnerability); Marsh Lake hydro storage adds about 1 MW reliable capacity. Overall capital costs are estimated at $40 million for Gladstone and $10.5 million for Marsh Lake storage. Earliest potential in-service for Gladstone is late 2017.

2015-2020 Average Annual Costs per kW.h

New resource supply options display widely varying annual ratepayer cost impacts per kW.h during the 2015-2020 period with assumed connected mine loads (see Figure 6-2 for annual ratepayer costs per kW.h with Scenario A loads and DSM/SSE, assuming average annual hydro generation):

- **LNG and Hydro Enhancements (Marsh & Gladstone) are lowest cost** – LNG and hydro enhancements cost less than 20 c/kW.h each year relative to diesel fuel and O&M (new diesel units) at approximately 30 c/kW.h or higher (LNG fuel and O&M cost is lowest at 11 to 13 c/kW.h)[25].

- **Wind and WTE slightly lower cost than Diesel** – Wind and WTE cost typically between 25 and 30 c/KW.h[26]; these capital intensive options are sensitive to load decline that is forecast starting in 2020 (lower loads result in higher average costs per KW.h).

- **Wood Biomass costs more than Diesel** – Wood biomass costs at or slightly below 35 c/kW.h until 2020, when costs rise above 35 c/kW.h[27]; this is a capital intensive option that is sensitive to load decline as forecast starting in 2020 (lower loads result in higher average costs per kW.h).

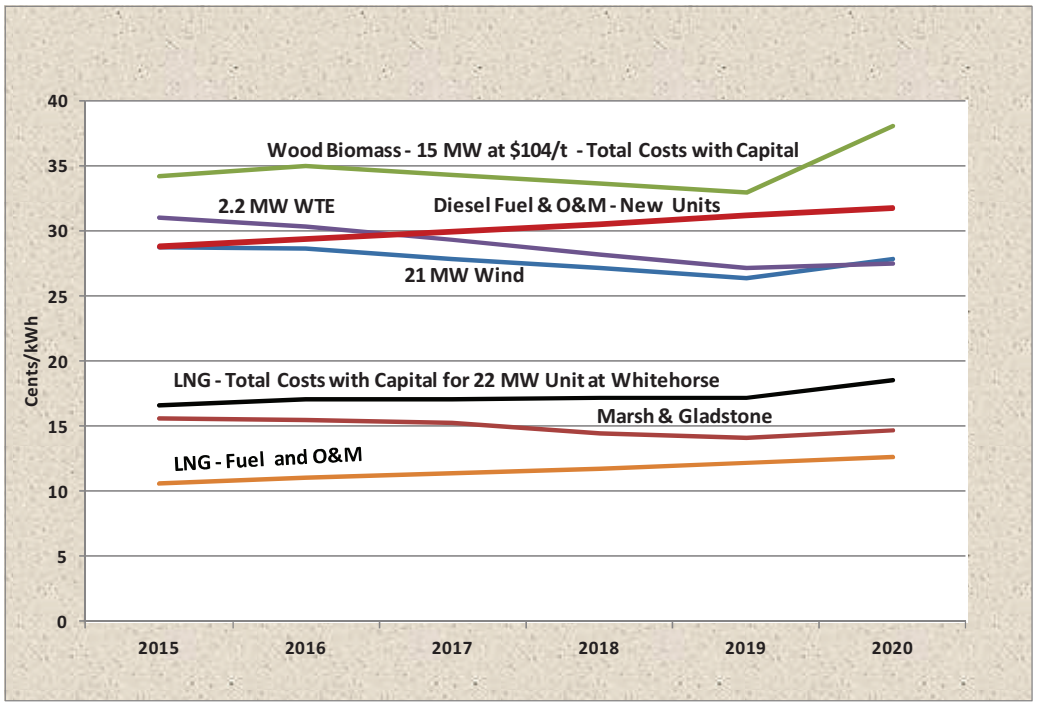
In summary, LNG is a flexible low capital cost option where unit fuel costs determine overall annual costs per kW.h. In contrast, higher capital costs per MW for other options result in costs per kW.h being sensitive to option scale and assumed grid loads.

[25] Forecasts assume diesel fuel and O&M cost escalation at 2% year (fuel price as approved by YUB in place in 2010). LNG costs assume 22 MW combined cycle generation units at Whitehorse (50% energy efficiency [6.562 Mcf/MW.h] and 44% average annual plant capacity factor) with LNG supplied by truck from Kitimat at cost of 2.7 cents per kW.h (2010$) for all LNG supply costs other than LNG fuel; cost of LNG fuel at assumed natural gas price in BC plus $3/MMBtu (2010$) to reflect conversion costs and impact of export pricing; assumed BC gas price at $5.5/MMBtu in 2015 ($6.07/MMBtu after inflation), $6.60/MMBtu in 2020 ($8.05/MMBtu after inflation) and $7.45/MMBtu in 2030 ($11.07/MMBtu after inflation). Although combined cycle provides opportunity for waste heat sales in Whitehorse, no waste heat revenue offsets assumed with LNG option in this analysis.

[26] Assumes use 25,000 ODT/year of MSW plus 3,800 ODT/year wood biomass at Whitehorse WTE plant, with district heat net revenues, tipping fees and other revenues of $3.3 million per year (2010$). See Figure 6-3.

[27] Wood Biomass plant assumed to be located adjacent to grid in Minto burn area with wood biomass requirement of 0.7 ODT/MW.h at an average cost (2010$) of $104/per ODT. Assume 2%/year inflation of costs.

Figure 6-2: Average Annual Costs per kW.h for Near-Term Resource Options – 2015-2020 (Scenario A Load with DSM/SSE – Cost Inflation at 2%/yr; higher for LNG)



Annual Cost (cents/kW.h)	2015	2016	2017	2018	2019	2020
Diesel Fuel & O&M - new units	29	29	30	31	31	32
Wood biomass 15 MW at $104/t						
Total Costs	34	35	34	34	33	38
Fuel + O&M	19	20	20	20	20	24
21 MW Wind	29	29	28	27	26	28
2.2 MW WTE	31	30	29	28	27	28
LNG - total costs with capital	17	17	17	17	17	19
LNG - fuel & O&M	11	11	11	12	12	13
Marsh & Gladstone	16	15	15	14	14	15

Note: Assumes 2%/yr inflation for 2010$ costs, except for LNG fuel cost which assumes specific real escalation of the 2010$ natural gas price as well as overall inflation at 2%/yr (per footnote 24 at page 28). All costs assume average annual hydro generation each year during the period.

Lifecycle Costs per kW.h (LCOE)

Resource options are more effective in displacing grid diesel generation to the extent that they can be focused in the priority diesel generation periods (winter/spring) and flexible to address relatively wide variability in annual hydro generation capability[28].

Figure 6-3 provides, by option, forecast lifecycle costs of energy (LCOE) per kW.h (2010$) of generation used to displace forecast diesel over the economic life of each option[29]. Separate LCOE forecasts for Scenario A load with DSM/SSE, for sensitivity tests for mine load diesel displacement extended to 2025 and 2030, and for full utilization of all generation to displace diesel are summarized below:

- **Forecast LCOE with no mine loads after 2021** – Only LNG and Marsh Lake & Gladstone have LCOE less than 30 c/kW.h (13.1 c/kW.h for Marsh/Gladstone and 18.4 c/kW.h for LNG); the highest LCOEs are Wind option (40 c/kW.h) and Wood Biomass (60.8 c/kW.h).

- **Forecast LCOEs decline as mine load diesel displacement is extended** – With mine loads extended to 2025, only LNG and Marsh Lake & Gladstone have LCOE less than 20 c/kW.h (10.1 c/kW.h for Marsh/Gladstone and 15.2 c/kW.h for LNG), and the highest LCOEs are Wind (26.5 c/kW.h) and Wood Biomass (37.1 c/kW.h) – with mine loads extended to 2030, further LCOE declines occur without changing the cost ranking of the options.

- **Full Utilization LCOE do not reflect forecast diesel displacement** – Forecast LCOEs with no mine loads after 2021 are much higher than Full Utilization LCOE which assume all generation can always be fully used to displace diesel, e.g., 53% higher for LNG (Forecast LCOE vs. Full Utilization LCOE), 111% higher for Marsh/Gladstone, 133% higher for WTE, 176% higher for Wind and 285% higher for 15 MW Wood Biomass.

  Figure 6-4 demonstrates how Full Utilization generation varies from Forecast net diesel displaced with Scenario A loads for a Wind option over a 25 year economic life (highlights the impact of mine shutdown when the resource has no flexibility to limit its ongoing generation or costs).

In summary, LNG and Hydro Enhancements (Marsh Lake & Gladstone Diversion) have the lowest LCOE, and Wood Biomass has the highest LCOE, under all Scenario A cases examined in Figure 6-3.

[28] This reality reflects the lack of grid connection in Yukon to external markets - and the resulting need to ensure where feasible that local generation matches the local grid load requirements (as surplus generation cannot otherwise be usefully used or sold). See Section 5 regarding grid hydro seasonal load and supply characteristics, as well as annual hydro supply variability. In the end, resource options for the grid in Yukon are valued based on ability to displace diesel generation, i.e., generation that is surplus to diesel displacement needs has little if any value to ratepayers.

[29] LCOE and present value cost assume discount rate of 6.56%/year for new generation assets based on YEC's 2009 GRA approved return on equity and cost of new long-term debt. Assumed project life varies by resource option, e.g., 20-years for LNG, 25 years for WTE and Wood Biomass and Wind, 65 years for Hydro enhancements.

Figure 6-3: Forecast Lifecycle Cost of Energy (LCOE - 2010$) by Near-Term Option - Scenario A Load with DSM/SSE

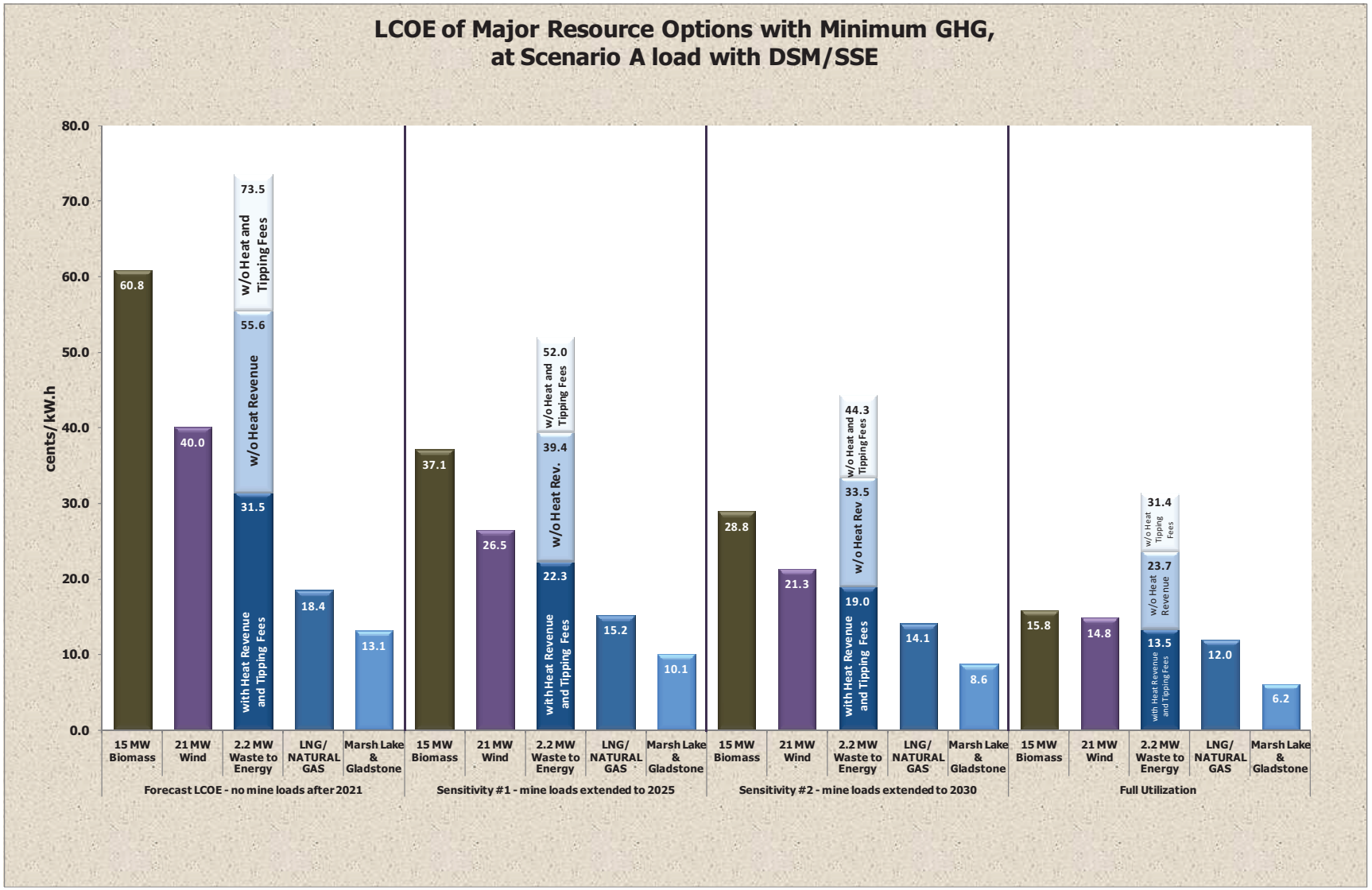
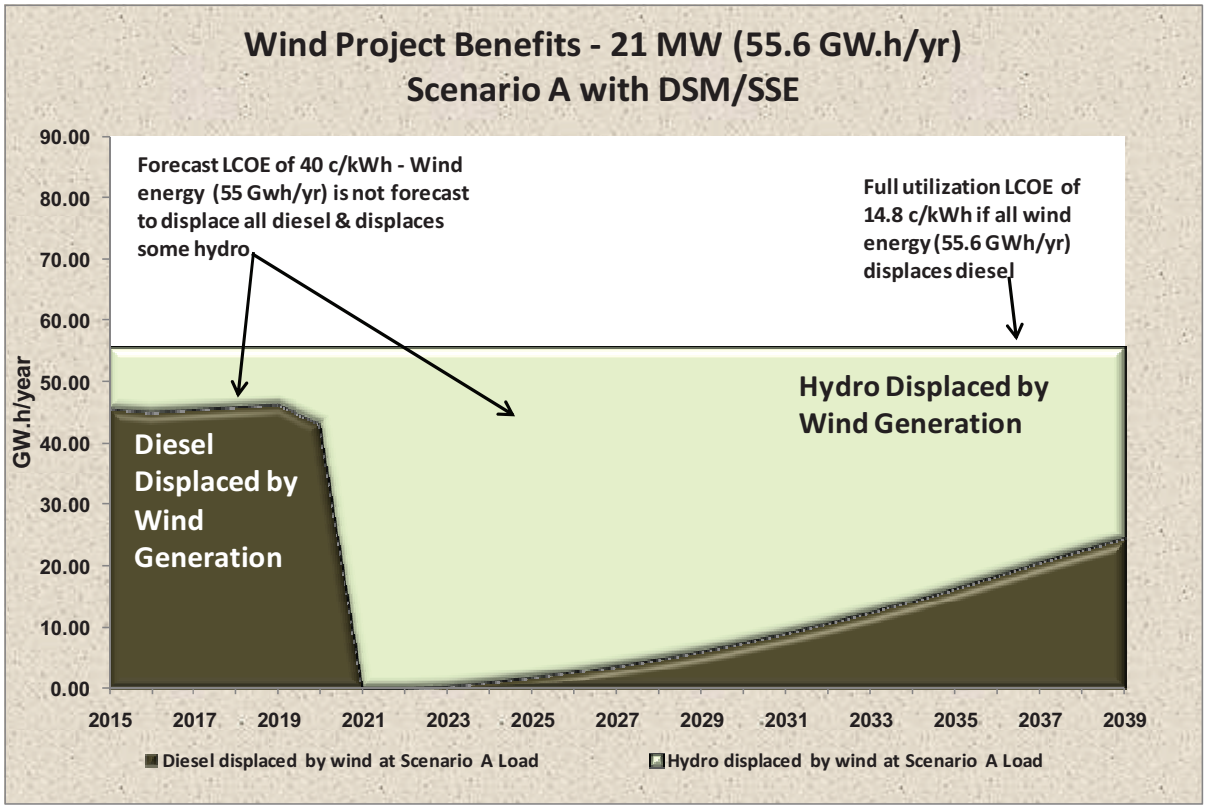


Figure 6-4: Wind Project: Displacing Diesel and Hydro at Scenario A Load with DSM/SSE (current forecast mine life, no mine loads after 2021)



Near-Term Portfolio Options to Default Diesel

Alternative portfolios including each of the above near-term resource options have been reviewed considering grid economic impacts, Yukon greenhouse gas emissions impacts and long-term development considerations. Near-term cost and rate impacts vary significantly depending in large part on the capital intensive nature of each resource option and its flexibility relative to major forecast load reductions after 2020 under all resource plan forecast scenarios.

Table 6-1 provides an overview of different resource portfolio near-term options indentified in the 2011 Resource Plan (Scenario A grid loads with DSM/SSE are assumed for this table)[30].

[30] The same Resource Portfolio Options apply for Scenario B loads with DSM/SSE, and for Scenario A or B loads with no DSM/SSE, subject to the LNG plant being 30 MW capacity rather than 22 MW capacity. Base Case Portfolio Options are more limited due to smaller scale of the diesel displacement loads, e.g., with DSM/SSE the options are Marsh Lake Storage & 2.2 MW WTE for Minimum GHG Portfolio, and LNG 4 MW or Marsh Lake Storage & LNG 4 MW for LNG Transition Portfolio [if no DSM/SSE, LNG plant scale increased to 8 MW]; for Base Case loads, LNG options assume simple cycle power plant (40% energy efficiency) and reliance on LNG availability in Yukon to supply off-grid mine loads.

In addition to the Default Diesel Portfolio, the following Portfolio Options are identified (resource options assumed to be in operation by start of 2015, except for Gladstone Diversion [assumed in operation by start of 2018]):

1. Minimum GHG Portfolio Options:
    a. Marsh Lake Storage & 15 MW Wood Biomass (89-92% reduction of grid diesel GHG for 2015-2019 period)[31].
    b. Marsh Lake Storage, Gladstone Diversion & 21 MW Wind (60-61% reduction of grid diesel GHG for 2015-17 period and 84-85% for 2018-19 period [after Gladstone]).
    c. Marsh Lake Storage, 21 MW Wind & 2.2 MW Waste-to-Energy (WTE) (70-74% reduction of grid diesel GHG for 2015-2019 period).
2. LNG Transition Portfolio Options:
    a. Marsh Lake Storage & LNG (22 MW) (52% reduction of grid diesel GHG for 2015-2019 period).
    b. LNG (22 MW) (48% reduction of grid diesel GHG for 2015-2019 period).

Table 6-1 compares the present value (PV) incremental generation costs of each Portfolio option over the 20-year planning period and the Forecast LCOE (levelized cost of energy over project life)[32].

- LNG Transition Portfolios have a much lower PV cost and Forecast LCOE than Default Diesel.
    - LNG Portfolio PV costs at 65-66% of PV costs for Default Diesel Portfolio.
    - LNG Forecast LCOE at 47-51% of Default Diesel Portfolio Forecast LCOE (61-66% if compare only with diesel fuel and O&M costs).
- LNG Transition Portfolios have a much lower PV cost and Forecast LCOE than any of the Minimum GHG Portfolio Options.
    - Minimum GHG Portfolio PV costs 110-120% of PV costs for Default Diesel Portfolio.
    - Minimum GHG Portfolio Forecast LCOE at 80-109% of Default Diesel Portfolio Forecast LCOE (104-141% if compare only with diesel fuel and O&M costs).

[31] The Wood Biomass resource option is typically assumed to operate year round – however, it is assumed to be flexible enough to shut down when grid annual load drops to very low levels after 2020 (as a result, the material O&M cost of $72.8/MW.h (2010$) is saved, providing this option with PV cost savings relative to other Minimum GHG resource options which do not have this flexibility).
[32] PV cost and LCOE assume discount rate of 6.56%/year based on YEC's 2009 GRA approved return on equity and cost of new long-term debt. PV cost excludes assumed $35.4 million PV cost for DSM/SSE over this period, which is common to all Portfolio options. Forecast LCOE for a specific resource option is cents per kW.h of forecast diesel displaced [2010$] over the assumed economic life of that resource option and assuming forecast diesel generation under Scenario A with DSM/SSE.

Table 6-1: Overview of Resource Portfolio Near-Term Options Scenario A with DSM/SSE: 2011-2030

	PV Cost million[1]	Forecast LCOE[2]	Capital Cost (2010$)		O&M Cost (2010$)		Reliable Capacity	Total Capacity	Energy Capability	Diesel Required/ Displaced
	(2010$)	c/kWh	$/MW	$million	$/MW.h	$mill./ year	MW	MW	GW.h/year	2015-19 av. GW.h/yr
Default Diesel Portfolio										
Diesel Energy	133.9	28.0			280.3	-			292.0	85
Diesel Capacity	34.7	8.1	1.5	55.6			37.1	37.1		
Total Default Diesel	**168.6**	**36.1**								
Min GHG Portfolio Options										
Marsh & 15 MW Wood Biomass										
Marsh Lake Storage	7.0	**34.8**		10.5	-	0.1	1.0	1.0	6.7	6
Wood Biomass (15 MW)*	121.8		5.7	85.5	72.8	4.0	15.0	15.0	120.0	72
Diesel Energy	39.7				280.3				166.4	7
Diesel Capacity	16.5		1.5	31.6			21.1	21.1		
Total	**185.0**			127.6			37.1	37.1		
*No O&M after 2020										
Marsh, Gladstone & 21 MW Wind										
Marsh Lake Storage	7.0	**29.0**		10.5		0.1	1.0	1.0	6.7	6
Gladstone Diversion	20.8			40.0		0.2	-	-	36.6	NA
Wind (21 MW)*	88.4		3.6	93.4		2.1	5.0	26.0	55.6	45
Diesel Energy	57.1				280.3				245.3	NA
Diesel Capacity	27.3		1.5	46.6			31.1	31.1		
Total	**200.6**			190.5			37.1	58.1		
*Includes 5MW DRUPS										
Marsh, 21 MW Wind, & 2.2 MW WTE										
Marsh Lake Storage	7.0	**39.4**		10.5		0.1	1.0	1.0	6.4	6
Wind (21 MW)*	88.4		3.6	93.4		2.1	5.0	26.0	55.6	45
2.2 MW Waste to Energy (WTE)	25.9		17.7	39.0		(0.3)	2.2	2.2	17.1	14
Diesel Energy	56.7				280.3				228.0	20
Diesel Capacity	24.6		1.5	43.3			28.9	28.9		
Total	**202.6**			186.2			37.1	58.1		
*Includes 5MW DRUPS										
LNG Transition Portfolio Options										
Marsh & 22 MW LNG										
Marsh Lake Storage	7.0	**17.1**		10.5		0.1	1.0	1.0	6.4	6
LNG (22 MW)	65.4		1.8	40.3	95.6-107.9	0.1	22.0	22.0	173.4	79
Diesel Energy	29.2				280.3				111.2	-
Diesel Capacity	10.6		1.5	21.1			14.1	14.1		
Total	112.1			71.9			37.1	37.1		
LNG (22 MW)										
LNG (22 MW)	69.0	**18.4**	1.8	40.3	95.6-107.9	0.1	22.0	22.0	173.4	85
Diesel Energy	29.2				280.3				119.1	-
Diesel Capacity	11.4		1.5	22.6			15.1	15.1		
Total	109.6			62.9			37.1	37.1		

Notes: 1. PV = Present Value cost over 20-year planning period (2011-2030). Excludes $35.4 million PV cost for DSM/SSE.
2. Forecast LCOE = Levelized Cost of Energy (cents/ kW.h of forecast diesel displaced [2010$]) over project life.

The LNG resource option has much lower incremental capital costs than the wood biomass or wind resource options examined, and much lower capital costs per MW than each of the Minimum GHG resource options. LNG, WTE and Wood Biomass resource options each provide reliable capacity equal to their plant capacity – in contrast, Wind and Gladstone each provide little if any reliable capacity benefits.

Comparative Rate Impacts for Near-Term Portfolio Options

The Default Diesel Portfolio shows material increases in grid diesel energy requirements by 2015 under all load scenarios. Assuming DSM/SSE, diesel fuel and O&M cost increases from 2011 to 2015 are projected at $4.3 million with Base Case loads, $25.9 million with Scenario A loads and $43.8 million with Scenario B loads (see Figure 5-1 and accompanying table). Increased revenues from new loads will offset some, but not all, of these increased costs - resulting in upward pressure on rates.

Unlike the Default Diesel Portfolio, LNG portfolio options allow major new incremental loads to occur by 2015 under Scenario A or B without requiring material rate increase impacts. As reviewed in Figure 6-2, average annual costs in 2015 with Scenario A loads and DSM/SSE are projected at 17 cents/kW.h with LNG (including capital costs) as compared to 29 cents/kW.h with diesel (fuel and O&M costs, excluding capital costs).

The Minimum GHG Portfolio options show varying rate impacts during 2015-2020 depending on the assumed load scenario. Overall, however, costs for these options during 2015-2019 are at best only slightly lower than diesel - and in several instances are higher than diesel fuel and O&M costs (see Figure 6-2).

After 2020 with Scenario A or B and DSM/SSE, the assumed drop in grid loads (when mine loads are forecast not to be connected, based on the then available information) at the outset could slightly reduce Default Diesel Portfolio rate impacts, but ongoing load growth by 2030 would lead to renewed rate increase pressures[33]. After the loss of the mine loads, LNG Transition Portfolio Options would continue to have lower rate impacts than any of the other non-diesel portfolio options - however, until later in the period (close to 2030) the Default Diesel Portfolio with these greatly reduced loads could have slightly lower rate impacts than the LNG Transition Portfolio Options[34].

A sensitivity test assuming connected mine loads continue to 2030 at sufficient levels to prevent a drop in grid diesel generation under the Default Diesel Portfolio indicates that the least cost LNG Transition

[33] Loss of mine loads leads to loss of all revenues from these loads, as well as reduced diesel costs as shown in Figure 5-1. All Portfolio Options, including Default Diesel, include assumed costs for DSM/SSE as well as capacity installed that are not reduced by mine load reductions.

[34] In cases with no DSM/SSE, the LNG Transition Portfolio Options would have lower rate impacts than Default Diesel in all years of the planning period (as well as lower rate impacts than any of the Minimum GHG Portfolio Options).

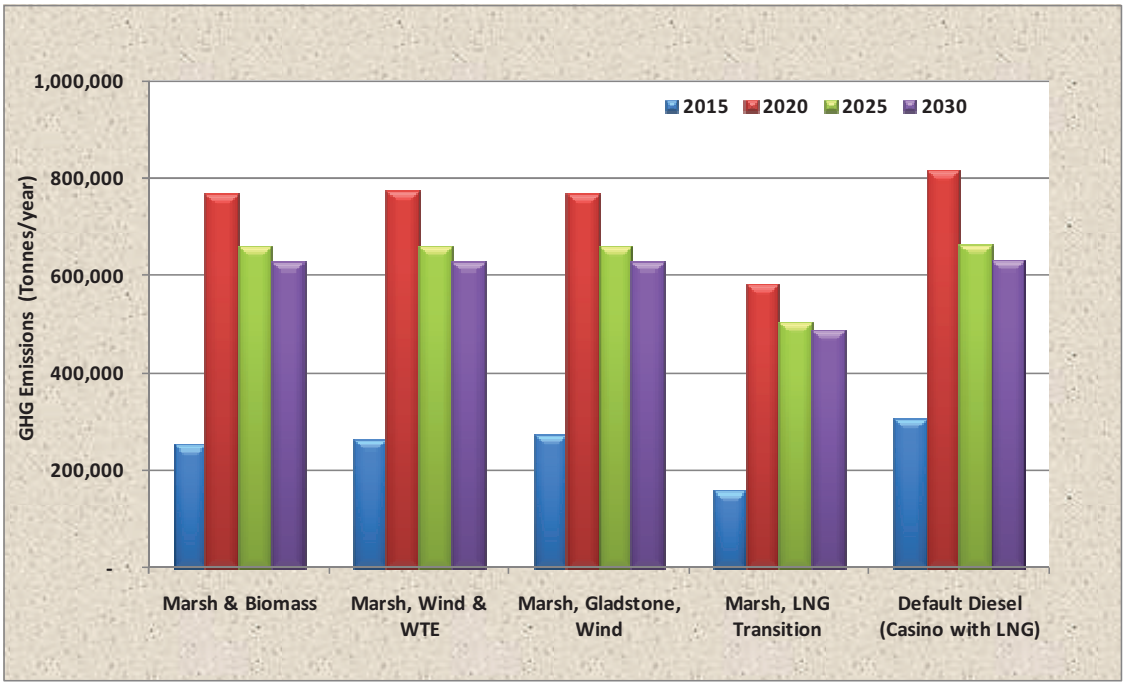
Portfolio Option continues through 2030 to show potential rate impacts that are materially lower than the potential rate impacts for all Minimum GHG Portfolio Options as well as the Default Diesel Portfolio.

Comparative GHG Emission Impacts for Near-Term Portfolio Options

LNG is the only non-diesel portfolio option examined for the near-term that can be used off-grid to reduce reliance on diesel (i.e., either off-grid communities or industrial customers).

Figure 6-5 demonstrates that when off-grid industrial and utility diesel community load opportunities are fully considered, near-term LNG supply development in Yukon as part of the LNG Transition approach has the potential to achieve far lower overall GHG emission levels from power generation in Yukon during the next 5-10 years than can be secured by grid-focused Minimum GHG Emissions Portfolio Options.

Figure 6-5: Portfolio Option Yukon GHG (tonnes/year) – 2015-2030
Grid Scenario A with DSM/SSE, Off-grid Diesel Community, & Off-Grid Mines



Total Yukon GHG Emissions (Tonnes/Year)[1]

	2015	2020	2025	2030
Marsh & Biomass	252,384	767,010	661,267	625,287
Marsh, Wind & WTE	263,266	775,226	661,267	625,287
Marsh, Gladstone, Wind	270,569	769,132	661,267	625,287
Marsh, LNG Transition[2]	158,844	582,266	505,355	488,089
Default Diesel (Casino with LNG)	306,067	815,235	662,522	630,560

1.Grid Scenario A with DSM/SSE, Off Grid Diesel Communities, & Off Grid Mines
2. Assumes LNG simple cycle at Watson Lake, LNG combined cycle at all mines.

The specified resource portfolios are examined in Figure 6-5, with any requirements not met by the specified resources assumed to be supplied by diesel generation under each portfolio. LNG is the only resource option other than diesel that can be applied in the near-term to off-grid as well as on grid requirements. The analysis excludes potential LNG impacts to reduce diesel and oil products in Yukon transportation and heating end uses (the largest GHG generating sectors in Yukon today).

- Yukon GHG emissions are materially lower in each time period with LNG than with any other resource option; reflects ability to apply LNG to off-grid diesel displacement.
- Overall LNG accessibility for all potential Yukon uses is facilitated by co-ordinated near-term planning and actions.

7.0 LONGER-TERM RESOURCE OPTIONS TO DEFAULT DIESEL

Greenfield Hydro Opportunities

A range of greenfield hydro resource project opportunities are potentially available to start construction before 2021, subject to appropriate planning and development of loads sufficient to fully utilize these resources[35]. These opportunities offer potential to establish sustainable lower cost electricity as well as low GHG emissions in a way similar to that secured by earlier legacy hydro developed in response to earlier major Yukon industrial mine developments.

Table 7-1 summarizes the available hydro sites by size of project, indicating key features as currently estimated (potential installed capacity, annual energy, capital cost and levelized lifecycle cost at full utilization)[36]. Total potential supply exceeds 6,800 GW.h/year at full utilization levelized cost (including transmission) below 15 cents per kW.h.

- **Hydro Options at less than 10 cents/kW.h** – Nine sites or schemes are identified with estimated Full Utilization LCOE's (2009$) below 10 cents per kW.h and over 4,390 GW.h per year of average annual sustainable energy (net of duplication among sites); four of these sites are Medium scale (11-60 MW) that could together provide over 850 GW.h/year; the other sites are Large scale (>60 MW).

- **Hydro Options at 10-15 cents/kW.h** – A further eight sites or schemes are identified with Full Utilization LCOE's between 10 and 15 cents per kW.h and over 2,000 GW.h of additional average annual sustainable energy; five of these sites are Medium scale (over 850 GW.h/year); the other sites are Large scale (>60 MW).

- **Other Medium Scale Hydro Options** – A further two Medium scale sites located north of the Watson Lake area are identified with Full Utilization LCOE's under 15 cents per kW.h if exceptionally high transmission cost estimates to connect to the existing grid are excluded from consideration. Together, these sites could provide over 375 GW.h per year of additional average annual sustainable energy.

[35] The geothermal option is identified in the 2011 Resource Plan as "other long-term options" in Yukon that might provide both low cost and low GHG emissions at some point during the planning period – however, beyond monitoring of related activities (e.g., geothermal exploration and confirmation drilling), the 2011 Resource Plan does not consider specific planning activities for the next five years. Similarly, monitoring of ongoing activities is all that is considered today with regard to potential development in the future of a natural gas pipeline, Eagle Plains gas, or transmission connection to the BC grid and/or Alaska.
[36] See Figure 1-2 for map showing the location of identified load and resource supply options.

Development of such longer-term renewable resource options is subject to connecting new grid loads that could fully utilize the specific resource options over 20-30 or more years.

- Potential off-grid mine developments prior to 2021 relying on fossil fuel generation are identified that could potentially exceed 1,500 GW.h/year and remain above 1,300 GW.h/year through 2045 in the event that three of these multi-decade off-grid mines are developed, i.e., the Casino Property west of the CSTP grid (940 GW.h/year), the Selwyn project located to the east of the WAF grid in the passes close to the border with NWT (147 GW.h/year), and the Northern Dancer project located near the Alaska Highway east of Teslin (200-300 GW.h/year).

- If the Alaska Highway Pipeline project proceeds, gas compressors for this project could potentially add 1,470 GW.h/year of additional equivalent energy requirements (six compressor stations) by approximately 2020/21 that would also be sustained over 25 years in the event that GHG emissions concerns support electrification initiatives.

Table 7-2 identifies potential off-grid mine loads and/or pipeline compressor loads that could radically change the electricity generation sector in Yukon during the next 5 to 10 years. These potential new loads offer the opportunity to plan for new legacy hydro development opportunities concurrent with actual development of new major mines or other major new loads. The following possible development packages are noted:

- **Develop Southern Lakes Grid Connection** – These are not low cost options; development of some of these options might be considered if Gladstone is not able to proceed and loads remain uncertain.

- **Develop Grid East of Ross River** – Potential options to consider in connection with Selwyn/Mactung mine loads, which offer 20+ years of load.

- **Develop Southern Grid to East Near Alaska Highway** – Potential options to consider in connection with Northern Dancer mine load and/or Alaska Highway Pipeline compression loads which offer 20+ years of load.

- **Develop Central & Western Yukon Grid** – Potential options to consider in connection with Casino and other mine loads south of Dawson City, which offer 20+ years of load.

Protecting the option to start construction for such projects before 2021 is contingent upon sustaining sufficient site specific planning processes as required throughout the next five year period through 2015. Figure 7-1 sets out proposed planning activities that would need to be pursued during the next five to ten years to protect the ability to start construction prior to 2021.

Coordination with LNG Transition Portfolio Option

The LNG Transition Portfolio Option is a near-term rather than a long-term legacy resource option for Yukon. The intent is to displace LNG use with appropriate renewable resource options when it is cost effective to do so, i.e., when sustained high utilization can be effectively achieved for renewable options so as to secure Forecast Utilization LCOEs that are equivalent to or less than LNG costs.

LNG Transition Portfolio Options are expected to show escalating costs as natural gas prices increase at a rate faster than general inflation. By 2020, the initial year costs for a new hydro development with a levelized cost (2010$) of 10 cents/kW.h might potentially correspond to the then current costs for LNG-supplied generation - in which case, subject to securing sufficient long-term load, the transition from LNG to new hydro could occur relatively smoothly[37].

At such time as new hydro develops, LNG grid generating unit capacity no longer needed for baseload energy generation can be retained for peaking, low water and emergency/grid reliability use. These units are flexible as to the range of such uses - and will likely be dual fuel in nature such that they can also use diesel fuel if so required. Furthermore, when new hydro is developed LNG supplies are expected to continue to be provided in Yukon to meet remaining off-grid power loads as well as other sector loads such as transportation[38]. Introduction of LNG/natural gas supplies in Yukon will also likely create longer-term development of natural gas use in the transportation and heating sectors.

[37] Figure 6-2 shows annual costs per kW.h during the period of forecast connected mine loads (2015-2020), indications that LNG annual costs (with capital) during this period remain well below annual costs for all renewable options other than the hydro enhancement options (Marsh Lake Storage and Gladstone Diversion) - by 2020, LNG costs in escalated dollars approximate 19 c/kW.h (13 cents for fuel and O&M only).

[38] These same considerations apply in the event that natural gas supplies come to be available directly in Yukon through the Alaska Highway Pipeline Project and/or Eagle Plain gas development. LNG liquefaction facilities may need to be moved to (or developed in) Yukon - but ongoing LNG requirements are anticipated to remain for off-grid power uses and other sectors.

Table 7-1: Summary of Potential Hydro Sites

		Installed Capacity (MW)	Annual Energy (GWh)	Capital Cost (Million $2009)	Levelized Cost (c/kWh)
Small Hydro Projects <10MW)					
20-23 c/kWh	Moon Lake	5.8	32.9	126.8*	19.9
	Tutshi River	4.2	30.3	135.5*	23.1
	Tutshi (Windy Arm)	5.9	39.4	164.9*	21.6
	Pine Creek at Atlin	3.5-8	23-52	NA	NA
Medium Hydro Projects (<60 MW)					
< 10 c/kWh	Hoole Canyon with Storage	40.4	275	460.1	8.6
	Granite Canyon Small	60.0	400	670.3	8.7
	Slate Rapids	41.6	266	505.6	9.8
	Finlayson	17.0	128.9	233.7**	9.4
10 to 15 c/kWh	Ross Canyon	30	181	495.0	14.1
	False Canyon	58	370	1,036.3**	14.5
	Two Mile Canyon	53.1	280	696.5	12.9
	Combined Slate Rapids[1] & Hoole	50.1	351.1	728.9	10.7
	Slate Rapids[1] (powerhouse at foot of dam	22.3	156.3	441.4	14.6
Other[2]	Middle Canyon	38.0	200	773.5***	20.0
	Upper Canyon	25.2	176.6	677.2***	19.8
Large Hydro Project (>60 mW)					
< 10 c/kWh	Granite Canyon High	254.0	1,783	1,680.7	4.9
	Fraser Falls Low	100.0	700	1,340.4	9.9
	Granite Canyon Low	80.0	600	934.8	7.3
	Fraser Falls High	300.0	2,100	2,540.6	6.3
	Combined Slate Rapids & Hoole	69.4	459	849.7*	9.6
10 to 15 c/kWh	Detour Canyon	65.0	435	1,057.0	12.6
	Detour Canyon w storage At Pelly Lakes	100.0	585	1,301.0	11.5
	Liard Canyon	93.5	659	1,554.6**	12.2

Notes:

1. Powerhouse at foot of dam

2. Excluding exceptionally high transmission costs to connect to existing grid, these sites would be under 15 cents per kW.h

* Transmission costs to connect to grid are 18% of cost for Tutshi (Windy Arm), 21% of cost for Combined Slate Rapids & Hoole Canyon, and 26-27% of cost for Moon Lake & Tutshi River.

** Transmission costs are 33% of cost for Liard Canyon, 36% of cost for Finlayson, and 38% of cost for False Canyon.

*** Transmission costs to connect to existing grid are estimated at 54-55% of cost for these sites.

Table 7-2: Yukon Industrial Load Opportunities and Potential Hydro Sites

POTENTIAL INDUSTRIAL LOAD OPPORTUNITIES

Developing low cost/low emission hydro options depends on connecting new grid loads that could adequately utilize the resource for 20-30 years

DEVELOP SOUTHERN LAKES GRID CONNECTIONS

Timing for development of these projects in the next decade will depend on whether or not Gladstone is developed, future grid loads and definition of distinct hydro project opportunities

DEVELOP GRID TO EAST OF ROSS RIVER

SELWYN (147 GWh/yr) **& MACTUNG**
30+ year load in service 2014/15 - A medium hydro project in the 17-30 MW range (129 to 181 GWh/yr) to the east of the northern WAF grid could match all or most of the Selwyn load

DEVELOP SOUTHERN GRID TO EAST NEAR ALASKA HWY

NORTHERN DANCER (200-300 GWh/yr) - a 30 year load in service in 2017 to east of Teslin. A medium hydro project to serve this load could provide basis for extension of grid in south-east portion of Yukon

PIPELINE COMPRESSOR - Marsh Lake - 245 GWh/yr load per compressor in service in 2020/21 - Could provide anchor load for a medium hydro project in 266-280 GWh range (25 year load)

PIPELINE COMPRESSOR - Alaska Hwy - 245 GWh/yr load per compressor in service in 2020/21; May provide an opportunity to develop sites and transmission in east Yukon such as Liard Canyon (25 year load); Liard Canyon may also support develpment of NORTHERN DANCER

DEVELOP CENTRAL & WESTERN YUKON GRID

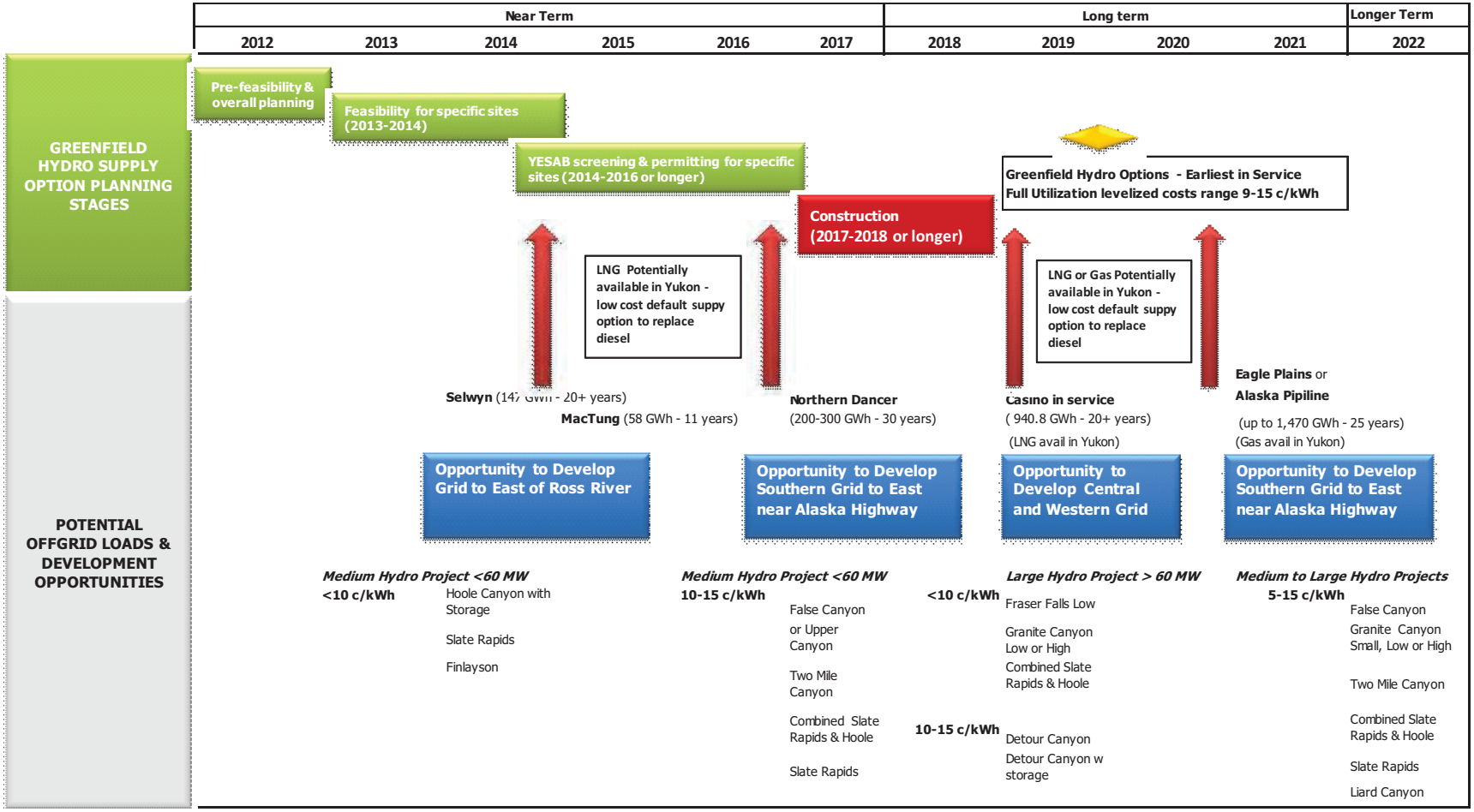
CASINO MINE (940.8 GWh/yr)
20-30 year load in service in 2018-19 - A large hydro project in the 69-100 MW range (450-700 GWh/yr) reasonably near the CSTP grid could match a large share of the Casino Load

POTENTIAL HYDRO DEVELOPMENT OPPORTUNITIES

		Installed Capacity (MW)	Annual Energy (GWh)	Levelized Cost (c/kWh)
Small Hydro Projects (<10MW)				
	Southern Lakes Projects			
20-23 c/kWh	Moon Lake	5.8	32.9	19.9
	Tutshi River	4.2	30.3	23.1
	Tutshi (Windy Arm)	5.9	39.4	21.6
	Pine Creek at Atlin	3.5 to 8	23-52	N/A
Medium Hydro Projects (<60 MW)				
< 10 c/kWh	Hoole Canyon with Storage	40.4	275	8.6
	Slate Rapids	41.6	266	9.8
	Finlayson	17	128.9	9.4
10-15 c/kWh	Ross Canyon	30	181	14.1
Medium Hydro Projects (<60 MW)				
10 to 15 c/kWh	False Canyon	58	370	14.5
	Middle Canyon*	38	200	20.0
	Upper Canyon*	25.2	176.6	19.8
	Two Mile Canyon	53.1	280	12.9
8.7 10 to 15 c/kWh	Combined Slate Rapids & Hoole	50.1	351.1	10.7
	Granite Canyon Small	60	400	8.7
	Slate Rapids	22.3	156.3	14.6
Large Hydro Project (> 60 MW)				
10-15 c/kWh	Liard Canyon	93.5	659	12.2
Large Hydro Project (> 60 MW)				
< 10 c/kWh	Granite Canyon Low	80	600	7.3
	Fraser Falls Low	100	700	9.9
	Granite Canyon High	254	1783	4.9
	Fraser Falls High	300	2100	6.3
	Combined Slate Rapids & Hoole	69.4	459	9.6
10 to 15 c/kWh	Detour Canyon	65	435	12.6
	Detour Canyon w storage	100	585	11.5

*Transmission costs to connect to existng grid are 54-55% of levelized cost.

Figure 7-1: Overview of Planning Activities for Greenfield Hydro Supply Option Development - 2011-2021



8.0 SUMMARY CONCLUSIONS & RECOMMENDED PLANS

Overview of Options

Figure 8-1 summarizes near-term options examined in the 2011 Resource Plan in the context of Yukon Energy's four key planning principles. Conservation/efficiencies (DSM/SSE) programs are being developed as an option to be pursued in combination with other selected resource options.

Figure 8-1: Near-Term Resource Supply Options[39]

OPTIONS	**Reliability** Winter Peak Capacity; Development Timing & Cost	**Affordability** Potential lifecycle cost per kWh if fully used	**Flexibility** Ratepayer Risk re: Mine Load Reductions	**Environmental Responsibility** Env. Mitigation; GHG Emission Reduction
Southern Lakes (Marsh Lake) Hydro Enhancement	**Medium**	**High**	**Medium**	**High**
Gladstone Diversion Hydro Enhancement	**Medium**	**High**	**Medium**	**High**
Conservation / Efficiencies	**Medium**	**High**	**Medium**	**High**
Biomass	**High**	**Medium**	**Low**	**High**
Liquefied Natural Gas	**High**	**Medium / High**	**High**	**Medium**
Wind	**Low**	**Low**	**Low**	**High**
Diesel	**High**	**Low**	**High**	**Low**

Table 8-1 provides an overview of the near-term resource options identified for potential construction start on the grid before 2015 (including a 3 MW wood biomass pilot plant option[40]), and the longer term resource options identified for potential construction start before 2021. The Gladstone Diversion project is excluded from the near-term options on the basis that construction start is not feasible before 2015, and

[39] See Table 4-1 for more detail.

[40] The 2011 Resource Plan examined various wood biomass plant options, ranging from 10 MW to 25 MW and at different locations to accommodate potential wood biomass supply (e.g., Whitehorse for 25 MW plant; 10 to 15 MW plant in Minto burn area option). Based on feedback from the workshop held on wood biomass, this option has been scaled back to a 2-3 MW wood biomass pilot plant option. Yukon Energy is currently developing a partnership with the Champagne and Aishihik First Nations and Dakwakada Development Corporation to examine opportunities for a small-scale (2-3 MW) wood biomass pilot project, potentially with existing wood operations at Haines Junction, and to seek funding support for this pilot plant.

earliest in-service is in late 2017. Table 8-2 provides a more detailed overview of the near-term resource option capabilities and costs under both Scenario A and B grid loads with DSM/SSE.

In the near-term, LNG is identified in the 2011 Resource Plan as the only near-term option that can totally displace Default Diesel on the grid during 2015-2019 with forecast Scenario A or B loads (e.g., with forecast diesel generation ranging from 85 to 143 GW.h/year with DSM/SSE). Excluding the relatively small energy impact Marsh Lake Storage hydro enhancement option (approximately 6 GW.h/year), LNG is also the lowest cost near-term option, with costs per kW.h of diesel displaced less than half the cost of diesel. Wood Biomass ranks second behind LNG in diesel displacement capability, but is the highest cost near-term option (with costs per kW.h of diesel displaced higher than the cost of diesel). The only other near-term option with potential ability to displace more than 50% of Scenario A diesel generation requirements (i.e., Wind) has 2015-2019 costs per KWh only slightly lower than diesel, and forecast LCOE costs that are higher than diesel under Scenario A or B loads with the assumed DSM/SSE.

In contrast to the near-term options, longer term hydro options are identified in the 2011 Resource Plan that offer a wide range of annual energy capability (e.g., options in Table 8-1 range from 33 to over 450 GW.h/year), with several options also having estimated Full Utilization LCOE at less than 10 cents/kW.h. The 2011 Resource Plan outlines the requirements for successful development of these longer term options, including securing appropriate long-term loads as required to adequately utilize such options over 20-30 or more years and sustaining sufficient and successful site specific planning processes over the next five years to protect the ability for potential construction start before 2021.

Tables 8-1 and 8-2 also show the extent to which each near-term resource option's economic feasibility (i.e., comparative LCOE) is affected by the option's flexibility to adapt to Yukon's isolated grid and the expected range of load and hydro generation conditions on this grid.

- LNG, Wood, Wind and Waste-to-Energy options, for example, show minimal variation in estimated LCOE when full utilization is simply assumed of all electricity generated for each option, e.g., LCOEs (2010$) for these options range from 12 c/kW.h for LNG to 17 c/kW.h for the 3 MW Wood Pilot.

- However, when Scenario A forecast loads (which are well in excess of Base Case loads) and expected hydro conditions on Yukon's isolated grid are considered, LNG is the only option with an LCOE at less than 20 c/kW.h for diesel displaced, and the 3 MW Wood Pilot is the only other option with an LCOE less than diesel fuel and O&M cost at 28 c/kW.h. Higher LCOEs for Wind, 15 MW Wood Biomass and 2.2 MW Waste-to-Energy options in this instance reflect relative

inflexibility to adapt to an assumed sharp drop in mine loads on the grid after 2020 as well as seasonal and annual variability in hydro generation on the grid.

LNG Transition Option Near-Term Benefits

In summary, the 2011 Resource Plan indicates that the LNG Transition Portfolio option provides a range of potential benefits relative to the other near-term grid generation options available for potential commitment before 2015:

- LNG is superior to diesel in terms of cost (affordability) and emissions (environmental responsibility); relative to near-term renewable resource options, LNG is less costly while also providing high reliability, flexibility and diversity of potential Yukon uses on and off-grid.
- Where established, LNG would displace diesel as the default option in Yukon (although dual fuel units could also cost effectively retain flexibility to use diesel if and when advantageous). Lower cost LNG fuel would affect the assessment of future resource choices and also incremental pricing and rate setting in the rate zones where it is utilized, i.e., run out rates for higher use levels could be set based on LNG costs rather than diesel fuel costs.
- Other potential development benefits include:
    - LNG is the only option to offer material reductions in near-term rate increase impacts relative to diesel under Scenario A or B loads, as well as the non-diesel option with the lowest rate impacts in the event that currently assumed mine closures reduce grid loads after 2020.
    - LNG provides a cost effective contribution to grid capacity planning requirements, and the planned retirements of all of YEC's diesel plant over the 20-year planning period.
    - As a result of the above impacts, LNG is the only option to offer opportunity to reduce present value diesel costs during the planning period under Scenarios A and B (projected reductions at 35% under Scenario A and 41% under Scenario B).
    - Overall, LNG offers high flexibility with ability to be turned off and ability to accommodate load changes; it can provide cost effective baseload generation and backup capacity, and can be cost effectively developed concurrently with hydro enhancements such as Marsh Lake Storage and Gladstone Diversion.
    - The LNG Transition Option can accommodate optimum timing for Gladstone diversion, other potential hydro enhancements or greenfield developments, and wind development

in response to confirmation of longer-term grid loads needed to secure reduced Forecast LCOE for these various renewable resource options.

- LNG is the only portfolio option that can be used off-grid to reduce reliance on diesel (i.e., off-grid communities such as Watson Lake and mines at various off-grid locations). This option can also be used to reduce GHG emissions in other sectors where GHG emissions impacts are more significant (e.g., transportation).

In order to pursue the LNG option for near-term development for power generation in Yukon by late 2014, Yukon Energy is pursuing further feasibility work to determine the optimum way to secure the LNG, the required timing and all related costs (including assessment of potential options for LNG supply chain development jointly with other interests to meet broader near and longer term Yukon opportunities). Feasibility work is also being pursued to optimize the specific Yukon Energy generation capacity and technology for power generation using LNG (including assessment of the optimum combination of combined cycle and simple cycle units in response to different potential load scenarios).

Resource Portfolios - Combining Options

Combining projects on the Yukon grid can dilute the benefits and raise LCOEs relative to what is shown for individual options.

For example, the Scenario A (with DSM/SSE) LCOE is 11.4 c/kW.h for Marsh Lake storage on its own and 8.0 c/kW.h for Gladstone Diversion on its own (see Table 8-1) - however, combining these two hydro enhancement projects results in a higher overall LCOE at 13.1 c/kW.h for the combined projects.

Similarly, LCOEs (2010$)per kW.h of displaced diesel generation for various renewable resource options under Scenario A loads are significantly higher when combined with the assumed DSM/SSE than when assessed without DSM/SSE[41]:

- Marsh Lake Storage LCOE: 11.4 c/kW.h with DSM/SSE, 8.6 c/kW,h without DSM/SSE.
- Gladstone Diversion LCOE: 12.0 c/kW.h with DSM/SSE, 6.5 c/kW,h without DSM/SSE.
- 2.2 MW Waste to Energy: 31.5 c/kW.h with DSM/SSE, 17.6 c/kW,h without DSM/SSE.
- 3 MW Wood Pilot: 35.4 c/kW.h with DSM/SSE (with assumed shut down in 2020), 22.7 c/kW,h without DSM/SSE (no shut down).
- 15 MW Wood Biomass LCOE (with assumed shut down after 2020): 40.1 c/kW.h with DSM/SSE, 17.8 c/kW,h without DSM/SSE.

[41] LNG LCOE for Scenario A also slightly reduced (18.4 c/kW.h with DSM/SSE, 14.0 c/kW.h without DSM/SSE).

- 21 MW Wind with 5 MW DRUPS: 40.0 c/kW.h with DSM/SSE, 19.6 c/kW.h without DSM/SSE.

In summary, dilution of benefits and higher LCOEs that result from combining projects highlight once again the extent to which load and hydro conditions on the isolated Yukon grid can critically affect economic assessment of resource option portfolios.

Table 8-1: Overview of Resource Options - Capabilities and Costs

	Capital ($2010 million)	Capacity (MW)	Energy Capability (Average GWh/yr)	2015-2019 Diesel Required/ Displaced (GWh/yr)	2015-2019 Annual Costs (cents/kW.h diesel displaced)	LCOE (2010 c/kWh) Scenario A	LCOE (2010 c/kWh) Extend 2019 load to 2030	LCOE (2010 c/kWh) Full Utilization
Near Term Options (able to start construction before 2015) with Scenario A Loads and DSM/SSE - Default Diesel is new capacity needed by 2030								
Default Diesel Requirement	56	37	292	85	29-31 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)
Waste to Energy	39	2.2	17	14	27-31	31.5	19.0	13.5
Wind with 5 MW DRUPS	93	26*	56	45	26-29	40.0	21.3	14.8
		*21 MW wind not firm						
		10.5 MW wind option was slightly less cost-effective at forecast loads.						
Marsh Lake Storage	10	NA	6.7	6.4	15-16	11.4	8.8	8.5
25 MW Wood Biomass	114	25	199	85	48-51	55.4*	42.8	16.6
15 MW Wood Biomass	86	15	120	72	33-35	40.1*	28.8	15.8
3 MW Wood Pilot (Haines J.)	19	3	24	18	28-29	35.4*	24.7	17
						*shut down after 2020		
LNG Transition	40	22	173	85	17	18.4	14.1	12
Long Term Options (Potential start construction before 2021)								
Gladstone Diversion	40	NA	36.6	29	14	12.03	8.0	5.7
Greenfield Hydro (examples)								
Moon Lake	127*	5.8	32.9	NA	NA	NA	NA	19.9*
Hoole Canyon (w storage)	460*	40.4	275	NA	NA	NA	NA	8.6*
Slate Rapids	506*	41.6	266	NA	NA	NA	NA	9.8*
Finlayson	234*	17.0	129	NA	NA	NA	NA	9.4*
Combined Slate & Hoole	850*	69.4	459	NA	NA	NA	NA	9.6*
	*Inc. Transmission to grid							*Inc. Transmission to grid

Table 8-2: Overview of Near-Term Resource Options - Capabilities and Costs: Scenario A Loads with DSM/SSE (options that could start construction before 2015 – Default Diesel Capacity is new grid capacity required before 2030)

	37 MW Default Diesel	22-30 MW LNG	15 MW Wood Biomass	3 MW Wood Pilot (Haines Junction)	21 MW Wind and 5 MW DRUPS[1]	2.2 MW Waste-to-Energy	Marsh Lake Storage
		Sc. A vs. Sc.B)					
Capital Cost (2010$ million)	56	40-55	86	19	93	39	10
Reliable Peak Winter Capacity Contribution (MW)	37	22-30	15	0	5	2.2	1
Annual Energy Supply (GW.h/year)							
Annual Energy Capability	292	173 - 236	120	24	56	17	6.7
2015-19 Average Diesel Energy Required/Displaced							
Scenario A Load with DSM/SSE	85	85	72	18	45	14	6.4
Scenario B Load with DSM/SSE	143	143	93	22	51	16	6.6
Near term supply Issues/risks	NA	LNG supply BC/Alta	Wood Supply Regime	NA	NA	NA	Regulator approval timing
2015-19 Annual Costs (cents/kW.h diesel displaced)	(fuel+O&M)	(All cost)	(All cost)	(All cost)	(All cost)	(All cost)	(All cost)
Scenario A Load with DSM/SSE	29-31	17	33-35	28-29	26-29	27-31	15-16
Scenario B Load with DSM/SSE	29-31	16-17	27	24-25	24-26	24-27	14-15
2015-19 Cost Savings (% of Diesel Fuel and O&M)							
Scenario A Load with DSM/SSE	NA	43%	-11%	1%	4%	1%	4%
Lifecycle Cost of Energy (2010 cents/kWh diesel displaced)	(fuel+O&M)	(All cost)	(All cost)	(All cost)	(All cost)	(All cost)	(All cost)
Scenario A Load with DSM/SSE	28.0	18.4	40.1*	35.4*	40.0	31.5	11.4
Scenario B Load with DSM/SSE	28.0	17.0	31.6*	30.0*	36.5	28.8	11.1
Extend Scenario A 2019 load to 2030	28.0	14.1	28.8	24.7	21.3	19.0	8.8
Full Utilization of all energy in each year	28.0	12	15.8	17	14.8	13.5	8.5
Ability to adjust to load changes	Flexible	Flexible	Semi-flexible	Semi-flexible	Not flexible	Not flexible	Semi-flexible

* Shut down after 2020

Note #1: 10.5 MW wind option was slightly less cost-effective at forecast loads.

Graphic Comparisons of Near-Term Options

Figures 8-2, 8-3 and 8-4 compare key features of the near-term options and Gladstone Diversion under Scenario A loads with DSM/SSE, highlighting each option's comparative diesel displacement capability (GW.h/year) during 2015-2019. DSM/SSE (conservation/efficiency) option impacts as assumed in the 2011 Resource Plan are also included for broad comparison[42].

Figures 8-2 and 8-3 compare lifecycle costs per kW.h (LCOE) and capital cost for each option, with Figure 8-3 showing the extent to which LCOE is reduced for each option under Scenario A if the 2019 grid loads are extended to 2030.

- Based on total capital costs ($2010) as shown in Figures 8-2 and 8-3, the wind and large scale biomass options require considerably higher capital costs than other near-term options, and LNG provides far greater diesel displacement than any other option requiring similar capital costs.

- Based on LCOE (2010$) for Scenario A loads with DSM/SSE as shown in Figure 8-2, near-term options with forecast lifecycle costs that are less the diesel include conservation/efficiency, hydro enhancements (Marsh Lake and Gladstone Diversion) and LNG; near-term option options with forecast lifecycle costs that are more than diesel include the biomass and wind options.

- Comparison of Figure 8-2 and 8-3 LCOE for any option highlights sensitivity to major changes in grid loads over the planning period, e.g., the wind and biomass options show significantly lower LCOE's if the 2019 grid loads are assumed to be extended to 2030.

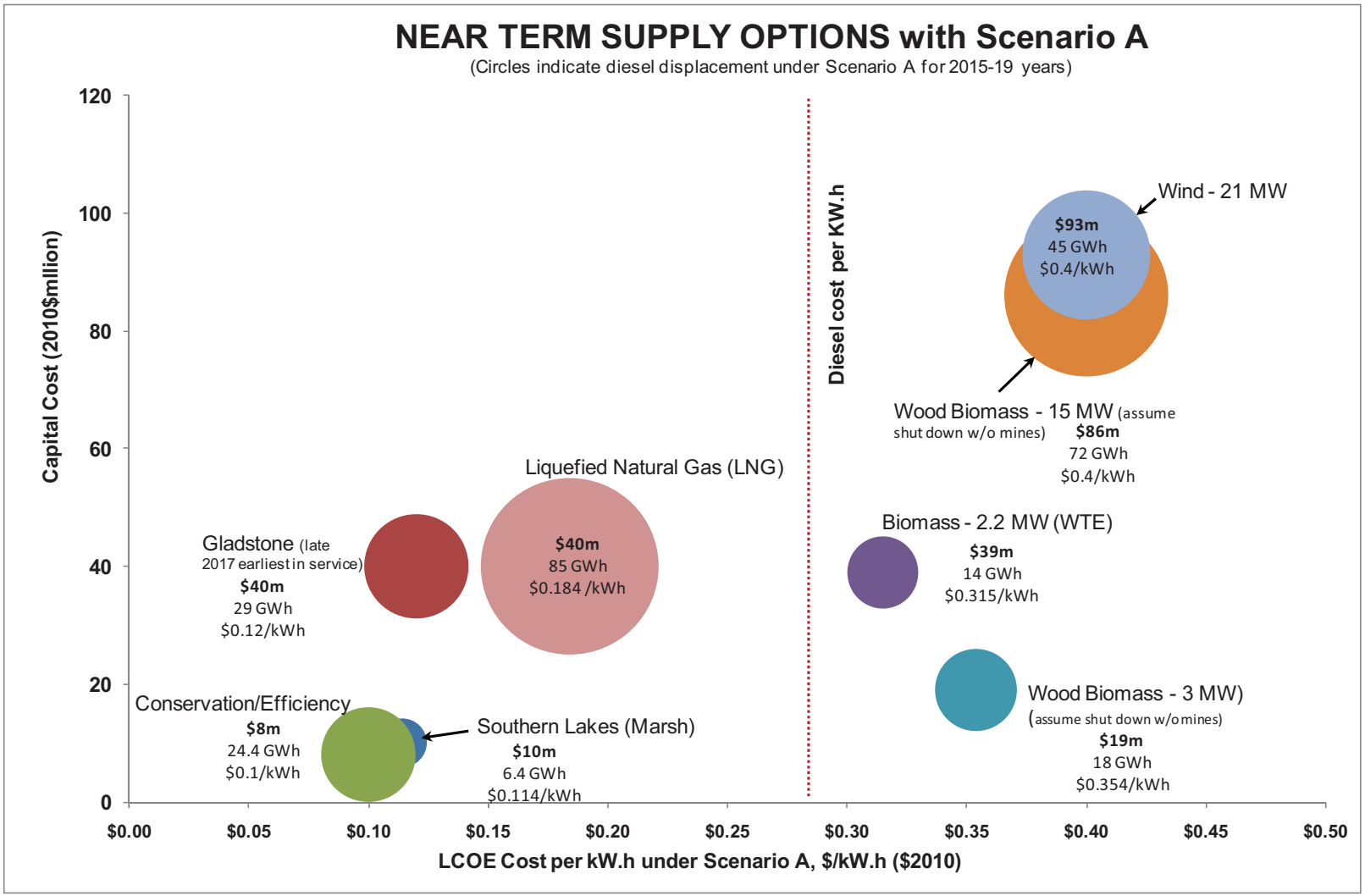
Figure 8-4 focuses on impacts in the 2015-2019 period, comparing costs per kW.h and percentage savings in diesel fuel and O&M costs for each option.

- Differences in cost per kW.h of diesel displaced for the first few years of operation (2015-19) reflect normal utility costing (e.g., capital costs charged per year decline over the project life).

- Comparative near-term diesel fuel and O&M cost savings for ratepayers reflect diesel displacement capability as well as near-term cost saving capability per kW.h relative to diesel generation for each option, and highlight LNG's overall cost saving benefits relative to other near-term options.

[42] These figures show the maximum potential DSM/SSE (conservation/efficiency) diesel displacement impacts assumed in the 2011 Resource Plan for non-industrial load reduction during the 2015-2019 time period. As noted in Appendix A, pending completion of current DSM/SSE planning, it is considered that likely DSM/SSE over the period to 2030 will be 50% of this maximum. In the near-term period from 2015 to 2019, DSM/SSE will be in an initial implementation phase and accordingly may be less (relative to the 2011 Resource Plan maximums) than levels expected to be achieved by 2030.

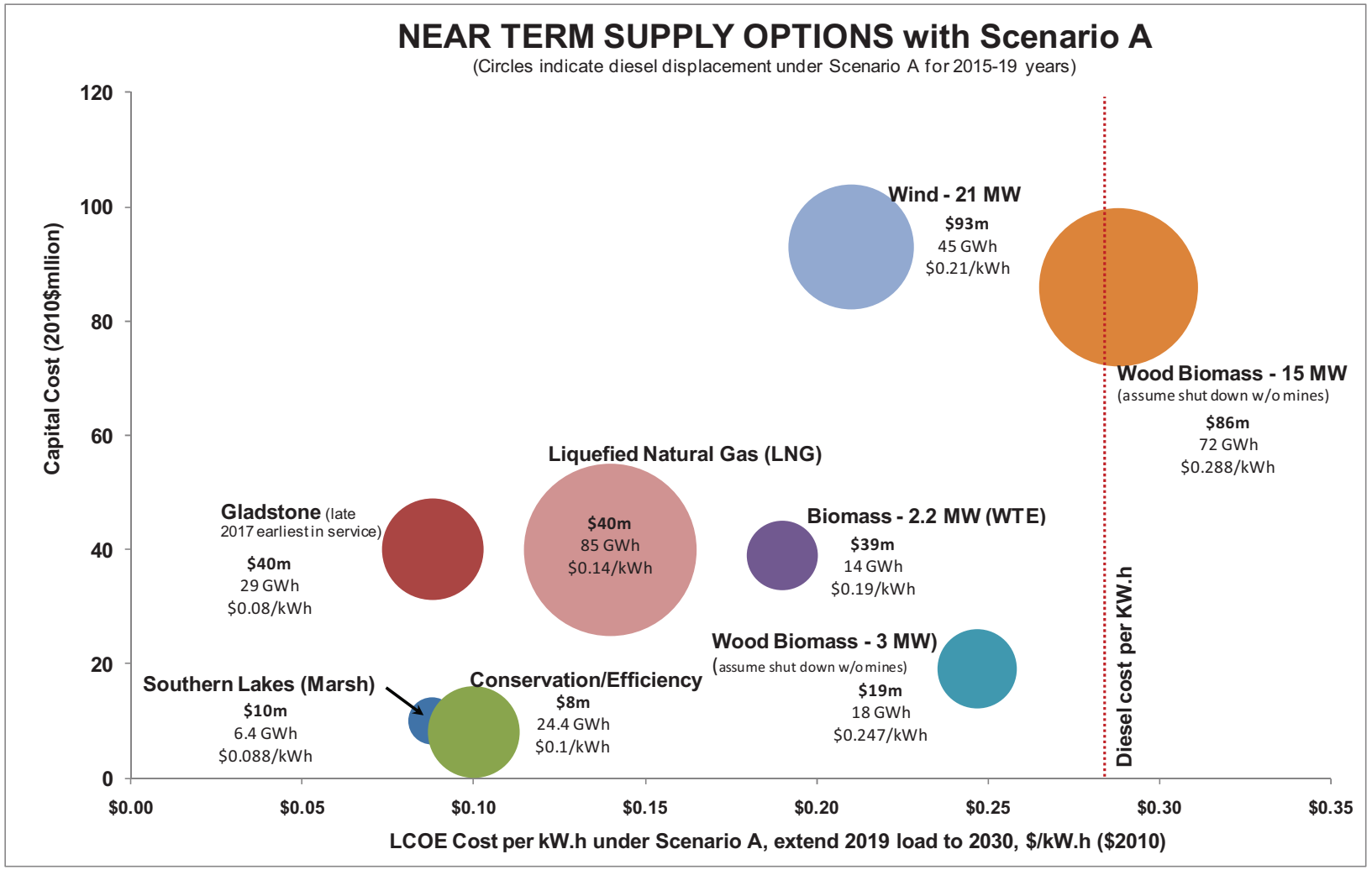
Figure 8-2: Overview of Near-Term Resource Options with Scenario A Loads (LCOE, Capital Cost & Diesel Displacement)



Source: Table 8-2 and Table 8-1.

Figure 8-3: Overview of Near-Term Resource Options with Scenario A Loads

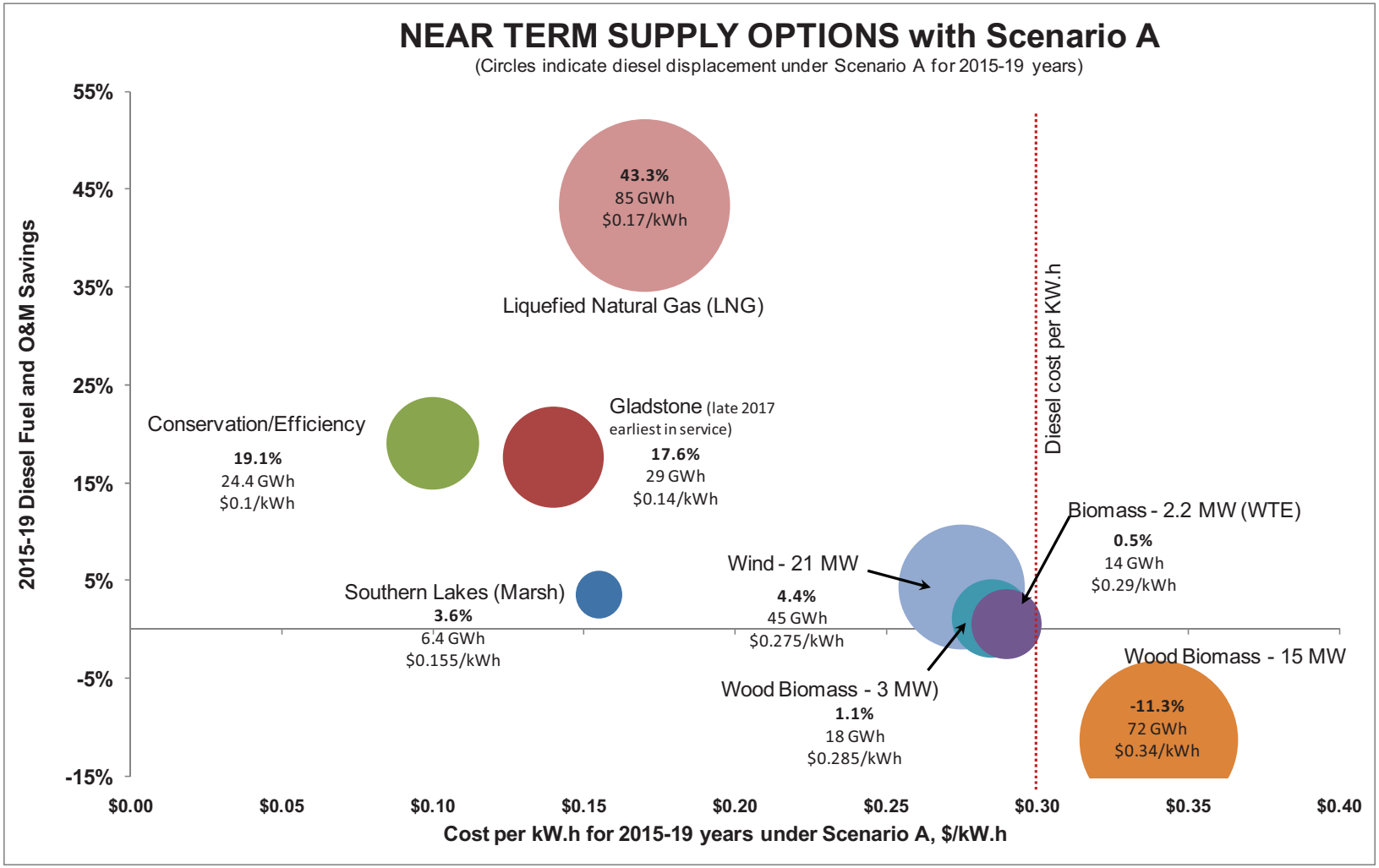
(LCOE with 2019 load extended to 2030, Capital Cost & Diesel Displacement)



Source: Table 8-2 and Table 8-1.

Figure 8-4: Overview of Near-Term Resource Options with Scenario A Loads 2015-2019

(Cost per kW.h, Diesel Fuel and O&M Savings, & Diesel Displacement)



Source: Table 8-2 and Table 8-1.

Recommended Plans

Based on the 2011 Resource Plan, Yukon Energy's recommended plans for the period prior to 2015 include the following (in addition to implementing cost-effective DSM/SSE pursuant to the separate ongoing planning process currently underway with other parties):

1. **LNG Transition Option:** Subject to successful completion of current assessments, determine whether Yukon Energy is able to establish LNG generating capability in Whitehorse prior to 2015 with sufficient capacity to displace grid diesel generation under current Base Case grid load forecasts, and determine the feasibility of utilizing LNG in the event that material additional near-term grid loads occur such as those assessed in Scenarios A and B. This action is being undertaken to implement LNG as a transition option that is able to meet current forecast loads with the least cost option available for near-term implementation, i.e., prior to 2015, and with reduced GHG and other emissions relative to diesel generation.

2. **Near-term Hydro Enhancements:**

    a. Complete the required environmental, engineering and remediation studies related to the Marsh Lake Storage hydro enhancement project and make a determination whether it is feasible and cost effective to proceed once this information is available.

    b. Plan within the next 6 to 12 months to reach a final determination regarding whether Gladstone Diversion is feasible to pursue further at this time, based on discussions with local First Nations and regulators.

3. **Future Development:**

    a. **Wind:** Finish current Ferry Hill wind monitoring in order to have this project shelf-ready to pursue through regulatory submissions and other development activity at such time as grid loads and other relevant conditions indicate that this project would be cost-effective to implement. Continue to examine for initial development the feasibility of smaller wind projects in the range of 10 MW to meet suitable grid loads.

    b. **Greenfield Hydro Sites:** Continue to carry out planning studies to identify and plan priority longer-term greenfield hydro development opportunities as recommended in the 2011 Resource Plan, including Hoole and Finlayson sites, and seek funding support for these activities.

4. Other Longer-Term Resource Planning:

a. **Geothermal:** Carry out scaled down geothermal investigations and look for funding support for geothermal exploration and studies, and seek funding support for these activities.

b. **Grid Extensions:** Continue to explore opportunities to extend the grid within Yukon, and to connect the Yukon grid to British Columbia and/or Alaska (including Skagway). A watching brief with regard to grid extensions to BC or Alaska and other potential longer-term resource options.

c. **Wood Biomass:** Identify and pursue opportunities for a small scale (e.g., 2 to 3 MW) wood biomass pilot project, potentially in association with existing wood operations at Haines Junction, and seek funding support for this pilot project.

d. **Other Options:** Continue watching briefs with regard to other resource options, including:
   i. Solar (cost-effective proven technology development suited to Yukon market conditions); and
   ii. Pipeline/natural gas (commitments by others regarding Alaska Highway Pipeline and/or potential Eagle Plain or other Yukon natural gas development).

APPENDIX A: UPDATED NEAR-TERM GRID LOAD SCENARIOS

The 2011 Resource Plan grid load scenarios are updated on an ongoing basis. As at spring 2012, four load scenarios are currently applicable for Yukon Energy grid generation and capacity planning (see Table A-1):

1. Load scenarios without connection of major new mines:

    a. **Base Case:**[43]

        i. GRA forecast loads for 2012 and 2013;
        ii. non-industrial growth after 2013 at 2.26%/year less 50% of DSM/SSE assumed in 2011 Resource Plan;
        iii. Minto generation load at 46.7 GW.h/yr (same as 2013) until 2019, and 23.4 GW.h in 2020 until mid-year (no load thereafter);
        iv. Alexco generation load at 21.7 GW.h/year 2014-16 (as compared to 15.9 GW.h/yr forecast in 2013); 15.0 GW.h/yr assumed 2017-2020 (no load thereafter); and
        v. Whitehorse Copper Tailings (WHCT) at 9.3 GW.h/yr 2014-2018 (as compared to 5.2 GW.h/yr in 2013) and 4.1 GW.h in 2019 (no load thereafter).

    b. **Base Case with Brewery Creek:** Base Case with the added connection, starting January 2014, of Brewery Creek mine with generation load assumed of 20.5 GW.h/yr in 2014 and 33.88 GW.h/yr thereafter until the end of 2023[44].

2. Load scenarios with connection of major new mines:

    a. **Scenario A:** Base Case with Brewery Creek and Victoria Gold mine, starting January 1, 2015 with generation load of 103.3 GW.h/yr that continues until the end of 2024 (no load thereafter)[45].

[43] The Base Case loads are expected to be reviewed in future to consider higher near-term non-industrial load growth (related to increased use of electric heat, consideration of Whistle Bend subdivision development impacts, and expected DSM/SSE timing which may indicate lower DSM/SSE impacts in near-term), and more recent information on Minto, Alexco and WHCT loads. The current Base Case does not consider Capstone's June 2012 announcement of Phase VI Pre-feasibility study results that extend Minto mine life to 2022. PPA negotiation for WHCT has not yet commenced.

[44] Negotiation of a PPA with Brewery Creek has not yet commenced. The load forecast includes expansion as provided by WHCT plans. This mine has expressed interest in connection in second half of 2013.

[45] PPA negotiations are ongoing with Victoria Gold (an earlier LOI set out principles for connection to the grid). It is assumed that Victoria Gold will pay all costs required for grid connection, plus upgrade of the Mayo-Keno line. The timing for connection of this mine remains uncertain (but will not be earlier than the Q1 2015 assumed in Scenario A).

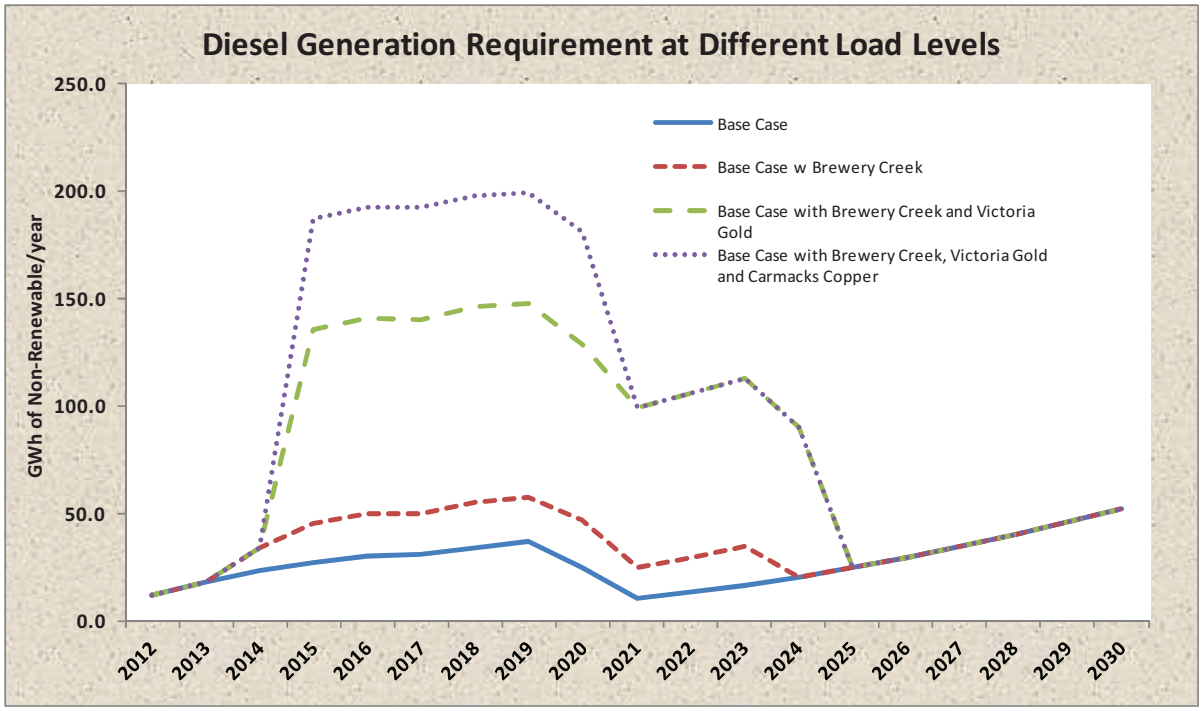
b. **Scenario B:** Base Case with Brewery Creek, Victoria Gold and Carmacks Copper mine, starting January 1, 2015 with generation load of 56.5 GW.h/yr that continues until the end of 2020 (no load thereafter)[46].

[46] Carmacks Copper has recently re-started its regulatory review processes, with an announced filing of a revised application planned this fall with YESAB, followed shortly thereafter with revised filing with the YWB. PPA discussions occurred in the past, and have been restarted – Carmacks Copper will be required to pay all costs required for grid connection plus a contribution to CSTP capital costs. The timing for connection of this mine remains uncertain, but could potentially occur during 2015 or (perhaps more likely) during 2016.

Table A-1: Updated Grid Load Scenarios

Forecast Years	Base Case			Base Case w Brewery Creek			Base Case with Brewery Creek and Victoria Gold			Base Case with Brewery Creek, Victoria Gold and Carmacks Copper		
	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)	Non-industrial Load (GW.h)	Industrial Load (GW.h)	Total Generation (GW.h)
2012	359.0	56.9	415.9	359.0	56.9	415.9	359.0	56.9	415.9	359.0	56.9	415.9
2013	362.6	67.8	430.4	362.6	67.8	430.4	362.6	67.8	430.4	362.6	67.8	430.4
2014	365.5	77.8	443.3	365.5	98.4	463.9	365.5	98.4	463.9	365.5	98.4	463.9
2015	371.3	77.8	449.1	371.3	111.7	483.0	371.3	215.0	586.2	371.3	271.5	642.8
2016	377.2	77.8	455.0	377.2	111.7	488.9	377.2	215.0	592.1	377.2	271.5	648.7
2017	383.2	71.1	454.3	383.2	104.9	488.2	383.2	208.2	591.4	383.2	264.7	648.0
2018	389.4	71.1	460.5	389.4	104.9	494.4	389.4	208.2	597.6	389.4	264.7	654.1
2019	395.7	65.9	461.6	395.7	99.8	495.5	395.7	203.0	598.8	395.7	259.6	655.3
2020	402.2	38.4	440.5	402.2	72.3	474.4	402.2	175.5	577.7	402.2	232.0	634.2
2021	408.8		408.8	408.8	33.9	442.7	408.8	137.1	545.9	408.8	137.1	545.9
2022	415.5		415.5	415.5	33.9	449.4	415.5	137.1	552.7	415.5	137.1	552.7
2023	422.4		422.4	422.4	33.9	456.3	422.4	137.1	559.6	422.4	137.1	559.6
2024	429.5		429.5	429.5		429.5	429.5	103.3	532.8	429.5	103.3	532.8
2025	436.7		436.7	436.7		436.7	436.7		436.7	436.7		436.7
2026	444.1		444.1	444.1		444.1	444.1		444.1	444.1		444.1
2027	451.7		451.7	451.7		451.7	451.7		451.7	451.7		451.7
2028	459.4		459.4	459.4		459.4	459.4		459.4	459.4		459.4
2029	467.3		467.3	467.3		467.3	467.3		467.3	467.3		467.3
2030	475.3		475.3	475.3		475.3	475.3		475.3	475.3		475.3

Figure A-1: Diesel Generation Requirements at Different Forecast Loads: 2012-2030



Diesel Energy Requirement (GWh)	2012	2015	2020	2025	2030
Base Case	11.5	27.0	24.4	24.5	51.9
Base Case with Brewery Creek	11.5	45.5	47.1	24.5	51.9
Base Case with Brewery Creek and Victoria Gold	11.5	135.2	128.8	24.5	51.9
Base Case with Brewery Creek, Victoria Gold and Carmacks Copper	11.5	187.1	181.0	24.5	51.9

Figure A-1 and table provide the forecast diesel generation requirement during the 20-year planning period for each of the load scenarios.

1. The numbers are based on updated load for 2012-2030.
2. Diesel requirement numbers are long-term average diesel.
3. Model run with Aishihik 10-year rolling average rule, Mayo Lake assumed in-service by winter 2013/14 (more recent information suggests earliest in-service is now winter 2014/15).

Diesel generation forecasts for each load scenario reflect long-term average hydro generation, i.e., the average hydro generation over 28 recorded water year conditions at the assumed load, as estimated by the power benefits model used by YEC for grid generation planning. Table A-2 and the Figure A-2 below it provide a detailed review of potential diesel generation variability for the year 2015 under each load scenario for each of the 28 water years (the figure shows the annual load duration curve for diesel for each load scenario).

Table A-2: Forecast Diesel Generation Variability (GW.h) Depending on Water Year Conditions - Load Scenarios for 2015 and 28 Water Years of Record

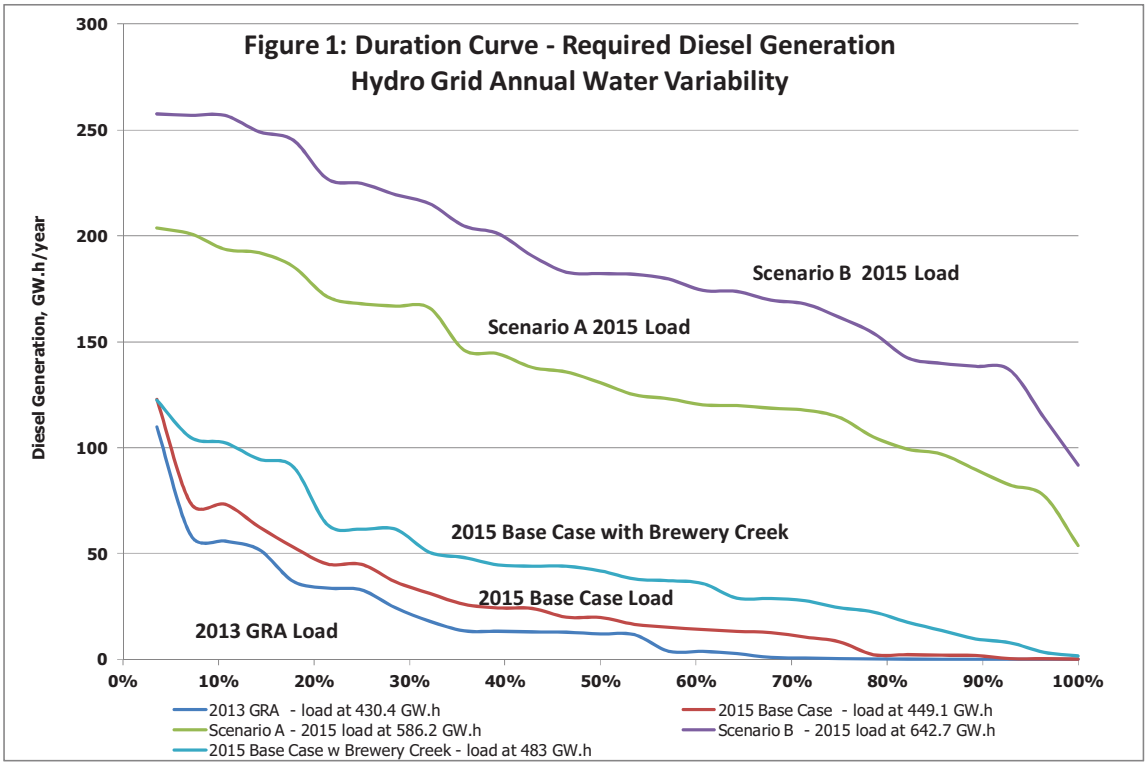
Average Annual Diesel Generation (Averaged Load Years for 28 Water Years)

Water Year	2013 GRA - load at 430.4 GW.h	2015 Base Case - load at 449.1 GW.h	2015 Base Case w Brewery Creek - load at 483 GW.h	Average diesel generation required (GW.h) Scenario A - 2015 load at 586.2 GW.h	Scenario B - 2015 load at 642.7 GW.h
1981	0.6	2.2	9.8	114.3	182.2
1982	2.6	10.5	48.2	135.7	181.8
1983	3.8	8.3	38.1	118.6	173.8
1984	11.6	19.9	63.7	168.0	226.8
1985	3.7	24.2	44.7	146.1	201.0
1986	0.9	16.5	44.1	125.0	169.6
1987	0.1	12.6	24.5	117.7	179.6
1988	0.0	14.1	27.8	105.1	142.5
1989	0.0	2.2	8.0	89.6	154.1
1990	0.1	1.8	17.7	123.1	174.3
1991	0.0	1.9	13.8	96.9	138.5
1992	0.0	0.3	1.8	53.8	91.9
1993	0.3	0.1	3.5	82.4	136.7
1994	0.0	0.3	22.5	185.5	249.0
1995	12.9	31.1	94.5	201.0	257.4
1996	51.8	62.5	104.8	203.7	256.7
1997	58.5	73.5	102.3	171.3	215.1
1998	36.8	44.8	90.9	193.7	256.8
1999	109.9	122.7	122.4	192.0	245.0
2000	55.9	73.2	61.5	130.7	167.9
2001	32.8	45.0	28.9	77.4	114.3
2002	24.3	36.5	35.9	120.2	182.9
2003	13.3	26.0	50.6	166.9	224.7
2004	33.6	52.9	61.5	165.9	219.4
2005	18.0	19.7	44.1	137.9	190.5
2006	12.8	15.1	37.3	144.3	204.7
2007	12.0	24.0	41.9	119.8	161.6
2008	13.5	13.2	29.1	99.3	139.9
Average	18.2	27.0	45.5	135.2	187.1

Distribution of Annual Water Year Loads (Figure 1)

	% of Years not less than	2013 GRA - load at 430.4 GW.h	2015 Base Case - load at 449.1 GW.h	2015 Base Case w Brewery Creek - load at 483 GW.h	Scenario A - 2015 load at 586.2 GW.h	Scenario B - 2015 load at 642.7 GW.h
1	4%	109.9	122.7	122.4	203.7	257.4
2	7%	58.5	73.5	104.8	201.0	256.8
3	11%	55.9	73.2	102.3	193.7	256.7
4	14%	51.8	62.5	94.5	192.0	249.0
5	18%	36.8	52.9	90.9	185.5	245.0
6	21%	33.6	45.0	63.7	171.3	226.8
7	25%	32.8	44.8	61.5	168.0	224.7
8	29%	24.3	36.5	61.5	166.9	219.4
9	32%	18.0	31.1	50.6	165.9	215.1
10	36%	13.5	26.0	48.2	146.1	204.7
11	39%	13.3	24.2	44.7	144.3	201.0
12	43%	12.9	24.0	44.1	137.9	190.5
13	46%	12.8	19.9	44.1	135.7	182.9
14	50%	12.0	19.7	41.9	130.7	182.2
15	54%	11.6	16.5	38.1	125.0	181.8
16	57%	3.8	15.1	37.3	123.1	179.6
17	61%	3.7	14.1	35.9	120.2	174.3
18	64%	2.6	13.2	29.1	119.8	173.8
19	68%	0.9	12.6	28.9	118.6	169.6
20	71%	0.6	10.5	27.8	117.7	167.9
21	75%	0.3	8.3	24.5	114.3	161.6
22	79%	0.1	2.2	22.5	105.1	154.1
23	82%	0.1	2.2	17.7	99.3	142.5
24	86%	0.0	1.9	13.8	96.9	139.9
25	89%	0.0	1.8	9.8	89.6	138.5
26	93%	0.0	0.3	8.0	82.4	136.7
27	96%	0.0	0.3	3.5	77.4	114.3
28	100%	0.0	0.1	1.8	53.8	91.9
		18.2	27.0	45.5	135.2	187.1

Figure A-2: Duration Curve – Required Diesel Generation Hydro Grid Annual Water Variability



Projected annual grid capacity MW surplus (shortfall) under each load scenario is provided in Table A-3, assuming existing plant and planned diesel unit retirements and applying YEC's approved N-1 and LOLE capacity planning criteria. These shortfalls assume that L172 is re-enforced (with by twinning or by provision for the 35 kV system to be able to by-pass this line between Takhini and McIntyre substations).

The following are noted regarding assumed diesel unit retirements, using projected shortfalls under the Base Case to demonstrate the impact of assumed retirements:

- 2015 Base Case shortfall of 3.3 MW: reflects following 8 MW of diesel unit retirements:
    - Mirrlees WD#1 and WD#2 retired in 2014/2015 (2011 Resource Plan rating of 3.50 and 4.5 MW=8 MW total).
    - Replacing one of these units with at least the same capacity would totally resolve the 2015 shortfall.
- 2020 Base Case shortfall of 15.7 MW: reflects following 13.11 MW of diesel unit retirements:
    - The above Mirrlees retirements (8 MW) plus.
    - Dawson retirement of 3 units (total 2.56 MW retired in 2017, 2018 and 2020).
    - Mayo retirement of 2 units (total 1.7 MW in 2019).
    - Faro retirement of 1 unit (0.85 MW in 2019).
- 2025 Base Case shortfall of 38.1 MW: reflects following 28.61 MW of diesel unit retirements:
    - The above 13.11 MW retired by 2020 plus.
    - Whitehorse retirement of 4 units (total 11.5 MW - last Mirrlees (4.5 MW) and 3 EMDs).
    - Faro Mirrlees unit (4.0 MW in 2021).
- 2030 Base Case shortfall of 51.5 MW: reflects following 34.41 MW of diesel unit retirements:
    - The above 28.61 MW retired by 2025 plus.
    - Whitehorse CAT (3.0 MW in 2026).
    - Faro CAT (2.8 MW in 2027).

Yukon Energy Corporation
20-Year Resource Plan: 2011-2030 **July 2012**

Table A-3: Grid Capacity Planning - Forecast MW Surplus (Shortfall) by Load Scenario: 2012-2030

Comparison of Peak, N-1 and LOLE requirements

Forecast Years	Base Case			Base Case w Brewery Creek			Base Case with Brewery Creek and Victoria Gold			Base Case with Brewery Creek, Victoria Gold and Carmacks Copper		
	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)	Peak MW	N-1 Surplus (shortfall) (MW)	LOLE Surplus (shortfall) (MW)
2012	80.1	7.2	7.2	80.1	7.2	7.2	80.1	7.2	7.2	80.1	7.2	7.2
2013	81.1	6.5	6.5	81.1	6.5	6.5	81.1	6.5	6.5	81.1	6.5	6.5
2014	82.6	2.4	2.4	83.8	2.4	2.4	83.8	2.4	2.4	83.8	2.4	2.4
2015	83.7	-3.3	-3.3	86.9	-3.3	-3.5	99.9	-3.3	-16.5	107.9	-3.3	-24.5
2016	84.9	-4.4	-4.4	88.1	-4.4	-4.6	101.1	-4.4	-17.6	109.1	-4.4	-25.6
2017	85.2	-6.5	-6.5	88.4	-6.5	-6.5	101.4	-6.5	-18.8	109.4	-6.5	-26.8
2018	86.4	-8.5	-8.5	89.6	-8.5	-8.5	102.6	-8.5	-20.8	110.6	-8.5	-28.8
2019	87.7	-12.3	-12.3	90.9	-12.3	-12.3	103.9	-12.3	-24.6	111.9	-12.3	-32.6
2020	89.0	-15.7	-15.7	92.2	-15.7	-15.7	105.2	-15.7	-28.0	113.2	-15.7	-36.0
2021	81.2	-25.5	-25.5	84.4	-25.5	-25.5	97.4	-25.5	-28.7	97.4	-25.5	-28.7
2022	82.5	-26.8	-26.8	85.7	-26.8	-26.8	98.7	-26.8	-30.0	98.7	-26.8	-30.0
2023	83.9	-28.2	-28.2	87.1	-28.2	-28.2	100.1	-28.2	-31.4	100.1	-28.2	-31.4
2024	85.3	-29.6	-29.6	85.3	-29.6	-29.6	98.3	-29.6	-29.6	98.3	-29.6	-29.6
2025	86.7	-38.1	-38.1	86.7	-38.1	-38.1	86.7	-38.1	-38.1	86.7	-38.1	-38.1
2026	88.2	-42.5	-42.5	88.2	-42.5	-42.5	88.2	-42.5	-42.5	88.2	-42.5	-42.5
2027	89.7	-46.8	-46.8	89.7	-46.8	-46.8	89.7	-46.8	-46.8	89.7	-46.8	-46.8
2028	91.2	-48.4	-48.4	91.2	-48.4	-48.4	91.2	-48.4	-48.4	91.2	-48.4	-48.4
2029	92.8	-49.9	-49.9	92.8	-49.9	-49.9	92.8	-49.9	-49.9	92.8	-49.9	-49.9
2030	94.4	-51.5	-51.5	94.4	-51.5	-51.5	94.4	-51.5	-51.5	94.4	-51.5	-51.5

TOPIC: **2.0 YUKON ENERGY SYSTEM SALES AND GENERATION**

REFERENCE: **Footnote 10 Page 2-5, "Based on forecast consumption at rates of 34 GW.h/year for Q1 2012, 37 GW.h/year for Q2, and 43 GW.h/year for Q3 onwards."**

Footnote 12 Page 2-5, "Pursuant to the Minto PPA [Section 4.5], Minto is required to provide written notice of the specified amount of the requested increase and YEC will have to determine if the facilities have transmission capacity to maintain that increased demand, as well as any potential requirement for an increase to the mine firm rate related such increase."

Lines 16-29 Page 2-5, "It is currently assumed Minto will remain at this level until late 2019. This increase in firm electricity requirement was subject to YEC upgrading substation equipment to accommodate the increased load, and Minto's payment of all of YEC's actual and reasonably incurred costs associated with the upgrade[13]."

Footnote 13 Page 2-5, "Costs estimated at $25,000 at time of agreement."

PREAMBLE:

Yukon Electrical is seeking clarification regarding service to Minto.

QUESTION:

a) Please discuss what is meant by "YEC will have to determine if the facilities have transmission capacity to maintain that increased demand." Is "diesel on the margin" considered as part of such a determination?

b) Please provide details of what upgrades are needed to substation equipment in order to accommodate the Minto forecast consumption and an updated cost estimate.

c) Please discuss what is meant by “actual and reasonably incurred costs”. How are reasonable costs determined?

d) Please explain the impact to YEC due to higher or lower than forecast amounts. How are gains/losses treated?

ANSWER:

(a)

In the Minto mine PPA [Section 4.5 Maximum Electric Demand] “facilities” refers to the transmission-related infrastructure required to meet customer demand at the mine site, and in this context relates to demand and is entirely focused on the capability of the existing transmission system to deliver electricity to the mine site. This does not specifically consider energy or generation.

Diesel on the margin is an energy related issue (and does not relate to demand or capacity), and has been historically defined as “diesel being used to meet long-term firm energy requirements of the WAF system, not just periodic peaking requirements.” In this regard, the transmission facilities referenced in Section 4.5 of the Minto PPA are demand-related and diesel on the margin would not be considered in this context.

(b)

Fans were required to be wired up on the transformer.

(c)

Pursuant to the Minto PPA, Minto Mine will pay the actual costs incurred by YEC to upgrade substation equipment in order to accommodate the increased Minto mine load.

(d)

There is no impact due to higher or lower than forecast amounts. Minto will be charged and will pay the actual amounts.

TOPIC: **2.0 YUKON ENERGY SYSTEM SALES AND GENERATION**

REFERENCE: **Lines 19-21 Page 2-6, "It is expected that Whitehorse Copper Tailings would commence service in Q3 of 2013 as an industrial customer of Yukon Energy and that a PPA will be negotiated in 2012 in order to facilitate delivery of power to the mine site."**

PREAMBLE:

Yukon Electrical seeks clarification regarding service to Whitehorse Copper Tailings.

QUESTION:

a) Please confirm that this customer is located within YECL's Whitehorse franchise area.

b) Please confirm that YECL has historically provided service to a customer located at the site Whitehorse Copper Tailings is proposing to operate at.

c) Please confirm that YECL has existing distribution facilities available for use at Whitehorse Copper Tailing's site.

d) Please explain on what basis YEC considers itself eligible to provide service to a customer within YECL's exclusive franchise area.

ANSWER:

(a) and **(d)**

Not confirmed. It is Yukon Energy's view that Yukon Electrical does not have a franchise to serve industrial customers.

(b) and **(c)**

Confirmed.

TOPIC: **2.0 YUKON ENERGY SYSTEM SALES AND GENERATION**

REFERENCE: **Lines 1-4 Page 2-14, "Yukon Energy forecasts average efficiency for diesel generation of 3.77 kW.h/litre in Whitehorse, 3.8 kW.h/litre in Faro and 3.72 kW.h/litre in Dawson and 3.37 kW.h/litre in Mayo, based on 2011 averages[31]. The overall grid average efficiency (3.67 kW.h/litre) is an increase from the 2009 GRA Application efficiency, where the approved forecast simple average efficiency was set at 3.6 kW.h/litre."**

PREAMBLE:

YECL is seeking further support for these quanta.

QUESTION:

a) Please explain how the above-referenced heat rates were determined.

b) Please provide detailed calculations (in Excel format) for forecast heat rates, including any historical heat rates relied upon to arrive at the forecast heat rates.

c) Please explain why the heat rate for Mayo is considerably lower than the other plants.

ANSWER:

(a) and **(b)**

Please see the response to YECL-YEC-1-17.

(c)

The lower fuel efficiency for Mayo diesel units in 2011 is due to lower efficiency rates when Mayo diesel units were run mostly for peaking and maintenance purposes, and have lower operating hours and diesel generation compared to the other YEC units. Furthermore, the diesel fuel cost forecasts for the test years are based on the entire diesel generation occurring at YEC's other 3 diesel plants and not at Mayo, so this

efficiency has no effect on the final revenue requirement. Please see Attachment 1 to YECL-YEC-1-17(a) for complete details.

TOPIC: **2.0 YUKON ENERGY SYSTEM SALES AND GENERATION**

REFERENCE: **Lines 17-18 Page 2-14, "The LOLE criterion also recognizes the role of transmission reliability, where relevant[33]."**

Footnote 33 Page 2-14, "The WAF system has substantial hydro generation availability that is directly affected by certain transmission; the WAF system also has been trending to an increasing probability of longer outages as it expands (particularly with expansion of residential and commercial loads and major reductions in industrial load). Yukon Energy has therefore now incorporated the LOLE approach, with recognition of transmission reliability where relevant, into its system planning criteria to better protect all of its firm customers from generation-related outages."

PREAMBLE:

YECL is seeking more information regarding reliability.

QUESTION:

a) Please explain the rationale for the increasing probability of longer outages and please provide calculations that support this increasing probability.

b) Please provide what measures have been put in place to mitigate the longer outages.

c) Please quantify "major reductions in industrial load" and explain how these reductions have reduced the probability of longer outages.

ANSWER:

(a) through **(c)**

The referenced footnote relates to prior conditions on the grid as discussed in earlier hearings leading to the adoption of the LOLE approach in the 2006 Resource Plan, i.e.,

loss of major industrial load in 1998 and recovery and expansion of residential and commercial loads after 2001.

TOPIC: **2.0 YUKON ENERGY SYSTEM SALES AND GENERATION**

REFERENCE: **Lines 14-21 Page 2-14, "Loss of Load Expectation (LOLE) – In 2006, Yukon Energy incorporated into its capacity planning criteria a probability based measure to evaluate the maximum loads that the WAF system can safely carry by identifying the potential interruption of service for any customer (forecast of the average number of system outages per year). The LOLE criterion also recognizes the role of transmission reliability, where relevant[33]. In 2006, the system-wide capacity planning criteria for WAF and MD provided that each system would be planned not to exceed a Loss of Load Expectation of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment."**

PREAMBLE:

YECL is seeking clarification of LOLE criteria.

QUESTION:

a) Please explain if LOLE includes planned outages? If yes, does LOLE include all planned outages, or just those for either planned maintenance or capital improvements?

ANSWER:

(a)

LOLE does not include planned outages.

TOPIC: **2.4 PEAK DEMAND FORECAST AND RELIABLE CAPACITY REQUIREMENT**

REFERENCE: **Lines 9-12 Page 2-15, " WAF and MD Community Criteria – Grid-served communities over about 300 people, other than Whitehorse (and, due to the earlier mine, the community of Faro), typically have local diesel generation installed to serve a dual purpose: overall grid support similar to major diesel installations at Whitehorse or Faro, as well as local supply during transmission outages."**

PREAMBLE:

YECL is seeking further information regarding local diesel generation.

QUESTION:

a) For each of these communities over 300 people (other than Whitehorse), please provide (i) the forecasted diesel consumption; (ii) unplanned outage support; (iii) peaking support; and (iv) planned outage support.

b) Please explain if YEC believes these local generators should be able to supply 100% of the local load during grid supply outages.

c) Please elaborate on whether YEC foresees YECL's grid-connected diesel standby plants, such as Haines Junction, being a Peaking plant.

ANSWER:

(a)

YEC does not forecast generation for communities where generation is provided by YECL.

For YEC communities, the assumed distribution of diesel generation shown in Table 2 is 50% at Whitehorse, 35% at Dawson City, and 15% at Faro. This forecast diesel is not broken out by the categories indicated in the question.

(b)

The criteria referenced is the third component of a multi-criteria capacity planning framework. It indicates that communities over about 300 people, where a diesel generator upwards of 1 MW or more in size could reasonably be located, would be preferred locations (all else being equal) for new capacity additions. For these communities, the general concept is that the installed generation could supply the local load during grid outages.

(c)

Generally, no. YEC does not typically rely upon the YECL grid connected diesel units to supply peaking capacity.

TOPIC: **2.0 YUKON ENERGY SYSTEM SALES AND GENERATION**

REFERENCE: **Lines 14-17 Page 2-16, "The reliable capacity is reduced to 77.5 MW for the N-1 event (in addition to removing 0.4 MW for Fish Lake hydro, assumes 37.0 MW at Aishihik and 1.75 MW at Haines Junction are not available at Whitehorse because of an interruption to the Aishihik transmission line)."**

PREAMBLE:

YECL is seeking clarification.

QUESTION:

a) Please explain why Fish Lake Hydro is deemed unavailable due to an interruption to the Aishihik transmission line.

ANSWER:

(a)

The referenced text reads 37.0 MW at Aishihik and 1.75 MW at Haines Junction are not available at Whitehorse because of an interruption to the Aishihik transmission line. This is in addition to removing 0.4 MW for Fish Lake hydro.

The referenced text does not suggest that Fish Lake Hydro is deemed unavailable due to an interruption of the Aishihik transmission line. The referenced text notes that Fish Lake hydro capacity is not included in YEC's N-1 and LOLE capacity requirement analysis as YEC's Integrated system peak forecast does not include peak demand associated with sales from Fish Lake hydro generation.

TOPIC: **Historical Actual & Forecast Industrial Loads**

REFERENCE: **Section 2.2.2 Major Industrial (entire section)**

> **Rate Schedule 39, "Base Load Energy: A Base Load Energy amount per month may be established for a customer at 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."**

PREAMBLE:

YECL is interested in more information in respect of Industrial Sales Forecasting.

QUESTION:

a) For each major industrial service, please provide (in Excel format):
   a. Historical Forecasts;
   b. Historical Actuals; and
   c. Current Forecasts.

b) For each major industrial service, please provide (in Excel format):
   a. Method for calculating industrial forecasts; and
   b. Calculations of current forecasts.

c) Considering "diesel-on-the-margin" and the referenced section of Rate 39, does YEC expect to establish base load energy amounts at "90% of forecast use" for any of the industrial customers during the test years?

d) Please discuss the consequences of over/under forecasting industrial sales with respect to the DCF and Rate Schedule 39.

ANSWER:

(a)

Please see Attachment 1 for the requested information.

Revised Response August 1, 2012

Since filing interrogatories July 27, 2012, it is noted that the Excel file provided as Attachment 1 to this response included the incorrect demand forecast for Alexco. This response is revised to correct this and is consistent with the response provided to UCG-YEC-1-20(b).

A revised Attachment 1 is provided.

(b)

Forecasts for each major industrial energy service are prepared based on the forecasts that each customer provides, and are not developed separately by Yukon Energy based on any calculation routines. Accordingly, no excel format calculations can be provided for these forecasts.

(c)

Based on the expected incremental diesel generation proposed to be included in rates in the test years, YEC does not currently expect to establish base load energy amounts at 90% of forecast use for any of the industrial customers during the test years.

(d)

There is no effect of over or under forecasting Industrial Sales on the DCF. The DCF solely operates to stabilize the costs related to water flow variations.

The implications of over or under forecasting industrial sales on Rate Schedule 39 is that revenues from Rate Schedule 39 will not arise as forecast. As per normal utility regulation, YEC is exposed to this risk within reasonably bounds as a load forecast variation (i.e., YEC will see the impacts of this variation on its income statement in the year in question). At grid loads forecast for the test years, YEC's incremental revenues will exceed YEC's incremental costs for industrial loads (see response to YUB-YEC-1-2(a)).

YEC Industrial Sales Forecasts and Actual sales

Year	Minto		Alexco		Whitehorse Copper Tailing		Total YEC	
	Forecast *	Actual	Forecast *	Actual	Forecast	Actual	Forecast *	Actual
	MW.h	MW.h	MW.h	MW.h	MW.h	MW.h	MW.h	MW.h
				Actual				
2009	29,023	29,355					29,023	29,355
2010	33,500	28,535	3,900	1,720			37,400	30,255
2011	31,000	31,819	11,800	11,440			42,800	43,259
				2012/13 GRA Forecast				
2012	39,250		13,059				52,309	
2013	43,000		14,590		4,774		62,364	

Notes:

1. The industrial sales forecast for 2009 as approved in 2009 GRA; forecasts for 2010 and 2011 are YEC`s internal forecasts.

2. The actual and forecast sales for Alexco only include sales under Rate Schedule 39 (i.e., do not include sales when Alexco served as general service customer).

3. In Mayo B Part III hearing Minto mine sales forecast to be approximate 32 GW.h in 2010 with annual increases of 2 GW.h until reaching a peak of 36 GW.h in 2012; Alexco sales forecast to be 5 GW.h in 2009 [includes general servcie sales], 10 GW.h in 2010, 12 GW.h in 2011, and 14 GW.h in 2012 and 2013. Please see response to YCS-YEC-1-9 from Mayo B Part III hearing.

YEC Industrial Annual Peak Forecasts and Actuals

Year	Minto		Alexco		Whitehorse Copper Tailing		Total YEC	
	Forecast *	Actual	Forecast *	Actual	Forecast	Actual	Forecast *	Actual
	kVA	kVA	kVA	kVA	kVA	kVA	kVA	kVA
				Actual				
2009	5,200	4,192					5,200	4,192
2010	4,755	4,511	2,000	2,369			6,755	6,880
2011	4,400	4,545	2,300	2,399			6,700	6,944
				2012/13 GRA Forecast				
2012	6,500		2,300				8,800	
2013	6,500		2,600		2,220		11,320	

Notes:
1. The industrial annual peak forecasts are YEC`s internal forecasts.
2. Actual are peak for year (many months may have been billed at lower demand).

TOPIC: **3.0 REVENUE REQUIREMENT**

REFERENCE: **Footnote 2 Page 3-4, "Fuel cost forecasts in Table 3.2 for 2012 and 2013 include cost of required diesel fuel for maintenance of diesel units." Footnote 3 Page 3-4, "In 2010 diesel generation of 0.85 GW.h is resulted from the construction activities due to capital projects. In 2011 Aishihik plant construction is estimated to have resulted in 3.18 GW.h [$0.8 million] of diesel generation in 2011 due to shut downs required of the Aishihik generation plant, and Mayo B plant construction (extended Mayo A shut down for tunnel tie in work) is estimated to have resulted in 1.5 GW.h [$0.4 million] of diesel generation, and 0.7 GW.h due to other capital projects. The costs for such diesel generation was charged to the capital costs for each respective project."**

PREAMBLE:

During YEC's Aishihik and CSTP capital projects, YECL was forced to:

(i) Burn additional diesel in Pelly to avoid an outage during construction of CSTP stage 2; and
(ii) Construct a temporary bypass substation to avoid burning diesel throughout peak summer holiday season in Haines Junction, which supplied YEC and YECL customers.

YECL is interested to know more about associated cost requirements for capital projects.

QUESTION:

Please provide if budgeted amounts within YEC's capital projects include diesel generation and other associated cost requirements of YEC and YECL's plants. If not, please explain why?

ANSWER:

YEC's budgeted amounts within YEC's capital projects include diesel generation and other associated cost requirements when these are forecast to be reasonably required for the project. Such YEC costs for diesel fuel were included, for example, in budgeted amounts for Aishihik Third Turbine to address costs related to expected Aishihik plant shutdowns as required for this project (see response to YUB-YEC-1-5).

With respect to the YECL diesel, Yukon Energy is not aware of any formal written request for compensation PRIOR to the commencement of these projects. The Company acknowledges receipt of invoices dated December 19 and December 20, 2011 that request reimbursement of costs for impacts of AH3 (Haines Junction bypass) and CSTP Stage 2 (Pelly Crossiong) respectively. Both of these items were received many months after budgets were set and in the case of CSTP Stage 2, six months after the project was put into service. On this basis, YEC sees no grounds for these claims.

TOPIC: **3.0 REVENUE REQUIREMENT**

REFERENCE: **3.3.3 Distribution Table 3.7 Page 3-9**

PREAMBLE:

YECL is interested in a further breakdown of distribution brushing costs.

QUESTION:

a) Please provide a breakdown of YEC's brushing costs per kilometer.

ANSWER:

(a)

For 2009 and 2010, distribution brushing was managed by district and line crew staff using hand slashing techniques. YEC estimates about 5-7 km were brushed in each of these years. In 2011, an external contractor was hired to brush about 20 km in Dawson, as well as a number of critical sites in Mayo. For 2012 and 2013, YEC intends to continue this approach and would expect to achieve similar results.

TOPIC: **3.0 REVENUE REQUIREMENT**

REFERENCE **3.3.4 General Operation and Maintenance, Table 3.8 Page 3-10**

PREAMBLE:

YECL is interested in further detail.

QUESTION:

a) Please provide a breakdown of transportation costs (descriptions and amounts) and please provide the average costs on a per unit basis.

ANSWER:

(a)

Please see Table 1 below. Note that the "# of units" figure includes an estimated number of licenced vehicles in the fleet. The calculation does not include numerous off-road vehicles and accessory equipment that is also maintained under this budget (e.g. Nodwell tracked line maintenance vehicle, snowmobiles, ATVs, and assorted trailers).

Table 1:
Transportation Cost Breakdown

	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
Fuel ($000)	236	239	324		
Parts/Materials ($000)	187	210	276		
Insurance ($000)	73	78	85		
Other ($000)	17	48	40		
Capital Allocations ($000)	(112)	(155)	(277)		
	401	419	449	427	451
# of Units	43	48	50	55	55
Avg Cost per unit ($000)	9	9	9	8	8

TOPIC: **5.0 CAPITAL PROJECTS**

REFERENCE: **5.2 CAPITAL WORKS Lines 16-18 Page 5-2, "This section reviews (a) major capital works projects (projects over $1 million) undertaken by Yukon Energy since the 2008/2009 GRA hearing and planned for 2012 and 2013, and (b) ongoing capital projects costing between $100,000 and $1 million forecast to occur in the 2012 and 2013 period."**

PREAMBLE:

YECL is interested in variances associated with YEC's major capital projects.

QUESTION:

a) Please provide the original forecast budget, actual costs and variances for all major capital projects over $1 million that YEC has undertaken since its 2008/2009 GRA.

b) Please explain which recommendations from the Mayo-Dawson City Transmission System Project auditor general report that YEC has implemented.

ANSWER:

(a)

The requested information is provided as follows for three of the major capital projects (costs over $1 million) that YEC has undertaken since the 2008/09 GRA (the list of the major capital projects in the Application is provided in Section 5.2.1 of the Application, including projects where $1 million has been undertaken prior to 2012, projects where this level of cost will not be exceeded until 2012 or 2013, and project where no costs will go into rates during the test years):

- **CSTP Stage 2**: A cost breakdown of CSTP2 (Board Approval Budget and Final Forecast Cost) and variance analysis is provided in response to CW-YEC-1-26 (a) and (b).

- **Mayo B**: A cost breakdown of Mayo B (February 2010 Forecast and Final Cost Estimate) is provided in response to CW-YEC-1-27(a) and (b).

- **Aishihik Third Turbine**: A cost breakdown of Aishihik Third Turbine (Construction Cost Estimates and Final Cost Estimates) CW-YEC-1-28(d).

A cost breakdown of **Mayo Hydro Substation** is provided in Table 1 below with variance that compares Budget (May 2011) with Forecast Final Cost Estimate (2012/13 GRA)

Table 1:
A cost breakdown of Mayo Hydro Substation Enhancements Approved Budget (May 2011) vs. Forecast Final Cost Estimate (2012/13 GRA)

	Approved Budget (Dec 2010)	Final Cost Estimate (2012/13 GRA)	Variance
69kV Ring Bus	$4,018,500	$4,924,500	$906,000
Mayo A Tie-in	$1,030,000	$1,142,000	$112,000
Re-supply Shunt Reactor	$150,000	$305,101	$155,101
Re-supply Mayo Town off 69kV	$990,000	$1,190,020	$200,020
Keno 69kV Line Transfer	$105,000	$205,072	$100,072
Dawson 69kV Line Transfer	$180,000	$215,225	$35,225
Construction Field Cost:	**$6,473,500**	**$7,981,918**	**$1,508,418**
Preliminary Engineering and Design:	$100,000	$162,977	$62,977
Detailed Engineering Design:	$800,000	$1,009,997	$209,997
Construction Management:	$295,000	$312,685	$17,685
YEC Cost (Owner's Cost):	$400,000	$337,672	-$62,328
Construction Financing Cost:	$100,182	$123,433	$23,251
Indirect Cost:	**$1,695,182**	**$1,946,764**	**$251,582**
Contingency:	$2,000,000	$225,000	-$1,775,000
Total Capital Cost:	**$10,168,682**	**$10,153,682**	**-$15,000**

A cost breakdown of **Aishihik Redundancy Project** (Original Budget Estimate, Construction Approval Budget Estimate and Final Cost Estimate please see response to CW-YEC-1-30(a) and (b).

A variance analysis of Construction Approval Cost Estimates and Forecast Final Cost Estimates is provided in Table 2 below:

Table 2:
Aishihik Redundancy Project Construction Approval Budget Estimate to Completion and Final Cost Estimate to End of 2011

	Construction Approval (Aug 2010)	Final Cost Estimate (2012/13 GRA)	Variance
Building	708,785	848,914	140,129
Supply Electro-Mechanical	1,868,648	1,990,377	121,729
Electrical Installation in Generating	948,203	900,245	-47,958
Electrical Installation Generating Control Room	-	250,660	250,660
Testing and Commissioning	58,827	330,907	272,080
Mobilization	23,558	125,983	102,425
Diesel Fuel	-	190,343	190,343
Estimated Construction Field Cost:	**3,608,021**	**4,637,429**	**1,029,408**
Contingency:	300,000	-	-300,000
Detail Design:	419,270	591,667	172,397
Construction Management:	207,334	306,323	98,989
YEC Cost (Owner's Cost):	-	493,736	493,736
Construction Financing Cost:	45,000	78,732	33,732
TOTAL CAPITAL COST:	**4,579,625**	**6,107,887**	**1,528,262**

A cost breakdown of **Enterprise System (JDE)** is provided in response to YUB-YEC-1-36. Budget Approval Cost Estimate for implementation (December 2010) of $2.134 million – however, this did not include the approximate $0.300 million for system selection costs (as described in the Application at page 5-20) incurred prior to approval of implementation.

A cost breakdown of **Whitehorse Spillway Improvements** is provided in response to UCG-YEC-1-54. As noted at page 5-16 of the Application August 2011 spending was approved for a total budget of $1.350 million for activities between 2011 and 2013. GRA forecast cost estimates indicate total spending of $1.247 ($0.104 difference from budgeted to forecast final costs).

A cost breakdown of the **Mayo Headgate Repair** project is provided in UCG-YEC-1-52. The Application at page 5-13 describes preliminary costs (including design and

contingencies (but excluding any energy outage costs) in the order of $1.2 million for the preferred option selected by YEC. The GRA Forecast Cost Estimates are $1.33 million. The GRA at page 5-13 notes additional cost of $0.200 was estimated to provide for a temporary bulkhead gate to facilitate shutdown of work in 2011 and address concerns related t timing of the Mayo B tunnel tie and work and prolonged Mayo Plant Shutdowns.

With regard to a cost breakdown of **Whistle Bend Subdivision Supply** please see response to YECL-YEC-1-31 and YECL-YEC-1-35.

With regard to a cost breakdown of **Victoria Gold - Grid Connection** and **Western Copper - Grid Connection** please see response to UCG-YEC-1-57 and UCG-YEC-1-58.

(b)

The recommendations provided by the Auditor General regarding the Mayo Dawson Transmission line (and YEC's response to each recommendation) are grouped into the following five main areas as described in the Main Points section of the report.

- **Shortcomings in definition of scope and costs:** YEC has engaged experienced technical resources early in the process who have frequently, and in detail, reviewed the outputs of design engineers to ensure such outputs are reasonable. As well, the Board of Directors is provided regular, detailed updates on cost, scope and progress.

- **Shortcomings in "design-build" approach:** YEC has not used the design build approach to projects since the MDTS project. Generally, projects use a more traditional contracting approach where separate contracts are let for preliminary and final engineering design, project management and construction. One notable exception to this general practice is Mayo B – in this case, owing to the aggressive timelines for completion, the company adopted the Alliance model to contracting, with very positive results. This approach will not work in all cases due mostly to the high administrative costs of setting up a more complicated structure but there are advantages where circumstances allow for it.

- **Shortcomings in project management:** For large projects such as CSTP Stage 2 and Mayo B, YEC has 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 has been hired to act as an owner's representative and monitor progress of all project construction activities.

- **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 from the 2008/2009 GRA 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 has devoted significant resources to the monitoring of project costs. For major projects at the construction approval stage, YEC's Board of Directors has required management to commit to reporting back to the Audit Committee on cost and progress generally at every meeting (roughly twice as frequently as normally scheduled). As well, extra resources in financial administration and senior financial management are dedicated to major projects to ensure satisfactory results.

TOPIC: **5.0 CAPITAL PROJECTS**

REFERENCE: **5.2.1 Major Projects over $1 Million, Lines 5-7 Page 5-4**

> **"Whistle Bend Subdivision Supply (forecast total spending of $5.23 million in the end of 2013, this project will not be in service before 2014 and therefore will not impact rates in the test years)."**

PREAMBLE:

YECL would like more information in respect of the Whistle Bend Subdivision Supply project.

QUESTION:

a) Please provide the business case for the Whistle Bend Subdivision Supply project.

ANSWER:

(a)

As recently reviewed with Yukon Electrical at a meeting on June 19, 2012 to discuss the approach to the Whistle Bend project, Yukon Energy is undertaking in collaboration with Yukon Electrical a review of how Whistle Bend should be connected to the system. A business case will be prepared once Yukon Energy has completed consultation with Yukon Electrical with regard to the Whistle Bend project. This consultation will inform any decision to proceed with the project.

Forecast spending on the Whistle Bend Subdivision Supply project in reality relates to two separate projects:

- Connection of Whistle Bend to grid and transformation requirements for such connection; and

- Utilization of the Whistle Bend subdivision and MacIntyre substation to address significant system reliability and protection issues.

Whistle Bend Connection Project

As the main generator and transmitter in Yukon, Yukon Energy has a responsibility to ensure that system reliability and protection issues are addressed on the integrated grid.

Yukon Energy's full understanding of the Whistle Bend connection project has developed only recently (and is still developing) – however, based on the recent meeting with Yukon Electrical on June 19, 2012 to discuss the Whistle Bend project, it is understood that electrical load from the Whistle Bend subdivision is expected to be very significant and in a range similar to a major industrial load (i.e., as high as 20 to 30 MW which is significantly higher than currently estimated for Victoria Gold [13 MW]). To ensure grid reliability and protection of the system due to connection of this material new load is expected to require Yukon Energy to make significant investments in additional transformation. Notably, unlike major industrial loads served by Yukon Energy (where the customer is fully responsible for all costs to connect to the grid), Yukon Energy is not aware of any recourse for seeking similar customer contributions related to the connection of this major new load.

System Reliability Issues

With regard to possible utilization of Whistle Bend subdivision to address significant system reliability and protection issues, as noted in the Application at Pages 2-15 and 2-16, the 2011 Resource Plan update evaluation on the capacity capability of the system indicated that the previous approach used for WAF was reasonable for the integrated system, subject to the 25 km line L172 between Takhini and Whitehorse being appropriately reinforced within the next few years to eliminate line constraint in this line segment. Yukon Energy noted that it was reviewing and assessing results of the system capability study and once this assessment was complete the most prudent option would be implemented to address this concern.

The two projects addressed in the Whistle Bend Subdivision Supply project capital cost projections are not currently planned to be completed in the test years and no approvals are currently being sought to include project costs in rates as part of this Application.

Please see response to YECL-YEC-1-35 and YUB-YEC-1-7.

TOPIC: **5.0 Capital Projects**

REFERENCE: **Lines 18-21 Page 5-9, "At the revised forecast net capital cost and a wide range of grid loads (i.e., 450 GW.h/year and higher) the levelized cost of energy (LCOE) for the project on its own approximates 9 to 11 cents/kW.h over an assumed 65 year economic life[5]."**

Footnote 5, Page 5-9, "Assumed net capital cost of $8.8 million, and average cost of capital of 6.51%/year, with 8.77% cost of equity and 5.0% cost of debt; assumed O&M cost of $6/MW.h. Diesel displacement under long term average hydro availability exceed 4 GW.h/year over this range with no Mayo B (i.e., the Aishihik Project was committed prior to Mayo B being committed)."

PREAMBLE:

YECL is interested in more information regarding the Aishihik Project.

QUESTION:

a) Please provide how many kWh per year this unit would be required to operate in order to achieve the LCOE.

b) Please provide the percentage of time this unit is forecast to operate while the other two units are not operating per year.

c) Please provide how long the license/water system (upstream and downstream) can continuously handle maximum output of all three units.

d) Please provide when the grid is expected to reach 450 GW.h/year.

e) Please provide what the LCOE was previous to the year determined in d) above.

f) Please provide detailed calculations for d) & e) above.

g) Please indicate if Mayo B is included in the LCOE. If not, what is the levelized cost of energy including Mayo B?

h) Please provide the annual diesel displacement with Mayo B in operation.

ANSWER:

(a)

Aishihik Unit #3 (AH 3) LCOE of 9 to 11 c/kW.h (2012$) as estimated in the Application is based on approximately 4 to 4.9 GW.h/year diesel displacement benefits with no Mayo B. The analysis reflects system diesel displacement benefit, as estimated by power benefit model runs with and without the AH3 unit, and does not involve estimates specifically as to how many kW.h per year this unit is assumed to operate. Summer hours of operation of AH3 at certain loads, for example, will serve to meet minimum flow requirements at Aishihik with more efficient energy generation but without direct diesel displacement during that season.

Overall, AH3's planned benefit as a smaller unit was to increase the hydro generation efficiency at Aishihik from the volume of water that is on average available at this power station. The increased hydro generation yields long term average diesel displacement benefits that vary with grid load and/or other resource options being connected to the grid.

(b)

YEC does not forecast dispatch of units by power plants.

AH3 is forecast to operate alone approximately 30 to 40% of the year, typically during summer periods when minimum flow conditions determine Aishihik operation requirements. AH3 operation on its own is likely to depend on the following conditions:

- System loading requirements;
- Water availability at Whitehorse for generation;

- Storage capability at Mayo; and

- Minimum flow licence requirements at Aishihik.

(c)

YEC does not intend to operate Aishihik Unit #3 in conjunction with the other units on a sustained basis. This is not the purpose of the unit (see response to (a) above regarding the original planned benefit from AH 3).

The total licenced maximum live storage in Aishihik is approximately 120 GW.h. If the lake was drawn down from the maximum licenced level, to the minimum licenced level, with no further inflows, this would sustain the installed 37 MW for approximately 3243.2 hours.

(d)

Based on 2012/13 GRA load forecast (including Minto, Alexco and Whitehorse Copper Tailings mines) and assumed growth rate at 2.26% for non-industrial load Integrated System (excluding Fish Lake generation) would reach approximately 450 GW.h/year load in 2014, prior to consideration of any load reductions for potential DSM/SSE. If Brewery Creek mine load is connected by 2014, the grid load excluding Fish Lake is expected to exceed 450 GW.h in that year even with allowance for DSM/SSE.

(e)

At 2013 load forecast and with assumed net capital cost of $8.8 million, and average cost of capital of 6.51%/year (with 8.77% cost of equity and 5.0% cost of debt) Aishihik Unit #3 LCOE would be approximately 11.7 cents/kW.h (2012$) without Mayo B (based on estimated 3.7 GW.h/year of long term average diesel displacement).

(f)

Please see Table 1 below for 2014 load estimate in (e) excluding Brewery Creek and any allowance for DSM/SSE.

The estimate for the 11.7 c/kW.h LCOE in (e) is based on a power benefits model assessment to determine the 3.7 GW.h/year long term average diesel displacement.

Table 1:
Estimated Yukon Integrated System load for 2014

	GW.h
2013 Non-Industrial Sales	333.5
2014 Non-Industrial Sales[1]	341.3
Industrial load	
Alexco	20.0
Minto	43.0
WHCT	8.6
Total Industrial Sales	71.6
Total YEC Sales for 2014	412.9
Losses at 8.7%	448.8
Estimated Fish Lake load	8.7
Total Integrated System Load for 2014	457.5

Note: 1. Assumed growth rate at 2.26% applied to Integrated System non-industrial sales including Fish Lake and then Fish Lake load subtracted to get YEC sales.

(g) and **(h)**

As noted in Footnote 5, Page 5-9 of the Application, Mayo B is not included in the LCOE (i.e., the Aishihik Project was committed prior to Mayo B being committed).

With Mayo B in-service and with the same assumptions (load, cost of capital) LCOE for the project on its own would approximate 10 to 12.7 cents/kW.h over an assumed 65 year economic life. The diesel displacement benefits of Aishihik Unit #3 with Mayo B in operation would be approximately 3.4 - 4.4 GW.h/year at 450-500 GW.h/year load level. This is slightly lower when compared to the case with no Mayo B in operation. However, in this case Mayo B diesel displacement benefits increase by the same amount as decrease in Aishihik Unit #3 benefits.

TOPIC: **5.2.1.4 Mayo Hydro – Substation Enhancements**

REFERENCE: **Lines 6-10 Page 5-10, "Added to the requirement to refurbish the substation, many ongoing external changes on the Yukon grid required material re-investment be done to the Mayo substation to ensure that it is equipped and fully capable of addressing the fundamental changes to the grid system at this time, including: Interconnection of the Whitehorse-Aishihik-Faro grid and the Mayo Dawson grid through the completion of the Carmacks Stewart Transmission Project - Stage 2."**

PREAMBLE:

YECL is interested in more information in respect of the Mayo Hydro Substation Enhancements project.

QUESTION:

a) Please provide if these costs are included in the Mayo B costs per kW.h comparisons? If not, please explain.

ANSWER:

(a)

An allocation of Mayo Hydro Substation Enhancement costs is included in the Mayo B cost per kWh comparisons.

The Mayo B Part 3 Application noted that due to the range of non-Mayo B material planning considerations and requirements associated with this substation, engineering and construction for the substation was addressed separately from the Mayo B Project. The Mayo B capital cost budget reviewed in the Part 3 Application included a set assignment of $0.6 million towards the substation project to cover costs for a least cost Mayo B connection option involving a simple single tap to the bus with appropriate disconnects for isolation. The current Application has increased this $0.600 million assignment to $0.750 million. This specific assignment of non-Mayo B costs was included in the Mayo B costs per kWh comparisons.

Please also see LE-YEC-1-22 and CW-YEC-1-29.

TOPIC: **Capital Projects**

REFERENCE: **5.2.1.4 Mayo Hydro – Substation Enhancements Lines 12-13 Page 5-10, "Additional new industrial loads in 2010 (i.e., Alexco mine) and anticipated potential future loads (e.g., Victoria Gold)."**

Lines 16-29 Page 2-5, "This increase in firm electricity requirement was subject to YEC upgrading substation equipment to accommodate the increased load, and Minto's payment of all of YEC's actual and reasonably incurred costs associated with the upgrade[13]."

PREAMBLE:

YECL is interested to know the breakdown of charges to the customers associated with the above-referenced substation enhancements.

QUESTION:

a) Please provide detailed charges for the Mayo Hydro enhancements including a breakdown of expenses for the industrial customer class.

b) Are these charges being invoiced to these industrial customers? If not, please explain.

ANSWER:

(a) and **(b)**

No breakdown of expenses exists for the industrial customer class, and no such charge is to be invoiced. The references to industrial loads was a reference to one of the various load considerations relevant to the upgrade of this substation to deal with the newly integrated grid, potential future requirements, replacement of very old facilities, etc.

Further, until December 31, 2013, industrial rates are fixed by OIC 2007/94 and OIC 2012/68. Cost allocation as between customer classes is addressed as part of a full Cost of Service Study that is jointly prepared by YEC and YECL, and which is currently not to be prepared until after OIC 2012/68 has expired.

Please see also response to CW-YEC-1-29; LE-YEC-1-22; YECL-YEC-1-33 and UCG-YEC-1-51(b).

TOPIC: **Capital Projects, 5.2.1.8 Whistle Bend Subdivision Supply**

REFERENCE: **Lines 23-25 Page 5-18**

> **"Although more refined estimates will be available after the 2012 review is completed, spending on this project is forecast at $50,000 in 2012 and $5 million in 2013."**

PREAMBLE:

YECL is interested in more information in respect of the Whistle Bend Subdivision Supply project.

QUESTION:

a) Please provide a breakdown of the $5 M forecast to be spent in 2013 for the Whistle Bend Subdivision Supply Capital Project.

ANSWER:

(a)

Please see response to YECL-YEC-1-31.

The forecast costs provided in the General Rate Application were high level estimates and are subject to review as the approach to this project is refined in 2012. These costs are not forecast to come into rates in the test years.

TOPIC: **Capital Projects, 5.2.2 Projects $100,000 to $1 Million**

REFERENCE: **Lines 14-15 Page 5-23, "Approximately $1.215 million of total forecast spending in 2012 is required for reliability purposes while approximately $2.387 million of total forecast spending in 2013 is required for reliability purposes."**

PREAMBLE:

YECL is interested in more information in respect of the bulk generation system reliability.

QUESTION:

a) Please provide how the reliability of the bulk generation system differs from the reliability experienced by other utilities.

ANSWER:

(a)

YEC generates reliability statistic as per the end user (i.e. the customer). These values are very comparable to other utilities as; SAIDI, SAIFI, and CAIDI. As far as the Bulk Generation System goes YEC uses the Forced Outages, Planned Outages, and Operating Factors. While these terms are used by other utilities YEC is really not comparable to other utilities as we are on an isolated grid. This means YEC may or may not require all of the generation to be run which would lower the overall Operating Factor whereas other utilities, especially for Hydro Generation, could and would still run the units for export sales if possible.

TOPIC: **Capital Projects**

REFERENCE: **Tab 5, 5.2.2 Projects $100,000 to $1 Million**

"Distribution projects in the test years also include the Faro mine connection (for the site abandonment plan, with costs expected to be offset by customer contribution), a new three phase distribution line at Dawson Dome, ongoing work to secure easements for distribution lines, and requirements for new customer extensions."

PREAMBLE:

YECL is interested in more information in respect of easements.

QUESTION:

a) Please explain what YEC's process is for securing easements on existing power lines.

ANSWER:

(a)

In 2005 YEC began the process of contacting the affected property owners to discuss their endorsement of an easement agreement. Information and documentation was provided to these customers and those which were signed are registered in the Land Titles Office. Those who did not sign are scheduled for follow-up discussions on an available time basis. This work is continual and planned to be ongoing.

TOPIC: **Capital Projects**

REFERENCE: **Tab 5, 5.3.1.1 Marsh Lake Storage – Total Deferred Costs of $4.830 Million to end of 2013 "The forecast cost to complete the project is currently estimated at $10.5 million with mitigation design (shoreline erosion and surface water) expected to comprise about one-half of this total cost."**

"Marsh Lake Storage is assumed to provide 1 MW of added reliable peak winter capacity."

PREAMBLE:

YECL is seeking clarification in respect of the Marsh Lake Storage project.

QUESTION:

a) Please indicate whether the $10.5 M of capital expense is in addition to the $4.8 M of deferred costs.

b) If the answer to a) is yes, please discuss whether this is representative of a typical proportion of feasibility study-to-project build costs.

c) Please provide if this project require additional generation upgrades to realize this additional capacity (i.e. new turbine/generator)? If so, are the upgrades included in the project cost estimate?

ANSWER:

(a) through **(c)**

The $10.5 million of capital expense is not in addition to the $4.8 million of deferred costs to the end of 2013. As noted on page 5-33 of the Application, $10.5 million is the assumed total capital cost (2010$) for the project.

There are no additional generation upgrades required to realize this additional capacity.

TOPIC: **CAPITAL PROJECTS**

REFERENCE: **Tab 5, 5.3.1.4 Mayo Lake Enhanced Storage – Total Deferred Costs of $2.1 Million**

"Yukon Energy subsequently completed a Project Agreement with the local First Nation (Nacho Nyak Dun First Nation) regarding the Mayo B and Mayo Lake projects."

PREAMBLE:

YECL is interested in more information in respect to the Mayo Lake Enhanced Storage project.

QUESTION:

a) Please provide a copy of the Project Agreement entered into with Nacho Nyak Dun First Nation.

ANSWER:

(a)

The Project Agreement with Nacho Nyak Dun First Nation is confidential and cannot be provided.

TOPIC: **Capital Projects**

REFERENCE: **Tab 5, 5.3.1.9 Geothermal – Total Deferred Costs of $2.633 Million**

"In this regard, 2012 work will follow the recommendations of the Borealis report (i.e., confirm temperature gradient and water quality and potentially some geophysical survey work)".

PREAMBLE:

YECL is interested in more information in respect of the Geothermal Deferred Costs.

QUESTION:

a) Please provide the temperature gradient requirement for power generation.

b) Please provide the nearest existing generation plant that uses technology similar to that recommended in the Borealis report.

c) Please provide what is the LCOE of the generation plant in b).

d) Please provide how close the investigated site is to an existing 3-phase line.

e) Please provide how far the furthest investigated site is to an existing 3-phase line.

ANSWER:

(a)

The temperature gradient is a low cost early exploration tool used to identify potential areas of interest for geothermal resource and cannot be used on its own to define the potential geothermal resource and reserve[1]. Specifically, the thermal gradient only provides an approximation of the depth to the geothermal resources and other

[1] The higher the thermal gradient, the greater the interest could be (in conjunction with other exploration data) as it may be indicative of a shallower geothermal resource.

exploration methods are required to define the potential geothermal resource and reserve in place [2].

(b)

The Borealis report recommends that binary cycle power plant technology be used for low temperature geothermal.

Yukon Energy is aware of binary cycle power plant technology use at geothermal plants in Alaska (Chena project), Nevada (Steamboat) and California (Heber Complex). In Canada, Borealis is looking at integrating binary cycle power plant as part of the Ft Liard Geothermal Project, completed in collaboration with Acho Dene Koe First Nations.

(c)

The geothermal power plant at Chena Hot Springs in Alaska reduced the cost of power from 30 cents/ kW.h to 5 cents/ kW.h, with further reductions expected once loans to fund project infrastructure are repaid (as reported in a final report on this project prepared for Alaska Energy Authority).

Preliminary cost and power benefit estimates for Yukon Energy suggest a 10 MWe geothermal plant could provide power at a real LCOE of 11 ¢/kWh using Yukon Energy's regulated rate of return, 95% capacity factor and project life of 30 years.

(d) and **(e)**

Currently, the investigated area spans over 45 km^2 within and just outside the City of Whitehorse. Once early exploration work is completed, the Corporation will be able to provide a better estimate of the distance between a potential geothermal plant and an existing 3-phase line.

[2] For example, if a thermal gradient of 40^{o}C/km is calculated from field observations and the target temperature for binary cycle power plant is 160^{o}C, advanced exploration methods would be needed to be able to provide information about the geothermal resource at depth of at least 4 km below ground surface.

TOPIC: **Capital Projects**

REFERENCE: **Tab 5, 5.3.2 Projects between $100,000 and $1 Million**

"Diesel Overhauls – DD-2, DD-3 and DD-5 will each require a total engine overall in the test years to maintain the unit's availability without decreasing engine life and reliability."

PREAMBLE:

YECL is interested in more information in respect of the Diesel Overhauls project.

QUESTION:

a) Please provide overhaul details including unit size, age, and engine hours for each of DD-2, DD-3 and DD-5.

ANSWER:

(a)

Please see tables below for details regarding unit size, age and engine hours for DD-2, DD-3 and DD-5 for 2009, 2010 and 2011 in Tables 1 to 3 below. A summary is provided in Table 4. YUB-YEC-1-11(b) provides as Attachment 1 YEC's 2011 Generation Inventory which provides information on unit name plate capacity, in service date and planned retirement date.

Table 1: 2009

Year	Unit	Total Hours
2009	DD2	131.3
	DD3	192.8
	DD5	219.8

Table 2: 2010

Year	Unit	Total Hours
2010	DD2	794.3
	DD3	884.5
	DD5	777.5

Table 3: 2011

Year	Unit	Total Hours
2011	DD2	2311
	DD3	1840
	DD5	3043

Table 4: Summary 2009-2011

Year	Unit	Total Hours
9-11	DD2	3236.6
	DD3	2917.3
	DD5	4040.3

TOPIC: **GRA 2012-13 Application**

REFERENCE: **All Relevant Schedules**

PREAMBLE:

YECL is interested in Forecast and Actual quanta for 2011.

QUESTION:

a) Please update FYF 2011 and Preliminary Actual 2011 with 2011 actual numbers in all schedules and prepare updated variance analyses.

ANSWER:

(a)

The GRA schedules for 2011 were prepared with data that is very near to actuals (for example, capital spending in the GRA versus actuals totals a difference of only approximately $15,000 on $95.8 million in capital spending).

Updating the entire GRA for 2011 actuals, including resulting implications on 2012 values for minor differences such as dividend and equity ratios, WIP balances, etc. is a massive effort with very little expected change, and is not possible in the time available.

Numerous interrogatories, where feasible, provide specific updates for various O&M categories for 2011 actuals as well as updating various individual projects for the actual 2011 spending as compared to GRA forecasts.

TOPIC: **Deferred Costs**

REFERENCE: **3.0 Revenue Requirement, Page 3-2, Lines 8-10**

PREAMBLE:

YECL wishes to gain an understanding of the prior planning study cost policy versus the revised policy.

QUESTION:

a) Please provide the previous 2008-2009 GRA approved planning study cost policy and outline the changes made and why these changes to the policy are required.

ANSWER:

(a)

See Attachment 1 to CW-YEC-1-33 which provides the previous planning cost accounting policy. The previous planning cost accounting policy was developed in 1992 and filed with the YUB as part of IR response BD-YEC/YECL-124 during the 1993/94 General Rate Application.

The rationale underlying the update for the Planning Cost Accounting Policy is outlined in detail in the response to YUB-YEC-1-39.

In sum, Yukon Energy has been engaged in an unprecedented level of planning activities (both to ensure continued safe and reliable operation of the existing system due to aged and end of life infrastructure and to provide new supply in order to meet growth on the integrated grid). For the current GRA, it was considered prudent to review and update the previous policy to ensure it reflected the current circumstances facing the Corporation. The new policy was developed to ensure that material accumulated costs in WIP are addressed and included in rates in a manner that moderates near-term rate impacts for ratepayers.

In many respects the framework and intent remains the same, and many of the changes provided in the proposed policy essentially provide greater additional clarity regarding how the policy is applied in practice.

A comparison of the previous and proposed planning cost accounting policy is as follows:

1. **Costs related to pure research and ongoing operations** - Both the previous policy and the proposed policy indicate that planning and study costs that are pure research in nature or that relate to ongoing operations are expensed in the year incurred. The proposed policy specifies that planning and study costs that relate to ongoing operations that provide long term or multi-year benefits to the system will be deferred and amortized pursuant to the policy.

2. **Reasonable Assurance Test** - Both the previous policy and the proposed policy provide that where the expected outcome of a planning and study cost is to extend the life of an existing asset or enhance its service potential or to add a new asset to the system the costs are capitalized to and amortized on the same basis as the related project. The proposed policy provides greater clarity compared to the previous policy and notes that for this condition to be met there must be “reasonable assurance” (as defined in footnote 2) that the project will proceed. Reasonable assurance test is discussed in greater detail in YUB-YEC-1-39(c).

3. **Studies and planning costs that do not meet Reasonable Assurance** - The proposed policy adds a new provision 2.3 to ensure an orderly process to address deferred costs on an ongoing basis. This specifies that planning cost that do not meet reasonable assurance will promptly be closed out in annual stages and amortized over 5 years. The previous policy only provided for two types of planning and studies costs: costs related to research and operations and costs related to defined projects that are expected to proceed. The proposed policy adds a middle stage that helps to ensure deferred costs are addressed in an orderly manner on an ongoing basis.

4. **Where project proceeds (reasonable assurance) and is later abandoned** - Both the previous policy and the proposed policy provide that where a project does not proceed the capitalized development costs will be amortized on a

straight line basis. The previous policy provides for amortization over a 5 year period while the proposed policy provides for amortization of these costs over a 10 year period.

5. **Water Licence Renewals** - The previous policy noted that planning and study costs related to water licence renewals shall be deferred and amortized over the term of the existing licence plus the expected term of the renewed licence. This has been amended in the proposed policy to specify that these costs will be deferred and amortized over the term of the renewed licence.

6. **Application of Policy** - Both the previous policy and the proposed policy note that management should use its best judgment in determining which of the above categories each specific study applies to.

7. **Transition Policy for 2012 & 2013 Test Years** – is specifically provided in the proposed policy to mitigate rate impacts in the test years.
    a. This is a one-time transition to address current balances for major projects in WIP that have not yet reached reasonable assurance with spending >$ 1million that are closed in the test years to be amortized over 10 years. This would affect Marsh Lake, Gladstone, Waste to Energy, Atlin Storage, and Geothermal.
    b. This transition provision also delays close out for certain projects (from 2011 to 2012) – this affects Marsh Lake, Gladstone and Waste to Energy.

TOPIC: **Use of LNG**

REFERENCE: **Fuel and Purchased Power, Lines 1-2 Page 3-5**

> **"These test year forecasts are adopted to address the transition to annual long-term average levels and potential future use of LNG at a materially lower cost than diesel."**

PREAMBLE:

YECL is interested in more information in respect of LNG.

QUESTION:

a) Please provide details of plans for use of LNG.

b) Please provide the calculation of net impact on fuel costs LNG versus diesel.

c) Please provide the basis for projecting LNG and diesel prices.

ANSWER:

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

Please see response to YUB-YEC-1-49 for a summary of current information that YEC can provide on LNG. The projections of LNG and diesel fuel prices assumed in the 2011 Resource Plan are provided in the Overview. Based on assessments to date, LNG fuel costs per kW.h are expected to be well below diesel fuel costs per kW.h, and ongoing studies are seeking to provide more specific assessments based on current gas and diesel price projections.

TOPIC: **Transmission and Distribution Costs**

REFERENCE: **Table 3.3 Non-Fuel O&M Expenses, Page 3-6**

PREAMBLE:

Additional information is required in order to understand the nature of the costs.

QUESTION:

a) For each of Transmission and Distribution, please provide details of costs for 2009-2013 by activity as follows:
   (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.

ANSWER:

(a)

Please see Table 1 below for detailed Distribution non-labour costs and Table 2 below for detailed Transmission non-labour costs.

Table 1:
Distribution Costs ($000s)

		2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	Proposed 2012	Proposed 2013
Distribution							
i	Supervision and Engineering (1)	5	1	1	1		
ii	Overhead Line Maintenance	63	63	70	85	73	77
iii	Underground line maintenance (2)						
iv	Substation Maintenance (3)						
v	Brushing	46	17	16	68	93	113
vi	Meter and Meter testing	47	28	18	25	20	21
vii	Service to outside parties (4)						
viii	Transformer repair and maintenance (5)						
ix	Street Light Maintenance	17	5	7	5	15	16
		178	114	111	184	201	226

(1) YEC tracks these expenses as Planning and Administration.

(2) YEC has no underground lines.

(3) Substation maintenance expenses are not tracked separately and are recorded with the overhead line maintenance category.

(4) This category of expense is not recorded for Distribution.

(5) Transformer repair and maintenance expenses are not tracked separately and are recorded with the overhead line maintenance category.

Table 2:
Transmission Cost ($000s)

		2009 GRA Compliance	Actual 2009	Actual 2010	FYF 2011	Proposed 2012	Proposed 2013
Transmission							
i	Supervision and Engineering (1)	1				5	5
ii	Overhead Line Maintenance	132	195	121	138	132	138
iii	Underground line maintenance (2)						
iv	Substation Maintenance (3)	102	174	86	142	118	71
v	Brushing	377	387	268	434	505	639
vi	Meter and Meter testing (4)						
vii	Service to outside parties (5)						
viii	Transformer repair and maintenance (6)						
ix	Street light maintenance						
		612	755	476	714	760	853

(1) YEC tracks these expenses as Planning and Administration.

(2) YEC has no underground lines.

(3) Substation maintenance expenses are not tracked separately and are recorded with the overhead line maintenance category.

(4) Metering expenses are not tracked separately for Transmission as the expense in this category is minimal.

(5) This category of expense is not tracked for Transmission.

(6) Transformer repair and maintenance expenses are not tracked separately and are recorded with the overhead line maintenance category.

TOPIC: **Employee Complement**

REFERENCE: **Table 3.4, Page 3-7**

PREAMBLE:

YECL seeks additional information with respect to employee complement.

QUESTION:

a) Please provide complete organizational chart(s) for all employees of YEC for the years 2009 to 2013.

b) Please expand Table 3.4 of the Application to identify the employee complement separately charged to O&M and Capital.

c) For the years 2009 to 2013, please provide the annual vacancy rate by department as well as the overall corporate vacancy rate.

ANSWER:

(a)

Please see Attachments 1-4 to this response.

(b)

Please see summary tables provided below for 2009, 2010, 2011 and 2012/2013 Forecast.

FTE Breakdown for 2009

Department	Admin/O&M FTE	Capital FTE	Total FTE
President	3.66	0.84	4.5
Communications	0.97	0.03	1
HR & IT	4.91	0.09	5
RP & Env.	1.44	0.56	2
Finance	13.30	0.78	14.08
Operations	34.37	6.24	40.61
ES	4.63	7.37	12
H&S	1.82	0.18	2
Totals	**65.11**	**16.08**	**81.19**

FTE Breakdown for 2010

Department	Admin/O&M FTE	Capital FTE	Total FTE
President	4.06	1.44	5.5
Communications	1.00	0.00	1
HR & IT	5.96	0.04	6
RP & Env.	0.82	1.18	2
Finance	13.13	0.56	13.69
Operations	35.16	6.33	41.49
ES	5.14	10.30	15.44
H&S	1.91	0.09	2
Totals	**67.17**	**19.95**	**87.12**

FTE Breakdown for 2011

Department	Admin/O&M FTE	Capital FTE	Total FTE
President	4.79	0.71	5.50
Communications	0.71	0.29	1.00
HR & IT	5.54	1.56	7.10
RP & Env.	4.61	1.39	6.00
Finance	13.36	2.39	15.75
Operations	32.38	9.06	41.44
ES	11.18	2.82	14.00
H&S	1.74	0.26	2.00
Totals	**74.31**	**18.48**	**92.79**

FTE Breakdown for 2012/2013

Department	Admin/O&M FTE	Capital FTE	Total FTE
President	4.47	0.03	4.50
Communications	1.00	0.00	1.00
HR & IT	6.21	0.04	6.25
RP & Env.	3.49	3.51	7.00
Finance	14.76	2.24	17.00
Operations	32.56	8.69	41.25
ES	5.22	7.78	13.00
H&S	1.97	0.03	2.00
Totals	**69.69**	**22.31**	**92.00**

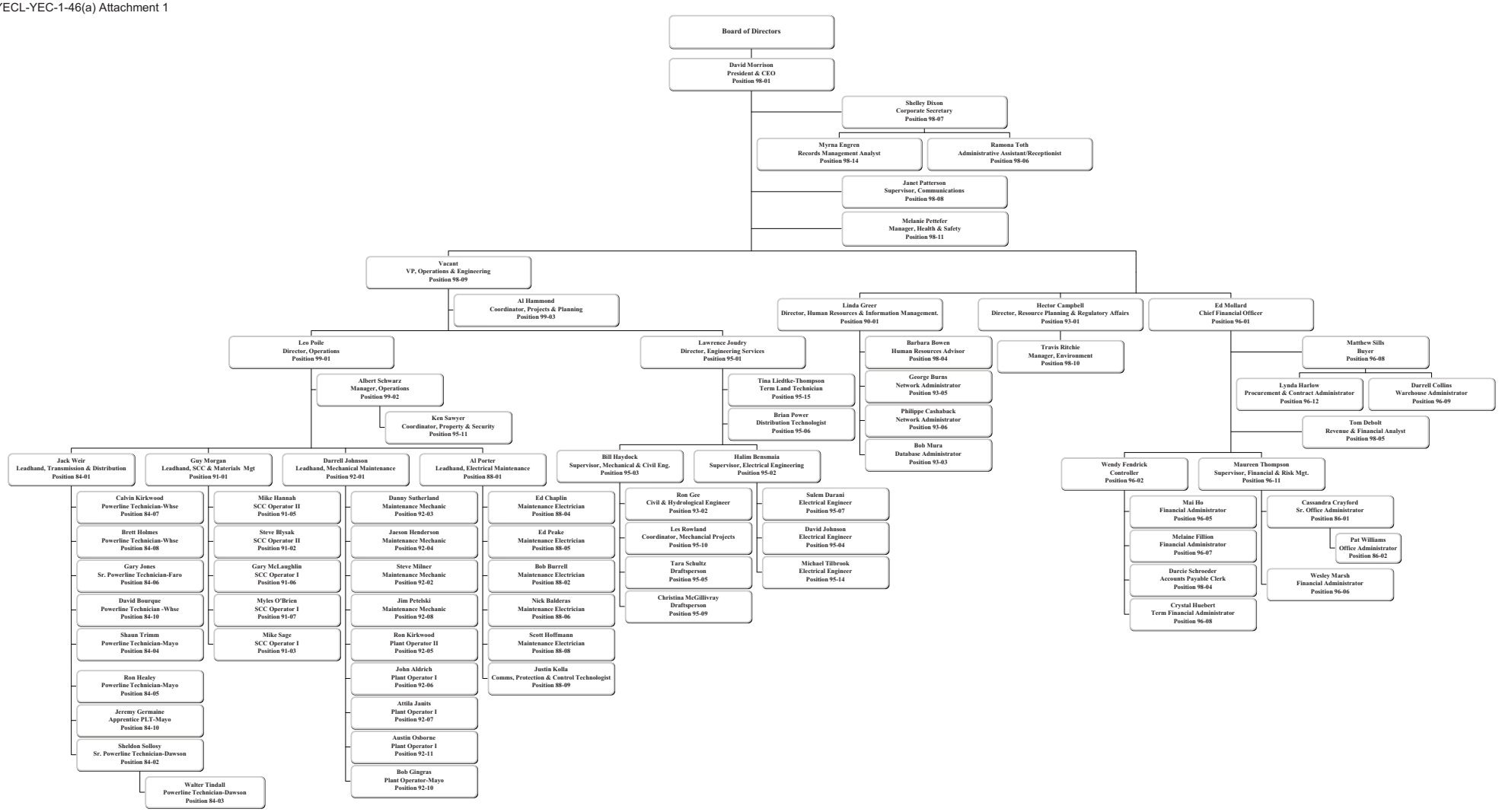
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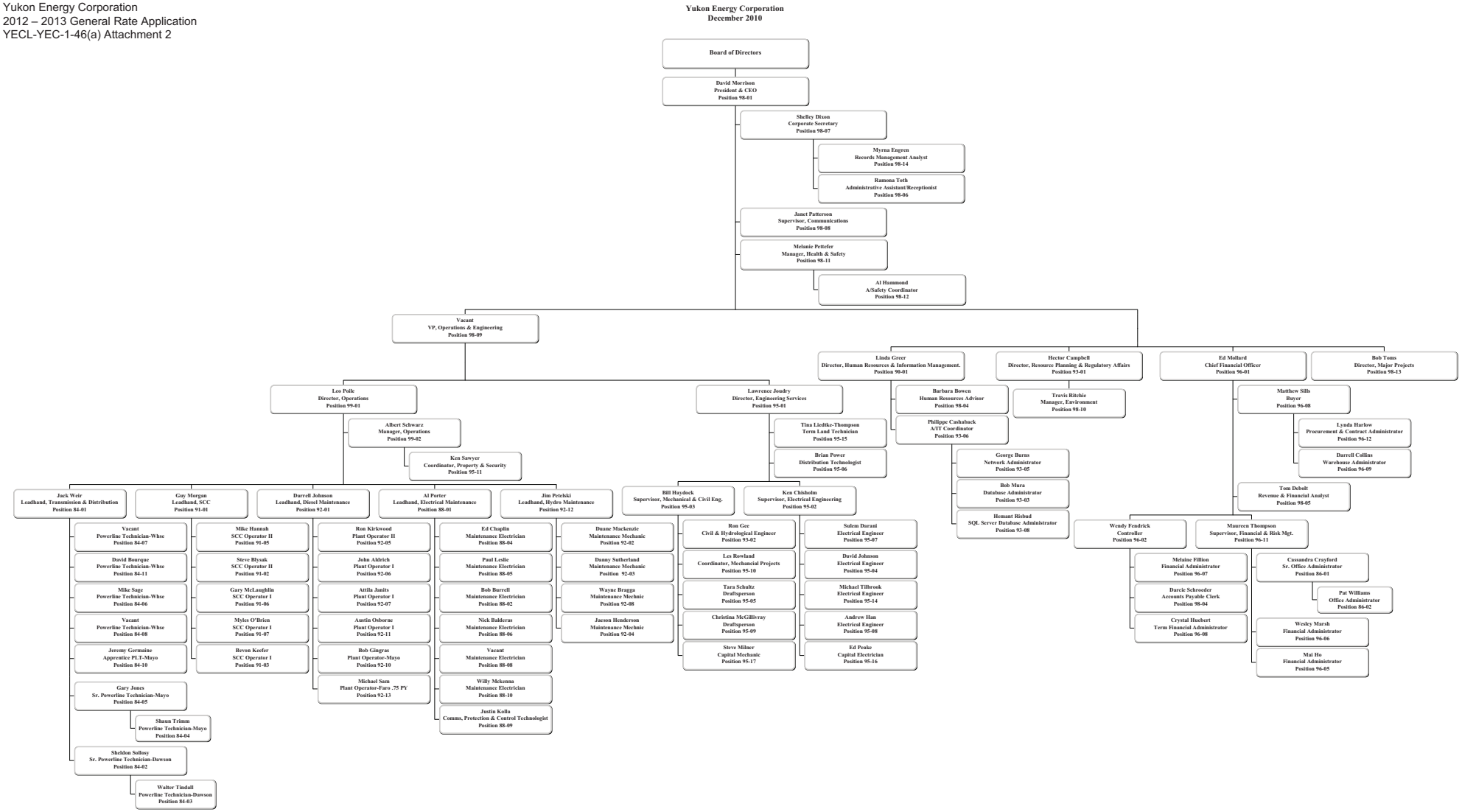
Annual vacancy rate by department is provided in Table 1 below.

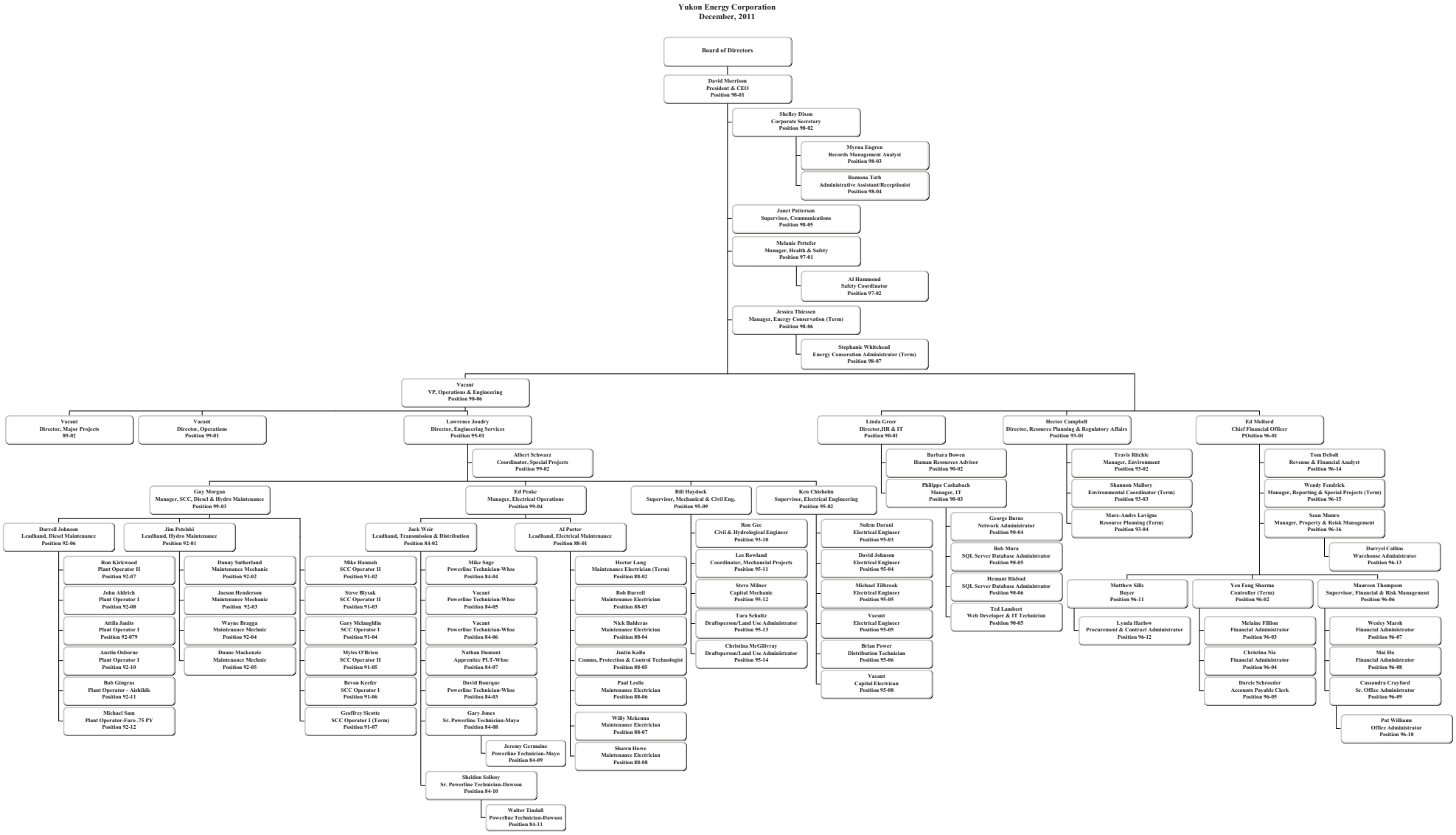
Table 1:
Annual Vacancy Rate by Department

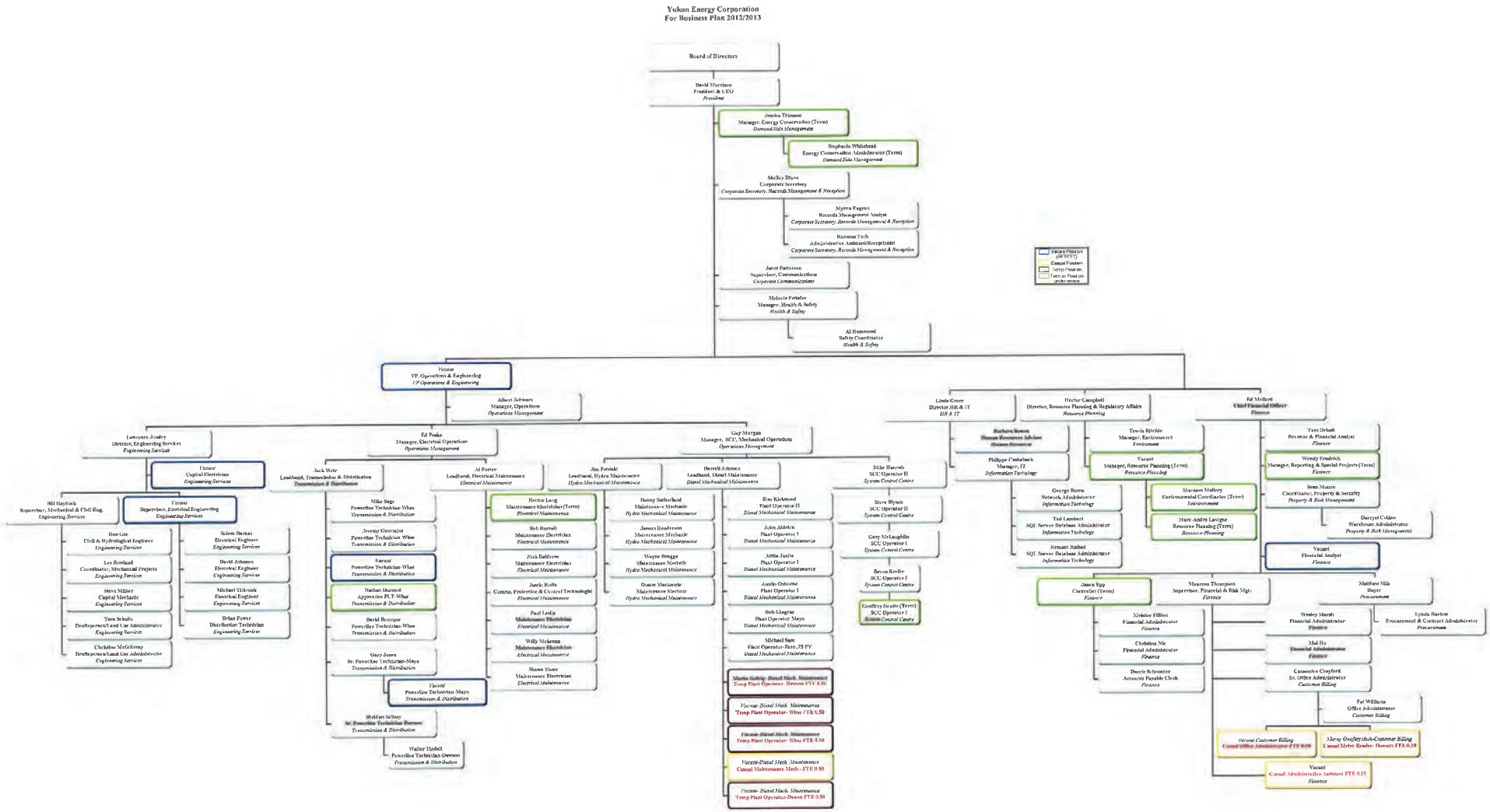
Department	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
President	1.00	1.00	1.00	0.38	0.38
Communications				0.38	0.38
Human Resources & Info. Mgmt.			0.15	0.38	0.38
Resource Planning & Environment			0.33	0.38	0.38
Finance, Cust. Acctg. & Purchasing		0.03	0.37	0.38	0.38
Operations	2.00	1.10	1.56	0.38	0.38
Engineering Services		-0.44		0.38	0.38
Health, Safety & Environment				0.38	0.38
Total Net	**3.00**	**1.69**	**3.41**	**3.00**	**3.00**

Yukon Energy Corporation
Dec 2009




Yukon Energy Corporation
December 2010
Board of Directors
David Morrison
President & CEO
Position 98-01
Shelley Dixon
Corporate Secretary
Position 98-07
Myrna Engren
Records Management Analyst
Position 98-14
Ramona Toth
Administrative Assistant/Receptionist
Position 98-06
Janet Patterson
Supervisor, Communications
Position 98-08
Melanie Pettefer
Manager, Health & Safety
Position 98-11
Al Hammond
A/Safety Coordinator
Position 98-12
Vacant
VP, Operations & Engineering
Position 98-09
Linda Greer
Director, Human Resources & Information Management.
Position 90-01
Barbara Bowen
Human Resources Advisor
Position 98-04
Philippe Cashaback
A/IT Coordinator
Position 93-06
George Burns
Network Administrator
Position 93-05
Bob Mura
Database Administrator
Position 93-03
Hemant Risbud
SQL Server Database Administrator
Position 93-08
Hector Campbell
Director, Resource Planning & Regulatory Affairs
Position 93-01
Travis Ritchie
Manager, Environment
Position 98-10
Ed Mollard
Chief Financial Officer
Position 96-01
Wendy Fendrick
Controller
Position 96-02
Melaine Fillion
Financial Administrator
Position 96-07
Darcie Schroeder
Accounts Payable Clerk
Position 98-04
Crystal Huebert
Term Financial Administrator
Position 96-08
Maureen Thompson
Supervisor, Financial & Risk Mgt.
Position 96-11
Cassandra Crayford
Sr. Office Administrator
Position 86-01
Pat Williams
Office Administrator
Position 86-02
Wesley Marsh
Financial Administrator
Position 96-06
Mai Ho
Financial Administrator
Position 96-05
Bob Toms
Director, Major Projects
Position 98-13
Matthew Sills
Buyer
Position 96-08
Lynda Harlow
Procurement & Contract Administrator
Position 96-12
Darrell Collins
Warehouse Administrator
Position 96-09
Tom Debolt
Revenue & Financial Analyst
Position 98-05
Leo Poile
Director, Operations
Position 99-01
Albert Schwarz
Manager, Operations
Position 99-02
Ken Sawyer
Coordinator, Property & Security
Position 95-11
Jack Weir
Leadhand, Transmission & Distribution
Position 84-01
Vacant
Powerline Technician-Whse
Position 84-07
David Bourque
Powerline Technician-Whse
Position 84-11
Mike Sage
Powerline Technician-Whse
Position 84-06
Vacant
Powerline Technician-Whse
Position 84-08
Jeremy Germaine
Apprentice PLT-Mayo
Position 84-10
Gary Jones
Sr. Powerline Technician-Mayo
Position 84-05
Shaun Trimm
Powerline Technician-Mayo
Position 84-04
Sheldon Sollosy
Sr. Powerline Technician-Dawson
Position 84-02
Walter Tindall
Powerline Technician-Dawson
Position 84-03
Guy Morgan
Leadhand, SCC
Position 91-01
Mike Hannah
SCC Operator II
Position 91-05
Steve Blysak
SCC Operator II
Position 91-02
Gary McLaughlin
SCC Operator I
Position 91-06
Myles O'Brien
SCC Operator I
Position 91-07
Bevon Keefer
SCC Operator I
Position 91-03
Darrell Johnson
Leadhand, Diesel Maintenance
Position 92-01
Ron Kirkwood
Plant Operator II
Position 92-05
John Aldrich
Plant Operator I
Position 92-06
Attila Janits
Plant Operator I
Position 92-07
Austin Osborne
Plant Operator I
Position 92-11
Bob Gingras
Plant Operator-Mayo
Position 92-10
Michael Sam
Plant Operator-Faro .75 PY
Position 92-13
Al Porter
Leadhand, Electrical Maintenance
Position 88-01
Ed Chaplin
Maintenance Electrician
Position 88-04
Paul Leslie
Maintenance Electrician
Position 88-05
Bob Burrell
Maintenance Electrician
Position 88-02
Nick Balderas
Maintenance Electrician
Position 88-06
Vacant
Maintenance Electrician
Position 88-08
Willy Mckenna
Maintenance Electrician
Position 88-10
Justin Kolla
Comms, Protection & Control Technologist
Position 88-09
Jim Petelski
Leadhand, Hydro Maintenance
Position 92-12
Duane Mackenzie
Maintenance Mechanic
Position 92-02
Danny Sutherland
Maintenance Mechanic
Position 92-03
Wayne Bragga
Maintenance Mechnic
Position 92-08
Jaeson Henderson
Maintenance Mechnic
Position 92-04
Lawrence Joudry
Director, Engineering Services
Position 95-01
Tina Liedtke-Thompson
Term Land Technician
Position 95-15
Brian Power
Distribution Technologist
Position 95-06
Bill Haydock
Supervisor, Mechanical & Civil Eng.
Position 95-03
Ken Chisholm
Supervisor, Electrical Engineering
Position 95-02
Ron Gee
Civil & Hydrological Engineer
Position 93-02
Les Rowland
Coordinator, Mechanical Projects
Position 95-10
Tara Schultz
Draftsperson
Position 95-05
Christina McGillivray
Draftsperson
Position 95-09
Steve Milner
Capital Mechanic
Position 95-17
Sulem Darani
Electrical Engineer
Position 95-07
David Johnson
Electrical Engineer
Position 95-04
Michael Tilbrook
Electrical Engineer
Position 95-14
Andrew Han
Electrical Engineer
Position 95-08
Ed Peake
Capital Electrician
Position 95-16


Yukon Energy Corporation
December, 2011
Board of Directors
David Morrison
President & CEO
Position 98-01
Shelley Dixon
Corporate Secretary
Position 98-02
Myrna Engren
Records Management Analyst
Position 98-03
Ramona Toth
Administrative Assistant/Receptionist
Position 98-04
Janet Patterson
Supervisor, Communications
Position 98-05
Melanie Pettefer
Manager, Health & Safety
Position 97-01
Al Hammond
Safety Coordinator
Position 97-02
Jessica Thiessen
Manager, Energy Conservation (Term)
Position 98-06
Stephanie Whitehead
Energy Conseration Administrator (Term)
Position 98-07
Vacant
VP, Operations & Engineering
Position 98-06
Vacant
Director, Major Projects
89-02
Vacant
Director, Operations
Position 99-01
Lawrence Joudry
Director, Engineering Services
Position 95-01
Albert Schwarz
Coordinator, Special Projects
Position 99-02
Guy Morgan
Manager, SCC, Diesel & Hydro Maintenance
Position 99-03
Darrell Johnson
Leadhand, Diesel Maintenance
Position 92-06
Jim Petelski
Leadhand, Hydro Maintenance
Position 92-01
Ron Kirkwood
Plant Operator II
Position 92-07
John Aldrich
Plant Operator I
Position 92-08
Attila Janits
Plant Operator I
Position 92-079
Austin Osborne
Plant Operator I
Position 92-10
Bob Gingras
Plant Operator - Aishihik
Position 92-11
Michael Sam
Plant Operator-Faro .75 PY
Position 92-12
Danny Sutherland
Maintenance Mechanic
Position 92-02
Jaeson Henderson
Maintenance Mechanic
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Wayne Bragga
Maintenance Mechnic
Position 92-04
Duane Mackenzie
Maintenance Mechnic
Position 92-05
Ed Peake
Manager, Electrical Operations
Position 99-04
Jack Weir
Leadhand, Transmission & Distribution
Position 84-02
Al Porter
Leadhand, Electrical Maintenance
Position 88-01
Mike Hannah
SCC Operator II
Position 91-02
Steve Blysak
SCC Operator II
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Gary Mclaughlin
SCC Operator I
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Myles O'Brien
SCC Operator II
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Bevon Keefer
SCC Operator I
Position 91-06
Geoffrey Sicotte
SCC Operator I (Term)
Position 91-07
Mike Sage
Powerline Technician-Whse
Position 84-04
Vacant
Powerline Technician-Whse
Position 84-05
Vacant
Powerline Technician-Whse
Position 84-06
Nathan Dumont
Apprentice PLT-Whse
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David Bourque
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Gary Jones
Sr. Powerline Technician-Mayo
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Powerline Technician-Mayo
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Sheldon Sollosy
Sr. Powerline Technician-Dawson
Position 84-10
Walter Tindall
Powerline Technician-Dawson
Position 84-11
Hector Lang
Maintenance Electrician (Term)
Position 88-02
Bob Burrell
Maintenance Electrician
Position 88-03
Nick Balderas
Maintenance Electrician
Position 88-04
Justin Kolla
Comms, Protection & Control Technologist
Position 88-05
Paul Leslie
Maintenance Electrician
Position 88-06
Willy Mckenna
Maintenance Electrician
Position 88-07
Shawn Howe
Maintenance Electrician
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Bill Haydock
Supervisor, Mechanical & Civil Eng.
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Electrical Engineer
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SQL Server Database Administrator
Position 90-05
Hemant Ribud
SQL Server Database Administrator
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Ted Lambert
Web Developor & IT Technician
Position 90-05
Hector Campbell
Director, Resource Planning & Regulatory Affairs
Position 93-01
Travis Ritchie
Manager, Environment
Position 93-02
Shannon Mallory
Environmental Coordinator (Term)
Position 93-03
Marc-Andre Lavigne
Resource Planning (Term)
Position 93-04
Ed Mollard
Chief Financial Officer
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Tom Debolt
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Position 96-14
Wendy Fendrick
Manager, Reporting & Special Projects (Term)
Position 96-15
Sean Munro
Manager, Property & Reisk Management
Position 96-16
Darryel Collins
Warehouse Administrator
Position 96-13
Matthew Sills
Buyer
Position 96-11
Lynda Harlow
Procurement & Contract Administrator
Position 96-12
Yeu Fang Sharma
Controller (Term)
Position 96-02
Melaine Fillion
Financial Administrator
Position 96-03
Christina Nie
Financial Administrator
Position 96-04
Darcie Schroeder
Accounts Payable Clerk
Position 96-05
Maureen Thompson
Supervisor, Financial & Risk Management
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Financial Administrator
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Mai Ho
Financial Administrator
Position 96-08
Cassandra Crayford
Sr. Office Administrator
Position 96-09
Pat Williams
Office Administrator
Position 96-10


Yukon Energy Corporation
For Business Plan 2012/2013
Board of Directors
David Morrison
President & CEO
Penultimo
Jessica Thiessen
Manager, Energy Conservation (Term)
Demand Side Management
Stephanie Whitehead
Energy Conservation Administrator (Term)
Demand Side Management
Shelley Dixon
Corporate Secretary
Corporate Secretary, Records Management & Reception
Myrna Rogers
Records Management Analyst
Corporate Secretary, Records Management & Reception
Ramona Teit
Administrative Assistant/Receptionist
Corporate Secretary, Records Management & Reception
Janet Patterson
Supervisor, Communications
Corporate Communications
Melanie Pettefer
Manager, Health & Safety
Health & Safety
Al Hammond
Safety Coordinator
Health & Safety
Vacant
VP, Operations & Engineering
VP Operations & Engineering
Albert Schwarz
Manager, Operations
Operations Management
Lawrence Zender
Director, Engineering Services
Engineering Services
Vacant
Capital Electrician
Engineering Services
Bill Haydock
Supervisor, Mechanical & Civil Eng.
Engineering Services
Vacant
Supervisor, Electrical Engineering
Engineering Services
Ron Gee
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Les Rowland
Coordinator, Mechanical Projects
Engineering Services
Steve Nither
Capital Mechanic
Engineering Services
Tara Schultz
Draftsperson/Land Use Administrator
Engineering Services
Christine McGilvery
Draftsperson/Land Use Administrator
Engineering Services
Salem Darnai
Electrical Engineer
Engineering Services
David Johnson
Electrical Engineer
Engineering Services
Michael Tikhonok
Electrical Engineer
Engineering Services
Brian Porter
Distribution Technician
Engineering Services
Ed Peake
Manager, Electrical Operations
Operations Management
Jack Wolz
Leadhand, Transmission & Distribution
Transmission & Distribution
Mike Sings
Powerline Technician-Whse
Transmission & Distribution
Jeremy Germaine
Powerline Technician-Whse
Transmission & Distribution
Vacant
Powerline Technician-Whse
Transmission & Distribution
Nathan Dumont
Apprentice PLT-Whse
Transmission & Distribution
David Bourque
Powerline Technician-Whse
Transmission & Distribution
Gary Jones
Sr. Powerline Technician-Mayo
Transmission & Distribution
Vacant
Powerline Technician-Mayo
Transmission & Distribution
Sheldon Selbsy
Sr. Powerline Technician Dawson
Transmission & Distribution
Walter Tisdell
Powerline Technician-Dawson
Transmission & Distribution
Al Porter
Leadhand, Electrical Maintenance
Electrical Maintenance
Hector Lacy
Maintenance Electrician (Term)
Powerhouse Maintenance
Bob Burrell
Maintenance Electrician
Electrical Maintenance
Nick Baldwin
Maintenance Electrician
Electrical Maintenance
Justin Kolla
Comms, Protection & Control Technologist
Electrical Maintenance
Paul Ledje
Maintenance Electrician
Electrical Maintenance
Willy Mckenna
Maintenance Electrician
Electrical Maintenance
Shawn Hoare
Maintenance Electrician
Electrical Maintenance
Guy Morgan
Manager, SCC, Mechanical Operations
Operations Management
Jim Fefeild
Leadhand, Hydro Maintenance
Hydro Mechanical Maintenance
Danny Sutherland
Maintenance Mechanic
Hydro Mechanical Maintenance
Jaesen Henderson
Maintenance Mechanic
Hydro Mechanical Maintenance
Wayne Briggs
Maintenance Mechanic
Hydro Mechanical Maintenance
Duane Mackenzie
Maintenance Mechanic
Hydro Mechanical Maintenance
Darrell Johnson
Leadhand, Diesel Maintenance
Diesel Mechanical Maintenance
Ron Kirkwood
Plant Operator II
Diesel Mechanical Maintenance
John Aldrich
Plant Operator I
Diesel Mechanical Maintenance
Attila Janke
Plant Operator I
Diesel Mechanical Maintenance
Austin Osborne
Plant Operator I
Diesel Mechanical Maintenance
Bob Gingras
Plant Operator Mayo
Diesel Mechanical Maintenance
Michael Sam
Plant Operator-Pers.-75 PY
Diesel Mechanical Maintenance
Vacant- Diesel Mech. Maintenance
Temp Plant Operator- Dawson FTE 0.50
Vacant- Diesel Mech. Maintenance
Temp Plant Operator- Whse FTE 0.50
Vacant- Diesel Mech. Maintenance
Temp Plant Operator- Whse FTE 0.50
Vacant- Diesel Mech. Maintenance
Casual Maintenance Mech - FTE 0.50
Vacant- Diesel Mech. Maintenance
Temp Plant Operator-Dawson FTE 0.50
Mike Hamrah
SCC Operator II
System Control Centre
Steve Blysik
SCC Operator II
System Control Centre
Gary McLaughlin
SCC Operator I
System Control Centre
Bevan Keefer
SCC Operator I
System Control Centre
Geoffrey Sicotte (Term)
SCC Operator I
System Control Centre
Linda Greer
Director HR & IT
HR & IT
Barbara Brown
Human Resources Advisor
Human Resources
Philippe Dunbabeck
Manager, IT
Information Technology
George Burns
Network Administrator
Information Technology
Ted Lambert
SQL Server Database Administrator
Information Technology
Bernard Bubbel
SQL Server Database Administrator
Information Technology
Hector Campbell
Director, Resource Planning & Regulatory Affairs
Resource Planning
Travis Ritchie
Manager, Environment
Environment
Vacant
Manager, Resource Planning (Term)
Resource Planning
Shannon Mallory
Environmental Coordinator (Term)
Environment
Marc-Andre Lavigne
Resource Planning (Term)
Resource Planning
Ed Mollard
Chief Financial Officer
Finance
Tom Delsett
Revenue & Financial Analyst
Finance
Wendy Fendrich
Manager, Reporting & Special Projects (Term)
Finance
Sean Moore
Coordinator, Property & Security
Property & Risk Management
Darryel Colaco
Warehouse Administrator
Property & Risk Management
Vacant
Financial Analyst
Finance
James Epp
Controller (Term)
Finance
Maureen Thompson
Supervisor, Financial & Risk Mgt.
Finance
Melanie Fillion
Financial Administrator
Finance
Christina Nie
Financial Administrator
Finance
Derek Schroeder
Accounts Payable Clerk
Finance
Matthew Mila
Buyer
Procurement
Wesley Marsh
Financial Administrator
Finance
Lynda Barlow
Procurement & Contract Administrator
Procurement
Mai Ho
Financial Administrator
Finance
Cassandra Crayford
Sr. Office Administrator
Customer Billing
Pat Williams
Office Administrator
Customer Billing
Vacant- Customer Billing
Casual Office Administrator FTE 0.08
Mary Onofiychuk-Customer Billing
Casual Meter Reader- Dawson FTE 0.28
Vacant
Casual Administrative Assistant FTE 0.35
Finance

TOPIC: **Non-Fuel Operating and Maintenance Expenses**

REFERENCE: **Table 3.3, Page 3-6**

PREAMBLE:

YECL seeks further information with respect to costs by activity and costs for contractor services

QUESTION:

a) For each of Production, Transmission, Distribution, General O&M and Administration, please provide costs by activity for the years 2009 to 2013 by the following components:
   (i) Labour;
   (ii) Fringe;
   (iii) Contractor services; and
   (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 the use of a contractor.

ANSWER:

(a)

Please see the response to UCG-YEC-1-26(a) for a breakdown of labour expense components.

Please see part (b) of this response for information on contractor services component of expenses.

(b)

Please see Table 1 below.

Table 1:
Consultant and Contractor Expenses ($000s)

	Actual 2009	Actual 2010	Actual 2011	GRA 2012	GRA 2013
Production	85	203	204	514	465
Transmission	523	362	504	598	725
Distribution	17	18	69	104	125
General	45	99	121	227	239
Administration	845	1,086	1,127	1,408	1,639
Total	**1,514**	**1,767**	**2,025**	**2,851**	**3,193**

It is not feasible to provide further detail as requested on each service provided 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.

TOPIC: **Non-Fuel Operating and Maintenance Expenses**

REFERENCE: **Table 3.3, Page 3-6**

PREAMBLE:

YECL requires an understanding of inflationary versus non-inflationary changes to approved levels of non-fuel O&M expense.

QUESTION:

a) Please provide the inflation rate used for in-scope versus out-of-scope labour costs for test year 2012 and 2013 and the relevant support of those rates.

b) Please provide the non-labour inflation rate used to determine the forecasts for 2012 and 2013 test years.

c) For Production, Transmission, Distribution, and General O&M lines in Table 3.3 of the Application, please separate the inflationary versus non-inflationary cost increases from the 2009 GRA approved level of expenditures compared to the 2012 test year forecast.

d) For the non-inflationary cost increases identified in part (c) above, please provide details to support the 2012 test year forecast.

e) For Production, Transmission, Distribution, and General O&M lines in Table 3.3 of the Application, please separate the inflationary versus non-inflationary cost increases from the 2012 test year forecast compared to the 2013 test year forecast.

f) For the non-inflationary cost increases identified in part (e) above, please provide details to support the 2013 test year forecast.

ANSWER:

(a)

Inflation rates were not used for determining 2012 and 2013 labour costs. These costs were based on collective bargaining agreement rates.

(b)

No inflation factor was applied to 2012 or 2013 forecasts.

(c)

The question is not clear. It is not possible to separate what actual cost increases were due to inflationary increases.

(d)

Please see the response to part (c).

(e)

Please see the response to (b).

(f)

Please see the Table 1 below.

Table 1:

Non-Fuel Operating and Maintenance Expenses Forecast

Description	Forecast 2012	Forecast 2013	Variance	Note
Production	1,449	1,437	-12	N/A
Transmission	760	853	93	1
Distribution	201	226	25	2
General	1,094	1,154	60	3

Notes:

1. Transmission forecasts increase by $0.093 million; this occurs due to $0.134 million increase in brushing expense less a decrease in substation maintenance due to cyclical maintenance not required in 2013 ($0.047 million).
2. Distribution forecasts increased due to higher forecasted brushing costs.
3. General O&M costs increased due to higher costs of maintenance of vehicles ($0.024 million) and properties ($0.030 million).

TOPIC: **Administration Expenses**

REFERENCE: **Communications expenses: Page 3-11 Lines 11-12 and Page 3-12 Lines 1-2**

PREAMBLE:

YECL requires details of increases to Communications expenses.

QUESTION:

a) Please provide details of the benefits provided by the $201,000 increase (191%) in forecast expenditures in 2012 versus the 2009 approved level of expenditures.

b) Please justify why this level of O&M is needed in 2013.

ANSWER:

(a) and **(b)**

Please see the response to YUB-YEC-1-20(a).

TOPIC: **Administration Expenses**

REFERENCE: **General expenses: Page 3-12 Lines 13-14**

PREAMBLE:

"General (forecast increase of $0.176 million by 2012 over 2009. Approved expense, increase of $0.189 million in 2013 over 2012 forecast and $0.365 million over 2009 GRA approved forecast)."

QUESTION:

a) Please provide a detailed breakdown of General expenses and justification for non-inflationary increases from the 2009 approved level of expenditures to $910,000 in 2012 and a further increase of $190,000 to $1.1 M in 2013.

ANSWER:

(a)

Please see the response to YUB-YEC-1-20(d).

TOPIC: **Reserve for Injuries and Damages (RFID)**

REFERENCE: **Appendix 3.1**

PREAMBLE:

"A recent study commissioned by the Corporation has concluded that an annual appropriation of $195,000 per year is appropriate; however, this annual appropriation has not yet been approved by the Board."

QUESTION:

a) Please provide details of the process that is followed when charging items to the RFID account, including an outline of all approvals required prior to charging items to the RFID account.

b) Please provide continuity schedules for the period 2009 to 2011 of the RFID account 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 account 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 the RFID account; and
   (iv) Evidence of appropriate sign offs and approvals for incident to be charged to the reserve.

ANSWER:

(a)

YEC has developed an RFID policy as directed by the Board in Order 2009-08. In accordance with this policy, uninsured and uninsurable losses and associated costs will be charged to the RFID if they meet the following criteria:

(a) The loss exceeds $10,000;

(b) The loss was sudden and accidental and not the result of normal wear and tear;

(c) The incident was of significance to the operation of the unit; and

(d) The loss was one of low probability, not normally expected to occur in a typical operating year.

The deductible portion of insured losses and any portion of a loss not covered by insurance and not related to betterment of the asset, and any extra expense related to an uninsurable or uninsurable unplanned plant outages will also be charged to the RFID.

Unplanned events are generally noted by operations staff and passed on to Finance. Depending on the nature of the event, a written or verbal report on the circumstances, description of the damage and estimated repair costs is prepared. If necessary, Finance will ask follow up questions. The CFO will then make the determination whether the charge qualifies for charging to the RFID. Generally, after the CFO authorizes, a work order is set up in the financial system for tracking costs associated with a given event.

Please refer to Appendix 3.1 of the Application for further details on YEC's RFID policy.

(b)

Please see Table 1 below.

Table 1:

YEC Reserve for Injuries and Damages Account Continuity Schedule ($000)

	2009	2010	2011
Opening Balance	**556**	**111**	**432**
Additions			
Premature VFD Failure	27		
Lost Tool Kit	2		
Aishihik Service Building Crane Cable Replacement	60		
Aishihik Pole Fire	24		
Vehicle Rollover Deductible	5		
Transfer from Reg Liability	(413)		
WH4 Rotor Crack Repair		315	12
MH1 Slip Ring Repair		74	
Aishihik Station Transformer		27	
Mayo Customer Damage		6	
Trail Blazer			3
S150 Cable & PT Repairs			2
Repair WD6 Premature Failure			271
Lewes Control Gate fire			4
Previous charges write-off (note 1)			(49)
Total	**(296)**	**421**	**244**
Annual Provision (note 2)	**(150)**	**(100)**	**(100)**
Closing Balance	**111**	**432**	**576**

Notes:

1. Based on a review of past charges to the account Yukon Energy wrote off amounts in 2011.
2. YUB Order 2009-08 directed YEC to charge $100,000 to this provision starting in 2008. As the order was issued after the 2008 accounts were closed, the increase in the provision for both years was recognized in income in the 2009 year.

(c)

2009

Premature VFD Failure

- **Description of Claim:** The VFD of the East Spillgate failed prematurely.
- **Date of Incident:** October 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:** There was approval from the CFO.

Lost tool kit

- **Description of Claim:** Lost tool kit.
- **Date of Incident:** April 2009.
- **Explanation:** Loss to uninsured asset.
- **Sign offs and approvals:** There was approval from the CFO.

Aishihik Service Building Crane Cable Replacement

- **Description of Claim:** During testing of the cable on the crane the cables failed.
- **Date of Incident:** April 2009.
- **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.

Aishihik Pole Fire

- **Description of Claim:** Burnt Pole on the Aishihik Line.
- **Date of Incident:** May 25, 2009.
- **Explanation:** Loss to uninsured asset.
- **Sign offs and approvals:** There was approval from the CFO.

Vehicle Rollover

- **Description of Claim:** Single vehicle accident.
- **Date of Incident:** October 30, 2009.
- **Explanation:** Insurance deductible on vehicle accident.
- **Sign offs and approvals:** There was approval from the CFO.

2010

WH4 Rotor Crack Repair

- **Description of Claim:** visible cracking on the surface of the rotor spider.
- **Date of Incident:** Came to attention in February of 2010.
- **Explanation:** Insured loss (sudden, accidental breakdown of insured property), not claimed due to estimated value of loss being slightly higher than deductible. Claiming this loss would increase insurance premiums.
- **Sign offs and approvals:** There was approval from the CFO.

MH1 Slip Ring Repair

- **Description of Claim:** Failure of the slip-rings/brushes on MH1.
- **Date of Incident:** April 2010.
- **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.

Mayo Customer Damage

- **Description of Claim:** Damages sustained by some customers in Mayo related to an outage.
- **Date of Incident:** September 8, 2010.
- **Explanation:** Loss to uninsured asset.
- **Sign offs and approvals:** There was approval from the CFO.

Aishihik Station Transformer

- **Description of Claim:** Leak in the Winter-Kennedy valves on the turbine floor. These valves are sused for flow testing and connects to the scrollcase with copper piping. Water sprayed into the station service transformer and the transformer immediately faulted.
- **Date of Incident:** July 2010.
- **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.

2011

Trail Blazer

- **Description of Claim:** vehicle went off the Aishihik Road setting the airbags to deploy.
- **Date of Incident:** November 25, 2010.
- **Explanation:** Insurance deductible on vehicle accident.
- **Sign offs and approvals:** There was approval from the CFO.

S150 Cable & PT Repairs

- **Description of Claim:** Repair of Cables and PT caused by flashover from squirrel contact.
- **Date of Incident:** May 8, 2011.

- **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.

Repair WD6 Premature Failure

- **Description of Claim:** Premature failure of WD-6. Replacement of power packs and repair of other damaged components.
- **Date of Incident:** March 2011.
- **Explanation:** Insured loss (sudden, accidental breakdown of insured property), not claimed due to estimated value of loss being slightly higher than deductible. Claiming this loss would increase insurance premiums.
- **Sign offs and approvals:** There was approval from the CFO.

Lewes Control Gate Fire

- **Description of Claim:** Electric gate on the Lewes Control Structure caught fire. Electric heat trace is expected as the cause.
- **Date of Incident:** October 21, 2011.
- **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.

TOPIC: **Transition to IFRS**

REFERENCE: **Costs, Appendix 6.2, Lines 5-8 Page 6.2-4, "Additional costs are, and will, continue to be incurred with respect to the conversion to IFRS due to increased internal and external consulting time, IT system costs and additional audit and other compliance costs. Costs for this extensive conversion process are expected to total $667,076 by the end of 2012."**

PREAMBLE:

YECL is interested in more information in respect of the Transition to IFRS.

QUESTION:

a) Please provide a detailed breakdown of costs incurred to date by year.

b) Please provide a detailed breakdown of forecasted cost for 2012 and 2013.

c) Please explain, specifically, what the current financial system limitations are that require investment in IT system hardware and/or software to change the accounting policy to IFRS from GAAP?

ANSWER:

(a)

A detailed breakdown of actual costs incurred to date to transition to IFRS is provided in Table 1 below.

Table 1:
Actual IFRS Expense (2009-2011)

	Actual 2009	Actual 2010	Actual 2011
In house Staff	52,065	52,467	53,425
Consultants/ Contractors	188,688	108,843	66,344
Other	14,354	17,531	12,052
Total	255,107	178,841	131,821

(b)

A detailed breakdown of forecast costs to complete transition to IFRS is provided in Table 2 below.

Table 2:
Forecast IFRS Expense (2012-2013)

	Forecast 2012	Forecast 2013
In house Staff	40	40
Consultants/ Contractors	40	40
Other	21	21
Total	101	101

(c)

The new accounting system allows two ledgers to be used. This will allow Yukon Energy to have a leading ledger for regulatory purposes. Yukon Energy will then have another ledger for IFRS purposes within the new accounting system.

TOPIC: **Planning and Study Costs**

REFERENCE: **Appendix 5.1 – Planning Accounting Policy, Page 5.1-1, "2.3 Planning costs incurred in relation to major projects that do not meet Reasonable Assurance will promptly be closed out in annual stages, and amortized over 5 years."**

PREAMBLE:

YECL is interested in more information in respect of YEC's Planning Accounting Policy.

QUESTION:

a) Please confirm that project costs that do not meet "Reasonable Assurance" and are deferred over 5 years would not be added to future Revenue Requirement.

b) Please provide details of all projects including dollar values, and from 2008 to 2012 that have not passed the "Reasonable Assurance "test" which have been expensed and/or deferred and amortized into future years. Please confirm these costs are not included in Revenue Requirement for the 2012 and 2013 test years.

ANSWER:

(a)

Not Confirmed. Costs that do not meet "Reasonable Assurance" and are deferred over 5 years and approved in the current Application will be included in future Revenues Requirement; YEC may also apply at a future date to have similar future project costs, incurred subsequent to (and not forecast in) this Application, added to future revenues requirements.

(b)

The amortization costs for deferred cost projects that have not passed the "reasonable assurance test" and that are being deferred and amortized in the test years are included in the current Revenue Requirement.

Please see Attachment 1 to YUB-YEC-1-39(j) for detailed list of feasibility study costs.

TOPIC: **Planning and Study Costs**

REFERENCE: **Appendix 5.1 – Planning Accounting Policy Page 5.1-2, "A one-time special transition approach for costs presently in WIP is to be implemented over 2012 and 2013 test years. Transition measures are intended to mitigate rate impacts from 5-year amortization of existing WIP costs incurred prior to Reasonable Assurance and that have climbed to over $1 million in the past few years."**

PREAMBLE:

YECL is interested in more information in respect of YEC's Planning Accounting Policy.

QUESTION:

a) Please provide details of all projects in WIP that are subject to this one-time special transition approach.

b) Please confirm these projects have not resulted in fixed asset additions as per Canadian Generally Accepted Accounting Principles.

c) Please provide the Board Approval reference or justification as to why these costs should be included in revenue requirement.

ANSWER:

(a)

Please see the Appendix 5.1, Footnote 4; projects subject to the one-time transition approach are those projects with deferred costs greater than $1 million – as listed, this includes Marsh Lake Storage, Atlin Storage, Gladstone, Geothermal, and Waste to Energy. Details on each project are provided in the Application (Section 5.3.1 Major Projects Over $ 1millions) and in the following IR responses:

- Marsh Lake Storage – responses to YUB-YEC-1-42; YECL-YEC-1-38; YCS-YEC-1-11.

- Atlin Storage – responses to YUB-YEC-1-44; YCS-YEC-1-13.

- Gladstone Diversion – responses to YUB-YEC-1-43; LE-YEC-1-25; YCS-YEC-1-12.

- Geothermal – responses to YUB-YEC-1-50; YECL-YEC-1-40.

- Waste to Energy/ Biomass – responses to YUB-YEC-1-47 and YCS-YEC-1-16.

(b)

Confirmed. These are still deferred costs and have not been transferred to fixed assets.

(c)

Please see response to YUB-YEC-1-24. These costs have been incurred by Yukon Energy consistent with the Board's findings in Section 5.3.2.1 of Board Order 2009-8. Yukon Energy is bringing these costs forward in the current application to have them reviewed by the Board to assess the prudency of the expenditure prior to including in ratebase.

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study March 1, 2012 KPMG letter to Mr. Ed Mollard, "While this preliminary document sets forth our conclusions, please note that it is not intended to be considered a complete narrative report. This document will be supplemented by a complete narrative report fully outlining our assumptions and methodologies which will be delivered at a future date."**

PREAMBLE:

YECL is interested in further information in respect of the KPMG Depreciation Study report.

QUESTION:

a) Please provide the "complete narrative report fully outlining [KPMG's] assumptions and methodologies" and why it was not provided as part of YEC's application.

ANSWER:

(a)

Please see Attachment 1 to this response for the complete narrative report.

The document provided as Tab 10 of the 2012/2013 General Rate Application was a Preliminary Summary of Results provided in early 2012 to ensure that updated information on depreciation rates and asset lives could be incorporated into the 2012/2013 General Rate Application. KPMG's scope of work included completing a more detailed report providing the analysis, assumptions and methods supporting the conclusions and recommendations provided in Tab 10. Specifically, at page 10-2 of Tab 10 KPMG notes, "While this preliminary document sets forth our conclusions, please note that it is not intended to be considered a complete narrative report. This document will be supplemented by a complete narrative report fully outlining our assumptions and methodologies which will be delivered at a future date."

KPMG

cutting through complexity™

Yukon Energy Corporation

Depreciation Study Project

July 23 2012



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July 23, 2012

PRIVATE

Mr. Ed Mollard
Chief Financial Officer
Yukon Energy Corporation
PO Box 5920
Whitehorse, Yukon Y1A 5L6

RE: Depreciation Study

Dear Mr. Mollard:

KPMG LLP's ("KPMG") has completed its depreciation study of certain tangible asset classes of Yukon Energy Corporation (the "Subject Assets," "Subject Property," or "Subject"). The scope of our engagement is outlined below.

We understand that the results of our depreciation study will be used by Yukon Energy Corporation ("YEC") management ("Management") to assist in their establishment of depreciable lives for the Subject Assets. No other use is intended or should be inferred.

Our opinions and conclusions are set forth on the following pages. Our work paper files contain the documentation that accompanies our analyses and supports our conclusions.

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Depreciation Study

Background

Background

In 2003, YEC conducted a depreciation study that was utilized to assess the reasonableness of adopting the average service life method in lieu of the continued application of the equal life group procedure in estimating depreciation of its tangible assets. Additionally, the 2003 depreciation study made recommendations regarding average service lives for each asset grouping. It is our understanding that the results of the depreciation study indicated that adopting the average service life method was reasonable and that longer (and in some cases shorter) average service lives were appropriate. The recommendations made in the depreciation study were ultimately adopted by YEC and approved by the regulatory board.

Given the passage of time since the completion of the previous depreciation study, YEC determined that a review of the existing average service lives was prudent to determine if any amendments to the current policy were appropriate. Accordingly, YEC engaged KPMG to conduct a new depreciation study to ascertain the reasonableness of the existing average service lives and to make recommendations for amended average service lives, where appropriate.

At the completion of the previous depreciation study, it was noted that certain asset classes were assigned average service lives based on analytical procedures that were conducted with certain data limitations. Accordingly, the average service lives of these classes were earmarked to be revisited for reasonableness at a future date. Hence, at YEC's request, KPMG has focused its efforts primarily on the following asset categories.

- Hydro Plant;
- Diesel Production; and
- Main Transmission.

In addition to revisiting the average service lives applied to the aforementioned asset classes, KPMG also calculated the true-up provision associated with the revised recommended average service lives. In allocating the true-up amount, KPMG estimated the recapture period with consideration to the probable remaining life of each asset group. Probable remaining lives were developed by estimating the effective ages of the asset groups and reviewing the corresponding probable remaining lives forecasted by the appropriate Iowa Curves.

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Depreciation Study

Scope of Work

Scope of Work

Our report has been prepared to assist with reviewing YEC's existing depreciation policy, estimating reasonable depreciation rates, and estimating remaining useful lives for each asset account. The procedures in our analysis included, but were not limited to the following.

- Analysis of historical data, including;
  - Review of prior depreciation study results and other information available for in-scope assets (hydro and transmission) to understand the nature of the assets, historical acquisition or construction dates, current depreciation rates, planned usage requirements and risk factors affecting useful lives and salvage values;
  - Interview engineers and other interested parties
- Reviewed and analyzed comparable company depreciation policies and normal useful life estimates;
- Reviewed assessment reports related to the Subject Assets to ascertain certain qualitative data;
- Discussed with Management the alternative methods for depreciating components (e.g. straight line, declining balance or sinking fund);
- Discussed current/future use of Subject Assets with Management and company engineers; and
- Assessed which available depreciation rate assessment models are appropriate from a quantitative and qualitative perspective for a utility the size of YEC.

Date of Value

Our analysis was conducted as at December 31, 2010 (the "Testing Date").

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Depreciation Study

Background – Company Overview

Yukon Energy Corporation

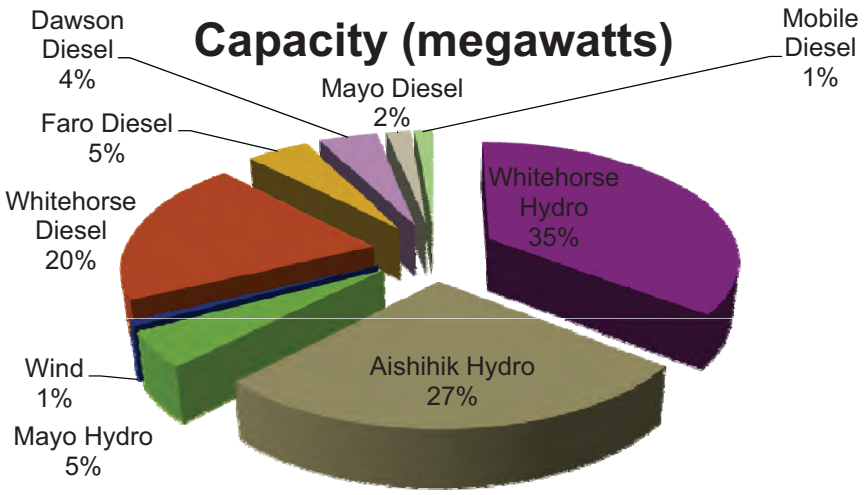
YEC is a publicly owned electrical utility, which was established in 1987. YEC primarily provides electricity to consumers in Dawson City, Mayo, and Faro in the Yukon region of Canada and relies upon hydro, diesel, and wind technology in its electricity generation process. YEC also provides bulk power to industrial customers as well as The Yukon Electrical Company Limited (An ATCO Company).

YEC is regulated by the Business Corporations Act, the Public Utilities Act and the Yukon Water Act.

Subject Property Overview

YEC's generating capability is primarily based upon hydro and diesel technology with a small portion allocated to wind technology for a total generating capacity as at the Testing Date of 112.4 megawatts. Within YEC's portfolio, hydro represents approximately 75.4 megawatts, diesel represents approximately 36.2 megawatts, and .8 megawatts is generated through wind technology.

The primary generation facilities are illustrated in the following graph and outlined on the following slide with indications of current operating capacities.



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Depreciation Study

Background – Company Overview (continued)

- **Whitehorse Hydro –** The Whitehorse generating facility was built in 1958 and was initially constructed with two hydro turbines. In 1969 a third turbine was added and a fourth turbine was installed in 1985. The Whitehorse hydro facility is capable of producing 40 megawatts of power in the summer and about 25 megawatts in the winter, where the difference in production is directly correlated with the status of the Yukon River.
- **Aishihik Hydro –** The Aishihik plant began operating in 1975 and was constructed to serve the growing electrical demands of Whitehorse and of a large lead-zinc mine at Faro in the central Yukon. The plant can produce 30 megawatts of power and YEC is in the process of installing a third 7 megawatt generator which will increase water use efficiency.
- **Mayo Hydro –** The Mayo hydro facility has served the Yukon region since 1951. It was originally developed to supply electricity to the United Keno Hill Mine at Elsa, located about 45 kilometers north of Mayo. It also supplies power to the communities of Mayo and Keno City and neighboring areas.

  The Keno mine closed down in 1989, leaving a surplus of hydro power in Mayo. To make use of this extra power, YEC built a transmission line from Mayo to Dawson City, some 232-kilometres away. The Keno mine has since re-started operations.

  The re-starting of Keno mine as well as the growing demand for electricity in the region has led to the construction of a new power house at Mayo with a capacity of an additional 10 megawatts which is referred to as Mayo B and began operation at the end of 2011.
- **Diesel Power –** Diesel, while more costly to operate than hydro, is required for standby purposes in case of an emergency and is also utilized as a supplemental generating resource during the winter months. YEC currently operates 21 diesel generators: 7 in Whitehorse, 2 in Mayo, 4 in Dawson, 4 in Faro and 4 mobile units.

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Depreciation Study

Background – Company Accounts

Description of Subject Assets – Accounts

For regulatory purposes, YEC categorizes its assets into 9 primary asset classes that are then further disaggregated into varying numbers of subclasses. The following table outlines the primary asset classes utilized by YEC as well as the relative weighting of each class with regards to their original cost while the following slides provide a breakdown of the relative weighting of each subaccount. The following cost figures are presented in Canadian dollars.

Class/Class Description	Cost	Percent of Total Cost
Land	1,126,675	0.4%
Hydro Plant - 140003	120,227,014	42.1%
Diesel Production - 140004	24,580,301	8.5%
Wind Turbine - 140005	3,148,905	1.1%
Main Transmission Facilities - 140006	85,422,003	29.9%
Sub Transmission Lines - 140007	15,491,635	5.4%
Distribution System - 140008	11,930,298	4.2%
Building and Other Equipment - 140009	19,539,510	6.8%
Transportation - 140014	4,313,442	1.5%
Total	**285,779,782**	**100.0%**

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Depreciation Study

Background – Company Subaccounts

Description of Subject Assets – Subaccounts

Class/Class Description	Cost	Percent of Total Cost
Land		
No Identification Number	1,126,675	0.4%
Total Land	**1,126,675**	**0.4%**
Hydro Plant		
140003.200 Structures and Improvements	10,854,779	3.8%
140003.205 Reservoirs, Dams, and Waterways	89,859,047	31.5%
140003.506 Waterwheels, Turbines & Generation	10,431,950	3.7%
140003.600 Accessory Electric Equipment	6,489,762	2.3%
140003.700 Misc Power Plant Equipment	2,542,719	0.0%
140003.730 Fencing	48,758	0.0%
Total Hydro Plant	**120,227,014**	**42.1%**
Diesel Production		
140004.200 Structures and Improvements	1,525,367	0.5%
140004.201 Buildings and Improvements	307,094	0.1%
140004.403 Fuel Holders, Products, and ACC	1,015,105	0.4%
140004.500 Generating Equipment and Prime	15,732,200	5.5%
140004.508	243,548	0.0%
140004.600 Accessory Electric Equipment	4,278,353	1.5%
140004.700 Misc Power Plant Equipment	1,478,633	0.5%
Total Diesel Production	**24,580,301**	**8.5%**
Wind Turbine		
140005.400 Wind Turbine	3,148,905	1.1%
Total Wind Turbine	**3,148,905**	**1.1%**

Class/Class Description	Cost	Percent of Total Cost
Main Transmission Facilities		
140006.300 Poles and Fixtures	35,465,743	12.4%
140006.304 Brushing	9,739,372	3.4%
140006.305 Survey Costs	2,787,405	1.0%
140006.402 Overhead Conductors / Poles	15,729,233	5.5%
140006.404 Overhead Conductors / Towers	277,975	0.1%
140006.710 Substation Equipment	21,342,570	7.5%
140006.720 Substation Buildings	32,750	0.0%
140006.730 Substation Fences	46,953	0.0%
Total Main Transmission Facilities	**85,422,003**	**29.9%**
Sub Transmission Lines		
140007.300 Poles and Fixtures	3,618,635	1.3%
140007.301 25Kv Minto Spur- Structure	2,646,132	0.9%
140007.304 Brushing	0	0.0%
140007.305 Survey costs	0	0.0%
140007.306	432,533	0.2%
140007.307	95,136	0.0%
140007.401 Overhead Conductors	989,127	0.3%
140007.405 Underground Conductors / Conduit	83,873	0.0%
140007.407	920,693	0.3%
140007.710	0	
140007.711	6,705,507	2.3%
Total Sub Transmission Lines	**15,491,635**	**5.4%**

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Depreciation Study
Background

Description of Subject Assets (continued)

Class/Class Description	Cost	Percent of Total Cost
Distribution System		
140008.300 Poles and Fixtures	3,570,732	1.3%
140008.304 Brushing	44,763	0.0%
140008.305 Survey costs	500,981	0.2%
140008.401 Overhead conductors - Poles	74,570	0.0%
140008.410 Overhead Costs	1,984,394	0.7%
140008.510 Underground Services	6,379	0.0%
140008.550 Wind Monitoring Equipment	281,251	0.0%
140008.610 Meters	314,136	0.1%
140008.620 Meter Equipment	1,188,413	0.1%
140008.710 Substation Equipment	64,798	0.4%
140008.720 Substation Buildings	573,505	0.0%
140008.815 Street Lights	3,290,797	0.2%
140008.905 Line Transformers	35,580	1.2%
140008.961 Sentinel Lights	0	0.0%
Total Distribution System	**11,930,298**	**4.2%**

Class/Class Description	Cost	Percent of Total Cost
Building and Other Equipment		
140009.110 Survey Costs Land	4,321	0.0%
140009.200 Structures and Improvements (Hydro)	490,156	0.2%
140009.201 Building and Improvements	8,458,407	3.0%
140009.202 Office Furniture and Equipment	1,389,826	0.5%
140009.210 Communication Site Towers	19,297	0.0%
140009.220 Communication Site Fences	36,663	0.0%
140009.310	0	0.0%
140009.320 Computer Hardware	1,920,814	0.7%
140009.330 Computer Software	842,508	0.3%
140009.505 Tool and Instruments	998,579	0.3%
140009.507 Wind monitoring equipment	140,508	0.0%
140009.605 Communication Equipment	3,780,557	1.3%
140009.810 Company Owned Houses / Land	36,512	0.0%
140009.820 Company Owned Houses	1,421,362	0.5%
140009.900	0	0.0%
Total Building and Other Equipment	**19,539,510**	**6.8%**
Transportation		
140014.411 Utility Vehicles	181,452	0.1%
140014.412 Sedans and Stationwagons	118,637	0.0%
140014.420	66,929	0.0%
140014.430 Pole Trailers > 10,000 Lbs	34,810	0.0%
140014.440 Trucks 3/4 to 2 Ton	2,217,586	0.8%
140014.470 Trucks > 3 Ton	692,397	0.2%
140014.490	1,001,630	0.4%
Total Transportation	**4,313,442**	**1.5%**

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Depreciation Study

General Methodology – Depreciation

Depreciation

Depreciation, for accounting purposes, reflects the consumption of capitalized assets over an estimated service life that accounts for the period of time the assets will be utilized. In other words, depreciation accounts for the amount of an asset that has been "used up" as at a specific point of time where the key factors are the asset's original cost, expected time period of usefulness, the rate at which the asset will be consumed, and any value that will be realized upon the disposition of the asset at the end of its useful life.

There are several methods utilized to estimate depreciation expense, all of which address the factors noted above, but the most common methodology applied in the public regulated utility is the age/life or straight-line method whereby the cost of an asset less net salvage value is amortized in equal installments over its estimated economic life. The following mathematical expression illustrates the calculation utilized to estimate periodic depreciation when applying the straight-line method.

$$\frac{\textit{Historical Cost of Asset}}{\textit{Service Life of Asset}} = \textit{Annual Depreciation Expense}$$

For the purposes of our analysis, and based on discussions with company management we have assumed the straight-line method to estimate depreciation expense.

Depreciation Calculation Example

To illustrate the calculation utilized to estimate the annual depreciation expense, consider the following example.

Assume asset group A has a historical cost basis of $1,000,000. Through the qualitative and quantitative methods employed, KPMG determines that the best fit Iowa curve is the R3-50. Therefore, the average service life concluded for asset group A is 50 years.

To estimate the annual depreciation expense utilizing the straight-line method, the cost basis of $1,000,000 is apportioned in equal amounts over the 50 year average service life, thereby resulting in an annual depreciation rate of 2 percent or $20,000.

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Depreciation Study

General Methodology – Average Service Life Overview

Average Service Life Overview

As previously noted, to estimate depreciation it is necessary to estimate the service life of an asset or an asset group. The concept of an average service life implies that the units within an asset group have different lives and experience different points of mortality. Thus, a service life must be estimated to reflect the average behavior of an asset within the subject group.

Survivor Curves – Iowa Curve Overview

As noted above, mortality is a key component considered when estimating average service life. By applying certain quantitative methods, one can draw comparisons between the actual and/or simulated behavior of the subject data available and industry recognized survivor curves.

Survivor curves graphically illustrate the percentage of a population surviving at a point in time. Data that can be deduced from survivor curves include the following:

- Average life of the group;
- Anticipated remaining useful life of the group; and
- Probable life of the group.

The most common survivor curves relied upon in the estimation of average service life of public utility assets are referred to as the Iowa Curves. Researchers at Iowa State University developed a retirement rate method that tracked actual property retirements for 176 different types of physical assets. The results of this work were published in Bulletin 125 of the Iowa Engineering Experiment Station in December 1935. The work was updated in *Statistical Analyses of Industrial Property Retirements* and four additional curves were added to the 18 original Iowa curves.

The major findings of this work is that assets have retirement rate characteristics that can be classified into categories based on the timing and frequency of asset retirements. The following slide provides an illustration of the left modal Iowa Curves.

The lower half of the figures (the frequency of retirement curves) gives an indication of the rate of retirement (the modal frequency). The lower number curves, such as the 0, 1, and 2 curves, have a wider dispersion than the higher number curves. The lack of dispersion in the higher number curves is indicative of a large number of retirements in a short period of time—the type of retirement history expected where company policy dictates when assets will be retired. For example, a gas utility that replaces service trucks after four years or 100,000 miles will show a large number of retirements in a short period of time.

The four major groupings—L, S, R, and O—are determined by the modal age of retirement relative to average life. Assets groups with L-curve characteristics have slightly more than 50 percent of their assets retired by the time the assets' average life is reached. This means that the majority of the assets have lives shorter than the average life, but that some for the assets last an extremely long time and drive up the average age calculation.

Just the opposite can be said for the R curves. The S curves are symmetrical about the average age—half of the retirements occur before average age, and half after. The O curves are sometimes referred to as bimodal curves since they exhibit a high retirement rate early on, transitioning to a much lower retirement rate later—similar to human actuarial experience before the turn of the century, when there was extremely high infant mortality.

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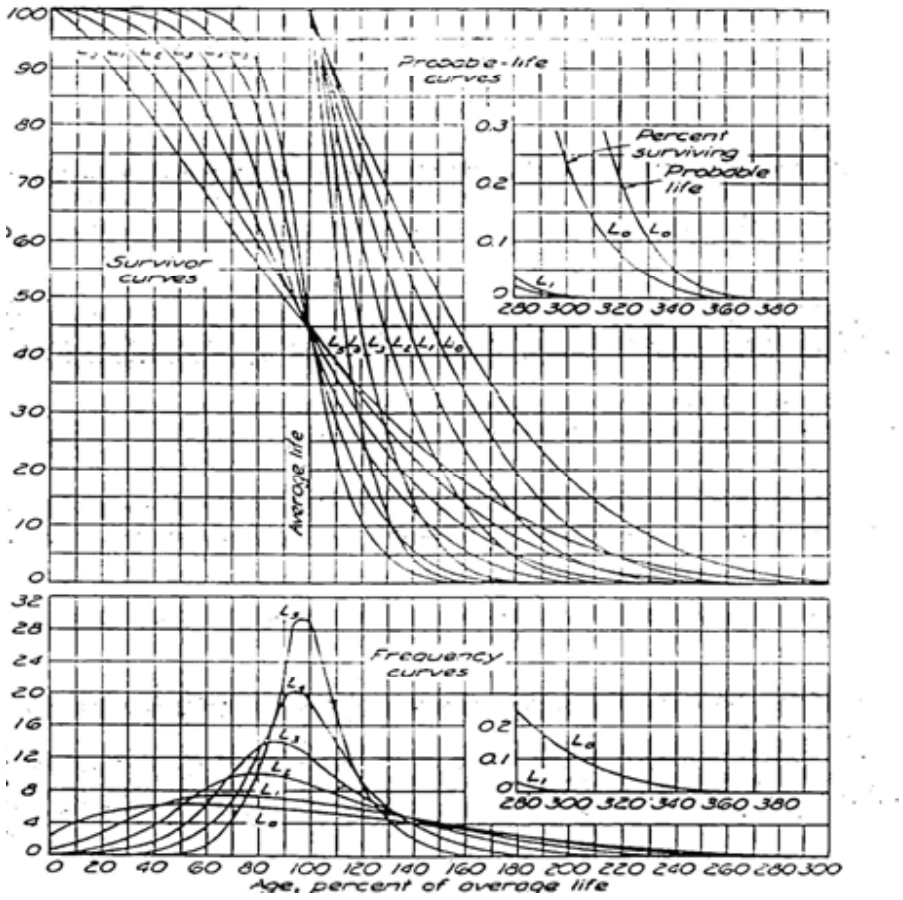
Depreciation Study

General Methodology – Average Service Life Overview (continued)

By observing actual asset retirement history for a group of similar assets, one can curve-fit the actual data to the Iowa Curves and reasonably predict an asset group's average service life, and the probable remaining life for an asset of any known age. The use of the retirement rate method and Iowa Curves allows one to refine published asset group useful life data and give a more scientific means of determining remaining life than the previously used "age-life percent good" or "effective life" direct value judgments.

To the right, please notice an illustration of the Left Modal Curves from the aforementioned Bulletin 125 of the Iowa Engineering Experiment Station for reference.

Iowa Curve Illustration – Left Modal Curves



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Depreciation Study

General Methodology – Average Service Life Estimation

Average Service Life Estimation

In estimating the average service life of an asset group, there are several accepted methodologies that can be applied: actuarial, simulated plant balance, and turnover. Each methodology relies on historical data of the asset group as a whole.

Actuarial methodologies include: the retirement rate method, the original group method, and the individual unit method. The retirement rate method is considered the preferred method as it examines the additions and retirements of an asset group over the entire period under analysis. Conversely, the original group method focuses on the original asset group only and its corresponding retirements; and the individual unit method focuses on retirements only.

The ***Simulated Plant Balance*** methodology is a difficult methodology to implement but is otherwise useful. Under this method, survival ratios under different survivor curves are utilized to create a simulated account balance. Each simulated account balance is compared to the actual asset account history, and the best match is selected as the appropriate survivor curve.

Turnover methodologies, including methods such as the half-cycle method and the asymptotic method, are generally considered weaker methods than the actuarial methods previously discussed. Turnover methods utilize retirement ratios without consideration to the age of the assets. Therefore, this method is useful in circumstances of limited data, but is also a weaker approach when asset age data is available.

The objective of each method is to determine the average service life of the asset group based on historical retirement patterns and the balance of assets surviving at each measured interval of time.

It should be noted that, while actual data is heavily relied upon, a prudent level of judgment is also applied in estimating average service lives as there are limitations to what is achievable solely with quantitative methods.

In addition to a review of historical data, there are also qualitative procedures taken to measure the average service life of an asset group. The primary qualitative method available is the comparable company method. In the comparable company method, asset lives applied by similar companies are collected and reviewed by category. Upon the completion of the review, ranges of comparable lives are created by asset category and utilized as an indication of accepted service lives within the subject industry.

In our analysis, we have applied both quantitative and qualitative procedures in estimating the average service lives of the Subject Assets. We applied an actuarial methodology referred to as the retirement-rate or annual-rate method in our quantitative procedures and the comparable company method in our qualitative procedures. In the comparable company method comparable regulated utility companies were researched in the US and Canada. Information regarding average service lives from the companies' annual reports were summarized and compared to the subject company. Information gathered included: company overview, geographic location, customers served, methods of power generation, transmission network, PP&E accounting lives by asset type, etc. The average service lives are then compared to the subject and used as a secondary data point.

A business description for each of the selected comparable companies is found in the "Comparable Companies" section below. The depreciable lives utilized by the comparable companies are discussed in the applicable asset account sections.

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Depreciation Study

Methodology Applied – Quantitative Approach

Quantitative Approach - Overview

As previously noted, we relied upon a statistical method known as the retirement-rate method in performing our quantitative analysis. The methodology followed in the quantitative approach is consistent with the approaches used in past YEC studies and with our experience with other utilities.

The results of the statistical analysis are indications of past experience and are studied to establish trends in historical service life, retirement dispersion patterns as given by Iowa Curves. Indicators of goodness-of-fit, a review of recorded accounting data, knowledge of the type of property involved, and the experience of others with similar property, including the depreciation parameters of the previous depreciation study, are used as aids in these determinations. Historical service lives and Iowa-type curves also are modified, if appropriate, to reflect future service conditions.

In establishing the service life estimates, consideration must be given to expected future conditions not reflected in historical statistics. If the factors that determine the historical average service life will not change significantly in the future, the historical average service life can be a reasonable estimate of the future average service life. However, changing technology, company growth, environmental and regulatory requirements, customer demands, and sometimes the experience of other utilities have a definite effect and must be considered in the determination of normal useful lives, future average service life, remaining life, and net salvage.

The accounting history of additions, retirements, and balances is used to study service life experience and trends for various regulated power generation plant accounts. When the dates of the installation and retirements are known and appropriately complied, study procedures known as actuarial methods can be used.

When such data are not available in a reliable form, techniques are available to simulate actual vintages of retired property. In this instance we were provided with information from a previous depreciation study as well as the additions and deletions from 2003 through year-end 2010 by management and these were used as the basis of our depreciation study.

The retirement rate method involves estimating the appropriate survivor curve for all property groups. For this study, these curves were based upon data from a previous depreciation study as well as additions and deletions provided by management from 2003 to 2010. The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each group is retired.

In our analysis, we analyzed historical retirement patterns for each asset class and conducted quantitative procedures to best fit the historical data to the most applicable Iowa Curves. While this was our primary quantitative method, it should be noted that certain adjustments and iterative processes were conducted to ensure that the most appropriate Iowa Curve was selected.

When conducting the statistical analysis, there were certain asset classes whose quantitative data presented limitations and required adjustments. Such instances included limited periods of experience (i.e. a long lived asset group with meaningful data over only a short duration) and wide experience bands with insignificant changes to the asset base, thereby making the comparative analysis over the entire duration of the experience infeasible.

For example, account 140003-205 has historical cost data originating in 1950. However, a material account balance does not occur until 1986. As such, we have adjusted our measurement period to consider the experience band that accurately reflects the retirement experience of the assets in service.

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Depreciation Study

Methodology Applied – Quantitative Approach (continued)

Data Interpretation Methods

General - All Data Points

In our analysis, the first step was to consider all historical data available for each account. Data were subsequently put into bands by year where exposures and retirements are measured. The historical data bands by year illustrated an actual partial survivor curve for each account.

Upon analyzing each asset account and their historical data, considerations were made to the reliability of the data regarding its duration, timing of costs incurred, and other key factors. After reviewing the data in its entirety, additional steps were taken to adjust the data to determine the most reasonable way to interpret a reasonable average service life. We've looked at each historical data set for each account in several ways to better understand them and improve the accuracy of our curve fitting process.

Non-Zero Data Points Only

In this case, KPMG removed any "zero" data points in the historical data set which would skew our concluded service life estimate downwards. The "zero" data points represented missing data, not full retirements in a given account; therefore, we believed it was reasonable to exclude these "zero" data points in certain cases.

Exclude Multiple Data Points with no Retirements

In some cases, certain data sets contained extended periods without any exposures/retirements. To examine these instances from another viewpoint, we've excluded data points in the historical data set where no exposures/retirements occurred. The goal of this adjustment to the historical data was to focus our curve fitting process to match years where changes occurred rather than periods of inactivity.

Extrapolated Growth

As previously noted, certain extrapolation procedures were conducted to provide more reasonable consideration to the quantitative data available. In our analysis, two extrapolation methods were utilized: linear and geometric. When limited data was available, both methods of extrapolation were applied to derive estimates of future retirement patterns. The combined historical and estimated future retirement patterns were then utilized in the curve fitting process to identify the Iowa Curve most appropriately reflected in the survivor patterns of the subject asset group.

The linear and geometric methods of extrapolation were performed by analyzing the number of data points for a given asset account, and measuring the geometric and arithmetic annual rate of change between the first and last data point. Utilizing the two calculated rates of change, two additional scenarios were constructed for each asset account under analysis by extrapolating from the last observed data point on the survivor curve.

The analysis of each asset class was performed with and without the extrapolation techniques in order to develop various scenarios in which to examine the historical asset retirement patterns. Judgment was used to determine whether an extrapolation of asset retirement patterns increased or decreased the usefulness of the quantitative analysis. Whether an extrapolation of the data was considered the best scenario in the quantitative analysis is noted at the bottom of each graphical analysis page in the individual account sections of this report.

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Depreciation Study

Methodology Applied – Quantitative Approach (continued)

Further Segmentation of Historical/Extrapolated Data Sets

In addition to the extrapolation and other considerations noted above, we have also examined various segments of the historical and extrapolated data sets in our curve fitting process.

To illustrate our method of segmentation, take a historical data set of 30 data points, which was also extrapolated to additional data points. We've applied our curve fitting process to various segments of this historical/extrapolated data set, including:

- All data points
- 0 - 50% - The first 15 data points
- 50 – 100% - Data points 16 through 30
- 100 - 150% - The first 15 extrapolated data points
- 50 - 150% - Data points 16 through 30 and the first 15 extrapolated data points.

Judgment was utilized to determine which segment of the given data best represented the retirement pattern of the asset account. The primary factors that affected our conclusion on the segmentation were the size and timing of the exposures and retirements, and the usefulness of the extrapolation methods.

Curve Fitting Process

As described in the preceding data interpretation section, we have examined each asset account's survivor patterns from several standpoints. For each interpretation of the data for a given account, we've used statistical measures to select a "best-fit" Iowa Curve. We have selected a "best-fit" Iowa Curve based on 18 Iowa Curve types (L0 – L5, S0 – S6, and R1 – R5) and 125 possible average service lives; therefore, we've examined 2,250 different Iowa Curves to statistically find the best fit for the data in each scenario.

Comparable Curve Fitting

In the event that ample data was unavailable to conduct curve fitting procedures, average service lives were derived based on comparable asset groupings. An illustration of this procedure is seen with structures and improvements that are noted in different accounts, but are expected to experience similar patterns of survival. Thus, it is not unreasonable to assume that similar assets found in different accounts would experience the comparable mortality rates.

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Depreciation Study

Methodology Applied – Qualitative Approach – Comparable Companies

Qualitative Approach

While a quantitative approach to estimating average service lives is based on actual retirement experience and discrete data as it relates to a specified group of assets, there are limitations of applying a methodology that relies strictly on quantitative methods.

Relying solely upon quantitative data presents several circumstances that can lead to an inaccurate measurement of average service life. First, the population of data being relied upon can have a limited duration of experience. Such circumstance arises primarily when reviewing long lived assets. For example, if an asset group is commonly assigned an average service life of 75 years, but the subject population of data only has a meaningful duration of 15 years, then there could be a lack of empirical data to support a 75 year life for the subject population despite the common acceptance of 75 years for the subject asset group.

A similar occurrence arises when an asset group experiences a material change that is not directly related to the retirement of assets. Such a change could be related to the addition of assets to an asset grouping that materially changes the balance in the account or significant retirements that are unrelated to the assets functionality.

Given the limitations of relying solely upon quantitative methods to estimate average service life, we have incorporated certain qualitative methods into our analysis. Comparable companies were selected on the basis of owning and operating the same type of hydro and electrical generation assets as YEC.

Comparable Companies

The primary qualitative method utilized to measure average service life is the comparable company method. In applying this method, the average service lives applied for similar asset groups by other companies is relied upon. Such data is commonly available in public company filings as well as depreciation studies that have been made publicly available.

The comparable companies relied upon in our study included, but was not limited, to the following:

- **British Columbia Hydro and Power Authority –** British Columbia Hydro and Power Authority, which operates as BC Hydro, distributes electricity to the 1.8 million residential and business customers. The province-owned utility owns more than 46,500 miles of transmission and distribution lines, and it operates hydroelectric and fossil-fueled power plants about 11,350 MW of generating capacity. Subsidiary Powerex markets and trades energy throughout North America. To increase efficiencies in green power production, in 2010 BC Hydro consolidated its transmission operations with those of the province-owned British Columbia Transmission. A Crown corporation owned by British Columbia, BC Hydro is regulated by British Columbia Utilities Commission.
- **Manitoba Hydro –** For this company, water and electricity are a productive mix. Manitoba Hydro-Electric (commonly called Manitoba Hydro) provides electricity to 532,000 customers in the province of Manitoba. Its power is generated from hydroelectric facilities capable of producing about 32 billion kilowatt-hours of electricity per year. Manitoba Hydro, which is owned by the government of Manitoba, also exports power to utilities and energy marketers in the US and other Canadian provinces. Through its Centra Gas subsidiary, the company distributes natural gas to 264,300 residential, commercial, and industrial customers in 100 communities in Manitoba.

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Depreciation Study

Methodology Applied – Qualitative Approach – Comparable Companies (continued)

Comparable Companies (continued)

- **Newfoundland Labrador Hydro –** Newfoundland and Labrador Hydro (Hydro), a Nalcor Energy company, has an installed generating capacity of 1,635 megawatts (MW). Over 80% of the energy generated in 2010 was clean, hydroelectric generation. Hydro's regulated assets include: nine hydroelectric generating stations, one oil-fired plant, four gas turbines, and 25 diesel plants. The company also maintains 54 high-voltage terminal stations, 25 lower-voltage interconnected distribution stations, and thousands of kilometres of transmission and distribution lines.
- **Snowy Hydro Limited –** Snowy Hydro Limited (Snowy Hydro) provides energy to the National Electricity Market (NEM) participants. It is a supplier of price risk financial hedge contracts to the electricity industry, and supply risk assurance to the irrigators industry. The company owns and operates the 3800 megawatt (MW) Snowy Mountains Hydro Electricity Scheme, 300MW Valley Power and 320MW Laverton North gas fired power stations, which are situated in Victoria. It operates a network of seven plants, 31 generation units 15 dams and 225 kilometers (km) of aqueducts and tunnels in the Kosciuszko Naional Park. Snowy Hydro also provides water for environmental releases and water to in-land irrigators.
- **NextEra Energy –** NextEra Energy, Inc. (NextEra) is a publicly traded utility and gas company. It engages in the provision of electricity and other related products and services in the US. The company operates business through its two subsidiaries, namely, Florida Power & Light Company (FPL); and NextEra Energy Resources, LLC (NextEra Energy Resources). FPL is an electric utility company, supplying power to more than 8.7 million customers and is active in energy conservation programs. NextEra Energy Resources provides electricity using clean and renewable fuels such as wind power and solar power. NextEra has combined generating capacity of about 43,000 megawatts (MW).

Comparable Companies (continued)

- **FirstEnergy Corp –** FirstEnergy Corp. (FirstEnergy) is an energy holding company. Through its subsidiaries and affiliates, the company is active in the generation, transmission and distribution of electricity. In addition, the company also provides energy management and other energy-related services. FirstEnergy serves nearly 11.3 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. Its generation subsidiaries operate power plants with a total system capacity of more than 13,000 MW. The generation portfolio of the company is comprised of coal-fired units, nuclear plants, gas & oil based plants, hydroelectric plants and wind generation plants.
- **ALLETE Inc. –** ALLETE, Inc. (ALLETE) is engages in the provision of energy services in the upper Midwest and also participates in real estate holdings in Florida. The company operates its business through two segments, namely, Regulated Operations, and Investments and Other. The Regulated Operations segment is engaged in the retail and wholesale of rate-regulated electric, natural gas, and water services. The Investments and Other segment are engaged in the coal mining business in North Dakota and real estate business in Florida. The company operates its business activities through four subsidiaries, namely, Minnesota Power, Superior Water Light and Power, BNI Coal, and ALLETE Properties.

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Depreciation Study

Methodology Applied – Qualitative Approach – Comparable Companies (continued)

Comparable Companies (continued)

- **NRG Energy, Inc. –** NRG Energy, Inc. (NRG Energy) is a wholesale power generation company in the US. It is engaged in ownership, development, construction and operation of power generation facilities across the country. The company generates power through a diversified portfolio products such as nuclear, wind and solar power. NRG also engages in the transaction and trading of fuel, energy and related products and provides transportation services in the US and international markets. In addition, NRG Energy together with its subsidiaries, engages in supply of electricity, energy services, and cleaner energy and carbon offset products to retail electricity customers.
- **Duke Energy Corporation –** Duke Energy Corporation (Duke Energy) is an energy utility company, engaged in the generation, transmission and distribution of electricity, natural gas and related energy services. It owns and operates regulated and unregulated power plants in North America and Latin America regions. The company has its operations in Indiana, Kentucky, North Carolina, Ohio and South Carolina in the US and in Brazil, Peru and Ecuador, El Salvador, Guatemala and Argentina. Duke Energy supplies and distributes electricity to approximately, four million US customers and has around 35,000 MW of the US generating capacity.
- **Southern Power –** Southern Power, a subsidiary of Southern Company, is among the largest wholesale energy providers in the Southeast U.S, meeting the electricity needs of municipalities, electric cooperatives and investor-owned utilities. The company owns and operates more than 7,500 megawatts with facilities in Alabama, Florida, Georgia and North Carolina and has an additional 820 megawatts committed to construction in North Carolina and Texas.

Comparable Companies (continued)

- **Green Mountain Power Corporation –** Green Mountain Power Corporation (Green Mountain Power Corporation) is a public utility company. The company is engaged in the distribution of electricity to the customers in the state of Vermont, US. In addition to this, its business activities comprised of nearly over 4,700 miles of its transmission and distribution lines. Further, it holds 29% working interest in Vermont Electric Power (VELCO), which is a high-voltage transmission operator in the state. During 2008, the company's customer base comprised of residential, commercial, and industrial. In addition, Green Mountain Power Corporation also offers wholesale electricity in New England, US.
- **Idaho Power Corporation –** Idaho Power Company (IPC) is a wholly-owned subsidiary of IDACORP, Inc. It is engaged in the generation, purchase, transmission, distribution and sale of electric energy. The company serves more than 492,000 general and business customers. The company generates hydroelectric power and thermal power and holds franchises in 71 cities in Idaho and nine cities in Oregon. IPC purchases power from private developers and from other utilities and power wholesalers. It also received certificate from respective public utility regulatory authorities to serve all or a part of 25 counties in Idaho and three counties in Oregon.

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Depreciation Study

Methodology Applied – Qualitative Approach – Comparable Companies (continued)

Comparable Companies (continued)

- **Northern States Power Corporation –** Northern States Power Company, together with its subsidiaries, engages in the generation, purchase, transmission, distribution, and sale of electricity in Minnesota, North Dakota, and South Dakota. It also purchases, transports, distributes, and sells natural gas to retail customers, as well as transports customer-owned natural gas in Minnesota and North Dakota. The company provides electric utility services to approximately 1.4 million customers; and natural gas utility services to approximately 0.5 million customers. It principally serves residential, commercial, and industrial customers, as well as public authorities and other customers. The company was incorporated in 2000 and is based in Minneapolis, Minnesota. Northern States Power Company is a subsidiary of Xcel Energy Inc.
- **Pacificorp –** PacifiCorp is engaged in generation, transmission and distribution of electricity. The company is a subsidiary of MidAmerican Energy Holdings Company (MEHC). PacifiCorp generates electricity through 78 coals, natural gas, hydroelectric, geothermal and wind based power plants with a total power generating capacity of 10,623MW. PacifiCorp transmits and distributes electricity over 16,200 miles of transmission lines. It is also involved in buying and selling of electricity on a wholesale basis. PacifiCorp has three business units, namely, Pacific Power, Rocky Mountain Power and PacifiCorp Energy.
- **PG&E Corporation –** PG&E Corporation (PG&E) is an energy-based holding company operating through its subsidiary, Pacific Gas and Electric Company (Pacific Gas and Electric), a public utility engaged in the following businesses: electricity and natural gas distribution; electricity generation, procurement, and transmission; and natural gas procurement, transportation, and storage. The company operates in northern and central California in the US. PG&E is headquartered in San Francisco, California and employed 19,424 people as of December 2010.

Comparable Companies (continued)

- **Public Service Company of Colorado –** Public Service Company of Colorado (PSCCo.) provides electricity and gas to a territory that includes Denver and other cities as well as rural sections of Colorado. Through its subsidiary, Cheyenne Light, Fuel & Power Co., the utility also serves customers in the environs of Cheyenne, Wyoming. Other subsidiaries of PSCCo. include Fuel Resources Development Co. (Fuelco), which explores for and develops new sources of oil and natural gas, and Westgas, which purchases, transmits, stores, and sells natural gas.
- **Public Service Company of New Hampshire – Northeast Utilities –** The Public Service Company of New Hampshire (PSNH) provides electricity across the Granite State. The company provides electric utility services to more than 490,000 homes and businesses in a 5,630-sq.-mi. area that encompasses more than 210 New Hampshire communities. Although the Northeast Utilities subsidiary owns three fossil-fueled and nine hydroelectric power plants that generate approximately 1,200 MW of capacity for transition and default energy services, it also has contracts to purchase power and buy it in the open market.

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Depreciation Study

Methodology Applied – Depreciation Expense/True-Up Provision

Depreciation Expense

As previously noted, depreciation expense was estimated based on the straight-line method where the average service life was utilized to develop the depreciation period. All estimates have been made as at the Testing Date and appear in the table of results.

Annual Provision for True-Up

After conducting quantitative and qualitative analyses, a conclusion was made for each asset class regarding average service life and probable remaining service life. The results derived from our analysis were then utilized to calculate the annual provision for true-up.

The true-up provision represents the amount of depreciation overage that has been realized relative to the implied accumulated depreciation based on the adjusted average service life being recommended. To calculate accumulated depreciation, the surviving cost basis as at the Testing Date was apportioned over the age of each asset group on a straight-line basis. The resulting estimate of accrued depreciation was then compared to the actual book accumulated depreciation. The resulting difference between estimated accumulated depreciation and book accumulated depreciation is noted as a variance which is then recaptured over the estimated average remaining life.

The true-up amount is generally apportioned on an annual, go-forward basis. A common method of estimating the recapture period is the remaining useful life of an asset group. As previously noted, Iowa Curves provide an indication of probable remaining life. Accordingly, we have utilized the remaining probable lives as derived from the various Iowa Curves to estimate the recapture period for the true-up.

Illustration of True-Up Calculation

The following equations outline the method utilized to calculate the true-up provision.

Step 1

$$\textit{Total True-Up} = \textit{Historical Accumulated Depreciation} - \textit{Calculated Accumulated Depreciation}$$

Step 2

Determine Probable Remaining Life using Iowa Curves

Step 3

$$\textit{Annual Provision for True-Up} = \frac{\textit{Total True-Up}}{\textit{Probable Remaining Life}}$$

To illustrate the true-up provision calculation, consider the following example. Assume the following characteristics of an asset group:

- Cost Basis of $1,000,000;
- Average Service Life of 10 years; and
- Actual Age of 5 years.

Based on the data above, the current annual depreciation rate of the asset group is 10% or $100,000 per annum and the net book value of the asset group is $500,000.

Now, assume that a depreciation study has been conducted and that the average service life has been revised from 10 to 20 years. Given the change in fact pattern, the depreciation rate should be 5 percent or $50,000 per annum and the net book value should be $750,000 rather than $500,000. The change in adopted service life results in a total true-up amount of $250,000, calculated by deducting the revised accumulated depreciation of $250,000 from the historical accumulated depreciation of $500,000 as illustrated in Step 1 above.

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Depreciation Study

Methodology Applied – Depreciation Expense/True-Up Provision (cont.)

Illustration of True-Up Calculation (continued)

Upon determining that the total true-up is $250,000, the next step in the analysis is to determine the period over which the true-up amount is recaptured. An accepted method for determining the recapture period is the probable remaining life of the asset group which can be estimated as the average service life less the actual age of the asset group or by analyzing Iowa Curves to ascertain a more precise indication of probable remaining service life. For simplicity in this example, assume the probable remaining service life is 15 years, calculated by taking the average service life of 20 years and deducting the asset group's actual age of 5 years.

After determining that the probable remaining life is 15 years, the total true-up amount of $250,000 can be apportioned in equal installments over the 15 year period to derive an annual true-up provision of $16,667, as illustrated in Step 3 on the previous slide.

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Results by Account

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Depreciation Study

Results by Account – Overview

Results by Account

The results from our analysis were developed based on a review of both quantitative and qualitative methods. We have conducted our analysis with consideration to both methods and have applied judgment where necessary to normalize the data and draw our conclusions. In the event that the quantitative data relied upon could support a considerably longer average service life than noted in our qualitative analysis, we have taken a conservative approach and determined that the shorter average service life noted in the qualitative analysis is a more prudent conclusion.

In the summary table of our results, certain asset classes are denoted as "n/a." Based on the quantitative and qualitative analyses conducted, the average service lives of the classes noted as "n/a' were determined to be reasonably represented by the lives currently applied by Management.

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Results by Account
Qualitative Analysis

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Depreciation Study Project

Qualitative Analysis – Comparable Companies – Hydro Plant – Account 140003

The following average service lives were noted for hydro assets of comparable companies.

British Columbia Hydro and Power Authority

- Structural Improvements – 100 Years

Manitoba Hydro

- Structural Improvements – 100 Years

Newfoundland Labrador Hydro

- Structural Improvements – 100 Years

Brookfield Hydro

- Dams, Structural Improvements – 115 Years

Snowy Hydro Limited

- Civil Works – 75 Years

Duke Energy

- Electric Generation, Distribution and Transmission – 8 to 125 Years
- Other Buildings and Improvements – 25 to 100 Years

In addition to comparable companies, various valuation publications were reviewed where for estimates of average service lives. The following service lives were noted in our research.

American Society of Appraisers Machinery & Technical Specialties Life Study

- Reservoirs, Dams, and Waterways – 150 Years
- Structures and Improvements – 45 to 75 Years
- Miscellaneous Power Equipment – 25 to 35 Years

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Depreciation Study Project

Qualitative Analysis – Comparable Companies – Diesel Production– Account 140004

YEC– Diesel Plant Assets

YEC owns and operates four diesel facilities and also maintains a fleet of mobile diesel equipment. The following table outlines the current diesel generation fleet.

Diesel Generation Fleet

Location	Unit Number	Capacity (kW)	In-Service Date	Planned Retirement Date	Age at Retirement
Faro	FD1	5,150	1970	2021	51
Faro	FD3	1,000	1989	2019	30
Faro	FD5	1,400	1990	2020	30
Faro	FD7	3,000	1992	2027	35
Dawson	DD1	800	1988	2018	30
Dawson	DD2	1,000	1987	2017	30
Dawson	DD3	1,000	1990	2020	30
Dawson	DD5	1,500	1996	2031	35
Mayo	MD1	1,000	1989	2019	30
Mayo	MD2	1,000	1989	2019	30
Whitehorse	WD1	3,920	1968	2013	45
Whitehorse	WD2	5,150	1968	2013	45
Whitehorse	WD3	5,150	1970	2021	51
Whitehorse	WD4	2,500	1975	2025	50
Whitehorse	WD5	2,500	1975	2025	50
Whitehorse	WD6	2,700	1990	2025	35
Whitehorse	WD7	3,300	1991	2026	35
Mobile	YM1	1,400	1990	2015	25
Mobile	YM2	150	1999	2024	25
Mobile	YM3	125	n/a	n/a	n/a
Mobile	YM4	35	n/a	n/a	n/a

Qualitative Analysis

Given the lack of comparable company data available, a review of the ages of the subject diesel generation assets at their respective projected retirement dates was conducted. Additionally, discussions were held with Management as well as company engineers. Based on the discussions held and a review of the data available, we believe an average service life of 40 years is reasonable.

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Depreciation Study Project

Qualitative Analysis – Comparable Companies– Main Transmission – Account 140006

Due to the lack of publicly available data for several miscellaneous categories, various valuation publications were reviewed for estimates of average service lives. The following service average lives were noted in our research.

American Society of Appraisers Machinery & Technical Specialties Life Study

- Buildings & Improvements – 30 to 50 Years
- Structures and Improvements – 45 to 75 Years
- Miscellaneous Power Equipment – 25 to 35 Years

Marshall Valuation Service

- Buildings & Improvements – 40 to 60 Years

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Depreciation Study Project

Qualitative Analysis – Comparable Companies– Main Transmission – Account 140006

The following average service lives were noted for comparable transmission assets.

Pacific Gas & Electric

- Electricity Distribution Facilities – 16 to 58 Years

Southern California Edison Co.

- Distribution Plant – 30 to 60 Years
- Transmission Plant – 35 to 65 Years

Pacificorp

- Distribution Plant – 44 to 52 Years
- Transmission Plant – 25 to 75 Years

Consumers Energy Co.

- Distribution – 12 to 75 Years

Duke Energy Carolinas LLC

- Regulated - Electric generation, distribution, and transmission – 8 to 125 Years
- Regulated - Other buildings and improvements – 25 to 100 Years
- Unregulated - Electric generation, distribution, and transmission – 8 to 100 Years
- Unregulated - Other buildings and improvements – 20 to 90 Years

ALLETE Inc.

- Distribution Plant – 14 to 65 Years
- Transmission Plant – 42 to 61 Years

Public Service Company of New Hampshire

- Distribution Plant – 40.4 Years
- Transmission Plant – 46.7 Years

Manitoba Hydro

- Metal Towers – 85 Years
- Poles & Fixtures – 55 Years
- Conductors & Devices – 60 Years
- Underground Conductors & Devices – 45 Years

In addition to comparable companies, various valuation publications were reviewed where for estimates of average service lives. The following service lives were noted in our research.

American Society of Appraisers Machinery & Technical Specialties Life Study

- Overhead Conductors – 33 to 50 Years
- Fencing – 13 to 20 Years

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Results by Account
Quantitative Analysis

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Depreciation Study Project

Experience Band
Hydro Plant – Account 140003-205

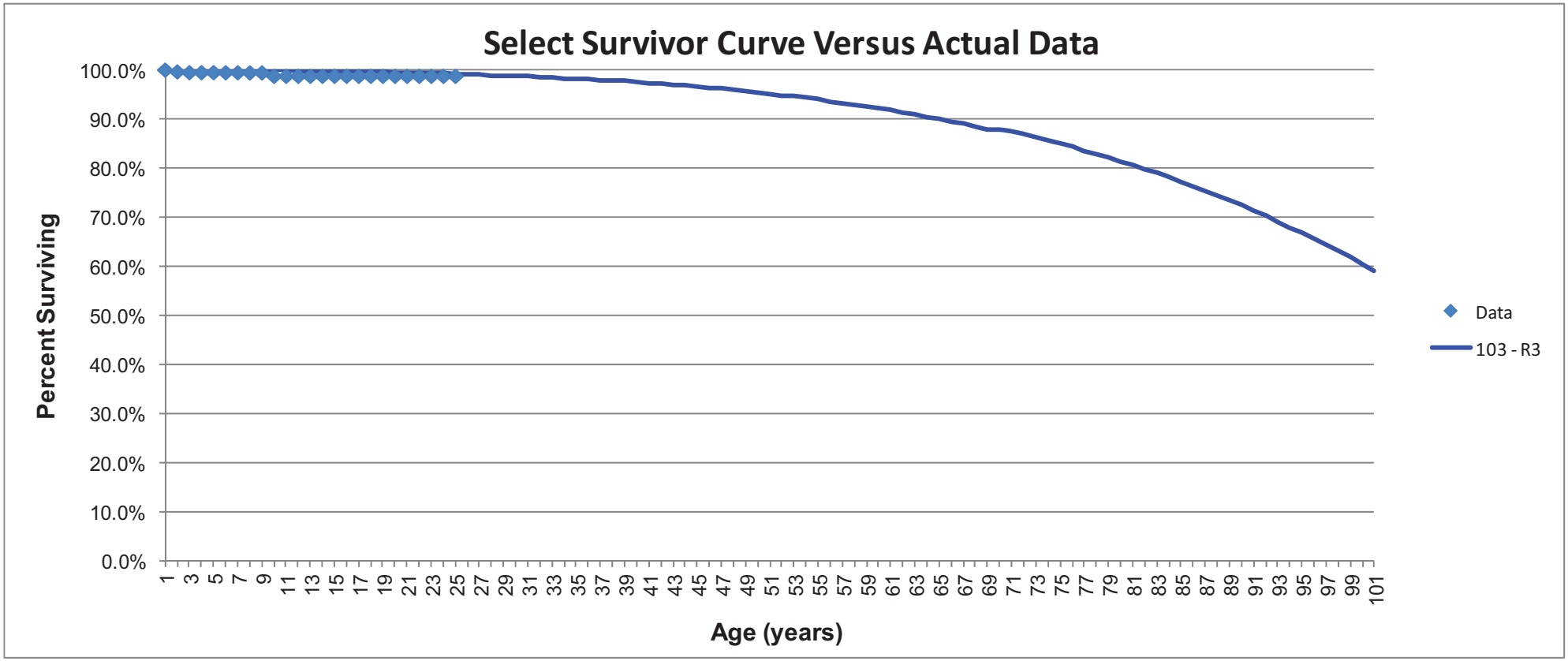
BAND 1980 - 2010							BAND 1950 - 1979						
Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning	Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning
2010	0.0	91,075,990	330,237	0.0036	0.9964	100.00%	1979	31.0	24,793	-	0.0000	1.0000	98.74%
2009	1.0	90,501,382	142,508	0.0016	0.9984	99.64%	1978	32.0	24,793	-	0.0000	1.0000	98.74%
2008	2.0	90,213,538	-	0.0000	1.0000	99.48%	1977	33.0	24,793	-	0.0000	1.0000	98.74%
2007	3.0	90,154,964	-	0.0000	1.0000	99.48%	1976	34.0	24,793	-	0.0000	1.0000	98.74%
2006	4.0	90,129,181	18,907	0.0002	0.9998	99.48%	1975	35.0	24,793	-	0.0000	1.0000	98.74%
2005	5.0	89,938,379	7,757	0.0001	0.9999	99.46%	1974	36.0	24,793	-	0.0000	1.0000	98.74%
2004	6.0	89,882,337	16,031	0.0002	0.9998	99.45%	1973	37.0	24,793	-	0.0000	1.0000	98.74%
2003	7.0	88,602,600	926	0.0000	1.0000	99.43%	1972	38.0	24,793	-	0.0000	1.0000	98.74%
2002	8.0	88,542,660	613,462	0.0069	0.9931	99.43%	1971	39.0	24,793	-	0.0000	1.0000	98.74%
2001	9.0	87,806,736	-	0.0000	1.0000	98.74%	1970	40.0	24,793	-	0.0000	1.0000	98.74%
2000	10.0	86,479,614	-	0.0000	1.0000	98.74%	1969	41.0	24,793	-	0.0000	1.0000	98.74%
1999	11.0	86,433,806	-	0.0000	1.0000	98.74%	1968	42.0	24,793	-	0.0000	1.0000	98.74%
1998	12.0	86,419,634	-	0.0000	1.0000	98.74%	1967	43.0	24,793	-	0.0000	1.0000	98.74%
1997	13.0	86,394,121	-	0.0000	1.0000	98.74%	1966	44.0	24,793	5,335	0.2152	0.7848	98.74%
1996	14.0	86,143,814	-	0.0000	1.0000	98.74%	1965	45.0	19,458	-	0.0000	1.0000	77.22%
1995	15.0	86,111,358	-	0.0000	1.0000	98.74%	1964	46.0	19,458	-	0.0000	1.0000	77.22%
1994	16.0	85,622,950	-	0.0000	1.0000	98.74%	1963	47.0	19,458	-	0.0000	1.0000	77.22%
1993	17.0	85,474,994	-	0.0000	1.0000	98.74%	1962	48.0	19,458	-	0.0000	1.0000	77.22%
1992	18.0	85,018,739	-	0.0000	1.0000	98.74%	1961	49.0	19,458	-	0.0000	1.0000	77.22%
1991	19.0	83,634,448	-	0.0000	1.0000	98.74%	1960	50.0	19,458	-	0.0000	1.0000	77.22%
1990	20.0	82,838,843	-	0.0000	1.0000	98.74%	1959	51.0	19,458	5,000	0.2570	0.7430	77.22%
1989	21.0	81,418,298	-	0.0000	1.0000	98.74%	1958	52.0	14,458	-	0.0000	1.0000	51.52%
1988	22.0	80,709,250	-	0.0000	1.0000	98.74%	1957	53.0	14,458	-	0.0000	1.0000	51.52%
1987	23.0	75,876,042	-	0.0000	1.0000	98.74%	1956	54.0	14,458	-	0.0000	1.0000	51.52%
1986	24.0	75,329,629	-	0.0000	1.0000	98.74%	1955	55.0	14,458	-	0.0000	1.0000	51.52%
1985	25.0	24,793	-	0.0000	1.0000	98.74%	1954	56.0	14,458	-	0.0000	1.0000	51.52%
1984	26.0	24,793	-	0.0000	1.0000	98.74%	1953	57.0	14,458	-	0.0000	1.0000	51.52%
1983	27.0	24,793	-	0.0000	1.0000	98.74%	1952	58.0	14,458	12,607	0.8720	0.1280	51.52%
1982	28.0	24,793	-	0.0000	1.0000	98.74%	1951	59.0	1,851	1,851	1.0000	0.0000	0.00%
1981	29.0	24,793	-	0.0000	1.0000	98.74%	1950	60.0	0	-	0.0000	0.0000	0.00%
1980	30.0	24,793	-	0.0000	1.0000	98.74%							

KPMG has only considered data as far back as 1986, which account for the majority of the expenditures.

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Depreciation Study Project

Survivor Curve
Hydro Plant – Account 140003-205



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Depreciation Study Project

Experience Band
Hydro Plant – Account 140003-506

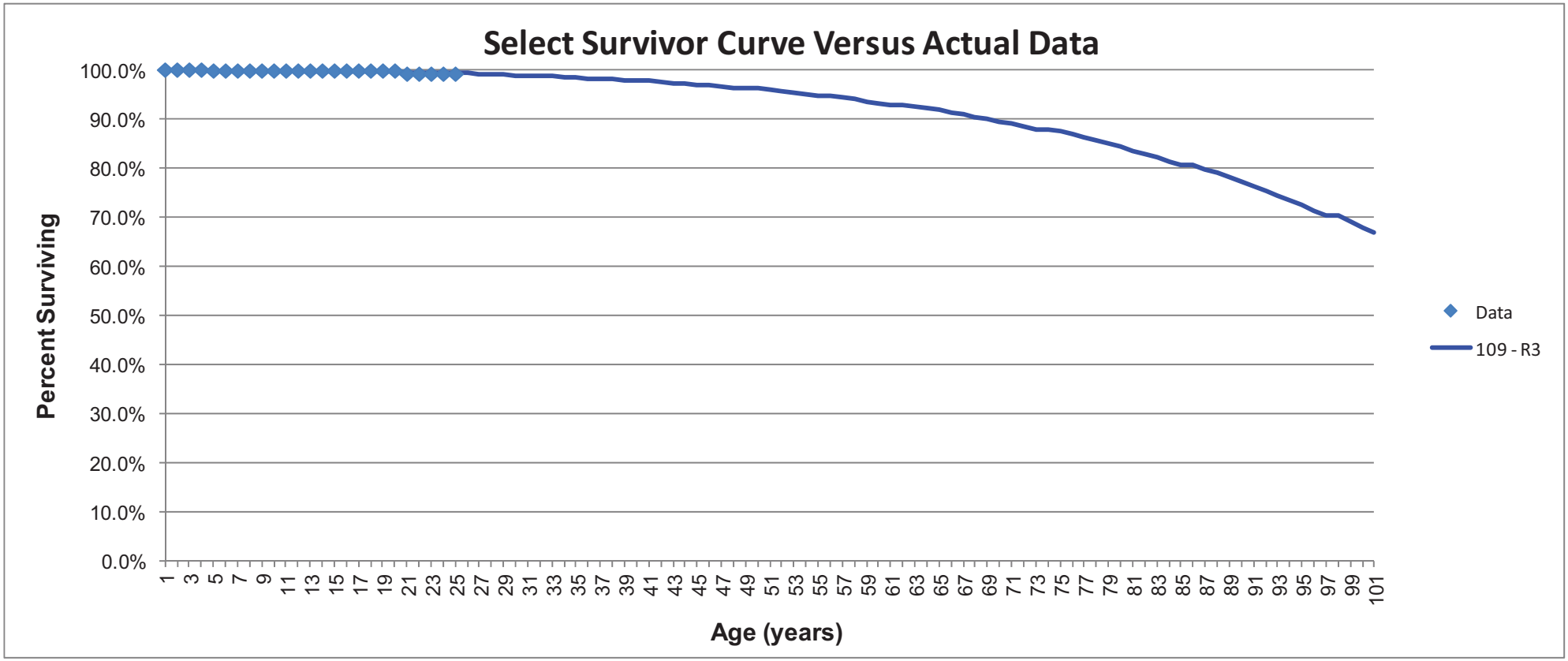
BAND 1980 - 2010							BAND 1950 - 1979						
Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning	Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning
2010	0.0	12,259,130	-	0.0000	1.0000	100.00%	1979	30.5	113,328	-	0.0000	1.0000	99.17%
2009	0.5	12,259,130	-	0.0000	1.0000	100.00%	1978	31.5	113,328	-	0.0000	1.0000	99.17%
2008	1.5	11,873,635	-	0.0000	1.0000	100.00%	1977	32.5	113,328	-	0.0000	1.0000	99.17%
2007	2.5	11,873,635	22,498	0.0019	0.9981	100.00%	1976	33.5	113,328	-	0.0000	1.0000	99.17%
2006	3.5	11,858,892	-	0.0000	1.0000	99.81%	1975	34.5	113,328	-	0.0000	1.0000	99.17%
2005	4.5	10,692,388	-	0.0000	1.0000	99.81%	1974	35.5	113,328	-	0.0000	1.0000	99.17%
2004	5.5	10,014,283	-	0.0000	1.0000	99.81%	1973	36.5	113,328	-	0.0000	1.0000	99.17%
2003	6.5	9,509,803	-	0.0000	1.0000	99.81%	1972	37.5	113,328	-	0.0000	1.0000	99.17%
2002	7.5	8,141,225	-	0.0000	1.0000	99.81%	1971	38.5	113,328	-	0.0000	1.0000	99.17%
2001	8.5	6,831,439	-	0.0000	1.0000	99.81%	1970	39.5	113,328	-	0.0000	1.0000	99.17%
2000	9.5	4,127,302	-	0.0000	1.0000	99.81%	1969	40.5	113,328	63,672	0.5618	0.4382	99.17%
1999	10.5	2,616,136	-	0.0000	1.0000	99.81%	1968	41.5	49,656	-	0.0000	1.0000	42.99%
1998	11.5	2,374,991	-	0.0000	1.0000	99.81%	1967	42.5	49,656	-	0.0000	1.0000	42.99%
1997	12.5	2,172,014	-	0.0000	1.0000	99.81%	1966	43.5	49,656	-	0.0000	1.0000	42.99%
1996	13.5	2,167,522	-	0.0000	1.0000	99.81%	1965	44.5	49,656	-	0.0000	1.0000	42.99%
1995	14.5	1,880,377	-	0.0000	1.0000	99.81%	1964	45.5	49,656	-	0.0000	1.0000	42.99%
1994	15.5	1,880,377	-	0.0000	1.0000	99.81%	1963	46.5	49,656	-	0.0000	1.0000	42.99%
1993	16.5	1,880,377	-	0.0000	1.0000	99.81%	1962	47.5	49,656	-	0.0000	1.0000	42.99%
1992	17.5	1,880,377	-	0.0000	1.0000	99.81%	1961	48.5	49,656	-	0.0000	1.0000	42.99%
1991	18.5	1,845,905	11,904	0.0064	0.9936	99.81%	1960	49.5	49,656	36,169	0.7284	0.2716	42.99%
1990	19.5	1,792,273	-	0.0000	1.0000	99.17%	1959	50.5	13,487	-	0.0000	1.0000	0.00%
1989	20.5	1,565,212	-	0.0000	1.0000	99.17%	1958	51.5	13,487	-	0.0000	1.0000	0.00%
1988	21.5	1,366,950	-	0.0000	1.0000	99.17%	1957	52.5	13,487	-	0.0000	1.0000	0.00%
1987	22.5	1,366,950	-	0.0000	1.0000	99.17%	1956	53.5	13,487	-	0.0000	1.0000	0.00%
1986	23.5	1,366,950	-	0.0000	1.0000	99.17%	1955	54.5	13,487	-	0.0000	1.0000	0.00%
1985	24.5	113,328	-	0.0000	1.0000	99.17%	1954	55.5	13,487	-	0.0000	1.0000	0.00%
1984	25.5	113,328	-	0.0000	1.0000	99.17%	1953	56.5	13,487	-	0.0000	1.0000	0.00%
1983	26.5	113,328	-	0.0000	1.0000	99.17%	1952	57.5	13,487	13,487	1.0000	0.0000	0.00%
1982	27.5	113,328	-	0.0000	1.0000	99.17%							
1981	28.5	113,328	-	0.0000	1.0000	99.17%							
1980	29.5	113,328	-	0.0000	1.0000	99.17%							

KPMG has only considered data since1986, which accounts for the majority of the expenditures.

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Depreciation Study Project

Survivor Curve
Hydro Plant – Account 140003-506



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Depreciation Study Project

Experience Band
Main Transmission – Account 140006-300

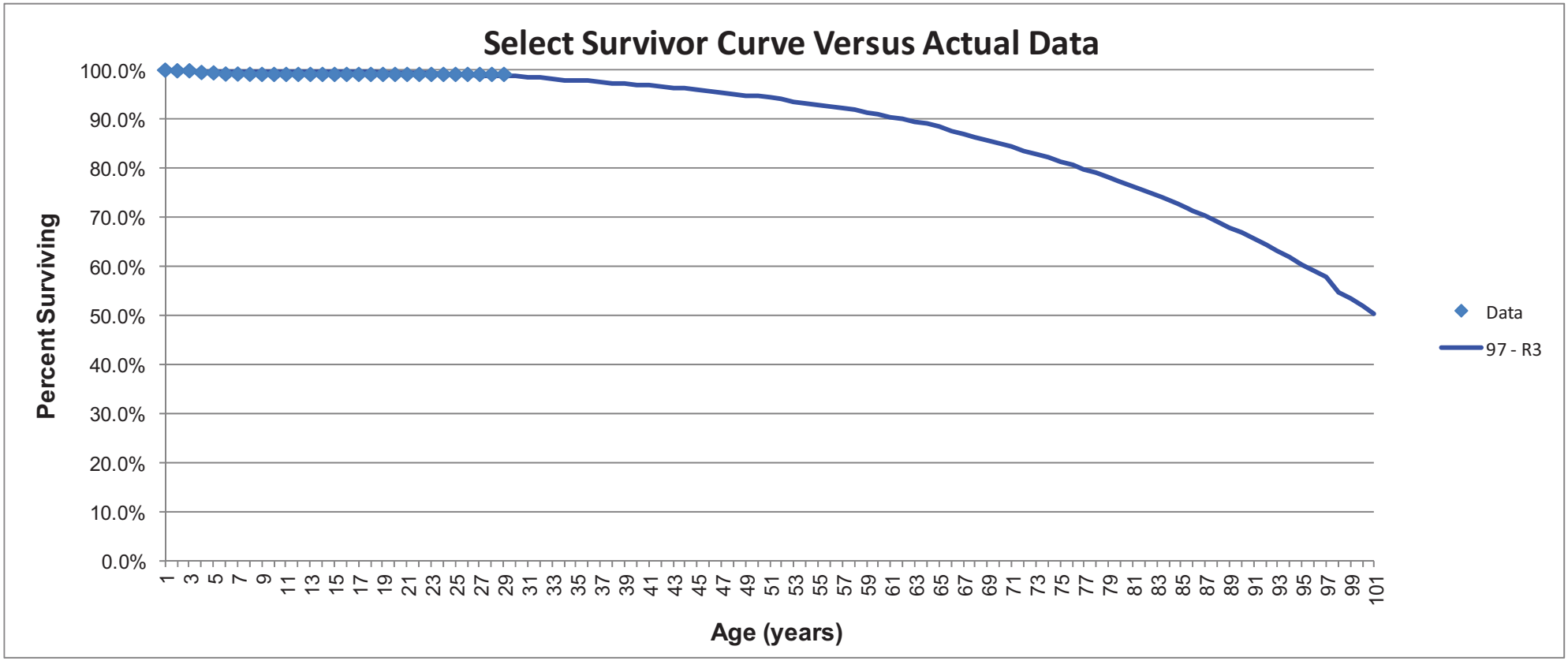
BAND 1980 - 2010							BAND 1950 - 1979						
Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning	Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning
2010	0.0	48,741,085	65,505	0.0013	0.9987	100.00%	1979	30.5	48,603	-	0.0000	1.0000	99.13%
2009	0.5	48,107,819	-	0.0000	1.0000	99.87%	1978	31.5	48,603	-	0.0000	1.0000	99.13%
2008	1.5	47,771,317	165,914	0.0035	0.9965	99.87%	1977	32.5	48,603	-	0.0000	1.0000	99.13%
2007	2.5	32,135,818	24,553	0.0008	0.9992	99.52%	1976	33.5	48,603	-	0.0000	1.0000	99.13%
2006	3.5	31,925,101	75,051	0.0024	0.9976	99.44%	1975	34.5	48,603	-	0.0000	1.0000	99.13%
2005	4.5	31,419,003	-	0.0000	1.0000	99.21%	1974	35.5	48,603	-	0.0000	1.0000	99.13%
2004	5.5	32,269,386	18,914	0.0006	0.9994	99.21%	1973	36.5	48,603	-	0.0000	1.0000	99.13%
2003	6.5	32,026,595	4,230	0.0001	0.9999	99.15%	1972	37.5	48,603	10,840	0.2230	0.7770	99.13%
2002	7.5	19,053,644	-	0.0000	1.0000	99.13%	1971	38.5	37,763	20,065	0.5313	0.4687	76.83%
2001	8.5	19,053,644	-	0.0000	1.0000	99.13%	1970	39.5	17,698	4,230	0.2390	0.7610	23.70%
2000	9.5	19,053,644	-	0.0000	1.0000	99.13%	1969	40.5	13,468	5,968	0.4431	0.5569	0.00%
1999	10.5	19,053,644	-	0.0000	1.0000	99.13%	1968	41.5	7,500	-	0.0000	1.0000	0.00%
1998	11.5	19,053,644	-	0.0000	1.0000	99.13%	1967	42.5	7,500	-	0.0000	1.0000	0.00%
1997	12.5	6,176,439	-	0.0000	1.0000	99.13%	1966	43.5	7,500	-	0.0000	1.0000	0.00%
1996	13.5	5,800,998	-	0.0000	1.0000	99.13%	1965	44.5	7,500	-	0.0000	1.0000	0.00%
1995	14.5	5,751,444	-	0.0000	1.0000	99.13%	1964	45.5	7,500	-	0.0000	1.0000	0.00%
1994	15.5	5,689,573	-	0.0000	1.0000	99.13%	1963	46.5	7,500	-	0.0000	1.0000	0.00%
1993	16.5	5,689,573	-	0.0000	1.0000	99.13%	1962	47.5	7,500	-	0.0000	1.0000	0.00%
1992	17.5	5,617,863	-	0.0000	1.0000	99.13%	1961	48.5	7,500	7,500	1.0000	0.0000	0.00%
1991	18.5	5,548,476	-	0.0000	1.0000	99.13%	1960	49.5	0	-	0.0000	0.0000	0.00%
1990	19.5	5,536,056	-	0.0000	1.0000	99.13%							
1989	20.5	5,482,512	-	0.0000	1.0000	99.13%							
1988	21.5	5,319,812	-	0.0000	1.0000	99.13%							
1987	22.5	5,253,081	-	0.0000	1.0000	99.13%							
1986	23.5	5,000,277	-	0.0000	1.0000	99.13%							
1985	24.5	4,942,371	-	0.0000	1.0000	99.13%							
1984	25.5	4,917,894	-	0.0000	1.0000	99.13%							
1983	26.5	4,882,830	-	0.0000	1.0000	99.13%							
1982	27.5	4,882,830	-	0.0000	1.0000	99.13%							
1981	28.5	48,603	-	0.0000	1.0000	99.13%							
1980	29.5	48,603	-	0.0000	1.0000	99.13%							

KPMG has only considered data as far back as 1982, which account for the majority of the expenditures.

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Depreciation Study Project

Survivor Curve
Main Transmission– Account 140006-300



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Depreciation Study Project

Experience Band
Main Transmission – Account 140006-710

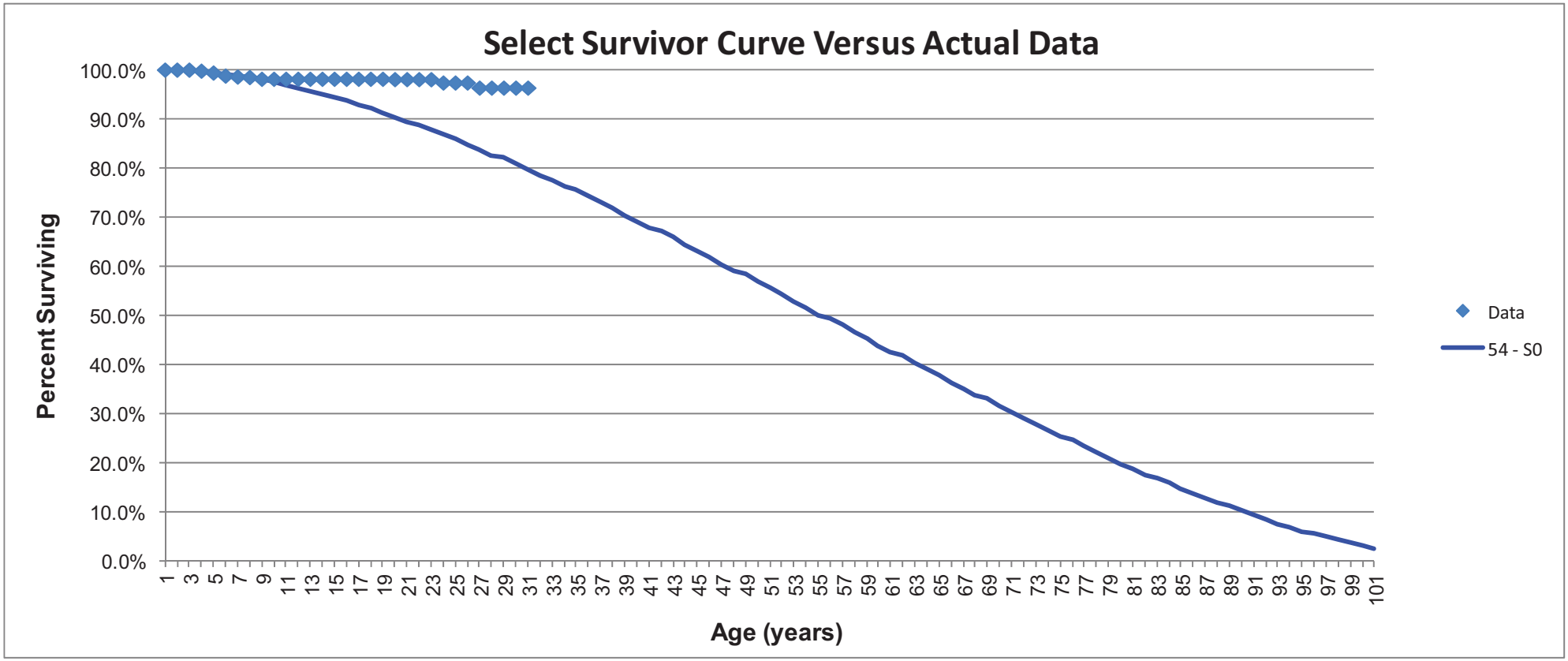
BAND 1980 - 2010							BAND 1950 - 1979						
Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning	Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning
2010	0.0	27,468,090	-	0.0000	1.0000	100.00%	1979	30.5	28,179	-	0.0000	1.0000	96.33%
2009	0.5	26,845,227	-	0.0000	1.0000	100.00%	1978	31.5	28,179	-	0.0000	1.0000	96.33%
2008	1.5	26,747,502	57,669	0.0022	0.9978	100.00%	1977	32.5	28,179	-	0.0000	1.0000	96.33%
2007	2.5	23,431,071	90,563	0.0039	0.9961	99.78%	1976	33.5	28,179	-	0.0000	1.0000	96.33%
2006	3.5	23,293,316	143,473	0.0062	0.9938	99.40%	1975	34.5	28,179	-	0.0000	1.0000	96.33%
2005	4.5	23,104,038	45,168	0.0020	0.9980	98.78%	1974	35.5	28,179	25,184	0.8937	0.1063	96.33%
2004	5.5	22,963,753	21,026	0.0009	0.9991	98.59%	1973	36.5	2,995	-	0.0000	1.0000	6.96%
2003	6.5	22,850,380	82,708	0.0036	0.9964	98.49%	1972	37.5	2,995	-	0.0000	1.0000	6.96%
2002	7.5	17,235,376	-	0.0000	1.0000	98.13%	1971	38.5	2,995	-	0.0000	1.0000	6.96%
2001	8.5	17,235,376	-	0.0000	1.0000	98.13%	1970	39.5	2,995	-	0.0000	1.0000	6.96%
2000	9.5	17,235,376	-	0.0000	1.0000	98.13%	1969	40.5	2,995	-	0.0000	1.0000	6.96%
1999	10.5	17,235,376	-	0.0000	1.0000	98.13%	1968	41.5	2,995	-	0.0000	1.0000	6.96%
1998	11.5	17,235,376	-	0.0000	1.0000	98.13%	1967	42.5	2,995	-	0.0000	1.0000	6.96%
1997	12.5	17,235,376	-	0.0000	1.0000	98.13%	1966	43.5	2,995	2,538	0.8474	0.1526	6.96%
1996	13.5	17,235,376	-	0.0000	1.0000	98.13%	1965	44.5	457	-	0.0000	1.0000	0.00%
1995	14.5	11,674,992	-	0.0000	1.0000	98.13%	1964	45.5	457	-	0.0000	1.0000	0.00%
1994	15.5	11,674,992	71	0.0000	1.0000	98.13%	1963	46.5	457	-	0.0000	1.0000	0.00%
1993	16.5	11,674,921	-	0.0000	1.0000	98.13%	1962	47.5	457	-	0.0000	1.0000	0.00%
1992	17.5	11,353,872	7,800	0.0007	0.9993	98.13%	1961	48.5	457	457	1.0000	0.0000	0.00%
1991	18.5	11,346,072	-	0.0000	1.0000	98.06%	1960	49.5	0	-	0.0000	0.0000	0.00%
1990	19.5	11,323,830	-	0.0000	1.0000	98.06%							
1989	20.5	11,147,907	2,371	0.0002	0.9998	98.06%							
1988	21.5	10,335,372	69,175	0.0067	0.9933	98.04%							
1987	22.5	10,106,827	-	0.0000	1.0000	97.37%							
1986	23.5	10,031,160	-	0.0000	1.0000	97.37%							
1985	24.5	7,679,277	80,171	0.0104	0.9896	97.37%							
1984	25.5	4,284,412	-	0.0000	1.0000	96.33%							
1983	26.5	2,075,579	-	0.0000	1.0000	96.33%							
1982	27.5	2,069,769	-	0.0000	1.0000	96.33%							
1981	28.5	2,068,360	-	0.0000	1.0000	96.33%							
1980	29.5	2,047,784	-	0.0000	1.0000	96.33%							

KPMG has only considered data since1980, which accounts for the majority of the expenditures.

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Depreciation Study Project

Survivor Curve
Main Transmission– Account 140006-710



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Depreciation Study Project

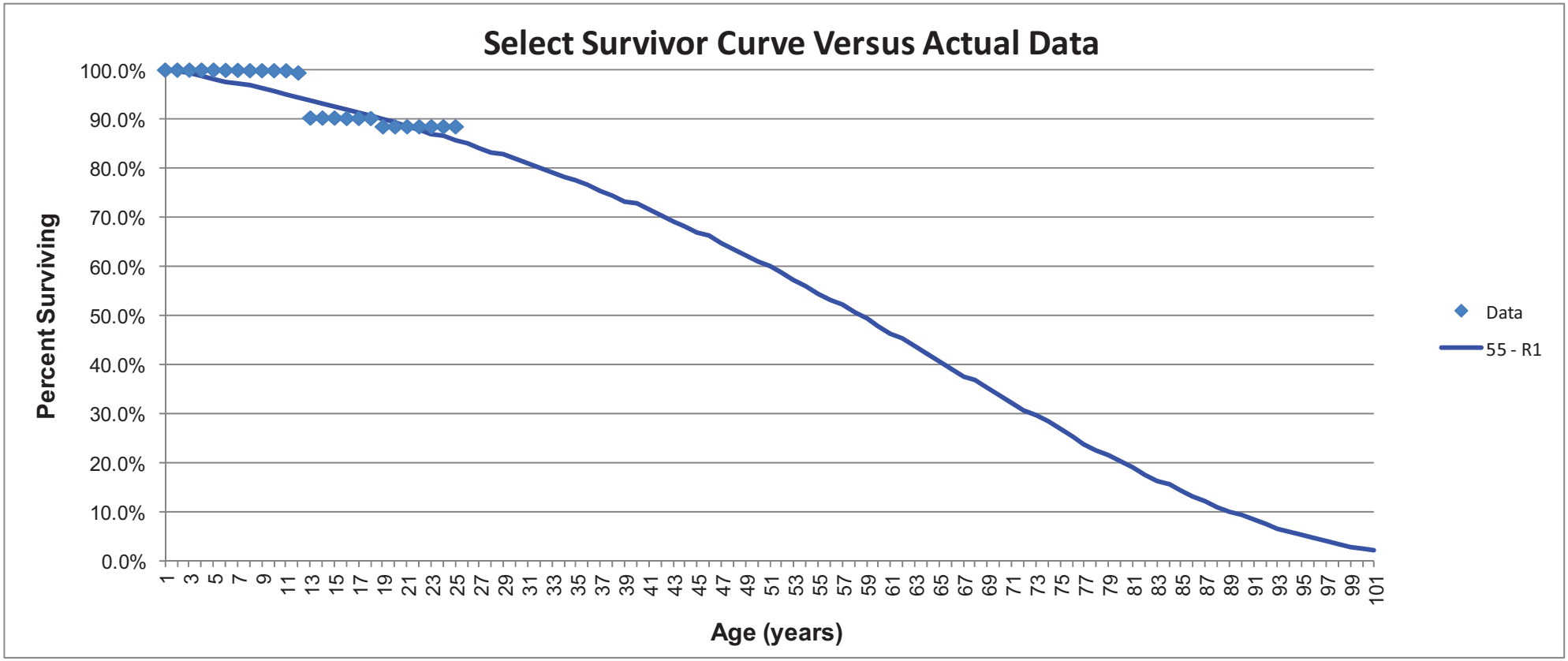
Experience Band
Buildings & Equipments – Account 140009-201

BAND 1986 - 2010						
Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning
2010	0.0	9,120,737	-	0.0000	1.0000	100.00%
2009	0.5	8,949,001	-	0.0000	1.0000	100.00%
2008	1.5	8,343,557	-	0.0000	1.0000	100.00%
2007	2.5	8,252,034	-	0.0000	1.0000	100.00%
2006	3.5	8,021,970	3,622	0.0005	0.9995	100.00%
2005	4.5	7,821,041	-	0.0000	1.0000	99.95%
2004	5.5	7,420,506	5,598	0.0008	0.9992	99.95%
2003	6.5	7,013,338	-	0.0000	1.0000	99.88%
2002	7.5	6,878,275	-	0.0000	1.0000	99.88%
2001	8.5	6,764,174	1,482	0.0002	0.9998	99.88%
2000	9.5	6,134,861	26,900	0.0044	0.9956	99.86%
1999	10.5	5,372,225	493,010	0.0918	0.9082	99.42%
1998	11.5	4,428,344	-	0.0000	1.0000	90.24%
1997	12.5	1,490,665	-	0.0000	1.0000	90.24%
1996	13.5	1,410,382	1,286	0.0009	0.9991	90.24%
1995	14.5	1,407,295	-	0.0000	1.0000	90.15%
1994	15.5	1,381,568	-	0.0000	1.0000	90.15%
1993	16.5	1,345,213	22,757	0.0169	0.9831	90.15%
1992	17.5	1,322,456	-	0.0000	1.0000	88.46%
1991	18.5	1,270,112	-	0.0000	1.0000	88.46%
1990	19.5	1,233,020	-	0.0000	1.0000	88.46%
1989	20.5	1,229,392	-	0.0000	1.0000	88.46%
1988	21.5	1,229,392	-	0.0000	1.0000	88.46%
1987	22.5	1,229,392	-	0.0000	1.0000	88.46%
1986	23.5	1,224,102	-	0.0000	1.0000	88.46%

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Depreciation Study Project

Survivor Curve
Buildings & Equipments – Account 140009-201



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Depreciation Study Project

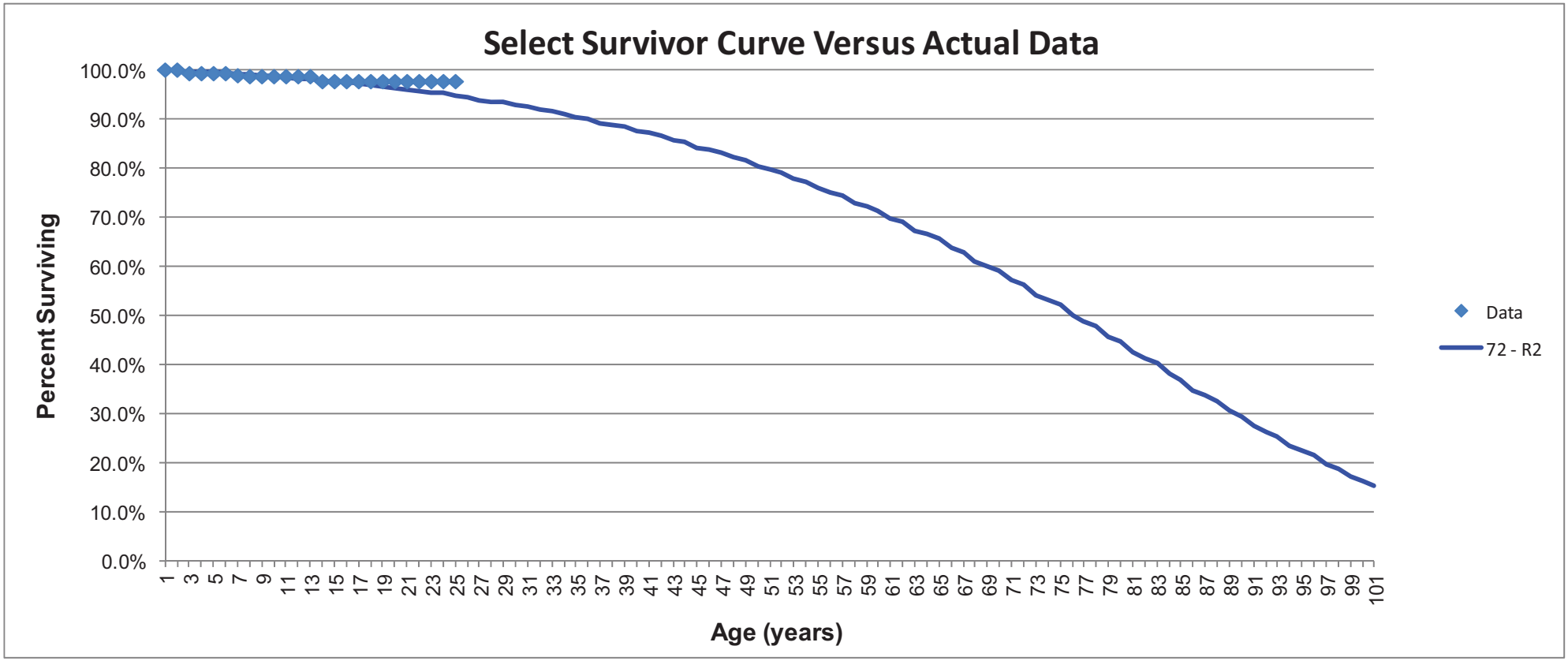
Experience Band
Diesel Production – Account 140004-200

BAND 1986 - 2010						
Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning
2010	0.0	1,847,377	-	0.0000	1.0000	100.00%
2009	0.5	1,847,377	13,264	0.0072	0.9928	100.00%
2008	1.5	1,847,377	-	0.0000	1.0000	99.28%
2007	2.5	1,826,417	-	0.0000	1.0000	99.28%
2006	3.5	1,826,417	-	0.0000	1.0000	99.28%
2005	4.5	1,826,417	7,902	0.0043	0.9957	99.28%
2004	5.5	1,826,417	3,534	0.0019	0.9981	98.85%
2003	6.5	1,826,417	-	0.0000	1.0000	98.66%
2002	7.5	1,541,247	-	0.0000	1.0000	98.66%
2001	8.5	1,256,077	-	0.0000	1.0000	98.66%
2000	9.5	1,256,077	-	0.0000	1.0000	98.66%
1999	10.5	1,215,352	-	0.0000	1.0000	98.66%
1998	11.5	1,215,352	12,139	0.0100	0.9900	98.66%
1997	12.5	1,203,213	-	0.0000	1.0000	97.66%
1996	13.5	1,203,213	-	0.0000	1.0000	97.66%
1995	14.5	1,203,213	-	0.0000	1.0000	97.66%
1994	15.5	1,127,266	-	0.0000	1.0000	97.66%
1993	16.5	1,121,041	-	0.0000	1.0000	97.66%
1992	17.5	1,094,064	-	0.0000	1.0000	97.66%
1991	18.5	1,086,202	-	0.0000	1.0000	97.66%
1990	19.5	886,340	-	0.0000	1.0000	97.66%
1989	20.5	311,348	-	0.0000	1.0000	97.66%
1988	21.5	275,482	-	0.0000	1.0000	97.66%
1987	22.5	273,987	-	0.0000	1.0000	97.66%
1986	23.5	258,987	-	0.0000	1.0000	97.66%

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Depreciation Study Project

Survivor Curve
Diesel Production – Account 140004-200



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Depreciation Study Project

Experience Band
Distribution System – Account 140008-905

BAND 1980 - 2010						
Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning
2010	0.0	3,534,869	-	0.0000	1.0000	100.00%
2009	0.5	3,523,129	-	0.0000	1.0000	100.00%
2008	1.5	3,459,471	-	0.0000	1.0000	100.00%
2007	2.5	3,427,904	346	0.0001	0.9999	100.00%
2006	3.5	3,415,117	7,050	0.0021	0.9979	99.99%
2005	4.5	3,338,572	24,718	0.0074	0.9926	99.78%
2004	5.5	3,206,837	953	0.0003	0.9997	99.04%
2003	6.5	3,110,339	838	0.0003	0.9997	99.01%
2002	7.5	2,888,927	615	0.0002	0.9998	98.99%
2001	8.5	2,888,927	615	0.0002	0.9998	98.97%
2000	9.5	2,888,927	615	0.0002	0.9998	98.95%
1999	10.5	2,888,927	615	0.0002	0.9998	98.93%
1998	11.5	2,888,927	615	0.0002	0.9998	98.91%
1997	12.5	2,888,927	615	0.0002	0.9998	98.89%
1996	13.5	2,888,927	615	0.0002	0.9998	98.87%
1995	14.5	2,621,796	-	0.0000	1.0000	98.85%
1994	15.5	2,609,266	478	0.0002	0.9998	98.85%
1993	16.5	2,608,788	3,593	0.0014	0.9986	98.83%
1992	17.5	2,560,653	331	0.0001	0.9999	98.69%
1991	18.5	2,557,991	-	0.0000	1.0000	98.68%
1990	19.5	2,557,991	331	0.0001	0.9999	98.68%
1989	20.5	2,297,334	239	0.0001	0.9999	98.67%
1988	21.5	2,183,603	-	0.0000	1.0000	98.66%
1987	22.5	1,858,342	-	0.0000	1.0000	98.66%
1986	23.5	1,823,874	-	0.0000	1.0000	98.66%
1985	24.5	1,390,356	-	0.0000	1.0000	98.66%
1984	25.5	1,169,416	-	0.0000	1.0000	98.66%
1983	26.5	237,729	-	0.0000	1.0000	98.66%
1982	27.5	155,526	-	0.0000	1.0000	98.66%
1981	28.5	90,285	-	0.0000	1.0000	98.66%
1980	29.5	87,246	689	0.0079	0.9921	98.66%

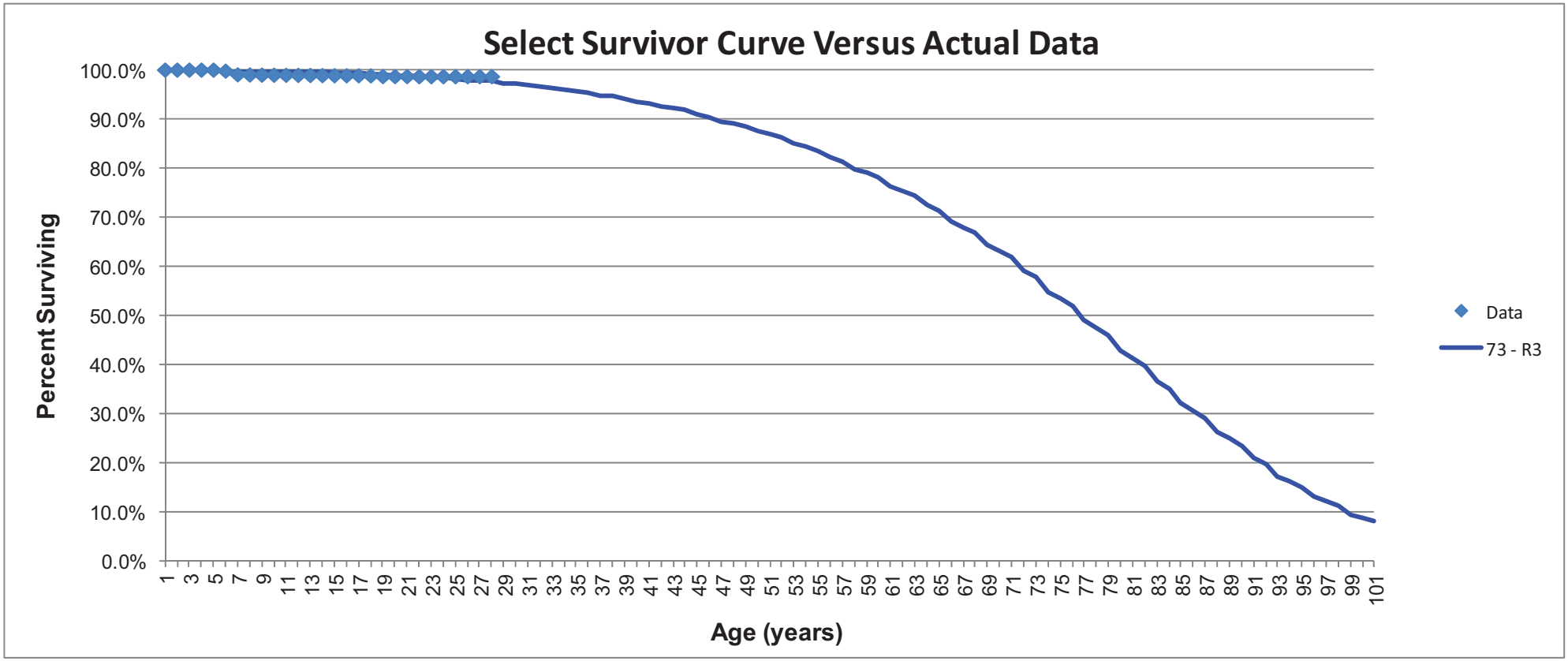
BAND 1960 - 1979						
Year	Age at Beginning of Interval	Exposures at Beginning	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning
1979	30.5	1,237	-	0.0000	1.0000	97.87%
1978	31.5	1,237	-	0.0000	1.0000	97.87%
1977	32.5	1,237	-	0.0000	1.0000	97.87%
1976	33.5	1,237	-	0.0000	1.0000	97.87%
1975	34.5	1,237	838	0.6774	0.3226	97.87%
1974	35.5	399	-	0.0000	1.0000	30.13%
1973	36.5	399	-	0.0000	1.0000	30.13%
1972	37.5	399	-	0.0000	1.0000	30.13%
1971	38.5	399	30	0.0752	0.9248	30.13%
1970	39.5	369	-	0.0000	1.0000	22.61%
1969	40.5	369	194	0.5257	0.4743	22.61%
1968	41.5	175	-	0.0000	1.0000	0.00%
1967	42.5	175	-	0.0000	1.0000	0.00%
1966	43.5	175	-	0.0000	1.0000	0.00%
1965	44.5	175	-	0.0000	1.0000	0.00%
1964	45.5	175	-	0.0000	1.0000	0.00%
1963	46.5	175	-	0.0000	1.0000	0.00%
1962	47.5	175	-	0.0000	1.0000	0.00%
1961	48.5	175	175	1.0000	0.0000	0.00%
1960	49.5	0	-	0.0000	0.0000	0.00%

KPMG has only considered data since1983, which accounts for the majority of the expenditures.

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Depreciation Study Project

Survivor Curve
Distribution System – Account 140008-905



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Results by Account

True-Up Calculation

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Number	Description	KPMG Estimated Survivor Curve	As of December 31, 2010												
			Provided by Yukon Management							Depreciation Expense			Depreciation Add-Back		
			Surviving Original Cost at 12/31/2010	Accumulated Depreciation	A/D Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accrued Depreciation	Accumulated Depreciation Variance	Annual Accrual Amount	Rate (%)	KPMG Probable Remaining Life [1]	Annual Provision for True-Up	Accounting Effective Age	KPMG Concluded Effective Age
Land															
n/a	Land	n/a	1,126,675	(13,369)	699	(87)	1,113,918	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Land			**1,126,675**	**(13,369)**	**699**	**(87)**	**1,113,918**	**-**	**-**	**-**			**-**		
Hydro Plant															
140003.200	Structures and Improvements	72 - R2	10,854,779	(3,558,901)	398,145	(77,806)	7,616,217	(2,261,412)	(977,149)	150,761	1.39	35	27,919	15	39
140003.205	Reservoirs, Dams, and Waterways	103 - R3	89,859,047	(39,320,006)	1,231,383	(215,442)	51,554,982	(20,172,923)	(18,131,142)	872,418	0.97	65	278,941	23	39
140003.506	Waterwheels,Turbines & Generation	85 - R3	10,431,950	(1,535,720)	27,655	11,344	8,935,229	(1,227,288)	(269,433)	122,729	1.18	47	5,733	10	39
140003.600	Accessory Electric Equipment	45 - R3	6,489,762	(1,301,774)	65,942	(9,942)	5,243,987	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140003.700	Misc Power Plant Equipment	30 - R2	2,542,719	(609,657)	83,244	(20,059)	1,996,247	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140003.730	Fencing	30 - R2	48,758	(5,999)			42,758	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Hydro Plant			**120,227,014**	**(46,332,057)**	**1,806,369**	**(311,906)**	**75,389,420**	**(23,661,624)**	**(19,377,725)**	**1,145,908**			**312,592**		
Diesel Production															
140004.200	Structures and Improvements	72 - R2	1,525,367	(593,353)	(219,959)	43,814	755,870	(336,646)	(432,852)	21,186	1.39	57	7,594	16	16
140004.201	Buildings and Improvements	55 - R1	307,094	(44,610)	(4,186)	666	258,964	(27,629)	(20,501)	5,584	1.82	50	410	5	5
140004.403	Fuel Holders, Products, and ACC	25 - R2	1,015,105	(623,699)	(122,114)	50,429	319,722	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140004.500	Generating Equipment and Prime	40 - R2	15,732,200	(6,322,968)	(1,672,846)	523,156	8,259,542	(6,740,580)	(732,079)	393,305	2.50	13	56,314	17	30
140004.508		n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n.a.	n/a	n/a
140004.600	Accessory Electric Equipment	45 - R3	4,278,353	(708,479)	(478,962)	72,911	3,163,823	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140004.700	Misc Power Plant Equipment	30 - R2	1,478,633	(397,778)	(371,646)	103,130	812,339	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Diesel Production			**24,336,753**	**(8,705,409)**	**(2,869,713)**	**794,107**	**13,799,285**	**(7,104,854)**	**(1,185,431)**	**420,074**			**64,318**		
Main Transmission Facilities															
140006.300	Poles and Fixtures	65 - R3	35,465,743	(4,941,581)	(1,517,669)	180,689	29,187,181	(4,910,641)	(1,367,921)	545,627	1.54	41	33,364	9	25
140006.304	Brushing	50 - R3	9,739,372	(1,130,197)	48,456	(5,815)	8,651,816	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.305	Survey Costs	50 - R2.5	2,787,405	(324,301)	(61,687)	7,403	2,408,819	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.402	Overhead Conductors / Poles	50 - R3	15,729,233	(1,865,191)	(45,903)	4,261	13,822,400	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.404	Overhead Conductors / Towers	50 - R3	277,975	(66,506)	(7,067)	848	205,250	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.710	Substation Equipment	54 - S0	21,342,570	(6,051,540)	(738,810)	94,989	14,647,209	(6,061,782)	(633,579)	395,233	1.85	34	18,635	15	21
140006.720	Substation Buildings	55 - R1	32,750	(7,756)	(496)	74	24,573	(5,955)	(2,223)	595	1.82	35	64	10	21
140006.730	Substation Fences	20 - R4	46,953	(8,829)	769	(230)	38,663	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Main Transmission Facilities			**85,422,003**	**(14,395,902)**	**(2,322,408)**	**282,218**	**68,985,912**	**(10,978,378)**	**(2,003,723)**	**941,455**			**52,062**		
Sub Transmission Lines															
140007.300	Poles and Fixtures	45- R3	3,618,635	(1,601,236)	(780,721)	103,059	1,339,737	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.301	25Kv Minto Spur- Structure	n/a	2,646,132	(459,388)	-		2,186,743	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.304	Brushing	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.305	Survey costs	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.306		n/a	432,533	(75,099)			357,434	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.307		n/a	95,136	(16,516)			78,620	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.401	Overhead Conductors	45- R3	989,127	(378,143)	(112,184)	17,189	515,989	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.405	Underground Conductors / Conduit	45 - S3	83,873	(32,775)	(194)	36	50,940	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.407		n/a	920,693	(159,839)			760,853	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.710	Substation Equipment	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.711		n/a	6,705,507	(1,164,126)			5,541,381	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Sub Transmission Lines			**15,491,635**	**(3,930,691)**	**(893,099)**	**120,284**	**11,518,772**	**-**	**-**	**-**			**-**		

As of December 31, 2010															
			Provided by Yukon Management							Depreciation Expense			Depreciation Add-Back		
Number	Description	KPMG Estimated Survivor Curve	Surviving Original Cost at 12/31/2010	Accumulated Depreciation	A/D Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accrued Depreciation	Accumulated Depreciation Variance	Annual Accrual Amount	Rate (%)	KPMG Probable Remaining Life [1]	Annual Provision for True-Up	Accounting Effective Age	KPMG Concluded Effective Age
Distribution System															
140008.300	Poles and Fixtures	35 - R2	3,570,732	(626,163)	(14,629)	2,628	2,932,567	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.304	Brushing	50 - R2	44,763	(10,680)	(3,235)	427	31,275	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.305	Survey costs	50 - R3	500,981	(43,799)	297		457,478	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.401	Overhead conductors - Poles	35 - R2	74,570	(13,959)			60,611	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.410	Overhead Costs	40 - R2	1,984,394	(429,445)	(78,539)	13,293	1,489,703	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.510	Underground Services	40 - R2.5	6,379	(1,651)	(454)	93	4,367	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.550	Wind Monitoring Equipment	n/a	n/a					n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.610	Meters	30 - R2	281,251	(106,358)	(33,787)	7,409	148,515	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.620	Meter Equipment	30 - R2	314,136	(74,287)	3,308	(555)	242,603	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.710	Substation Equipment	40 - R2	1,188,413	(263,858)	(50,938)	9,459	883,075	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.720	Substation Buildings	55 - R1	64,798	(25,321)	(20,272)	3,619	22,824	(22,455)	(19,520)	1,178	1.82	37	528	19	19
140008.815	Street Lights	40 - R2	573,505	(112,169)	(99,674)	17,096	378,758	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.905	Line Transformers	40 - R2.5	3,290,797	(1,206,043)	(564,652)	107,313	1,627,415	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.961	Sentinel Lights	30 - L2	35,580	(18,984)	(12,948)	4,109	7,757	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Distribution System			**11,930,298**	**(2,932,718)**	**(875,523)**	**164,891**	**8,286,948**	**(22,455)**	**(19,520)**	**1,178**			**528**		
Building and Other Equipment															
140009.110	Survey Costs Land	50 - R2	4,321	(1,261)	(601)	83	2,543	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.200	Structures and Improvements (Hydro)	40 - R2.5	490,156	(97,536)	(3,049)	479	390,050	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.201	Building and Improvements	55 - R1	8,458,407	(2,274,046)	(459,881)	79,602	5,804,082	(1,707,364)	(946,961)	153,789	1.82	45	21,044	11	11
140009.202	Office Furniture and Equipment	20 - SQ	1,389,826	(630,145)	(130,011)	54,324	683,995	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.210	Communication Site Towers	30 - R2	19,297	(6,320)	(1,115)	240	12,102	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.220	Communication Site Fences	20 - R4	36,663	(15,689)	326	(105)	21,195	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.310		n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.320	Computer Hardware	5 - SQ	1,920,814	(812,719)	70,421	(70,421)	1,108,095	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.330	Computer Software	5 - SQ	842,508	(333,477)	(7,872)	7,872	509,031	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.505	Tool and Instruments	20 - SQ	998,579	(353,282)	(168,321)	61,636	538,612	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.507	Wind monitoring equipment	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.605	Communication Equipment	20 - L4	3,780,557	(1,291,842)	(53,911)	22,314	2,457,118	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.810	Company Owned Houses / Land	30 - R3	36,512	(14,062)	7,862	(1,902)	28,410	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.820	Company Owned Houses	30 - R3	1,421,362	(1,260,705)	365,433	(89,514)	436,576	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.900		n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Building and Other Equipment			**19,399,002**	**(7,134,653)**	**(380,719)**	**64,609**	**12,678,882**	**(1,707,364)**	**(946,961)**	**153,789**			**21,044**		
Transportation															
140014.411	Utility Vehicles	7 - L2	181,452	(143,408)	12,716	(12,716)	38,044	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.412	Sedans and Stationwagons	7 - L2	118,637	(106,473)	6,160	(6,160)	12,164	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.420		n/a	66,929	(240)			66,690	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.430	Pole Trailers > 10,000 Lbs	25 - R1.5	34,810	(5,599)	(748)	189	28,652	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.440	Trucks 3/4 to 2 Ton	10 - R2	2,217,586	(934,130)	(17,178)	15,617	1,281,895	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.470	Trucks > 3 Ton	20 - R3	692,397	(134,682)	(12,391)	4,225	549,549	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.490		n/a	1,001,630	(31,812)			969,818	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Transportation			**4,313,442**	**(1,356,344)**	**(11,441)**	**1,154**	**2,946,811**	**-**	**-**	**-**			**-**		
Total			**285,395,726**	**(86,023,946)**	**(5,809,234)**	**1,168,188**	**196,435,568**	**(43,474,674)**	**(23,533,360)**	**2,662,404**			**450,543**		

Notes:
[1] Calculated based on the concluded effective age and the remaining area under the survivor curve.
[2] "n/a" values reflect asset classes which KPMG reviewed, however a change was deemed unnecessary.

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study**

PREAMBLE:

Experience and background of KPMG's depreciation personnel.

QUESTION:

a) Please provide for each person who prepared the depreciation study:
- Their curriculum vitae.
- Previous depreciation studies they have prepared and defended and in front of what courts or administration tribunals.
- Whether they are members of the Society of Depreciation Professionals (SDP).
- Whether they have attended any of the SDP Depreciation Courses or any other non-SDP Depreciation courses. Please provide the courses and content covered.
- Whether they are Certified Depreciation Professionals certified by the SDP.

ANSWER:

(a)

The curriculum vitae of the KPMG personnel who prepared the depreciation study for YEC are provided as Attachment 1 to this response.

The following is noted:

- As evidenced in the curriculum vitae provided, these individuals have prepared and reviewed various depreciation studies for various clients in relation to financial reporting, tax, valuation studies, depreciation studies etc., including National Grid, AES, Sprint, Georgia Power, Qwest, CenturyTel, MetroPCS,and Equinix.

- The KMPG engagement team are members of the SDP.

- Several members of the KPMG engagement team have attended courses offered by the SDP.

- The members of the KPMG engagement team are in the process of being certified as Certified Depreciation Professionals by the SDP.



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Function and Specialization

James is a member of the economic and valuation services ("EVS") practice specializing in tangible and intangible asset valuations.

Professional Associations

- ASA Candidate
- CCIM Candidate
- SDP Member

Languages

- English

Education, Licenses & Certifications

- MBA, Cornell University
- BS Electrical Engineering, Georgia Tech
- Private Pilot

Background

James joined KPMG in 2008 and is currently a manager in KPMG's EVS practice. Since joining KPMG, he has had significant experience across a broad range of projects including business combinations, joint ventures, real estate valuations, personal property valuations, depreciation studies, lease valuations, bankruptcy related valuations, impairment testing and other commercial valuations. Before KPMG, James worked briefly at an investment bank, Brooks, Houghton & Company, as a summer associate in 2007 while completing his MBA at Cornell University. Prior to that, James worked as an electrical engineer at the Naval Surface Warfare Center of Panama City, Florida.

Professional and Industry Experience

James has had broad industry experience including: semiconductor, electronics, technology, mining and exploration, utilities, off-shore wind, real estate, telecommunication, materials, automotive, financial, healthcare, retail and construction. James has supported business combinations under ASC 805 by both performing the necessary asset valuations and reviewing other appraisers' work. James has supported numerous management teams in testing their long-lived assets for impairment under ASC 360, as well as testing their company's goodwill for impairment under ASC 350. James has assisted companies emerging from bankruptcy with fair value opinions and accounting/tax related fresh start valuations. James has had significant experience with the valuation of leases for various purposes, such as purchase price allocations and ASC 840 (FAS 13) testing.

Examples of Past Assignments and Engagement Work

- Performed a valuation analysis of several chemical manufacturing facilities for tax purposes. The analysis was accepted by the IRS and resulted in significant tax savings for the client.
- Performed a pricing analysis for a potential joint venture related to the offshore wind energy industry.
- Served a key role in a fresh start valuation related to a major U.S. automotive company as it emerged from bankruptcy.
- Supported a mining and exploration client through a business combination and componentization exercise by providing guidance on accounting measures as well as developing comprehensive valuation models to value fleets of heavy construction and mining equipment.
- Assisted in the valuation of the intangible assets, personal property assets and real estate related to a major healthcare acquisition.
- Held a key role in the valuation of the leases, personal property and real estate for a printing/media company as it emerged from bankruptcy.
- Performed numerous valuation analyses relating to ASC 350 and ASC 360 impairment testing for clients across a broad range of industries. Multiple valuation methodologies and assumptions were considered in each project, with sensitivity analyses performed to support conclusions and provide insight for clients.
- Completed a 6 month rotation with the KPMG Corporate Finance practice in London, UK.

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Function and Specialization

Vimal leads our tangible asset practice in the Southwest region and specializes in valuations for financial reporting, tax reporting, and insurance proposes

Professional Associations

- Senior member, American Society of Appraisers
- Member, Society of Depreciation Professionals

Education, Licenses & Certifications

- MBA – Finance, Fordham University
- BS - Mechanical Engineering NYU-Polytechnic University

Background

Vimal Patel is a Principal in the Economic and Valuation Services Practice in Houston, Texas. He has been assisting clients for more than 16 years in connection with mergers, acquisitions, divestitures, joint ventures, corporate restructuring, and bankruptcy. His industry knowledge has involved a wide range of valuation assignments including: energy, telecommunications, automotive, high-tech, financial services, pharmaceutical, consumer and industrial products, and healthcare. The purpose of his engagements are related to financial reporting, fresh start accounting, fairness opinions, debt financing, privatization, depreciation studies, property tax, insurance replacement cost analyses, tax reporting, financing and sale leaseback. Mr. Patel has managed and conducted numerous multibillion dollar valuations and has a strong international background, having conducted valuations of assets for businesses located in Central and South America, Europe, the Middle East, Asia, and Australia.

Professional and Industry Experience

Prior to joining KPMG, Vimal was a Senior Director with Kroll Associates, Inc., where he developed and oversaw all operational, technical, and marketing functions for its global tangible asset valuation team. Prior to Kroll, Vimal led the tangible asset team in the South region of Standard & Poor's Corporate Value Consulting group (Formerly with Pricewaterhouse Coopers). He has significant industry expertise as a result of working as a senior project manager for KeySpan Energy, a multi-billion dollar energy company and also as an associate engineer for Brooklyn Union Gas Company.

- Fresh Start Accounting. Vimal has conducted numerous valuation engagements for clients emerging from bankruptcy, related to fresh start accounting. His experience in this sector relates specially to automotive, telecom, and energy industry.
- Reorganization. Vimal has conducted a valuation of a 5 billion dollar energy company's midstream and downstream North American assets in connection with reorganization.
- Private Equity Buyout. Vimal has provided financial advisory and valuation services to one of the top five domestic wireless companies with over eleven billion dollars of assets through out the United States.
- International Financial and Tax Reporting. Vimal has performed a valuation of assets acquired by a large international power generation portfolio that included twelve projects, including forty-five power plants located in the United Kingdom, Italy, Spain, Portugal, Puerto Rico, the Philippines and Australia.
- General Business Planning. Vimal has conducted a valuation of Croatia's entire telecom network, which included fixed line, cellular and paging network systems.
- Property Insurance Placement. Vimal has determined the insurable replacement cost of multi-billion dollar refineries, petrochemical complexes, and E&P assets around the world for property placement purposes to support insurance policy underwriting.

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Function and Specialization
Brian specializes in the valuation of Real and Personal Property.

Representative Clients
- International Paper
- Rock-Tenn Company
- ABB
- General Motors Corp.
- BBVA Compass Bank
- CVS Caremark
- Barclays
- Morgan Stanley

Professional Associations
- American Society of Appraisers – Candidate Member
- Society of Depreciation Professionals - Member

Languages
English (Native), Spanish (Conversational)

Education, Licenses & Certifications
- Shippensburg University of Pennsylvania – BS Finance (Management) '06
- Completed American Society of Appraisers Classes: ME201, ME202, ME203, ME204, and ME206.

Background
Brian joined KPMG in 2008 and is currently a Manager in KPMG's Economic & Valuation Services (EVS) practice. Brian has over 6 years of experience performing a broad range of valuation services including: business combinations, joint ventures, real estate valuations, personal property valuations, lease valuations, SAS 73/101 reviews, depreciation studies, bankruptcy related valuations, impairment testing and other commercial valuations.

Prior to joining KPMG, Brian was an Associate at Marshall & Stevens Inc. in their Capital Asset Valuation group where he primarily performed tangible asset valuations.

Professional and Industry Experience
Brian has extensive experience in performing purchase price allocations for both GAAP and IFRS. He has also performed work in compliance with Accounting Standard Codification Topics 805, 310, 350, 360, and SAS 73/101 reviews.

His knowledge spans a wide range of industries and his experience includes projects with international valuation components.

Technical Skills and Recent Projects
- Built and applied financial models to analyze and prepare the fair values of the client's assets.
- Performed valuation analysis using comparable company, comparable transaction, direct and indirect cost approaches, and discounted cash flow analyses.
- Performed several "green-field" replacement cost analyses in the, pulp and paper, automotive, converting, mining, oil and gas, utility, and chemical industries.
- Developed tangible asset values for portfolios of pulp and paper mills and corrugated container/converting facilities.
- Served a key role in a fresh start valuation related to a major U.S. automotive company as it emerged from bankruptcy.
- Completed tangible asset pricing analyses for major soft drink bottling company.

Other Activities
- Brian is involved with Bowling for Kid's Sake to help raise money for less fortunate children.
- Brian is involved with the First Tee Program which promotes the game of golf to less fortunate children.
- Brian is involved with the Boys School at Fitzsimmons which he serves as a mentor to 11th grade students interested in the Finance and Accounting industries.

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Function and Specialization

John McMann is a senior manager with the Economic and Valuation Services Practice of KPMG LLP. He specializes in personal and real property valuation.

Representative Clients

AES Corporation
Southern Company
Dynegy
Mirant
RRI Energy Inc.

Professional Associations

The American Society of Appraisers (ASA)
The Appraisal Institute
Society of Depreciation Professionals
CCIM Institute
Royal Institute of Chartered Surveyors
Association for the Advancement of Cost Engineering International

Languages

English

Education, Licenses & Certifications

Bachelors of Arts, Emory University
Masters of Science in Real Estate, Georgia State University
Accredited Senior Member of the ASA in Machinery and Technical Specialties
Registered Real Estate Appraiser in the State of Georgia

Background

Prior to joining KPMG in 2007, John was employed for five years by an international valuation firm where he specialized in tangible asset valuation.

Professional and Industry Experience

Mr. McMann has over ten years of valuation experience, in which he has advised clients on tangible asset valuation matters in a wide-range of transactions. Mr. McMann has conducted tangible asset valuations and SAS reviews of personal and real property for compliance with SFAS 114, 141, 142, 143, 144, GASB 34, IFRS 3, fresh start accounting, liability estimation, depreciation studies, and internal management planning. He has also provided valuation services for insurance studies, property tax appeals, fixed asset management, and Sarbanes Oxley compliance.

- Extensive personal property valuation experience in the mining, oil and gas, power generation, chemical manufacturing, building materials, general manufacturing, food manufacturing, and pulp and paper industries.
- Real property experience includes valuations and reviews of industrial properties, retail centers, healthcare facilities, hotels/resorts, residential properties, development projects, and subdivisions.
- International valuation experience includes Brazil, Bulgaria, Canada, Chile, England, France, Germany, India, Korea, the Netherlands, Peru, Poland, Taiwan, and Thailand.

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TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Scope of Work, "Analysis of historical data, including; Review of prior depreciation study results and other information available for in-scope assets to understand the nature of the assets, historical acquisition or construction dates, current depreciation rates, planned usage requirements and risk factors affecting useful lives and salvage values; Interview engineers and other interested parties."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide all the notes and/or summaries of the "interviews with engineers and other interested parties".

ANSWER:

(a)

KPMG held various discussions with engineers and others, but did not prepare formal final working notes for these conversations.

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Net Salvage Estimates Page 10-7, "In our analysis, we have reviewed the current net salvage estimates applied by Yukon. As these estimates are highly subjective, we have based our review upon our prior experience conducting similar analyses. Estimates of net salvage have been made on a percentage basis by class and are applicable to the historical cost basis of the assets."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide the "subjective" analysis that was used in determining the net salvage estimates for each Fixed Asset account.

b) Please provide a complete listing of the "prior experience conducting similar analyses."

c) Please provide the historical actual net salvage data (i.e. retirements, net salvage or gross salvage and cost of retirement by year by account) for each of YEC's Fixed Asset accounts.

ANSWER:

(a)

The net salvage analysis was excluded from the scope of the study undertaken by KPMG. See also response to CW-YEC-1-42(a).

(b)

The KPMG engagement team has prepared and reviewed various depreciation studies for clients in connection with financial reporting, tax, valuation studies, depreciation studies, etc.

(c)

Please see Table 1 below for the requested information.

Table 1:

Historical Actual Costs for Reserve for Site Restoration ($000)

Object Description	2008 closing	2009	2010	2011	Grand Total
Land Hydro N/S					
Land Diesel N/S	34				34
Land Rights N/S					
Structures and Improvements	(29)	67	120		158
Resevoirs Dams and Waterways A	(4,254)			43	(4,211)
Waterwheels, Tubines and Gener	364				364
Accessory Electric Equip A/D N	70				70
Misc Power Plant Equip A/D NS	(16)	10			(6)
Structures and Improvements	(25)				(25)
Building & Improvements N/S	31				31
Survey Costs A/D NS					
Fuel Holders, Products and Acc	65				65
Generating Equipment and Prime	(160)	8	20		(131)
Accessory Electric Equip A/D N	(61)				(61)
Misc Power Plant Equip A/D NS	(40)				(40)
Wind Turbine A/D NS	(82)				(82)
Poles and Fixtures A/D NS	(1,085)	60	73		(951)
Brushing A/D NS	(76)				(76)
Survey Costs A/D NS	(47)				(47)
Overhead Conductors/Poles A/D	(73)				(73)
Overhead Conductors/Towers A/	(12)				(12)
Substation Equipment A/D NS	(112)				(112)
Substation Buildings A/D NS	()				()
Substation Fences A/D NS	()				()
Poles and Fixtures A/D NS	(818)				(818)
Overhead Conductors A/D NS	(191)				(191)
Underground Conductors/Conduit	()				()
Poles and Fixtures A/D NS	119		30		149
Brushing A/D NS	(4)				(4)
Survey Costs A/D NS					
Overhead Conductors A/D NS	23				23
Overhead Services A/D NS	(5)				(5)
Underground Services A/D NS	()				()
Meters A/D NS	(1)				(1)
Meter Equipment A/D NS	(1)				(1)
Substation Equipment A/D NS	(4)				(4)
Substation Buildings A/D NS	16				16
Street Lights A/D NS	50				50
Line Transformers A/D NS	67				67
Sentinel Lights A/D NS	7				7
Survey Costs Land A/D NS	()				()
Structures & Improv. Hydro				10	10
Building and Improvements A/D	203				203
Office Furniture & Equip A/D N	11	15			26
Communication Site Towers A/D	1				1
Communication Site Fences A/D	1				1
MainFrame Computor(APL Share)	8				8
Computer Hardware A/D NS	(16)				(16)
Tools and Instruments A/D NS	(2)				(2)
Communication Equip A/D NS	28				28
Company Owned Houses A/D NS	856				856
Disel Improvements A/D NS					
Trucks and Pole Trailers A/D N					
Trucks 3/4 to 2 ton A/D NS	(9)				(9)
	(5,168)	**160**	**243**	**53**	**(4,711)**

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Evaluation of Statistical Data Page 10-8, "Indicators of goodness-of-fit, a review of recorded accounting data, knowledge of the type of property involved, and the experience of others with similar property, including the depreciation parameters of the previous depreciation study, are used as aids in these determinations."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide the "indicators of goodness-of-fit" for each fixed asset account, how the indicators of "goodness-of-fit" are calculated and how they are used in the Depreciation Study.

ANSWER:

(a)

Please see response to YECL-YEC-1-60(d).

Indicators of good fit refer to the curve fitting process where historical retirement patterns are matched with the best fitting survivor curves.

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Statistical Analysis Page 10-8, "Through the utilization of survivor curves, it is possible to estimate the average service life, average remaining life, and probable life of an asset group. In our analysis, we analyzed historical retirement patterns for each asset class and conducted quantitative procedures to best fit the historical data to the most applicable Iowa Curves. While this was our primary quantitative method, it should be noted that certain adjustments and iterative processes were conducted to ensure that the most appropriate Iowa Curve was selected. When conducting the statistical analysis, there were certain asset classes whose quantitative data presented limitations and required adjustments."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide the "quantitative procedures to best fit the historical data to the most applicable Iowa Curve".

b) Please provide a complete list of these "certain asset classes whose quantitative data presented limitations" and detail what these limitations were and what was done in respect of these assets to address the limitations in quantitative data.

c) Please provide the "adjustments and iterative processes" that "were conducted to ensure that the most appropriate Iowa Curve was selected".

d) Please provide the detailed calculations (in Excel format) derived from the statistical analysis that was conducted. Please provide detailed computer printouts in support of the same.

ANSWER:

(a)

KPMG use 18 Iowa Curves in the curve fitting process to compare to the retirement data. The 18 Iowa curves were: L0 - L5, S0 - S6 and R1 - R5. The 18 curves were further examined across normal useful lives of 1 - 125 years. Therefore, 2,250 Iowa curves (18*125) were examined in KPMG's analysis to best-fit to the subject data.

For a given asset account, the actual retirement data was graphically analyzed and compared to each Iowa Curve. The differences/errors between the actual data and a given Iowa curve were calculated for each year of data, and the sum of these errors was calculated. The sum of errors was compared across all of the Iowa Curves, and the Iowa Curve with the least sum of errors was selected as the best fitting Iowa Curve.

(b)

Please see Table 1 below for a full review of the approach adopted by KPMG to the various accounts. Also see the response to YECL-YEC-1-64(a).

Table 1 Depreciation Methodology by Class

Account Class	Sub-Account	Description	Methodology Considered			Concluded Methodology	Quantitative Analysis Notes
			KPMG Review	Quantitative Approach	Qualitative Approach		
Land	140002.003	Hydraulic Production	Yes	No	No	Review - No Change	Excluded due to small account size.
Land	140002.004	Diesel Production	Yes	No	No	Review - No Change	Excluded due to small account size.
Land	140002.006	Main Transmission Facilities	Yes	No	No	Review - No Change	Excluded due to small account size.
Land	140002.009	General Plant	Yes	No	No	Review - No Change	Excluded due to small account size.
Land	140002.106	Rights	Yes	No	No	Review - No Change	Excluded due to small account size.
Land	140002.106	Rights	Yes	No	No	Review - No Change	Excluded due to small account size.
Hydro Plant	140003.200	Structures and Improvements	Yes	No	Yes	Qualitative	Excluded due to small account size.
Hydro Plant	140003.205	Reservoirs, Dams, and Waterways	Yes	Yes	Yes	Quantitative	Utilized quantitative approach.
Hydro Plant	140003.506	Waterwheels,Turbines & Generation	Yes	Yes	Yes	Qualitative	Results of quantitative analysis yielded a longer life estimate than is attainable in our experience.
Hydro Plant	140003.600	Accessory Electric Equipment	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Hydro Plant	140003.700	Misc Power Plant Equipment	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Hydro Plant	140003.730	Fencing	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Diesel Production	140004.200	Structures and Improvements	Yes	Yes	Yes	Quantitative	Utilized quantitative approach.
Diesel Production	140004.201	Buildings and Improvements	Yes	No	Yes	Qualitative	Excluded due to small account size.
Diesel Production	140004.403	Fuel Holders, Products, and ACC	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Diesel Production	140004.500	Generating Equipment and Prime	Yes	No	Yes	Qualitative	Excluded due to small account size.
Diesel Production	140004.508	n/a	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Diesel Production	140004.600	Accessory Electric Equipment	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Diesel Production	140004.700	Misc Power Plant Equipment	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Wind Turbine	140005.400	Wind Turbine	Yes	No	No	Review - No Change	Excluded due to small account size.
Main Transmission Facilities	140006.300	Poles and Fixtures	Yes	Yes	Yes	Qualitative	Results of quantitative analysis yielded a longer life estimate than is attainable in our experience.
Main Transmission Facilities	140006.304	Brushing	Yes	Yes	Yes	Review - No Change	Retirement data not sufficient to conduct a quantitative analysis.
Main Transmission Facilities	140006.305	Survey Costs	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Main Transmission Facilities	140006.402	Overhead Conductors / Poles	Yes	Yes	Yes	Review - No Change	Retirement data not sufficient to conduct a quantitative analysis.
Main Transmission Facilities	140006.404	Overhead Conductors / Towers	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Main Transmission Facilities	140006.710	Substation Equipment	Yes	Yes	Yes	Quantitative	Utilized quantitative approach.
Main Transmission Facilities	140006.720	Substation Buildings	Yes	No	Yes	Qualitative	Excluded due to small account size.
Main Transmission Facilities	140006.730	Substation Fences	Yes	No	Yes	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.300	Poles and Fixtures	Yes	No	No	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.301	25Kv Minto Spur- Structure	Yes	No	No	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.304	Brushing	Yes	No	No	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.305	Survey costs	Yes	No	No	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.306	n/a	Yes	No	No	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.307	n/a	Yes	No	No	Review - No Change	Excluded due to small account size.

Table 1:
Depreciation Methodology by Class (continued)

Account Class	Sub-Account	Description	Methodology Considered			Concluded Methodology	Quantitative Analysis Notes
			KPMG Review	Quantitative Approach	Qualitative Approach		
Sub Transmission Lines	140007.401	Overhead Conductors	Yes	No	No	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.405	Underground Conductors / Conduit	Yes	No	No	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.407	n/a	Yes	No	No	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.710	Substation Equipment	Yes	No	No	Review - No Change	Excluded due to small account size.
Sub Transmission Lines	140007.711	n/a	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.300	Poles and Fixtures	Yes	Yes	No	Review - No Change	Retirement data not sufficient to conduct a quantitative analysis.
Distribution System	140008.304	Brushing	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.305	Survey costs	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.401	Overhead conductors - Poles	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.410	Overhead Costs	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.510	Underground Services	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.550	Wind Monitoring Equipment	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.610	Meters	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.620	Meter Equipment	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.710	Substation Equipment	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.720	Substation Buildings	Yes	No	Yes	Qualitative	Excluded due to small account size.
Distribution System	140008.815	Street Lights	Yes	No	No	Review - No Change	Excluded due to small account size.
Distribution System	140008.905	Line Transformers	Yes	Yes	No	Review - No Change	Results of quantitative analysis yielded a longer life estimate than is attainable in our experience.
Distribution System	140008.961	Sentinel Lights	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.110	Survey Costs Land	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.200	Structures and Improvements (Hydro)	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.201	Building and Improvements	Yes	Yes	Yes	Quantitative	Utilized quantitative approach.
Building and Other Equipmen	140009.202	Office Furniture and Equipment	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.210	Communication Site Towers	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.220	Communication Site Fences	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.310	n/a	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.320	Computer Hardware	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.330	Computer Software	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.505	Tool and Instruments	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.507	Wind monitoring equipment	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.605	Communication Equipment	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.810	Company Owned Houses / Land	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.820	Company Owned Houses	Yes	No	No	Review - No Change	Excluded due to small account size.
Building and Other Equipmen	140009.900	n/a	Yes	No	No	Review - No Change	Excluded due to small account size.
Transportation	140014.411	Utility Vehicles	Yes	No	No	Review - No Change	Excluded due to small account size.
Transportation	140014.412	Sedans and Stationwagons	Yes	No	No	Review - No Change	Excluded due to small account size.
Transportation	140014.420	n/a	Yes	No	No	Review - No Change	Excluded due to small account size.
Transportation	140014.430	Pole Trailers > 10,000 Lbs	Yes	No	No	Review - No Change	Excluded due to small account size.
Transportation	140014.440	Trucks 3/4 to 2 Ton	Yes	No	No	Review - No Change	Excluded due to small account size.
Transportation	140014.470	Trucks > 3 Ton	Yes	No	No	Review - No Change	Excluded due to small account size.
Transportation	140014.490	n/a	Yes	No	No	Review - No Change	Excluded due to small account size.

(c)

Please see Attachment 1 to part (d) below.

As previously discussed, actual data was compared to the various Iowa Curves as part of the curve fitting process for a given account. When comparing actual data to the Iowa Curves, KPMG analyzed the entire range of data and also analyzed various segments of the data (for curve fitting). KPMG analyzed the actual data, and also extrapolated the data past the historical amounts to better understand the possible curve fitting. Extrapolations were made by determining percent change over the retirement data available, and using the calculated percentage to project/extrapolate retirement further into the future. To determine the extrapolated annual change, KPMG utilized the formula: Extrapolated Annual Change = [((% surviving final) / (% surviving initial)) ^ (1 / (years-1))] - 1.

For example, if there were 20 years of retirement data for an account, KPMG fit Iowa curves to: (1) versus all of the actual retirement data (years 1-20); (2) versus the first half of the retirement data (years 1-10); (3) versus the last half of the retirement data (years 11-20); (4) versus the next 10 years of extrapolated retirement data (years 21 - 30); and (5) versus the last 10 years of actual data and first 10 years of extrapolated data (years 11 - 30).

The rationale for analyzing the various segments of the retirement data was to best fit the survivor curves to the points where change/retirements were occurring in the accounts.

After curve fitting Iowa Curves to each of the segments as discussed above for a given account, KPMG analyzed the results to select a final Iowa Curve under our quantitative analysis for that given account.

(d)

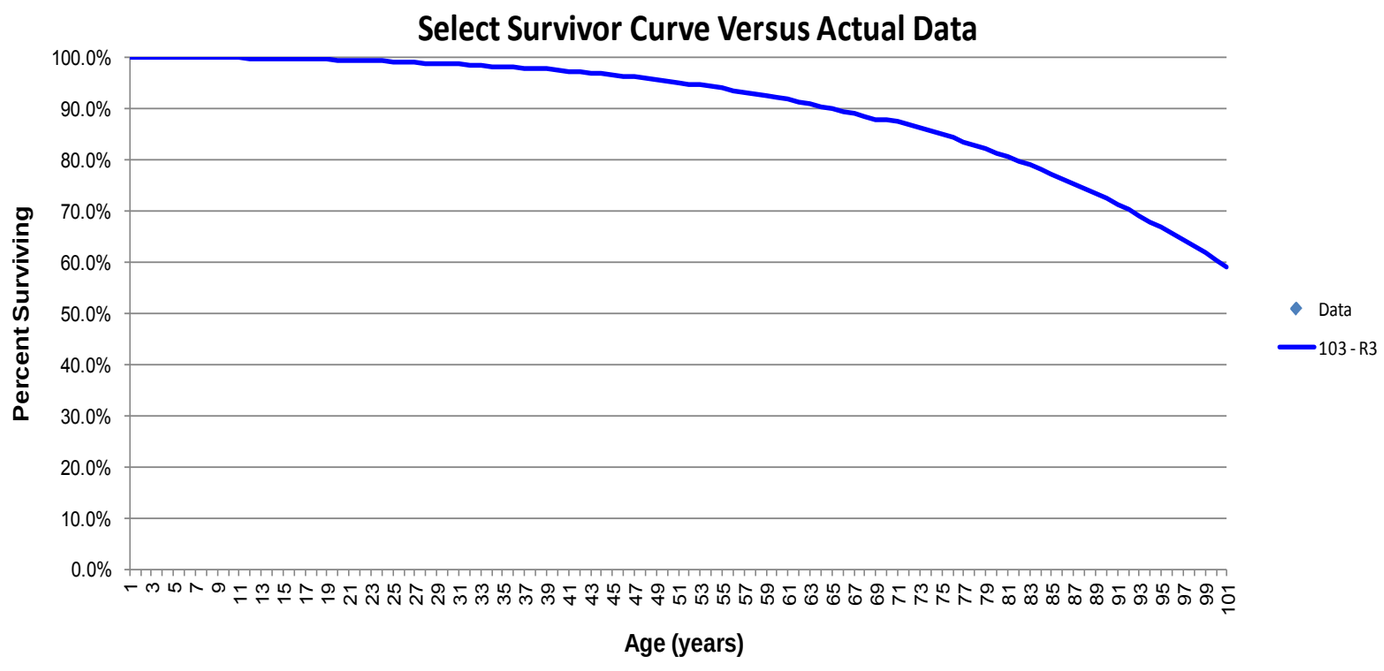
Please see Attachment 1 to this response.

Of the population of asset accounts, statistical analysis (curve fitting) was considered for the accounts which were considered to have a larger account balance. Therefore, 10 accounts were considered for statistical analysis. Of the 10 accounts considered, three

were excluded due to lack of retirement data for a meaningful analysis. Of the remaining seven accounts, four of the seven were concluded upon under the statistical analysis. Of the three not concluded upon, the statistical analysis yielded an estimate of normal useful life which was too high in KPMG's experience, therefore, KPMG relied on other methods to estimate a lower normal useful life for these asset accounts. Please refer to YECL-YEC-1-64(a) and YECL-YEC-1-60(b) for additional information.

Summary of Quantitative Analysis for Account 140003.205

Hydro Plant - Reservoirs, Dams and Waterways



Experience Band 1986 - 2010						
Year	Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning of Interval
2010	0.0	91,075,990	330,237	0.0036	0.9964	100.00%
2009	1.0	90,501,382	142,508	0.0016	0.9984	99.64%
2008	2.0	90,213,538	-	0.0000	1.0000	99.48%
2007	3.0	90,154,964	-	0.0000	1.0000	99.48%
2006	4.0	90,129,181	18,907	0.0002	0.9998	99.48%
2005	5.0	89,938,379	7,757	0.0001	0.9999	99.46%
2004	6.0	89,882,337	16,031	0.0002	0.9998	99.45%
2003	7.0	88,602,600	926	0.0000	1.0000	99.43%
2002	8.0	88,542,660	613,462	0.0069	0.9931	99.43%
2001	9.0	87,806,736	-	0.0000	1.0000	98.74%
2000	10.0	86,479,614	-	0.0000	1.0000	98.74%
1999	11.0	86,433,806	-	0.0000	1.0000	98.74%
1998	12.0	86,419,634	-	0.0000	1.0000	98.74%
1997	13.0	86,394,121	-	0.0000	1.0000	98.74%
1996	14.0	86,143,814	-	0.0000	1.0000	98.74%
1995	15.0	86,111,358	-	0.0000	1.0000	98.74%
1994	16.0	85,622,950	-	0.0000	1.0000	98.74%
1993	17.0	85,474,994	-	0.0000	1.0000	98.74%
1992	18.0	85,018,739	-	0.0000	1.0000	98.74%
1991	19.0	83,634,448	-	0.0000	1.0000	98.74%
1990	20.0	82,838,843	-	0.0000	1.0000	98.74%
1989	21.0	81,418,298	-	0.0000	1.0000	98.74%
1988	22.0	80,709,250	-	0.0000	1.0000	98.74%
1987	23.0	75,876,042	-	0.0000	1.0000	98.74%
1986	24.0	75,329,629	-	0.0000	1.0000	98.74%

**Yellow highlights indicate curve fitting runs where the results were concluded upon

*Std. errors are expressed as actual amounts, while normalized errors are percentages. There is little variation between the two.

Summary of Conclusions		
Scenario	**Best Curve**	**Indicated Error**
Extrapolated Growth (geometric)		
Std. Errors - All Data	125 - R4	22.1930
Std. Errors - 100% to 150% of Client Data	106 - R3	0.0242
Std. Errors - 50% to 150% of Client Data	103 - R3	0.1000
Normalized Errors - All Data	125 - R4	23.7289
Normalized Errors - 100% to 150% of Client Data	106 - R3	0.0246
Normalized Errors - 50% to 150% of Client Data	103 - R3	0.1014
Extrapolated Growth (linear)		
Std. Errors - All Data	125 - R4	22.0944
Std. Errors - 100% to 150% of Client Data	103 - R3	0.0240
Std. Errors - 50% to 150% of Client Data	103 - R3	0.0998
Normalized Errors - All Data	125 - R4	23.6704
Normalized Errors - 100% to 150% of Client Data	103 - R3	0.0244
Normalized Errors - 50% to 150% of Client Data	103 - R3	0.1012
All Data Points (Zeroes Incl. after End)		
Normalized Errors - All Data	124 - R2	0.0956
Non-Zero Data Points Only		
Std. Errors - All Data	124 - R2	0.0945
Normalized Errors - All Data	124 - R2	0.0956
Ignore Multiple Years w/o Retirements		
Std. Errors - All Data	121 - R2	0.0219
Normalized Errors - All Data	121 - R2	0.0221

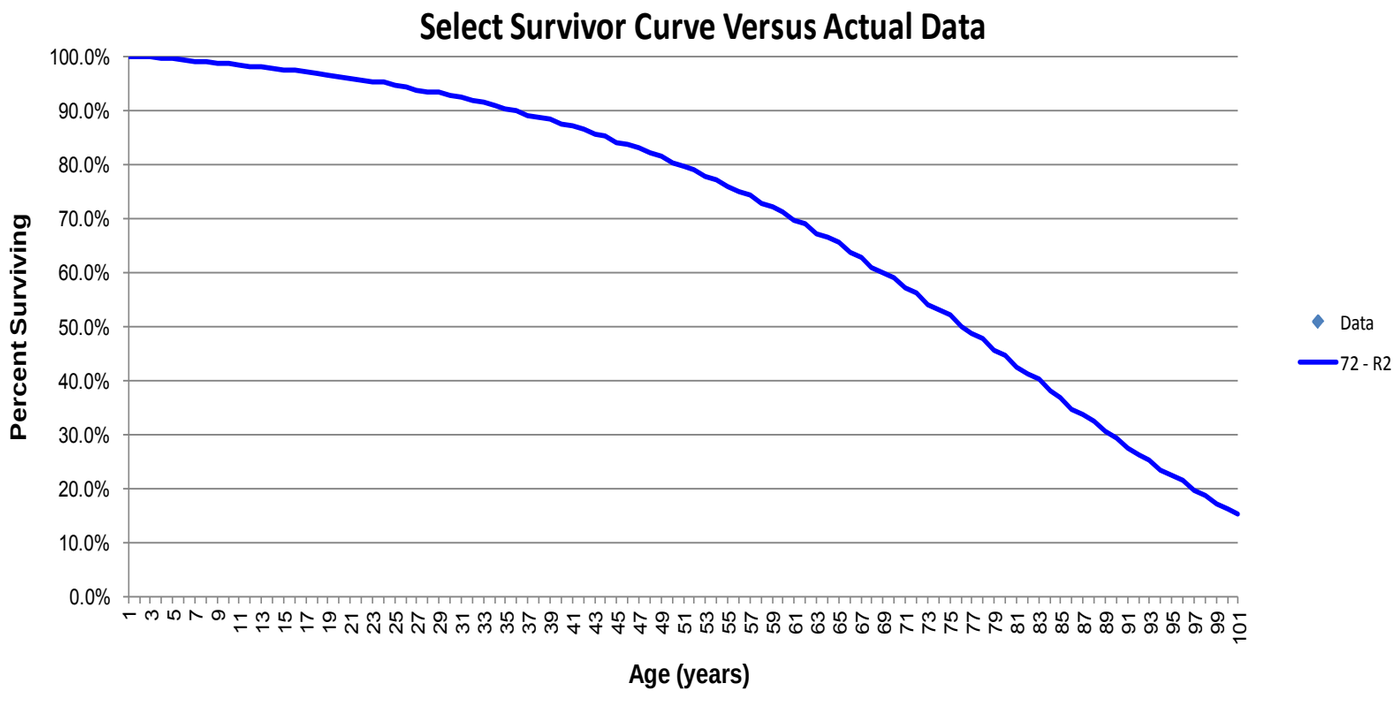
Scenario Summary	
Scenario	**NUL Range**
Under Extrapolation Scenarios	103 - 125
Non Extrapolation Scenarios	121 - 124
Conclusions	
Best Scenario	**Best Curve**
Extrapolation	**103 - R3**

Selected Curve Statistical Comparison						
Age	Actual Data	Actual Data Extrapolated	103 - R3 Curve	Error	Total Error	Notes
0	**1.0000**	**1.0000**	**1.0000**		**0.1000**	Selected Last 50% and First 50% of Extrapolated Data for Curve Fitting
1	**0.9964**	**0.9964**	**1.0000**			
2	**0.9948**	**0.9948**	**0.9998**			
3	**0.9948**	**0.9948**	**0.9997**			
4	**0.9948**	**0.9948**	**0.9995**			
5	**0.9946**	**0.9946**	**0.9993**			
6	**0.9945**	**0.9945**	**0.9991**			
7	**0.9943**	**0.9943**	**0.9988**			
8	**0.9943**	**0.9943**	**0.9986**			
9	**0.9874**	**0.9874**	**0.9983**			
10	**0.9874**	**0.9874**	**0.9980**			
11	**0.9874**	**0.9874**	**0.9977**			
12	**0.9874**	**0.9874**	**0.9974**			
13	**0.9874**	**0.9874**	**0.9970**			
14	**0.9874**	**0.9874**	**0.9966**	0.0092		
15	**0.9874**	**0.9874**	**0.9962**	0.0088		
16	**0.9874**	**0.9874**	**0.9957**	0.0083		
17	**0.9874**	**0.9874**	**0.9953**	0.0079		
18	**0.9874**	**0.9874**	**0.9948**	0.0073		
19	**0.9874**	**0.9874**	**0.9942**	0.0068		
20	**0.9874**	**0.9874**	**0.9936**	0.0062		
21	**0.9874**	**0.9874**	**0.9930**	0.0056		
22	**0.9874**	**0.9874**	**0.9923**	0.0049		
23	**0.9874**	**0.9874**	**0.9916**	0.0042		
24	**0.9874**	**0.9874**	**0.9909**	0.0034		
25	**n/a**	**0.9869**	**0.9901**	0.0032		
26	**n/a**	**0.9864**	**0.9892**	0.0028		
27	**n/a**	**0.9859**	**0.9883**	0.0025		
28	**n/a**	**0.9853**	**0.9874**	0.0020		
29	**n/a**	**0.9848**	**0.9863**	0.0015		
30	**n/a**	**0.9843**	**0.9853**	0.0010		
31	**n/a**	**0.9838**	**0.9841**	0.0004		
32	**n/a**	**0.9833**	**0.9830**	0.0003		
33	**n/a**	**0.9827**	**0.9817**	0.0010		
34	**n/a**	**0.9822**	**0.9804**	0.0018		
35	**n/a**	**0.9817**	**0.9804**	0.0013		
36	**n/a**	**0.9812**	**0.9790**	0.0022		
37	**n/a**	**0.9807**	**0.9775**	0.0032		
38	**n/a**	**0.9801**	**0.9760**	0.0042		
39	**n/a**	**0.9796**	**0.9743**			
40	**n/a**	**0.9791**	**0.9726**			
41	**n/a**	**0.9786**	**0.9708**			
42	**n/a**	**0.9781**	**0.9690**			
43	**n/a**	**0.9776**	**0.9670**			
44	**n/a**	**0.9770**	**0.9649**			
45	**n/a**	**0.9765**	**0.9628**			
46	**n/a**	**0.9760**	**0.9605**			
47	**n/a**	**0.9755**	**0.9581**			
48	**n/a**	**0.9750**	**0.9557**			
49	**n/a**	**0.9745**	**0.9531**			
50	**n/a**	**0.9740**	**0.9504**			
51	**n/a**	**0.9734**	**0.9476**			
52	**n/a**	**0.9729**	**0.9447**			
53	**n/a**	**0.9724**	**0.9416**			
54	**n/a**	**0.9719**	**0.9384**			
55	**n/a**	**0.9714**	**0.9351**			
56	**n/a**	**0.9709**	**0.9317**			
57	**n/a**	**0.9704**	**0.9281**			
58	**n/a**	**0.9699**	**0.9244**			
59	**n/a**	**0.9693**	**0.9205**			
60	**n/a**	**0.9688**	**0.9165**			
61	**n/a**	**0.9683**	**0.9123**			
62	**n/a**	**0.9678**	**0.9080**			
63	**n/a**	**0.9673**	**0.9035**			
64	**n/a**	**0.9668**	**0.8988**			
65	**n/a**	**0.9663**	**0.8940**			
66	**n/a**	**0.9658**	**0.8890**			
67	**n/a**	**0.9653**	**0.8838**			
68	**n/a**	**0.9648**	**0.8784**			
69	**n/a**	**0.9642**	**0.8784**			
70	**n/a**	**0.9637**	**0.8728**			
71	**n/a**	**0.9632**	**0.8671**			
72	**n/a**	**0.9627**	**0.8611**			
73	**n/a**	**0.9622**	**0.8549**			
74	**n/a**	**0.9617**	**0.8485**			

Selected Curve Statistical Comparison						
Age	Actual Data	Actual Data Extrapolated	103 - R3 Curve	Error	Total Error	Notes
75	n/a	0.9612	0.8419			
76	n/a	0.9607	0.8351			
77	n/a	0.9602	0.8280			
78	n/a	0.9597	0.8207			
79	n/a	0.9592	0.8131			
80	n/a	0.9587	0.8053			
81	n/a	0.9582	0.7972			
82	n/a	0.9576	0.7889			
83	n/a	0.9571	0.7803			
84	n/a	0.9566	0.7714			
85	n/a	0.9561	0.7622			
86	n/a	0.9556	0.7528			
87	n/a	0.9551	0.7431			
88	n/a	0.9546	0.7330			
89	n/a	0.9541	0.7227			
90	n/a	0.9536	0.7121			
91	n/a	0.9531	0.7012			
92	n/a	0.9526	0.6899			
93	n/a	0.9521	0.6784			
94	n/a	0.9516	0.6666			
95	n/a	0.9511	0.6545			
96	n/a	0.9506	0.6421			
97	n/a	0.9501	0.6293			
98	n/a	0.9496	0.6163			
99	n/a	0.9491	0.6031			
100	n/a	0.9486	0.5895			
101	n/a	0.9481	0.5757			
102	n/a	0.9476	0.5617			
103	n/a	0.9471	0.5474			
104	n/a	0.9466	0.5474			
105	n/a	0.9461	0.5329			
106	n/a	0.9456	0.5182			
107	n/a	0.9451	0.5034			
108	n/a	0.9446	0.4883			
109	n/a	0.9441	0.4732			
110	n/a	0.9436	0.4579			
111	n/a	0.9431	0.4425			
112	n/a	0.9426	0.4271			
113	n/a	0.9421	0.4116			
114	n/a	0.9416	0.3962			
115	n/a	0.9411	0.3807			
116	n/a	0.9406	0.3654			
117	n/a	0.9401	0.3501			
118	n/a	0.9396	0.3349			
119	n/a	0.9391	0.3198			
120	n/a	0.9386	0.3050			
121	n/a	0.9381	0.2903			
122	n/a	0.9376	0.2759			
123	n/a	0.9372	0.2617			
124	n/a	0.9367	0.2478			
125	n/a	0.9362	0.2342			
126	n/a	0.9357	0.2210			
127	n/a	0.9352	0.2081			
128	n/a	0.9347	0.1956			
129	n/a	0.9342	0.1835			
130	n/a	0.9337	0.1718			
131	n/a	0.9332	0.1605			
132	n/a	0.9327	0.1497			
133	n/a	0.9322	0.1392			
134	n/a	0.9317	0.1293			
135	n/a	0.9312	0.1197			
136	n/a	0.9307	0.1106			
137	n/a	0.9303	0.1020			
138	n/a	0.9298	0.1020			
139	n/a	0.9293	0.0938			
140	n/a	0.9288	0.0860			
141	n/a	0.9283	0.0786			
142	n/a	0.9278	0.0717			
143	n/a	0.9273	0.0652			
144	n/a	0.9268	0.0591			
145	n/a	0.9263	0.0533			
146	n/a	0.9258	0.0480			
147	n/a	0.9254	0.0430			
148	n/a	0.9249	0.0384			
149	n/a	0.9244	0.0341			
150	n/a	0.9239	0.0301			

Summary of Quantitative Analysis for Account 140004.200

Diesel Production - Structures and Improvements



Experience Band 1986 - 2010						
Year	Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning of Interval
2010	0.0	1,847,377	-	0.0000	1.0000	100.00%
2009	0.5	1,847,377	13,264	0.0072	0.9928	100.00%
2008	1.5	1,847,377	-	0.0000	1.0000	99.28%
2007	2.5	1,826,417	-	0.0000	1.0000	99.28%
2006	3.5	1,826,417	-	0.0000	1.0000	99.28%
2005	4.5	1,826,417	7,902	0.0043	0.9957	99.28%
2004	5.5	1,826,417	3,534	0.0019	0.9981	98.85%
2003	6.5	1,826,417	-	0.0000	1.0000	98.66%
2002	7.5	1,541,247	-	0.0000	1.0000	98.66%
2001	8.5	1,256,077	-	0.0000	1.0000	98.66%
2000	9.5	1,256,077	-	0.0000	1.0000	98.66%
1999	10.5	1,215,352	-	0.0000	1.0000	98.66%
1998	11.5	1,215,352	12,139	0.0100	0.9900	98.66%
1997	12.5	1,203,213	-	0.0000	1.0000	97.66%
1996	13.5	1,203,213	-	0.0000	1.0000	97.66%
1995	14.5	1,203,213	-	0.0000	1.0000	97.66%
1994	15.5	1,127,266	-	0.0000	1.0000	97.66%
1993	16.5	1,121,041	-	0.0000	1.0000	97.66%
1992	17.5	1,094,064	-	0.0000	1.0000	97.66%
1991	18.5	1,086,202	-	0.0000	1.0000	97.66%
1990	19.5	886,340	-	0.0000	1.0000	97.66%
1989	20.5	311,348	-	0.0000	1.0000	97.66%
1988	21.5	275,482	-	0.0000	1.0000	97.66%
1987	22.5	273,987	-	0.0000	1.0000	97.66%
1986	23.5	258,987	-	0.0000	1.0000	97.66%

**Yellow highlights indicate curve fitting runs where the results were concluded upon

*Std. errors are expressed as actual amounts, while normalized errors are percentages. There is little variation between the two.

Summary of Conclusions		
Scenario	**Best Curve**	**Indicated Error**
Extrapolated Growth (geometric)		
Std. Errors - 100% to 150% of Client Data	81 - R3	0.0564
Normalized Errors - 100% to 150% of Client Data	81 - R3	0.0582
Extrapolated Growth (linear)		
Std. Errors - 100% to 150% of Client Data	81 - R3	0.0563
Normalized Errors - 100% to 150% of Client Data	81 - R3	0.0581
Non-Zero Data Points Only		
Std. Errors - All Data	97 - R2	0.1002
Std. Errors - 0% to 50% of Client Data	72 - R2	0.0336
Std. Errors - 50% to 100% of Client Data	105 - R2	0.0450
Normalized Errors - All Data	97 - R2	0.1021
Normalized Errors - 0% to 50% of Client Data	72 - R2	0.0339
Normalized Errors - 50% to 100% of Client Data	105 - R2	0.0460

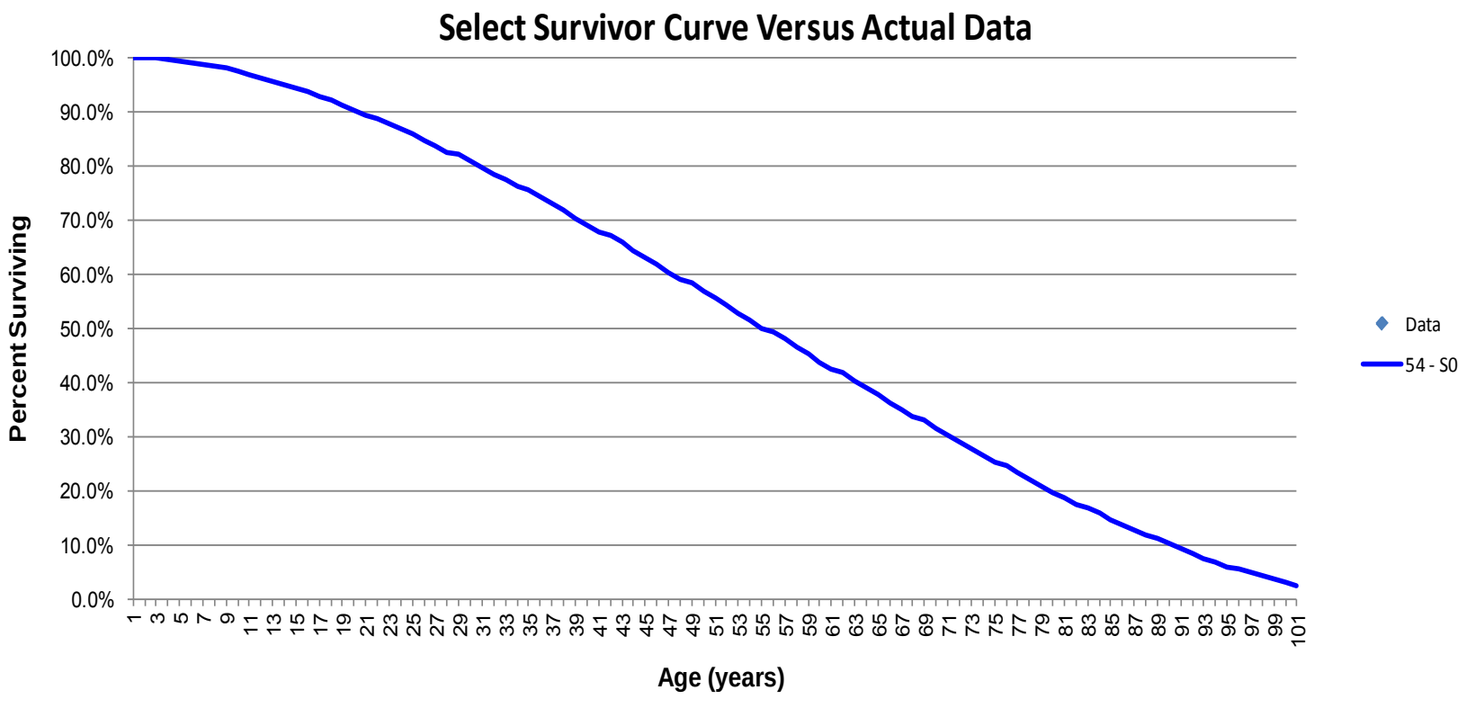
Scenario Summary	
Scenario	**NUL Range**
Under Extrapolation Scenarios	81
Non Extrapolation Scenarios	72 - 105
Conclusions	
Best Scenario	**Best Curve**
Non Extrapolation	**72 - R2**

Selected Curve Statistical Comparison					
Age	Actual Data	72 - R2 Curve	Error	Total Error	Notes
0	**1.0000**	**1.0000**	0.0000	**0.0336**	Selected First 50% of client data
1	**1.0000**	**0.9991**	0.0009		
2	**0.9928**	**0.9981**	0.0053		
3	**0.9928**	**0.9960**	0.0032		
4	**0.9928**	**0.9949**	0.0021		
5	**0.9928**	**0.9938**	0.0010		
6	**0.9885**	**0.9914**	0.0030		
7	**0.9866**	**0.9902**	0.0037		
8	**0.9866**	**0.9876**	0.0011		
9	**0.9866**	**0.9863**	0.0003		
10	**0.9866**	**0.9849**	0.0017		
11	**0.9866**	**0.9819**	0.0046		
12	**0.9866**	**0.9804**	0.0062		
13	**0.9766**	**0.9772**	0.0006		
14	**0.9766**	**0.9755**			
15	**0.9766**	**0.9737**			
16	**0.9766**	**0.9701**			
17	**0.9766**	**0.9682**			
18	**0.9766**	**0.9642**			
19	**0.9766**	**0.9622**			
20	**0.9766**	**0.9600**			
21	**0.9766**	**0.9556**			
22	**0.9766**	**0.9533**			
23	**0.9766**	**0.9509**			
24	**0.9766**	**0.9459**			
25	**n/a**	**0.9434**			
26	**n/a**	**0.9380**			
27	**n/a**	**0.9352**			
28	**n/a**	**0.9323**			
29	**n/a**	**0.9263**			
30	**n/a**	**0.9232**			
31	**n/a**	**0.9167**			
32	**n/a**	**0.9133**			
33	**n/a**	**0.9099**			
34	**n/a**	**0.9027**			
35	**n/a**	**0.8990**			
36	**n/a**	**0.8913**			
37	**n/a**	**0.8873**			
38	**n/a**	**0.8831**			
39	**n/a**	**0.8746**			
40	**n/a**	**0.8702**			
41	**n/a**	**0.8657**			
42	**n/a**	**0.8563**			
43	**n/a**	**0.8514**			
44	**n/a**	**0.8414**			
45	**n/a**	**0.8362**			
46	**n/a**	**0.8309**			
47	**n/a**	**0.8198**			
48	**n/a**	**0.8142**			
49	**n/a**	**0.8024**			
50	**n/a**	**0.7963**			
51	**n/a**	**0.7901**			
52	**n/a**	**0.7773**			
53	**n/a**	**0.7707**			
54	**n/a**	**0.7571**			
55	**n/a**	**0.7500**			
56	**n/a**	**0.7429**			
57	**n/a**	**0.7281**			
58	**n/a**	**0.7206**			
59	**n/a**	**0.7128**			
60	**n/a**	**0.6970**			
61	**n/a**	**0.6888**			
62	**n/a**	**0.6721**			
63	**n/a**	**0.6635**			
64	**n/a**	**0.6548**			
65	**n/a**	**0.6370**			
66	**n/a**	**0.6279**			
67	**n/a**	**0.6093**			
68	**n/a**	**0.5997**			
69	**n/a**	**0.5901**			
70	**n/a**	**0.5705**			
71	**n/a**	**0.5605**			
72	**n/a**	**0.5402**			
73	**n/a**	**0.5300**			
74	**n/a**	**0.5196**			

Selected Curve Statistical Comparison					
Age	Actual Data	72 - R2 Curve	Error	Total Error	Notes
75	n/a	0.4986			
76	n/a	0.4879			
77	n/a	0.4772			
78	n/a	0.4557			
79	n/a	0.4448			
80	n/a	0.4230			
81	n/a	0.4121			
82	n/a	0.4012			
83	n/a	0.3793			
84	n/a	0.3684			
85	n/a	0.3467			
86	n/a	0.3359			
87	n/a	0.3251			
88	n/a	0.3039			
89	n/a	0.2934			
90	n/a	0.2727			
91	n/a	0.2625			
92	n/a	0.2525			
93	n/a	0.2328			
94	n/a	0.2232			
95	n/a	0.2138			
96	n/a	0.1954			
97	n/a	0.1865			
98	n/a	0.1693			
99	n/a	0.1610			
100	n/a	0.1530			
101	n/a	0.1374			
102	n/a	0.1300			
103	n/a	0.1158			
104	n/a	0.1091			
105	n/a	0.1025			
106	n/a	0.0902			
107	n/a	0.0843			
108	n/a	0.0733			
109	n/a	0.0681			
110	n/a	0.0632			
111	n/a	0.0539			
112	n/a	0.0496			
113	n/a	0.0455			
114	n/a	0.0379			
115	n/a	0.0344			
116	n/a	0.0280			
117	n/a	0.0251			
118	n/a	0.0224			
119	n/a	0.0175			
120	n/a	0.0153			
121	n/a	0.0114			
122	n/a	0.0098			
123	n/a	0.0082			
124	n/a	0.0056			
125	n/a	0.0046			
126	n/a	0.0028			
127	n/a	0.0021			
128	n/a	0.0016			
129	n/a	0.0007			
130	n/a	0.0005			
131	n/a	0.0003			
132	n/a	0.0001			
133	n/a	0.0000			
134	n/a	0.0000			
135	n/a	0.0000			
136	n/a	0.0000			
137	n/a	0.0000			
138	n/a	0.0000			
139	n/a	0.0000			
140	n/a	0.0000			
141	n/a	0.0000			
142	n/a	0.0000			
143	n/a	0.0000			
144	n/a	0.0000			
145	n/a	0.0000			
146	n/a	0.0000			
147	n/a	0.0000			
148	n/a	0.0000			
149	n/a	0.0000			
150	n/a	0.0000			

Summary of Quantitative Analysis for Account 140006.710

Main Transmission - Substation Equipment



Experience Band 1980 - 2010						
Year	Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning of Interval
2010	0.0	27,468,090	-	0.0000	1.0000	100.00%
2009	0.5	26,845,227	-	0.0000	1.0000	100.00%
2008	1.5	26,747,502	57,669	0.0022	0.9978	100.00%
2007	2.5	23,431,071	90,563	0.0039	0.9961	99.78%
2006	3.5	23,293,316	143,473	0.0062	0.9938	99.40%
2005	4.5	23,104,038	45,168	0.0020	0.9980	98.78%
2004	5.5	22,963,753	21,026	0.0009	0.9991	98.59%
2003	6.5	22,850,380	82,708	0.0036	0.9964	98.49%
2002	7.5	17,235,376	-	0.0000	1.0000	98.13%
2001	8.5	17,235,376	-	0.0000	1.0000	98.13%
2000	9.5	17,235,376	-	0.0000	1.0000	98.13%
1999	10.5	17,235,376	-	0.0000	1.0000	98.13%
1998	11.5	17,235,376	-	0.0000	1.0000	98.13%
1997	12.5	17,235,376	-	0.0000	1.0000	98.13%
1996	13.5	17,235,376	-	0.0000	1.0000	98.13%
1995	14.5	11,674,992	-	0.0000	1.0000	98.13%
1994	15.5	11,674,992	71	0.0000	1.0000	98.13%
1993	16.5	11,674,921	-	0.0000	1.0000	98.13%
1992	17.5	11,353,872	7,800	0.0007	0.9993	98.13%
1991	18.5	11,346,072	-	0.0000	1.0000	98.06%
1990	19.5	11,323,830	-	0.0000	1.0000	98.06%
1989	20.5	11,147,907	2,371	0.0002	0.9998	98.06%
1988	21.5	10,335,372	69,175	0.0067	0.9933	98.04%
1987	22.5	10,106,827	-	0.0000	1.0000	97.37%
1986	23.5	10,031,160	-	0.0000	1.0000	97.37%
1985	24.5	7,679,277	80,171	0.0104	0.9896	97.37%
1984	25.5	4,284,412	-	0.0000	1.0000	96.33%
1983	26.5	2,075,579	-	0.0000	1.0000	96.33%
1982	27.5	2,069,769	-	0.0000	1.0000	96.33%
1981	28.5	2,068,360	-	0.0000	1.0000	96.33%
1980	29.5	2,047,784	-	0.0000	1.0000	96.33%

**Yellow highlights indicate curve fitting runs where the results were concluded upon

*Std. errors are expressed as actual amounts, while normalized errors are percentages. There is little variation between the two.

Summary of Conclusions		
Scenario	**Best Curve**	**Indicated Error**
Extrapolated Growth (geometric)		
Std. Errors - All Data	125 - R3	18.6886
Std. Errors - 0% to 50% of Client Data	79 - R2	0.0621
Std. Errors - 50% to 100% of Client Data	112 - R2	0.0303
Std. Errors - 100% to 150% of Client Data	125 - R2	0.0524
Std. Errors - 50% to 150% of Client Data	125 - R2	0.1043
Normalized Errors - All Data	125 - R3	21.7686
Normalized Errors - 0% to 50% of Client Data	79 - R2	0.0631
Normalized Errors - 50% to 100% of Client Data	112 - R2	0.0312
Normalized Errors - 100% to 150% of Client Data	125 - R2	0.0552
Normalized Errors - 50% to 150% of Client Data	125 - R2	0.1089
Extrapolated Growth (linear)		
Std. Errors - All Data	125 - R3	18.1940
Std. Errors - 0% to 50% of Client Data	79 - R2	0.0621
Std. Errors - 50% to 100% of Client Data	112 - R2	0.0303
Std. Errors - 100% to 150% of Client Data	125 - R2	0.0491
Std. Errors - 50% to 150% of Client Data	125 - R2	0.1010
Normalized Errors - All Data	125 - R3	21.4139
Normalized Errors - 0% to 50% of Client Data	79 - R2	0.0631
Normalized Errors - 50% to 100% of Client Data	112 - R2	0.0312
Normalized Errors - 100% to 150% of Client Data	125 - R2	0.0517
Normalized Errors - 50% to 150% of Client Data	125 - R2	0.1054
All Data Points (Zeroes Incl. after End)		
Std. Errors - 0% to 50% of Client Data	79 - R2	0.0621
Std. Errors - 50% to 100% of Client Data	112 - R2	0.9883
Normalized Errors - All Data	112 - R2	0.1259
Normalized Errors - 0% to 50% of Client Data	79 - R2	0.0631
Normalized Errors - 50% to 100% of Client Data	112 - R2	0.0291
Non-Zero Data Points Only		
Std. Errors - All Data	112 - R2	0.1235
Std. Errors - 0% to 50% of Client Data	79 - R2	0.0621
Std. Errors - 50% to 100% of Client Data	112 - R2	0.0283
Normalized Errors - All Data	112 - R2	0.1259
Normalized Errors - 0% to 50% of Client Data	79 - R2	0.0631
Normalized Errors - 50% to 100% of Client Data	112 - R2	0.0291
Ignore Multiple Years w/o Retirements		
Std. Errors - All Data	120 - R2	0.0381
Std. Errors - 0% to 50% of Client Data	54 - S0	0.0068
Std. Errors - 50% to 100% of Client Data	120 - R2	0.0066
Normalized Errors - All Data	120 - R2	0.0386
Normalized Errors - 0% to 50% of Client Data	54 - S0	0.0069
Normalized Errors - 50% to 100% of Client Data	120 - R2	0.0068

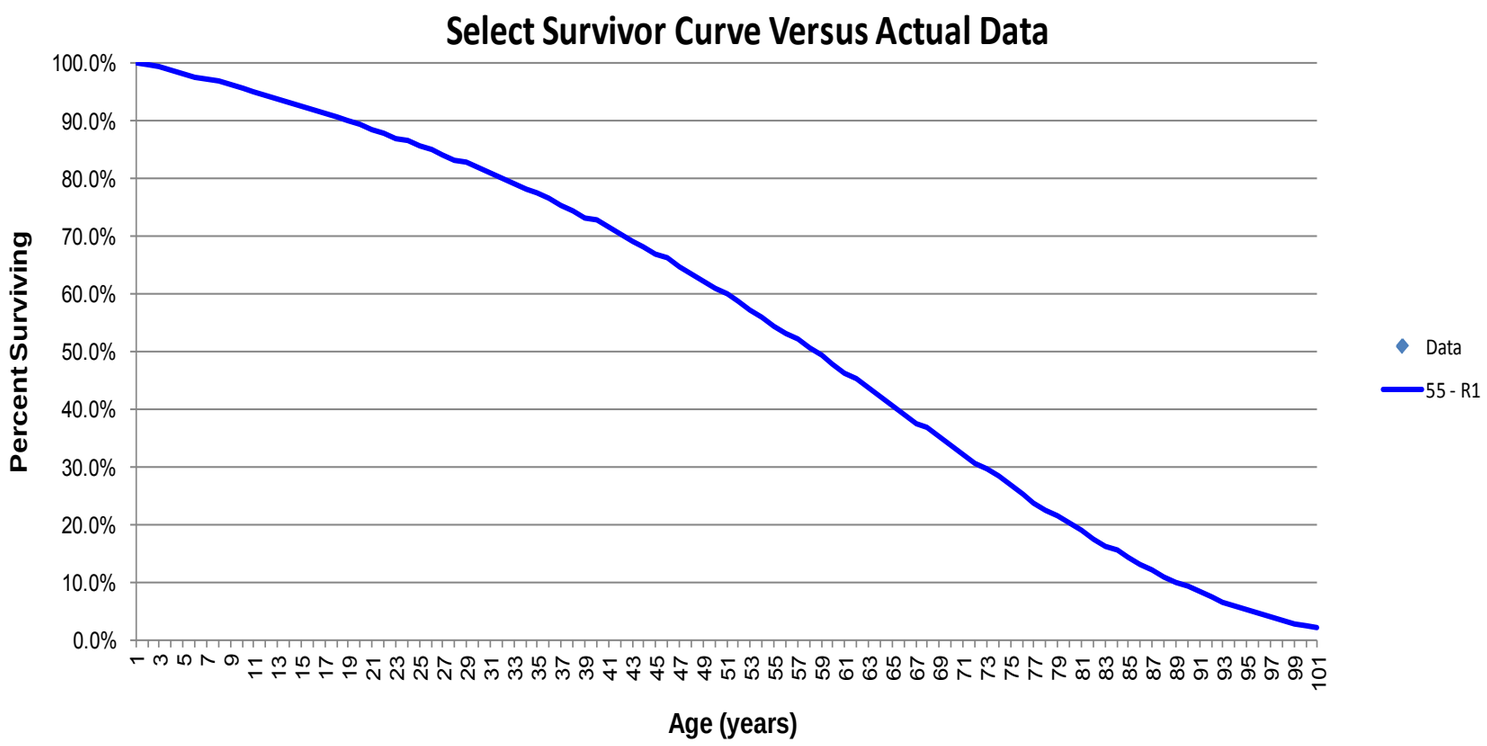
Scenario Summary	
Scenario	**NUL Range**
Under Extrapolation Scenarios	79 - 125
Non Extrapolation Scenarios	54 - 120
Conclusions	
Best Scenario	**Best Curve**
Non Extrapolation	**54 - S0**

Selected Curve Statistical Comparison						
Age	Actual Data	Ignore Repeating Data	54 - S0 Curve	Error	Total Error	Notes
0	**1.0000**	**1.0000**	**1.0000**	0.0000	**0.0068**	Seleted First 50% of client data for curve fitting
1	**1.0000**	**n/a**	**0.9998**	0.0000		
2	**1.0000**	**1.0000**	**0.9986**	0.0014		
3	**0.9978**	**0.9978**	**0.9965**	0.0013		
4	**0.9940**	**0.9940**	**0.9937**	0.0003		
5	**0.9878**	**0.9878**	**0.9903**	0.0025		
6	**0.9859**	**0.9859**	**0.9863**	0.0004		
7	**0.9849**	**0.9849**	**0.9841**	0.0009		
8	**0.9813**	**n/a**	**0.9793**	0.0000		
9	**0.9813**	**n/a**	**0.9739**	0.0000		
10	**0.9813**	**n/a**	**0.9681**	0.0000		
11	**0.9813**	**n/a**	**0.9619**	0.0000		
12	**0.9813**	**n/a**	**0.9552**	0.0000		
13	**0.9813**	**n/a**	**0.9481**	0.0000		
14	**0.9813**	**n/a**	**0.9444**	0.0000		
15	**0.9813**	**n/a**	**0.9367**	0.0000		
16	**0.9813**	**n/a**	**0.9287**			
17	**0.9813**	**n/a**	**0.9203**			
18	**0.9813**	**0.9813**	**0.9115**			
19	**0.9806**	**n/a**	**0.9025**			
20	**0.9806**	**n/a**	**0.8931**			
21	**0.9806**	**0.9806**	**0.8883**			
22	**0.9804**	**0.9804**	**0.8785**			
23	**0.9737**	**n/a**	**0.8684**			
24	**0.9737**	**n/a**	**0.8580**			
25	**0.9737**	**0.9737**	**0.8474**			
26	**0.9633**	**n/a**	**0.8366**			
27	**0.9633**	**n/a**	**0.8255**			
28	**0.9633**	**n/a**	**0.8198**			
29	**0.9633**	**n/a**	**0.8084**			
30	**0.9633**	**0.9633**	**0.7968**			
31	**n/a**	**n/a**	**0.7849**			
32	**n/a**	**n/a**	**0.7729**			
33	**n/a**	**n/a**	**0.7607**			
34	**n/a**	**n/a**	**0.7545**			
35	**n/a**	**n/a**	**0.7421**			
36	**n/a**	**n/a**	**0.7295**			
37	**n/a**	**n/a**	**0.7167**			
38	**n/a**	**n/a**	**0.7038**			
39	**n/a**	**n/a**	**0.6908**			
40	**n/a**	**n/a**	**0.6777**			
41	**n/a**	**n/a**	**0.6711**			
42	**n/a**	**n/a**	**0.6578**			
43	**n/a**	**n/a**	**0.6444**			
44	**n/a**	**n/a**	**0.6309**			
45	**n/a**	**n/a**	**0.6173**			
46	**n/a**	**n/a**	**0.6037**			
47	**n/a**	**n/a**	**0.5900**			
48	**n/a**	**n/a**	**0.5831**			
49	**n/a**	**n/a**	**0.5693**			
50	**n/a**	**n/a**	**0.5555**			
51	**n/a**	**n/a**	**0.5417**			
52	**n/a**	**n/a**	**0.5278**			
53	**n/a**	**n/a**	**0.5139**			
54	**n/a**	**n/a**	**0.5000**			
55	**n/a**	**n/a**	**0.4930**			
56	**n/a**	**n/a**	**0.4791**			
57	**n/a**	**n/a**	**0.4653**			
58	**n/a**	**n/a**	**0.4514**			
59	**n/a**	**n/a**	**0.4376**			
60	**n/a**	**n/a**	**0.4238**			
61	**n/a**	**n/a**	**0.4169**			
62	**n/a**	**n/a**	**0.4031**			
63	**n/a**	**n/a**	**0.3895**			
64	**n/a**	**n/a**	**0.3759**			
65	**n/a**	**n/a**	**0.3624**			
66	**n/a**	**n/a**	**0.3489**			
67	**n/a**	**n/a**	**0.3356**			
68	**n/a**	**n/a**	**0.3289**			
69	**n/a**	**n/a**	**0.3157**			
70	**n/a**	**n/a**	**0.3027**			
71	**n/a**	**n/a**	**0.2897**			
72	**n/a**	**n/a**	**0.2769**			
73	**n/a**	**n/a**	**0.2642**			
74	**n/a**	**n/a**	**0.2517**			

Selected Curve Statistical Comparison						
Age	Actual Data	Ignore Repeating Data	54 - S0 Curve	Error	Total Error	Notes
75	n/a	n/a	0.2455			
76	n/a	n/a	0.2332			
77	n/a	n/a	0.2210			
78	n/a	n/a	0.2091			
79	n/a	n/a	0.1974			
80	n/a	n/a	0.1858			
81	n/a	n/a	0.1745			
82	n/a	n/a	0.1690			
83	n/a	n/a	0.1580			
84	n/a	n/a	0.1472			
85	n/a	n/a	0.1367			
86	n/a	n/a	0.1265			
87	n/a	n/a	0.1166			
88	n/a	n/a	0.1117			
89	n/a	n/a	0.1022			
90	n/a	n/a	0.0929			
91	n/a	n/a	0.0840			
92	n/a	n/a	0.0755			
93	n/a	n/a	0.0673			
94	n/a	n/a	0.0594			
95	n/a	n/a	0.0556			
96	n/a	n/a	0.0483			
97	n/a	n/a	0.0414			
98	n/a	n/a	0.0349			
99	n/a	n/a	0.0289			
100	n/a	n/a	0.0233			
101	n/a	n/a	0.0183			
102	n/a	n/a	0.0159			
103	n/a	n/a	0.0116			
104	n/a	n/a	0.0079			
105	n/a	n/a	0.0048			
106	n/a	n/a	0.0024			
107	n/a	n/a	0.0007			
108	n/a	n/a	0.0000			
109	n/a	n/a	0.0000			
110	n/a	n/a	0.0000			
111	n/a	n/a	0.0000			
112	n/a	n/a	0.0000			
113	n/a	n/a	0.0000			
114	n/a	n/a	0.0000			
115	n/a	n/a	0.0000			
116	n/a	n/a	0.0000			
117	n/a	n/a	0.0000			
118	n/a	n/a	0.0000			
119	n/a	n/a	0.0000			
120	n/a	n/a	0.0000			
121	n/a	n/a	0.0000			
122	n/a	n/a	0.0000			
123	n/a	n/a	0.0000			
124	n/a	n/a	0.0000			
125	n/a	n/a	0.0000			
126	n/a	n/a	0.0000			
127	n/a	n/a	0.0000			
128	n/a	n/a	0.0000			
129	n/a	n/a	0.0000			
130	n/a	n/a	0.0000			
131	n/a	n/a	0.0000			
132	n/a	n/a	0.0000			
133	n/a	n/a	0.0000			
134	n/a	n/a	0.0000			
135	n/a	n/a	0.0000			
136	n/a	n/a	0.0000			
137	n/a	n/a	0.0000			
138	n/a	n/a	0.0000			
139	n/a	n/a	0.0000			
140	n/a	n/a	0.0000			
141	n/a	n/a	0.0000			
142	n/a	n/a	0.0000			
143	n/a	n/a	0.0000			
144	n/a	n/a	0.0000			
145	n/a	n/a	0.0000			
146	n/a	n/a	0.0000			
147	n/a	n/a	0.0000			
148	n/a	n/a	0.0000			
149	n/a	n/a	0.0000			
150	n/a	n/a	0.0000			

Summary of Quantitative Analysis for Account 140009-201

Buildings and Other Equipment - Buildings and Improvements



Experience Band 1986 - 2010						
Year	Age at Beginning of Interval	Exposures at Beginning of Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving Beginning of Interval
2010	0.0	9,120,737	-	0.0000	1.0000	100.00%
2009	0.5	8,949,001	-	0.0000	1.0000	100.00%
2008	1.5	8,343,557	-	0.0000	1.0000	100.00%
2007	2.5	8,252,034	-	0.0000	1.0000	100.00%
2006	3.5	8,021,970	3,622	0.0005	0.9995	100.00%
2005	4.5	7,821,041	-	0.0000	1.0000	99.95%
2004	5.5	7,420,506	5,598	0.0008	0.9992	99.95%
2003	6.5	7,013,338	-	0.0000	1.0000	99.88%
2002	7.5	6,878,275	-	0.0000	1.0000	99.88%
2001	8.5	6,764,174	1,482	0.0002	0.9998	99.88%
2000	9.5	6,134,861	26,900	0.0044	0.9956	99.86%
1999	10.5	5,372,225	493,010	0.0918	0.9082	99.42%
1998	11.5	4,428,344	-	0.0000	1.0000	90.24%
1997	12.5	1,490,665	-	0.0000	1.0000	90.24%
1996	13.5	1,410,382	1,286	0.0009	0.9991	90.24%
1995	14.5	1,407,295	-	0.0000	1.0000	90.15%
1994	15.5	1,381,568	-	0.0000	1.0000	90.15%
1993	16.5	1,345,213	22,757	0.0169	0.9831	90.15%
1992	17.5	1,322,456	-	0.0000	1.0000	88.46%
1991	18.5	1,270,112	-	0.0000	1.0000	88.46%
1990	19.5	1,233,020	-	0.0000	1.0000	88.46%
1989	20.5	1,229,392	-	0.0000	1.0000	88.46%
1988	21.5	1,229,392	-	0.0000	1.0000	88.46%
1987	22.5	1,229,392	-	0.0000	1.0000	88.46%
1986	23.5	1,224,102	-	0.0000	1.0000	88.46%

**Yellow highlights indicate curve fitting runs where the results were concluded upon

*Std. errors are expressed as actual amounts, while normalized errors are percentages. There is little variation between the two.

Summary of Conclusions		
Scenario	**Best Curve**	**Indicated Error**
Extrapolated Growth (geometric)		
Std. Errors - 50% to 100% of Client Data	57 - R1	0.1716
Std. Errors - 100% to 150% of Client Data	71 - R1	0.0667
Std. Errors - 50% to 150% of Client Data	70 - R1	0.3851
Normalized Errors - 50% to 100% of Client Data	57 - R1	0.1927
Normalized Errors - 100% to 150% of Client Data	71 - R1	0.0787
Normalized Errors - 50% to 150% of Client Data	70 - R1	0.4369
Extrapolated Growth (linear)		
Std. Errors - 50% to 100% of Client Data	57 - R1	0.1713
Std. Errors - 50% to 150% of Client Data	69 - R1	0.3566
Normalized Errors - 50% to 100% of Client Data	57 - R1	0.1924
Normalized Errors - 50% to 150% of Client Data	69 - R1	0.4043
All Data Points (Zeroes Incl. after End)		
Std. Errors - 50% to 100% of Client Data	54 - R1	0.9918
Normalized Errors - All Data	76 - L0	0.5086
Normalized Errors - 50% to 100% of Client Data	**55 - R1**	0.1648
Non-Zero Data Points Only		
Std. Errors - All Data	76 - L0	0.4778
Std. Errors - 50% to 100% of Client Data	55 - R1	0.1468
Normalized Errors - All Data	76 - L0	0.5086
Normalized Errors - 50% to 100% of Client Data	**55 - R1**	0.1648
Ignore Multiple Years w/o Retirements		
Std. Errors - All Data	47 - S1	0.1509
Std. Errors - 50% to 100% of Client Data	56 - R1	0.0515
Normalized Errors - All Data	47 - S1	0.1640
Normalized Errors - 50% to 100% of Client Data	56 - R1	0.0576

Scenario Summary	
Scenario	**NUL Range**
Under Extrapolation Scenarios	57 - 71
Non Extrapolation Scenarios	47 - 76
Conclusions	
Best Scenario	**Best Curve**
Non Extrapolation	**55 - R1**

Selected Curve Statistical Comparison						
Age	Actual Data	55 - R1 Curve	Error	Normalized Error	Total Error	Notes
0	**1.0000**	**1.0000**			**0.1648**	Seleted Last 50% of client data for curve fitting
1	**1.0000**	**0.9974**				
2	**1.0000**	**0.9921**				
3	**1.0000**	**0.9867**				
4	**1.0000**	**0.9812**				
5	**0.9995**	**0.9755**				
6	**0.9995**	**0.9726**				
7	**0.9988**	**0.9666**				
8	**0.9988**	**0.9606**				
9	**0.9988**	**0.9544**				
10	**0.9986**	**0.9480**				
11	**0.9942**	**0.9415**				
12	**0.9024**	**0.9382**				
13	**0.9024**	**0.9315**				
14	**0.9024**	**0.9246**	0.0223	0.0247		
15	**0.9015**	**0.9177**	0.0162	0.0179		
16	**0.9015**	**0.9105**	0.0090	0.0100		
17	**0.9015**	**0.9069**	0.0054	0.0060		
18	**0.8846**	**0.8996**	0.0150	0.0170		
19	**0.8846**	**0.8921**	0.0075	0.0085		
20	**0.8846**	**0.8845**	0.0001	0.0001		
21	**0.8846**	**0.8768**	0.0078	0.0088		
22	**0.8846**	**0.8689**	0.0157	0.0178		
23	**0.8846**	**0.8648**	0.0198	0.0223		
24	**0.8846**	**0.8567**	0.0279	0.0316		
25	**n/a**	**0.8483**				
26	**n/a**	**0.8398**				
27	**n/a**	**0.8311**				
28	**n/a**	**0.8267**				
29	**n/a**	**0.8176**				
30	**n/a**	**0.8084**				
31	**n/a**	**0.7990**				
32	**n/a**	**0.7893**				
33	**n/a**	**0.7794**				
34	**n/a**	**0.7743**				
35	**n/a**	**0.7641**				
36	**n/a**	**0.7536**				
37	**n/a**	**0.7428**				
38	**n/a**	**0.7318**				
39	**n/a**	**0.7262**				
40	**n/a**	**0.7148**				
41	**n/a**	**0.7031**				
42	**n/a**	**0.6912**				
43	**n/a**	**0.6790**				
44	**n/a**	**0.6665**				
45	**n/a**	**0.6602**				
46	**n/a**	**0.6474**				
47	**n/a**	**0.6343**				
48	**n/a**	**0.6210**				
49	**n/a**	**0.6074**				
50	**n/a**	**0.6006**				
51	**n/a**	**0.5867**				
52	**n/a**	**0.5725**				
53	**n/a**	**0.5582**				
54	**n/a**	**0.5437**				
55	**n/a**	**0.5290**				
56	**n/a**	**0.5215**				
57	**n/a**	**0.5066**				
58	**n/a**	**0.4914**				
59	**n/a**	**0.4762**				
60	**n/a**	**0.4608**				
61	**n/a**	**0.4531**				
62	**n/a**	**0.4376**				
63	**n/a**	**0.4220**				
64	**n/a**	**0.4064**				
65	**n/a**	**0.3907**				
66	**n/a**	**0.3750**				
67	**n/a**	**0.3672**				
68	**n/a**	**0.3515**				
69	**n/a**	**0.3359**				
70	**n/a**	**0.3204**				
71	**n/a**	**0.3050**				
72	**n/a**	**0.2973**				
73	**n/a**	**0.2821**				
74	**n/a**	**0.2670**				

Selected Curve Statistical Comparison						
Age	Actual Data	55 - R1 Curve	Error	Normalized Error	Total Error	Notes
75	n/a	0.2522				
76	n/a	0.2375				
77	n/a	0.2231				
78	n/a	0.2160				
79	n/a	0.2020				
80	n/a	0.1883				
81	n/a	0.1749				
82	n/a	0.1619				
83	n/a	0.1556				
84	n/a	0.1432				
85	n/a	0.1312				
86	n/a	0.1196				
87	n/a	0.1086				
88	n/a	0.0980				
89	n/a	0.0929				
90	n/a	0.0831				
91	n/a	0.0739				
92	n/a	0.0652				
93	n/a	0.0570				
94	n/a	0.0532				
95	n/a	0.0459				
96	n/a	0.0392				
97	n/a	0.0331				
98	n/a	0.0277				
99	n/a	0.0227				
100	n/a	0.0205				
101	n/a	0.0164				
102	n/a	0.0129				
103	n/a	0.0099				
104	n/a	0.0073				
105	n/a	0.0061				
106	n/a	0.0041				
107	n/a	0.0024				
108	n/a	0.0012				
109	n/a	0.0004				
110	n/a	0.0000				
111	n/a	0.0000				
112	n/a	0.0000				
113	n/a	0.0000				
114	n/a	0.0000				
115	n/a	0.0000				
116	n/a	0.0000				
117	n/a	0.0000				
118	n/a	0.0000				
119	n/a	0.0000				
120	n/a	0.0000				
121	n/a	0.0000				
122	n/a	0.0000				
123	n/a	0.0000				
124	n/a	0.0000				
125	n/a	0.0000				
126	n/a	0.0000				
127	n/a	0.0000				
128	n/a	0.0000				
129	n/a	0.0000				
130	n/a	0.0000				
131	n/a	0.0000				
132	n/a	0.0000				
133	n/a	0.0000				
134	n/a	0.0000				
135	n/a	0.0000				
136	n/a	0.0000				
137	n/a	0.0000				
138	n/a	0.0000				
139	n/a	0.0000				
140	n/a	0.0000				
141	n/a	0.0000				
142	n/a	0.0000				
143	n/a	0.0000				
144	n/a	0.0000				
145	n/a	0.0000				
146	n/a	0.0000				
147	n/a	0.0000				
148	n/a	0.0000				
149	n/a	0.0000				
150	n/a	0.0000				

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Information Gathering and Processing, Page 10-9, "The accounting history of additions, retirements, and balances is used to study service life experience and trends for various regulated power generation plant accounts. When the dates of the installation and retirements are known and appropriately complied, study procedures known as actuarial methods can be used. When such data are not available in a reliable form, techniques are available to simulate actual vintages of retired property. In this instance we were provided with information from a previous depreciation study as well as the additions and deletions from 2003 through year-end 2010 by management and were used as the basis of our depreciation study."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide the "history of additions, retirements, and balances" that were used to study the service life expectations and trends for each fixed asset account or specific property. For the historical data provided, please indicate whether the data is a gross addition, a retirement, a transfer, an adjustment, a beginning plant balance or an ending plant balance. If this information is different from the historical fixed asset sub-ledger, please provide a comparison between YEC's Fixed Asset Sub-ledger and the "history of additions, retirements, and balances."

b) Please provide the "previous depreciation study" referenced and the Method, Procedure and Technique that was used in that depreciation study. If the Method, Procedure and/or Technique has changed from the previous depreciation study to KPMG's filed depreciation study, please describe the change and reasons for change to KPMG's filed depreciation study.

c) If the Method, Procedure and/or Technique has changed in KPMG's filed depreciation study, please provide a revised Depreciation study using the previous Method, Procedure and Technique.

ANSWER:

(a)

Please see response to YECL-YECL-1-60(d).

(b)

Please refer to Attachment 1 to this response which provides the Depreciation Study undertaken by Gannett Fleming in 2004 to support the 2005 Required Revenues and Related Matters Application.

The Method, Procedure and/or Technique employed by KPMG was similar to the 2003 depreciation study. KPMG utilized a Qualitative Approach, specifically the Comparable Company Method, in addition to the quantitative approach when measuring average service lives. This method was used to benchmark or check the reasonableness found via the quantitative method.

(c)

The Method, Procedure, and Technique did not change from the previous study. In addition, KPMG also performed a Qualitative analysis of comparable companies.

TAB 11
DEPRECIATION STUDY

YUKON ENERGY CORPORATION

WHITEHORSE, YUKON

DEPRECIATION STUDY

CALCULATED ANNUAL
DEPRECIATION ACCRUAL RATES
RELATED TO ELECTRIC UTILITY PLANT
AS OF DECEMBER 31, 2003



Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania **Calgary, Alberta** **Valley Forge, Pennsylvania**

YUKON ENERGY CORPORATION
Whitehorse, Yukon

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES

RELATED TO ELECTRIC UTILITY PLANT

AS OF DECEMBER 31, 2003

GANNETT FLEMING, INC. – VALUATION AND RATE DIVISION



GANNETT FLEMING, INC.
Suite 277
200 Rivercrest Drive S.E.
Calgary, Alberta T2C 2X5

Office: (403) 257-5946
Fax: (403) 257-5947
www.gannettfleming.com

November 1, 2004

Yukon Energy Corporation
2 Miles Canyon Way
Whitehorse, Yukon Y1A 6S7

Attention Mr. Ed Mollard, Corporate Accountant

Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric utility plant in service of Yukon Energy Corporation, as of December 31, 2003. Our report presents a description of the methods used in the estimation of depreciation, the statistical analysis of service life, and the summary and detailed tabulations of annual and accrued depreciation.

The calculated annual depreciation accrual rates presented in the report are related to the utility plant in service as of December 31, 2003. The depreciation rates are based on the straight line average service life group procedures, including a provision to true-up the depreciation reserve where a variance from the calculated depreciation exists.

We gratefully acknowledge the assistance of Yukon Energy Corporation personnel in the completion of this study.

Respectfully submitted,

GANNETT FLEMING, INC.

LARRY E. KENNEDY
Director, Canadian Operations
Valuation and Rates Division

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I-1 PART I. INTRODUCTION AND RECOMMENDATIONS

YUKON ENERGY CORPORATION

DEPRECIATION STUDY
CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES
RELATED TO ELECTRIC UTILITY PLANT AS OF DECEMBER 31, 2003

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation and net salvage study for Yukon Energy Corporation ("Company"). The purpose of the study was to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of electric utlity plant as of December 31, 2003. The depreciation and net salvage accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation.

Part I, Introduction, contains statements with respect to the scope of the report. Part II, Methods Used in the Estimation of Depreciation, presents the methods used in the estimation of average service lives, survivor curves and net salvage percents and in the calculation of depreciation. Part III, Results of Study, presents a summary of annual and accrued depreciation and net salvage requirements, the statistical analyses of service life, and the detailed tabulations of annual and accrued depreciation.

BASES OF THE STUDY

The annual and accrued depreciation were calculated by the straight line method using the average service life procedure applied on a whole life basis. The depreciation calculations were based on the attained ages of the estimated service lives. Net salvage requirements and annual accrual were based on the estimated net salvage. For both the

depreciation and net salvage accrual rates and reserve requirements, the variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of the assets.

An approach used by an increasing number of utilities in which general plant is amortized over the period during which it renders most of its service value was used in this study for certain general plant accounts. The amortization periods in this concept are longer than the initial period of highest and best use, but less than the total possible period during which the assets are used. The use of amortization rather than depreciation also avoids the need to prepare costly inventories of equipment in order to determine retirements inasmuch as the equipment is retired from the books when fully amortized. For general plant structures and equipment such as Survey Costs Land, Structures and Improvements (Hydro), Building and Improvements, Communication Site Towers, Communication Site Fences & Communications Equipment, standard depreciation accounting using the total service life is more appropriate inasmuch as the assets render service on a more uniform basis.

ESTIMATION OF SERVICE LIFE

The service life estimates were based on judgment that incorporated analyses of available historical data, a review of policies and outlook with management, a general knowledge of the electric utility industry, and comparisons of the service life estimates from studies of other electric utilities. Explanations of the methods used in the analysis of service life and the factors considered in the estimation of life characteristics for several major property groups are presented in Part II, Methods Used in the Estimation of Depreciation. Statistical support for the estimates is set forth in Part III, Results of Study.

The data analyzed for the purpose of estimating survivor characteristics were compiled from the property records of Yukon Energy Corporation. These data included plant additions, retirements, sales, transfers, and adjustments through December 31, 2003. The retirement rate method was used for the analysis of the retirement activity related to the depreciable properties of the Company. Each retirement rate analysis resulted in a life table which, when plotted, formed an original survivor curve. The original survivor curve as plotted from the life table represents the average pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the complete service life characteristics of the property group, interpretation of these original curves is required in order to use them as a valid consideration in the process of service life estimation. The Iowa type curves were used for these interpretations.

The survivor curve estimates for amortizable general plant consist of the selected amortization period and a square survivor curve. The selected amortization period was based on judgment which incorporated a consideration of the period during which the assets will render most of their service, and the amortization period and service lives used by other electrical utilities. The square survivor curve indicates that there will be no dispersion of retirement inasmuch as all assets in the group will be retired at the end of the amortization period.

ESTIMATION OF NET SALVAGE

The net salvage estimates for depreciable and amortizable property were based primarily on the judgment of Gannett Fleming that incorporated analyses of available historical data, a review of policies and outlook with management, a general knowledge of

the electric utility industry, and comparisons of the net salvage estimates from studies of other electric utilities. The estimates of net salvage are expressed as the average net salvage percent of the investment to be incurred or recovered upon its retirement. Separate calculations of the annual net salvage accrual rate have been developed in this report.

CALCULATION OF DEPRECIATION

The annual and accrued depreciation were calculated by the straight-line method using the average service life procedure. The calculations were based on original costs and attained ages as of December 31, 2003.

There are primarily two different approaches used by utilities in Canada and the United States in calculating depreciation, the equal life group procedure and the average service life procedure. Both procedures have been approved and adopted by regulatory authorities across North America. Although, in the opinion of Gannett Fleming, the equal life procedure is superior to the average service life procedure in matching depreciation expense with the loss of service value, the average life procedure is also a widely accepted method. The management of Yukon Energy directed Gannett Fleming to calculate annual and accrued depreciation using the average service life procedure in order to ensure toll stability.

Gannett Fleming agrees that toll stability is an overall rate making objective that needs to be considered in the development of appropriate depreciation policies. As such, Gannett Fleming accepts the decision of Yukon Energy Corporation to convert to the average service life procedure in the calculation of the depreciation rates. However, Gannett Fleming has also advised Yukon Energy that it should reconsider the use of the equal life group procedure in future depreciation studies.

The calculated annual depreciation and net salvage amounts are determined on a whole life basis. That is, use of the annual amount from age zero to the maximum age will result in complete capital recovery assuming the life and net salvage forecasts are realized. However, the calculated rates have not been used since the current plant was placed in service and there will be variations from the life and net salvage forecasts.

In order to adjust for past and future variances, a true-up procedure is proposed in which the difference between the calculated accrued depreciation and the book accumulated provision for depreciation is amortized over the composite remaining life of the asset group. In the circumstances of the computer hardware and software accounts, the differences have been completely amortized in 2003.

Explanations of the calculation of annual and accrued depreciation are presented in Part II, Methods Used in the Estimation of Depreciation. Summary and detailed tabulations of depreciation are set forth in Part III, Results of Study.

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

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PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current repairs or covered by insurance.

Depreciation as used in accounting is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual depreciation based on the straight line method requires the estimation of average life and salvage. These subjects are discussed in the sections that follow.

LIFE ESTIMATION

Average Service Life. The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units that survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

Survivor Curves. The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be geometrically calculated. The average life is obtained by calculating the area under the survivor curve, from age zero to maximum age, and dividing this area by the ordinate at age zero, which is 100%. The average remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the attained age to maximum age, and dividing this area by the percent surviving at the attained age.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves are those in which the greatest frequency of retirement occurs at average service life. The right moded curves are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numerical subscripts represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which

industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[1] These type curves have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis. The estimates of the appropriate survivor curves for most of the significant depreciable property groups were based in part upon calculated survivor curves that incorporated plant retirement experience through 2003. The retirement rate method was used for the analysis of the retirement activity related to the property groups of Yukon Energy Corporation, except for the four groups for which amortization accounting is proposed. The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired and is explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[4] "Engineering Valuation and Depreciation,"[5] and "Depreciation

[1]Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[2]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[3]Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

[4]Winfrey, Robley, Supra Note 1.

[5]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.

Systems."[6] Each retirement rate analysis resulted in a table which, when plotted, formed an original survivor curve. Each original survivor curve as plotted from the life table represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa type curves were used in these interpretations.

Survivor Curve Judgments. The survivor curve estimates were based on judgment that considered a number of factors. The primary factors were the statistical analyses of data; current policies and outlook as determined during conversations with management; and survivor curve estimates from other companies.

Account 140003.205 – Hydro Plant – Resevoirs, Dams, and Waterways represents 41 percent of the depreciable plant studied. The retirements and other plant transactions, for the period 1952 through 2003 were analyzed by the retirement rate method. The original survivor curve as plotted on III-17 provides a statistical indication of the retirement patterns to date for this account. Typical service lives for Resevoirs, Dams, and Waterways range widely. The Iowa 50-R4 is, in the view of Gannett Fleming, the appropriate representation of life characteristics of this account and is a reasonable interpretation of the limited historical data and within the range of lives used in the industry and consistent with management expectations.

Account 140006.710 – Main Transmission – Substation Equipment, represents 8 percent of the depreciable plant studied. Historical retirements, additions and other plant

[6]Wolf, Frank and W. Chester Fitch. Depreciation Systems. Iowa State University Press, 1994.

transactions for the period 1960 through 2003 were analyzed by the retirement rate method. The original survivor curve as plotted on page III-51 indicates a moderate level of retirement at age 7.5 years. The previously approved estimate for this account was the Iowa 40-R3. The Iowa 40–R2.5 survivor curve, selected in this study to represent the life characteristics of this account is a reasonable interpretation of the historical data and within the range of lives used in the industry and consistent with management expectations.

For Account 140004.500 – Diesel Production – Generating Equipment and Prime, representing 5 percent of depreciable plant, historical retirements, additions, and other plant transactions for the period 1971 to 2003 were analyzed. The original survivor curve as plotted on page III-33 indicates virtually no retirement activity. The Iowa 30-R2 survivor curve, selected in this study to represent the life characteristics of this account is a reasonable interpretation of the limited historical data and within the range of lives used in the industry and consistent with management expectations. The previously approved estimate for this account was the Iowa 30-S0.5

The survivor curve estimates for the remaining depreciable accounts were based on similar considerations of historical analyses and management outlook for this company and other electric utility companies.

SALVAGE ESTIMATION

Given the limited retirement experience, the estimates of net salvage were based primarily on judgment. The net salvage estimates were based on considerations of several factors including the net salvage characteristics of other electric utility properties, knowledge of management's plans and operating practices, and previous net salvage

estimates used by the company. The estimates of salvage are expressed as percents of the cost of plant retired.

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

After the survivor curve and salvage are estimated, the annual depreciation accrual rate can be calculated. In the average service life procedure, the annual accrual rate is computed by the following equation:

$$Annual\ Accrual\ Rate, Percent = \frac{(100\% - Net\ Salvage, Percent)}{Average\ Service\ Life}.$$

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which will not be allocated to expense through future depreciation accruals, if current forecasts of life characteristics are used as a basis for straight line depreciation accounting.

The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account, based upon the attained age and the estimated survivor curve. The accrued depreciation ratios are calculated as follows:

$$Ratio = (1 - \frac{Average\,Remaining\,Life\,Expectancy}{Average\,Service\,Life})\,(1 - Net\ Salvage, Percent).$$

The application of these procedures is described for a single unit of property and a group of property units. Salvage is omitted from the description for ease of application.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1,000}{(4+6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1,000\,(1 - \frac{6}{10}) = \$400.$$

Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group.

In the average service life procedure, the rate of annual depreciation is based on the average life or average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life. In this procedure, the accrued depreciation is based on the average service life of the group and the average remaining life of each vintage

within the group derived from the area under the survivor curve between the attained age of the vintage and the maximum age.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for four Building and Other Equipment accounts that represent numerous units of property, but a very small portion of depreciable electric plant in service. The accounts and their amortization periods are as follows:

Account	Amortization Period, Years
Account 140009.202 – Office Furniture & Equip.	20
Account 140009.320 – Computer Hardware	5
Account 140009.330 – Computer Software	5
Account 140009.505 – Tools and Instruments	20

For the purposes of calculating annual amortization amounts as at December 31, 2003, the book depreciation reserve for each plant account is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

MONITORING OF BOOK ACCUMULATED DEPRECIATION

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics and net salvage materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

It is recommended that Yukon Energy Corporation adopt the standard policy of the Alberta Energy and Utilities Board[7], where the recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation, for all

[7]Pages 31 through 37 of Decision No. E82131 of The Public Utilities Board for the Province of Alberta, dated June 21, 1982, in the matter of an application by TransAlta Utilities Corporation.

accounts excepting the computer hardware and software accounts, is based on an amortization period equal to the composite remaining life for each property group.

The composite remaining life for use in reducing accumulated depreciation variances is derived by compositing the individual equal life group remaining lives in accordance with the following equation:

$$Composite\ Remaining\ Life = \frac{\sum(\frac{Book\ Cost}{Life}\ x\ Remaining\ Life)}{\sum\frac{Book\ Cost}{Life}}.$$

The book costs and lives of the several equal life groups, which are summed in the foregoing equation, are defined by the estimated future survivor curve.

Inasmuch as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

$$Composite\ Remaining\ Life = \frac{\sum Whole\ Life\ Future\ Accruals}{\sum Whole\ Life\ Annual\ Accruals}$$

or

$$Composite\ \ Remaining\ \ Life = \frac{\sum Book\ \ Cost\ -\ Calc.\ \ Reserve}{\sum Whole\ \ Life\ \ Annual\ \ \ Accrual}.$$

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PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation and the annual provision for true-up (amortization of the accumulated depreciation variance), and the annual and accrued net salvage provisions for true-up are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line average service life group method of depreciation calculations based on estimates which reflect considerations of current historical evidence and expected future conditions.

The calculated accrued depreciation represents that portion of the depreciable cost which will not be allocated to future annual expense through depreciation accruals, if current forecasts of service life and salvage materialize and are used as a basis for straight line average service life depreciation accounting.

DESCRIPTION OF STATISTICAL SUPPORT

The results of the statistical analyses of service life are presented in the section beginning on page III-12.

The survivor curves for each account are presented in graphical form. The charts depict the smooth survivor curve and original survivor curve(s), when applicable, related to

each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of electric plant as of December 31, 2003, is presented in Tables 1, 1A, 2, and 2A. Table 1 sets forth the estimated survivor curve, the original cost, and the total calculated annual depreciation amount and rates related to electric plant as of December 31, 2003. Table 1A sets forth the estimated survivor curve, the estimated net salvage percentages, the original cost, and the total calculated annual depreciation amount and rates required for the collection of the net salvage amounts. Table 2 presents the calculation of the annual true-up provision required for the recovery of the original cost of the assets in each account. Table 2A presents the calculation of the annual true-up required for the recovery of the net salvage provision required for the retirement costs of plant.

The tables of the calculated annual and accrued depreciation are presented in account sequence in the section beginning on page III-97. The tables indicate the estimated survivor curve and salvage percent for the account and set forth for each installation year the original cost, the calculated annual accrual rate and amount, and the calculated accrued depreciation factor and amount.

YUKON ENERGY CORPORATION

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

DEPRECIATION EXPENSE

Account		Estimated Survivor	Estimated Net	Surviving Original Cost	Annual Accrual	
Number	Description	Curve	Salvage	at 12/31/2003	Amount	Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)= (6)/(5)
Land						
140002.003	Hydraulic Production	N/A	0	65,241.17	N/A	-
140002.004	Diesel Production	N/A	0	27,640.17	N/A	-
140002.006	Main Transmission Facilities	N/A	0	354,382.66	N/A	-
140002.009	General Plant	N/A	0	211,564.04	N/A	-
140002.106	Rights	50 - R2.5	0	78,433.78	1,569	2.00
	Total Land			737,261.82	1,569.00	
Hydro Plant						
140003.200	Structures and Improvements	40 - R3	(5)	9,026,258.27	225,656	2.50
140003.205	Reservoirs, Dams, and Waterways	50 - R4	(10)	87,847,100.94	1,756,942	2.00
140003.506	Waterwheels,Turbines & Generation	65 - R3	(10)	7,815,993.10	120,366	1.54
140003.600	Accessory Electric Equipment	45 - R3	(10)	5,670,864.32	125,893	2.22
140003.700	Misc Power Plant Equipment	30 - R2	(10)	1,433,153.61	47,724	3.33
	Total Hydro Plant			111,793,370.24	2,276,581.50	
Diesel Production						
140004.200	Structures and Improvements	40 - R2.5	(5)	1,529,107.51	38,228	2.50
140004.201	Buildings and Improvements	40 - R2.5	(5)	135,674.00	3,392	2.50
140004.403	Fuel Holders, Products, and ACC	25 - R2	(10)	937,013.89	37,481	4.00
140004.500	Generating Equipment and Prime	30 - R2	(5)	11,065,007.88	368,465	3.33
140004.600	Accessory Electric Equipment	45 - R3	(10)	2,667,231.79	59,213	2.22
140004.700	Misc Power Plant Equipment	30 - R2	(10)	1,071,098.95	35,668	3.33
	Total Diesel Production			17,405,134.02	542,445.04	
Wind Turbine						
140005.400	Wind Turbine	30 - S2	(5)	3,146,746.00	104,787	3.33
	Total Wind Turbine			3,146,746.00	104,786.64	
Main Transmission Facilities						
140006.300	Poles and Fixtures	50 - R3	(35)	19,000,436.70	380,009	2.00
140006.304	Brushing	50 - R3	0	5,842,648.08	116,853	2.00
140006.305	Survey Costs	50 - R2.5	0	1,877,251.94	37,545	2.00
140006.402	Overhead Conductors / Poles	50 - R3	(15)	7,614,999.30	152,300	2.00
140006.404	Overhead Conductors / Towers	50 - R3	(20)	277,975.00	5,560	2.00
140006.710	Substation Equipment	40 -R2.5	(15)	17,047,609.25	426,190	2.50
140006.720	Substation Buildings	40 - R2	(10)	32,750.00	819	2.50
140006.730	Substation Fences	20 - R4	(5)	6,928.00	346	5.00
	Total Main Transmission Facilities			51,700,598.27	1,119,621.64	
Sub Transmission Lines						
140007.300	Poles and Fixtures	45- R3	(30)	3,596,433.09	79,841	2.22
140007.401	Overhead Conductors	45 - R3	(30)	981,146.00	21,781	2.22
140007.405	Underground Conductors / Conduit	45 - S3	(10)	83,872.00	1,862	2.22
	Total Sub Transmission Lines			4,661,451.09	103,484.23	
Distribution System						
140008.300	Poles and Fixtures	35 - R2	(30)	1,748,922.18	50,019	2.86
140008.304	Brushing	50 - R2	0	41,938.00	839	2.00
140008.410	Overhead Costs	40 - R2	0	1,516,727.00	37,918	2.50
140008.510	Underground Services	40 - R2.5	(5)	6,379.00	159	2.50

YUKON ENERGY CORPORATION

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

DEPRECIATION EXPENSE

Account Number	Account Description	Estimated Survivor Curve	Estimated Net Salvage	Surviving Original Cost at 12/31/2003	Annual Accrual Amount	Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)= (6)/(5)
140008.550	Wind Monitoring Equipment	25 - R2	(5)	101,249.47	4,050	4.00
140008.610	Meters	30 - R2	0	177,573.00	5,913	3.33
140008.620	Meter Equipment	30 - R2	0	85,491.00	2,847	3.33
140008.710	Substation Equipment	40 - R2	(5)	520,230.94	13,006	2.50
140008.720	Substation Buildings	45 - R2	(5)	58,941.00	1,308	2.22
140008.815	Street Lights	40 - R2	(15)	198,801.49	4,970	2.50
140008.905	Line Transformers	40 - R2.5	0	2,878,257.97	71,956	2.50
140008.961	Sentinel Lights	30 - L2	(5)	29,756.00	991	3.33
	Total Distribution System			7,364,267.05	193,976.90	
Building and Other Equipment						
140009.110	Survey Costs Land	50 - R2	0	4,321.00	86	2.00
140009.200	Structures and Improvements (Hydro)	40 - R2.5	(15)	356,065.10	8,902	2.50
140009.201	Building and Improvements	40 - R2.5	(5)	6,331,246.55	158,281	2.50
140009.202	Office Furniture and Equipment	20 - SQ	0	1,308,199.79	65,410	5.00
140009.210	Communication Site Towers	30 - R2	(15)	19,297.00	643	3.33
140009.220	Communication Site Fences	20 - R4	0	36,663.00	1,833	5.00
140009.320	Computer Hardware	5- SQ	0	942,047.01	153,459	16.29
140009.330	Computer Software	5 - SQ	0	1,199,559.11	239,912	20.00
140009.505	Tool and Instruments	20 - SQ	0	861,433.88	43,072	5.00
140009.605	Communication Equipment	20 - L4	0	1,649,349.36	82,467	5.00
140009.810	Company Owned Houses / Land	30 - R3	15	63,539.18	1,798	2.83
140009.820	Company Owned Houses	30 - R3	15	1,056,018.00	29,891	2.83
	Total Building & Other Equipment			13,827,738.98	785,753.92	
Transportation						
140014.411	Utility Vehicles	7 - L2	20	143,577.22	16,414	11.43
140014.412	Sedans and Stationwagons	7 - L2	20	119,184.00	13,625	11.43
140014.430	Pole Trailers > 10,000 Lbs	25 - R1.5	20	18,156.00	581	3.20
140014.440	Trucks 3/4 to 2 Ton	10 - R2	20	924,342.64	73,947	8.00
140014.470	Trucks > 3 Ton	20 - R3	20	151,100.00	6,044	4.00
	Total Transportation			1,356,359.86	110,611.26	
	Total Utility Plant Reviewed			211,992,927.33	5,238,830.13	
Account Not Reviewed						
140008.305	Survey Costs			(2,824.91)		
	Total Utility Plant in Service			211,990,102	5,238,830	

YUKON ENERGY CORPORATION

TABLE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

NET SALVAGE REQUIREMENTS

Account Number	Account Description	Estimated Survivor Curve	Estimated Net Salvage	Surviving Original Cost at 12/31/2003	Annual Accrual Amount	Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)= (6)/(5)
Land						
140002.003	Hydraulic Production	N/A	0	65,241.17	N/A	-
140002.004	Diesel Production	N/A	0	27,640.17	N/A	-
140002.006	Main Transmission Facilities	N/A	0	354,382.66	N/A	-
140002.009	General Plant	N/A	0	211,564.04	N/A	-
140002.106	Rights	50 - R2.5	0	78,433.78	-	0.00
	Total Land			737,261.82	-	
Hydro Plant						
140003.200	Structures and Improvements	40 - R3	(5)	9,026,258.27	11,283	0.12
140003.205	Reservoirs, Dams, and Waterways	50 - R4	(10)	87,847,100.94	175,694	0.20
140003.506	Waterwheels,Turbines & Generation	65 - R3	(10)	7,815,993.10	12,037	0.15
140003.600	Accessory Electric Equipment	45 - R3	(10)	5,670,864.32	12,589	0.22
140003.700	Misc Power Plant Equipment	30 - R2	(10)	1,433,153.61	4,772	0.33
	Total Hydro Plant			111,793,370.24	216,375.37	
Diesel Production						
140004.200	Structures and Improvements	40 - R2.5	(5)	1,529,107.51	1,911	0.13
140004.201	Buildings and Improvements	40 - R2.5	(5)	135,674.00	170	0.12
140004.403	Fuel Holders, Products, and ACC	25 - R2	(10)	937,013.89	3,748	0.40
140004.500	Generating Equipment and Prime	30 - R2	(5)	11,065,007.88	18,423	0.17
140004.600	Accessory Electric Equipment	45 - R3	(10)	2,667,231.79	5,921	0.22
140004.700	Misc Power Plant Equipment	30 - R2	(10)	1,071,098.95	3,567	0.33
	Total Diesel Production			17,405,134.02	33,740.30	
Wind Turbine						
140005.400	Wind Turbine	30 - S2	(5)	3,146,746.00	5,239	0.17
	Total Wind Turbine			3,146,746.00	5,239.33	
Main Transmission Facilities						
140006.300	Poles and Fixtures	50 - R3	(35)	19,000,436.70	133,003	0.70
140006.304	Brushing	50 - R3	0	5,842,648.08	-	0.00
140006.305	Survey Costs	50 - R2.5	0	1,877,251.94	-	0.00
140006.402	Overhead Conductors / Poles	50 - R3	(15)	7,614,999.30	22,845	0.30
140006.404	Overhead Conductors / Towers	50 - R3	(20)	277,975.00	1,390	0.50
140006.710	Substation Equipment	40 -R2.5	(15)	17,047,609.25	63,929	0.38
140006.720	Substation Buildings	40 - R2	(10)	32,750.00	82	0.25
140006.730	Substation Fences	20 - R4	(5)	6,928.00	17	0.25
	Total Main Transmission Facilities			51,700,598.27	221,265.68	
Sub Transmission Lines						
140007.300	Poles and Fixtures	45- R3	(30)	3,596,433.09	23,952	0.67
140007.401	Overhead Conductors	45 - R3	(30)	981,146.00	6,534	0.67
140007.405	Underground Conductors / Conduit	45 - S3	(10)	83,872.00	186	0.22
	Total Sub Transmission Lines			4,661,451.09	30,672.92	
Distribution System						
140008.300	Poles and Fixtures	35 - R2	(30)	1,748,922.18	15,006	0.86
140008.304	Brushing	50 - R2	0	41,938.00	-	0.00
140008.410	Overhead Costs	40 - R2	0	1,516,727.00	-	0.00
140008.510	Underground Services	40 - R2.5	(5)	6,379.00	8	0.12

YUKON ENERGY CORPORATION

TABLE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

NET SALVAGE REQUIREMENTS

Account Number	Account Description	Estimated Survivor Curve	Estimated Net Salvage	Surviving Original Cost at 12/31/2003	Annual Accrual Amount	Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)= (6)/(5)
140008.550	Wind Monitoring Equipment	25 - R2	(5)	101,249.47	203	0.20
140008.610	Meters	30 - R2	0	177,573.00	-	0.00
140008.620	Meter Equipment	30 - R2	0	85,491.00	-	0.00
140008.710	Substation Equipment	40 - R2	(5)	520,230.94	650	0.13
140008.720	Substation Buildings	45 - R2	(5)	58,941.00	65	0.11
140008.815	Street Lights	40 - R2	(15)	198,801.49	746	0.38
140008.905	Line Transformers	40 - R2.5	0	2,878,257.97	-	0.00
140008.961	Sentinel Lights	30 - L2	(5)	29,756.00	50	0.17
	Total Distribution System			7,364,267.05	16,726.98	
Building and Other Equipment						
140009.110	Survey Costs Land	50 - R2	0	4,321.00	-	0.00
140009.200	Structures and Improvements (Hydro)	40 - R2.5	(15)	356,065.10	1,335	0.38
140009.201	Building and Improvements	40 - R2.5	(5)	6,331,246.55	7,914	0.13
140009.202	Office Furniture and Equipment	20 - SQ	0	1,308,199.79	-	0.00
140009.210	Communication Site Towers	30 - R2	(15)	19,297.00	96	0.50
140009.220	Communication Site Fences	20 - R4	0	36,663.00	-	0.00
140009.320	Computer Hardware	5- SQ	0	942,047.01	-	0.00
140009.330	Computer Software	5 - SQ	0	1,199,559.11	-	0.00
140009.505	Tool and Instruments	20 - SQ	0	861,433.88	-	0.00
140009.605	Communication Equipment	20 - L4	0	1,649,349.36	-	0.00
	Total Building & Other Equipment			12,708,181.80	9,345.70	
	Total Utility Plant Reviewed			209,517,010.29	533,366.28	
Account Not Reviewed						
140008.305	Survey Costs			(2,824.91)		
	Total Utility Plant in Service			209,514,185	533,366	0.25

YUKON ENERGY CORPORATION

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP RELATED TO ESTIMATED ORIGINAL COST AT DECEMBER 31, 2003

ACCUMULATED DEPRECIATION

Account Number	Account Description	Surviving Original Cost 12/31/2003	Calculated Accrued Depreciation	Book Accumulated Depreciation	Accumulated Depreciation Variance	Probable Remaining Life	Annual Provision for True-Up
(1)	(2)	(3)	(4)	(5)	(6) = (4)-(3)	(7)	(8)=(6)/(7)
Land							
140002.003	Hydraulic Production	65,241.17	-		-	N/A	-
140002.004	Diesel Production	27,640.17	-	-	-	N/A	-
140002.006	Main Transmission Facilities	354,382.66	-	-	-	N/A	-
140002.009	General Plant	211,564.04	-	-	-	N/A	-
140002.106	Rights	78,433.78	2,731	2,032	699	48.2	15
	Total Land	737,261.82	2,731	2,032	699		15
Hydro Plant							
140003.200	Structures and Improvements	9,026,258.27	2,033,125	1,634,980	398,145	30.7	12,969
140003.205	Reservoirs, Dams, and Waterways	87,847,100.94	27,477,621	26,246,238	1,231,383	34.3	35,900
140003.506	Waterwheels,Turbines & Generation	7,815,993.10	583,389	728,388	(144,999)	60.2	(2,409)
140003.600	Accessory Electric Equipment	5,670,864.32	643,104	577,162	65,942	39.8	1,657
140003.700	Misc Power Plant Equipment	1,433,153.61	235,899	152,655	83,244	24.9	3,343
	Total Hydro Plant	111,793,370.24	30,973,138	29,339,423	1,633,715		51,461
Diesel Production							
140004.200	Structures and Improvements	1,529,107.51	355,965	621,507	(265,542)	31.4	(8,457)
140004.201	Buildings and Improvements	135,674.00	7,964	12,150	(4,186)	37.7	(111)
140004.403	Fuel Holders, Products, and ACC	937,013.89	353,775	499,001	(145,226)	15.9	(9,134)
140004.500	Generating Equipment and Prime	11,065,007.88	3,524,801	5,505,856	(1,981,055)	20.7	(95,703)
140004.600	Accessory Electric Equipment	2,667,231.79	425,271	931,318	(506,047)	39.3	(12,877)
140004.700	Misc Power Plant Equipment	1,071,098.95	371,296	751,983	(380,687)	21.8	(17,463)
	Total Diesel Production	17,405,134.02	5,039,072	8,321,815	(3,282,743)		(143,744)
Wind Turbine							
140005.400	Wind Turbine	3,146,746.00	434,507	692,480	(257,973)	26.2	(9,846)
	Total Wind Turbine	3,146,746.00	434,507	692,480	(257,973)		(9,846)
Main Transmission Facilities							
140006.300	Poles and Fixtures	19,000,436.70	1,820,771	3,342,805	(1,522,034)	45.7	(33,305)
140006.304	Brushing	5,842,648.08	119,993	71,537	48,456	48.9	991
140006.305	Survey Costs	1,877,251.94	17,884	79,571	(61,687)	49.5	(1,246)
140006.402	Overhead Conductors / Poles	7,614,999.30	252,640	303,607	(50,967)	48.4	(1,053)
140006.404	Overhead Conductors / Towers	277,975.00	25,590	32,657	(7,067)	45.4	(156)
140006.710	Substation Equipment	17,047,609.25	3,127,303	3,916,383	(789,080)	32.8	(24,057)
140006.720	Substation Buildings	32,750.00	1,841	2,337	(496)	37.8	(13)
140006.730	Substation Fences	6,928.00	1,552	783	769	15.5	50
	Total Main Transmission Facilities	51,700,598.27	5,367,574	7,749,680	(2,382,106)		(58,790)
Sub Transmission Lines							
140007.300	Poles and Fixtures	3,596,433.09	1,034,075	1,795,973	(761,898)	32.3	(23,588)
140007.401	Overhead Conductors	981,146.00	216,946	326,153	(109,207)	35.1	(3,111)
140007.405	Underground Conductors / Conduit	83,872.00	19,832	21,022	(1,190)	34.3	(35)
	Total Sub Transmission Lines	4,661,451.09	1,270,853	2,143,148	(872,295)		(26,734)
Distribution System							
140008.300	Poles and Fixtures	1,748,922.18	80,339	94,968	(14,629)	33.4	(438)
140008.304	Brushing	41,938.00	3,791	7,026	(3,235)	45.5	(71)
140008.410	Overhead Costs	1,516,727.00	158,532	239,070	(80,538)	35.9	(2,243)
140008.510	Underground Services	6,379.00	449	653	(204)	37.3	(5)
140008.550	Wind Monitoring Equipment	101,249.47	4,577	8,549	(3,972)	23.9	(166)
140008.610	Meters	177,573.00	50,271	73,274	(23,003)	21.8	(1,055)
140008.620	Meter Equipment	85,491.00	25,517	31,073	(5,556)	21.1	(263)
140008.710	Substation Equipment	520,230.94	104,679	155,540	(50,861)	32.3	(1,575)
140008.720	Substation Buildings	58,941.00	15,128	35,400	(20,272)	33.6	(603)
140008.815	Street Lights	198,801.49	41,213	139,640	(98,427)	35.0	(2,812)
140008.905	Line Transformers	2,878,257.97	643,897	1,203,974	(560,077)	31.6	(17,724)
140008.961	Sentinel Lights	29,756.00	11,036	23,979	(12,943)	18.9	(685)
	Total Distribution System	7,364,267.05	1,139,429	2,013,146	(873,717)		(27,642)
Building and Other Equipment							
140009.110	Survey Costs Land	4,321.00	575	1,176	(601)	43.1	(14)
140009.200	Structures and Improvements (Hydro)	356,065.10	16,406	19,455	(3,049)	38.2	(80)
140009.201	Building and Improvements	6,331,246.55	911,319	1,367,514	(456,195)	34.7	(13,147)
140009.202	Office Furniture and Equipment	1,308,199.79	357,925	480,913	(122,988)	15.6	(7,884)
140009.210	Communication Site Towers	19,297.00	1,441	2,556	(1,115)	27.8	(40)
140009.220	Communication Site Fences	36,663.00	2,750	2,424	326	18.5	18
140009.320	Computer Hardware	942,047.01	631,717	597,726	33,991	2.2	15,450
140009.330	Computer Software	1,199,559.11	706,545	714,417	(7,872)	2.1	(3,749)
140009.505	Tool and Instruments	861,433.88	304,910	461,544	(156,634)	16.7	(9,379)

YUKON ENERGY CORPORATION

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP RELATED TO ESTIMATED ORIGINAL COST AT DECEMBER 31, 2003

ACCUMULATED DEPRECIATION

Account Number	Account Description	Surviving Original Cost 12/31/2003	Calculated Accrued Depreciation	Book Accumulated Depreciation	Accumulated Depreciation Variance	Probable Remaining Life	Annual Provision for True-Up
(1)	(2)	(3)	(4)	(5)	(6) = (4)-(3)	(7)	(8)=(6)/(7)
140009.605	Communication Equipment	1,649,349.36	503,247	553,256	(50,009)	14.1	(3,547)
140009.810	Company Owned Houses / Land	63,539.18	7,862	-	7,862	24.8	317
140009.820	Company Owned Houses	1,056,018.00	236,967	21,972	214,995	25.9	8,301
	Total Building & Other Equipment	13,827,738.98	3,681,664	4,222,953	(541,289)		(13,753)
Transportation							
140014.411	Utility Vehicles	143,577.22	39,181	26,465	12,716	4.5	2,826
140014.412	Sedans and Stationwagons	119,184.00	52,985	46,825	6,160	3.1	1,987
140014.430	Pole Trailers > 10,000 Lbs	18,156.00	714	1,462	(748)	23.8	(31)
140014.440	Trucks 3/4 to 2 Ton	924,342.64	249,279	266,457	(17,178)	6.6	(2,603)
140014.470	Trucks > 3 Ton	151,100.00	14,747	27,138	(12,391)	17.6	(704)
	Total Transportation	1,356,359.86	356,906	368,347	(11,441)		1,475
	Total Utility Plant Reviewed	211,992,927.33	48,265,874.00	54,853,024.12	(6,587,150.12)		(227,558.86)
Account Not Reviewed							
140008.305	Survey Costs	(2,824.91)	-	(297)	297		
	Total Utility Plant in Service	211,990,102.42	48,265,874.00	54,852,727.12	(6,586,853.12)		(227,558.86)

YUKON ENERGY CORPORATION

TABLE 2A. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP RELATED TO ESTIMATED ORIGINAL COST AT DECEMBER 31, 2003

"SALVAGE"

Account Number	Account Description	Surviving Original Cost 12/31/2002	Calculated Accrued Depreciation	Book Accumulated Depreciation	Accumulated Salvage Variance	Probable Remaining Life	Annual Provision for True-Up
(1)	(2)	(3)	(4)	(5)	(6) = (4)-(3)	(7)	(8)=(6)/(7)
Land							
140002.003	Hydraulic Production	65,241.17	-	-	-	N/A	-
140002.004	Diesel Production	27,640.17	-	-	-	N/A	-
140002.006	Main Transmission Facilities	354,382.66	-	-	-	N/A	-
140002.009	General Plant	211,564.04	-	-	-	N/A	-
140002.106	Rights	78,433.78	-	-	-	48.2	-
	Total Land	737,261.82	-	-	-		-
Hydro Plant							
140003.200	Structures and Improvements	9,026,258.27	101,656	263,865	(162,209)	30.7	(5,284)
140003.205	Resevoirs, Dams, and Waterways	87,847,100.94	2,747,762	3,911,722	(1,163,960)	34.3	(33,935)
140003.506	Waterwheels,Turbines & Generation	7,815,993.10	58,339	(451,801)	510,140	60.2	8,474
140003.600	Accessory Electric Equipment	5,670,864.32	64,310	57,160	7,150	39.8	180
140003.700	Misc Power Plant Equipment	1,433,153.61	23,590	15,109	8,481	24.9	341
	Total Hydro Plant	111,793,370.24	2,995,657	3,796,055	(800,398)		(30,224)
Diesel Production							
140004.200	Structures and Improvements	1,529,107.51	17,798	22,840	(5,042)	31.4	(161)
140004.201	Buildings and Improvements	135,674.00	398	(879)	1,277	37.7	34
140004.403	Fuel Holders, Products, and ACC	937,013.89	35,378	22,787	12,592	15.9	792
140004.500	Generating Equipment and Prime	11,065,007.88	176,240	(57,549)	233,789	20.7	11,294
140004.600	Accessory Electric Equipment	2,667,231.79	42,527	59,751	(17,224)	39.3	(438)
140004.700	Misc Power Plant Equipment	1,071,098.95	37,130	35,101	2,029	21.8	93
	Total Diesel Production	17,405,134.02	309,471	82,052	227,419		11,614
Wind Turbine							
140005.400	Wind Turbine	3,146,746.00	21,725	65,899	(44,174)	26.2	(1,686)
	Total Wind Turbine	3,146,746.00	21,725	65,899	(44,174)		(1,686)
Main Transmission Facilities							
140006.300	Poles and Fixtures	19,000,436.70	637,270	1,096,650	(459,380)	45.7	(10,052)
140006.304	Brushing	5,842,648.08	-	64,295	(64,295)	48.9	(1,315)
140006.305	Survey Costs	1,877,251.94	-	(8,423)	8,423	49.5	170
140006.402	Overhead Conductors / Poles	7,614,999.30	37,896	36,077	1,819	48.4	38
140006.404	Overhead Conductors / Towers	277,975.00	6,398	10,263	(3,865)	45.4	(85)
140006.710	Substation Equipment	17,047,609.25	469,095	199,583	269,512	32.8	8,217
140006.720	Substation Buildings	32,750.00	184	8	176	37.8	5
140006.730	Substation Fences	6,928.00	78	39	39	15.5	3
	Total Main Transmission Facilities	51,700,598.27	1,150,921	1,398,493	(247,572)		(3,020)
Sub Transmission Lines							
140007.300	Poles and Fixtures	3,596,433.09	310,223	811,605	(501,382)	32.3	(15,523)
140007.401	Overhead Conductors	981,146.00	65,084	173,729	(108,645)	35.1	(3,095)
140007.405	Underground Conductors / Conduit	83,872.00	1,983	101	1,882	34.3	55
	Total Sub Transmission Lines	4,661,451.09	377,290	985,435	(608,145)		(18,563)
Distribution System							
140008.300	Poles and Fixtures	1,748,922.18	24,102	(88,393)	112,495	33.4	3,368
140008.304	Brushing	41,938.00	-	2,895	(2,895)	45.5	(64)
140008.410	Overhead Costs	1,516,727.00	-	5,166	(5,166)	35.9	(144)
140008.510	Underground Services	6,379.00	21	7	14	37.3	0
140008.550	Wind Monitoring Equipment	101,249.47	229	-	229	23.9	10
140008.610	Meters	177,573.00	-	510	(510)	21.8	(23)
140008.620	Meter Equipment	85,491.00	-	501	(501)	21.1	(24)
140008.710	Substation Equipment	520,230.94	5,234	3,721	1,513	32.3	47
140008.720	Substation Buildings	58,941.00	756	(16,416)	17,172	33.6	511
140008.815	Street Lights	198,801.49	6,182	(49,400)	55,582	35.0	1,588
140008.905	Line Transformers	2,878,257.97	-	59,879	(59,879)	31.6	(1,895)
140008.961	Sentinel Lights	29,756.00	552	(6,352)	6,904	18.9	365
	Total Distribution System	7,364,267.05	37,076	(87,884)	124,960		3,740
Building and Other Equipment							
140009.110	Survey Costs Land	4,321.00	-	42	(42)	43.1	(1)
140009.200	Structures and Improvements (Hydro)	356,065.10	2,461	(826)	3,287	38.2	86
140009.201	Building and Improvements	6,331,246.55	45,566	(188,033)	233,599	34.7	6,732
140009.202	Office Furniture and Equipment	1,308,199.79	-	(12,111)	12,111	15.6	776
140009.210	Communication Site Towers	19,297.00	216	(859)	1,075	27.8	39
140009.220	Communication Site Fences	36,663.00	-	(874)	874	18.5	47
140009.320	Computer Hardware	942,047.01	-	15,586	(15,586)	2.2	(7,085)
140009.330	Computer Software	1,199,559.11	-	-	-	2.1	-
140009.505	Tool and Instruments	861,433.88	-	1,959	(1,959)	16.7	(117)

YUKON ENERGY CORPORATION

TABLE 2A. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP RELATED TO ESTIMATED ORIGINAL COST AT DECEMBER 31, 2003

"SALVAGE"

Account Number	Account Description	Surviving Original Cost 12/31/2002	Calculated Accrued Depreciation	Book Accumulated Depreciation	Accumulated Salvage Variance	Probable Remaining Life	Annual Provision for True-Up
(1)	(2)	(3)	(4)	(5)	(6) = (4)-(3)	(7)	(8)=(6)/(7)
140009.605	Communication Equipment	1,649,349.36	-	(24,885)	24,885	14.1	1,765
	Total Building & Other Equipment	12,708,181.80	48,243	(210,002)	258,245		2,242
	Total Utility Plant Reviewed	209,517,010.29	4,940,383.00	6,030,047.49	(1,089,664.49)		(35,897.13)
Account Not Reviewed							
140008.305	Survey Costs	(2,824.91)	-	153	(153)		
	Total Utility Plant in Service	209,514,185.38	4,940,383.00	6,030,200.26	(1,089,817.26)		(35,897.13)

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Determination of Average Service Life Page 10-9, "The average service life of the facilities were developed using the retirement rate method as well as the comparable company method."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide the detailed calculations used to determine the "average service life of the facilities" that "were developed using the retirement rate method." Please provide all supporting computer printouts and logic utilized in the computer printouts.

ANSWER:

(a)

Please see response to YECL-YEC-1-60(d).

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Extrapolation Methods Page 10-9, "When limited data was available, methods of extrapolation were applied to derive an estimate of future retirement patterns, which were then utilized in the curve fitting process to identify the Iowa Curve the most appropriately reflected the survivor patterns of the subject asset group."**

PREAMBLE:

Tab 10 – Depreciation Study – Extrapolation Methods Page 10-9, "When limited data was available, methods of extrapolation were applied to derive an estimate of future retirement patterns, which were then utilized in the curve fitting process to identify the Iowa Curve the most appropriately reflected the survivor patterns of the subject asset group."

QUESTION:

a) Please provide the "methods of extrapolations" that were used for each applicable fixed asset account.

b) Please provide all authoritative sources that prescribe the "method of extrapolation" described.

c) Please provide a listing of other regulated companies who have used a similar methodology.

ANSWER:

(a)

Please see response to YECL-YEC-1-60 (d).

(b) and **(c)**

When the actual retirement data ends with a portion of the population surviving (greater than zero percent), it is called a stub survivor curve. Stub curves are generally what are analyzed during depreciation studies, since a portion of the assets under analysis are typically still in existence. Therefore, for comparative purposes, an extrapolation is performed to facilitate the curve fitting process. Extrapolation is implicit in the curve fitting process of survivor curves to actual data.

Extrapolation is a common component of depreciation studies and is mentioned in many publicly available studies such as: UGI Central Penn Gas, Inc. (Docket No. R-2010-2214415) and Application of Kentucky Utilities Company For an Adjustment of its Electric Rates (CASE NO. 2012-00221).

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Comparable Curve Fitting, Page 10-9, "In the event that ample data was unavailable to conduct curve fitting procedures, average service lives derived based on comparable asset grouping."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please list all fixed asset accounts where "ample data was unavailable to conduct curve fitting procedures" and reasons for the insufficient data.

ANSWER:

(a)

Please see response to YECL-YEC-1-60(b) for accounts where data was considered but was insufficient to facilitate the curve fitting process.

Asset accounts where data was available and a quantitative analysis was performed included:

- Account 140003-205 - Hydro Plant - Reservoirs, Dams and Waterways;
- Account 140003-506 - Hydro Plant - Waterwheels, Turbines & Generation;
- Account 140004-200 - Diesel Production - Structures and Improvements;
- Account 140006-300 - Main Transmission - Poles and Fixtures;
- Account 140006-710 - Main Transmission - Substation Equipment;
- Account 140008-905 – Distribution System – Line Transformers; and

- Account 140009-201 - Buildings and Other Equipment - Buildings and Improvements.

All other asset accounts were not analyzed utilizing a quantitative analysis.

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Qualitative Approach Page 10-10, "A similar occurrence arises when an asset group experiences a material change that is not directly related to the retirement of assets."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide and describe in detail those asset groups which experienced "a material change that is not directly related to the retirement of assets." Please provide what the material change is and why it is not considered reliable for curve fitting or average service life determination.

ANSWER:

(a)

Please see response to YECL-YEC-1-64(a).

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Comparable Companies Page 10-10, "The primary qualitative method utilized to measure average service life is the comparable company method. In applying this method, the average service lives applied for similar asset groups by other companies is relied upon."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide for each of the comparable companies identified, a comparison by fixed asset account of the selected Iowa Curve, Average Service Life, Net Salvage (or Gross Salvage and Cost of Retirement) to YEC.

b) Please provide for each of the comparable companies identified, the Depreciation Method, Procedure and Technique used by each company for their current Depreciation study.

ANSWER:

(a)

Please refer to pages 27-28 of the updated KPMG depreciation study report (YECL-YEC-1-55(a) Attachment 1). Information procured to conduct the comparable company method is public in nature and was used to benchmark the findings from the quantitative approach. Specific Iowa Curves used by the comparable companies were not identified, however KPMG relied upon public information regarding range of useful lives per asset class of several of the comparable companies.

(b)

Please see the complete narrative report provided as Attachment 1 to YECL-YEC-1-55(a). KPMG relied upon company actual data to calculate the results.

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Accumulated Depreciation Page 10-14, "To calculate accumulated depreciation, the surviving cost basis as at the Testing Date was apportioned over the age of each asset group on a straight-line basis."**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide the detailed calculations used to apportion accumulated depreciation over the age of each asset group.

ANSWER:

(a)

Please see Attachment 1 to this response.

As of December 31, 2010															
			Provided by Yukon Management							Depreciation Expense			Depreciation Add-Back		
Number	Description	KPMG Estimated Survivor Curve	Surviving Original Cost at 12/31/2010	Accumulated Depreciation	A/D Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accrued Depreciation	Accumulated Depreciation Variance	Annual Accrual Amount	Rate (%)	KPMG Probable Remaining Life [1]	Annual Provision for True-Up	Accounting Effective Age	KPMG Concluded Effective Age
Land															
n/a	Land	n/a	1,126,675	(13,369)	699	(87)	1,113,918	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Land			**1,126,675**	**(13,369)**	**699**	**(87)**	**1,113,918**	**-**	**-**	**-**			**-**		
Hydro Plant															
140003.200	Structures and Improvements	72 - R2	10,854,779	(3,558,901)	398,145	(77,806)	7,616,217	(2,261,412)	(977,149)	150,761	1.39	35	27,919	15	39
140003.205	Reservoirs, Dams, and Waterways	103 - R3	89,859,047	(39,320,006)	1,231,383	(215,442)	51,554,982	(20,172,923)	(18,131,142)	872,418	0.97	65	278,941	23	39
140003.506	Waterwheels,Turbines & Generation	85 - R3	10,431,950	(1,535,720)	27,655	11,344	8,935,229	(1,227,288)	(269,433)	122,729	1.18	47	5,733	10	39
140003.600	Accessory Electric Equipment	45 - R3	6,489,762	(1,301,774)	65,942	(9,942)	5,243,987	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140003.700	Misc Power Plant Equipment	30 - R2	2,542,719	(609,657)	83,244	(20,059)	1,996,247	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140003.730	Fencing	30 - R2	48,758	(5,999)			42,758	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Hydro Plant			**120,227,014**	**(46,332,057)**	**1,806,369**	**(311,906)**	**75,389,420**	**(23,661,624)**	**(19,377,725)**	**1,145,908**			**312,592**		
Diesel Production															
140004.200	Structures and Improvements	72 - R2	1,525,367	(593,353)	(219,959)	43,814	755,870	(336,646)	(432,852)	21,186	1.39	57	7,594	16	16
140004.201	Buildings and Improvements	55 - R1	307,094	(44,610)	(4,186)	666	258,964	(27,629)	(20,501)	5,584	1.82	50	410	5	5
140004.403	Fuel Holders, Products, and ACC	25 - R2	1,015,105	(623,699)	(122,114)	50,429	319,722	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140004.500	Generating Equipment and Prime	40 - R2	15,732,200	(6,322,968)	(1,672,846)	523,156	8,259,542	(6,740,580)	(732,079)	393,305	2.50	13	56,314	17	30
140004.508		n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n.a.	n/a	n/a
140004.600	Accessory Electric Equipment	45 - R3	4,278,353	(708,479)	(478,962)	72,911	3,163,823	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140004.700	Misc Power Plant Equipment	30 - R2	1,478,633	(397,778)	(371,646)	103,130	812,339	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Diesel Production			**24,336,753**	**(8,705,409)**	**(2,869,713)**	**794,107**	**13,799,285**	**(7,104,854)**	**(1,185,431)**	**420,074**			**64,318**		
Main Transmission Facilities															
140006.300	Poles and Fixtures	65 - R3	35,465,743	(4,941,581)	(1,517,669)	180,689	29,187,181	(4,910,641)	(1,367,921)	545,627	1.54	41	33,364	9	25
140006.304	Brushing	50 - R3	9,739,372	(1,130,197)	48,456	(5,815)	8,651,816	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.305	Survey Costs	50 - R2.5	2,787,405	(324,301)	(61,687)	7,403	2,408,819	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.402	Overhead Conductors / Poles	50 - R3	15,729,233	(1,865,191)	(45,903)	4,261	13,822,400	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.404	Overhead Conductors / Towers	50 - R3	277,975	(66,506)	(7,067)	848	205,250	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.710	Substation Equipment	54 - S0	21,342,570	(6,051,540)	(738,810)	94,989	14,647,209	(6,061,782)	(633,579)	395,233	1.85	34	18,635	15	21
140006.720	Substation Buildings	55 - R1	32,750	(7,756)	(496)	74	24,573	(5,955)	(2,223)	595	1.82	35	64	10	21
140006.730	Substation Fences	20 - R4	46,953	(8,829)	769	(230)	38,663	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Main Transmission Facilities			**85,422,003**	**(14,395,902)**	**(2,322,408)**	**282,218**	**68,985,912**	**(10,978,378)**	**(2,003,723)**	**941,455**			**52,062**		
Sub Transmission Lines															
140007.300	Poles and Fixtures	45- R3	3,618,635	(1,601,236)	(780,721)	103,059	1,339,737	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.301	25Kv Minto Spur- Structure	n/a	2,646,132	(459,388)	-		2,186,743	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.304	Brushing	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.305	Survey costs	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.306		n/a	432,533	(75,099)			357,434	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.307		n/a	95,136	(16,516)			78,620	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.401	Overhead Conductors	45- R3	989,127	(378,143)	(112,184)	17,189	515,989	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.405	Underground Conductors / Conduit	45 - S3	83,873	(32,775)	(194)	36	50,940	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.407		n/a	920,693	(159,839)			760,853	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.710	Substation Equipment	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.711		n/a	6,705,507	(1,164,126)			5,541,381	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Sub Transmission Lines			**15,491,635**	**(3,930,691)**	**(893,099)**	**120,284**	**11,518,772**	**-**	**-**	**-**			**-**		

As of December 31, 2010														
			Provided by Yukon Management						Depreciation Expense			Depreciation Add-Back		
Number	Description	KPMG Estimated Survivor Curve	Surviving Original Cost at 12/31/2010	Accumulated Depreciation	A/D Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accrued Depreciation	Accumulated Depreciation Variance	Annual Accrual Amount	Rate (%)	KPMG Probable Remaining Life [1]	Annual Provision for True-Up	Accounting Effective Age	KPMG Concluded Effective Age
Distribution System															
140008.300	Poles and Fixtures	35 - R2	3,570,732	(626,163)	(14,629)	2,628	2,932,567	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.304	Brushing	50 - R2	44,763	(10,680)	(3,235)	427	31,275	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.305	Survey costs	50 - R3	500,981	(43,799)	297		457,478	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.401	Overhead conductors - Poles	35 - R2	74,570	(13,959)			60,611	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.410	Overhead Costs	40 - R2	1,984,394	(429,445)	(78,539)	13,293	1,489,703	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.510	Underground Services	40 - R2.5	6,379	(1,651)	(454)	93	4,367	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.550	Wind Monitoring Equipment	n/a	n/a					n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.610	Meters	30 - R2	281,251	(106,358)	(33,787)	7,409	148,515	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.620	Meter Equipment	30 - R2	314,136	(74,287)	3,308	(555)	242,603	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.710	Substation Equipment	40 - R2	1,188,413	(263,858)	(50,938)	9,459	883,075	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.720	Substation Buildings	55 - R1	64,798	(25,321)	(20,272)	3,619	22,824	(22,455)	(19,520)	1,178	1.82	37	528	19	19
140008.815	Street Lights	40 - R2	573,505	(112,169)	(99,674)	17,096	378,758	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.905	Line Transformers	40 - R2.5	3,290,797	(1,206,043)	(564,652)	107,313	1,627,415	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.961	Sentinel Lights	30 - L2	35,580	(18,984)	(12,948)	4,109	7,757	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Distribution System			**11,930,298**	**(2,932,718)**	**(875,523)**	**164,891**	**8,286,948**	**(22,455)**	**(19,520)**	**1,178**			**528**		
Building and Other Equipment															
140009.110	Survey Costs Land	50 - R2	4,321	(1,261)	(601)	83	2,543	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.200	Structures and Improvements (Hydro)	40 - R2.5	490,156	(97,536)	(3,049)	479	390,050	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.201	Building and Improvements	55 - R1	8,458,407	(2,274,046)	(459,881)	79,602	5,804,082	(1,707,364)	(946,961)	153,789	1.82	45	21,044	11	11
140009.202	Office Furniture and Equipment	20 - SQ	1,389,826	(630,145)	(130,011)	54,324	683,995	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.210	Communication Site Towers	30 - R2	19,297	(6,320)	(1,115)	240	12,102	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.220	Communication Site Fences	20 - R4	36,663	(15,689)	326	(105)	21,195	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.310		n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.320	Computer Hardware	5 - SQ	1,920,814	(812,719)	70,421	(70,421)	1,108,095	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.330	Computer Software	5 - SQ	842,508	(333,477)	(7,872)	7,872	509,031	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.505	Tool and Instruments	20 - SQ	998,579	(353,282)	(168,321)	61,636	538,612	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.507	Wind monitoring equipment	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.605	Communication Equipment	20 - L4	3,780,557	(1,291,842)	(53,911)	22,314	2,457,118	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.810	Company Owned Houses / Land	30 - R3	36,512	(14,062)	7,862	(1,902)	28,410	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.820	Company Owned Houses	30 - R3	1,421,362	(1,260,705)	365,433	(89,514)	436,576	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.900		n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Building and Other Equipment			**19,399,002**	**(7,134,653)**	**(380,719)**	**64,609**	**12,678,882**	**(1,707,364)**	**(946,961)**	**153,789**			**21,044**		
Transportation															
140014.411	Utility Vehicles	7 - L2	181,452	(143,408)	12,716	(12,716)	38,044	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.412	Sedans and Stationwagons	7 - L2	118,637	(106,473)	6,160	(6,160)	12,164	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.420		n/a	66,929	(240)			66,690	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.430	Pole Trailers > 10,000 Lbs	25 - R1.5	34,810	(5,599)	(748)	189	28,652	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.440	Trucks 3/4 to 2 Ton	10 - R2	2,217,586	(934,130)	(17,178)	15,617	1,281,895	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.470	Trucks > 3 Ton	20 - R3	692,397	(134,682)	(12,391)	4,225	549,549	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.490		n/a	1,001,630	(31,812)			969,818	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Transportation			**4,313,442**	**(1,356,344)**	**(11,441)**	**1,154**	**2,946,811**	**-**	**-**	**-**			**-**		
Total			**285,395,726**	**(86,023,946)**	**(5,809,234)**	**1,168,188**	**196,435,568**	**(43,474,674)**	**(23,533,360)**	**2,662,404**			**450,543**		

Notes:

[1] Calculated based on the concluded effective age and the remaining area under the survivor curve.

[2] "n/a" values reflect asset classes which KPMG reviewed, however a change was deemed unnecessary.

Hydro Plant Assets - Effective Age Calculation								
Site	In-Service Year	Chronological Age	Design Capacity (MW)	% of Design Capacity	RCN	% of Total RCN	Concluded Weight [1]	Effective Age Contribution
Mayo	1952	58	5	6.7%	45,555	13.9%	10.3%	6.0
Whitehorse (1)	1958	52	20	26.7%	88,164	26.8%	26.7%	13.9
Whitehorse (2)	1985	25	20	26.7%	88,164	26.8%	26.7%	6.7
Aishihik	1975	35	30	40.0%	106,921	32.5%	36.3%	12.7
Total			**75**	**100%**	**328,804**	**100%**	**100%**	**39.2**

Notes:

[1] Concluded weight is based on equal consideration given to percent design capacity and percent of replacement cost.

Main Transmission Facilities - Poles & Fixtures - Effective Age Calculation								
Site	In-Service Year	Chronological Age	Voltage (kV)	Length (km)	RCN ($ million)	% of Total RCN	Concluded Weight [1]	Effective Age Contribution
Keno	1951	59	69	45	11	4.3%	4.3%	2.6
Mayo - Dawson	2002	8	69	220	55	21.7%	21.7%	1.7
WAF	1974	36	138	500	145	57.1%	57.1%	20.6
CSTP I	2008	2	138	130	43	16.9%	16.9%	0.3
Total			**414**	**895**	**254**	**100%**	**100%**	**25.2**

Notes:

[1] Concluded weight is based on replacement cost.

Diesel Production - Generating Equipment - Effective Age Calculation							
Site	Unit #	In-Service Year	Chronological Age	MCR Rating (kW)	% of Total Rating	Concluded Weight [1]	Effective Age Contribution
Faro	FD1	1970	40	4,000	10.4%	10.4%	4.2
Faro	FD3	1989	21	850	2.2%	2.2%	0.5
Faro	FD5	1990	20	1,200	3.1%	3.1%	0.6
Faro	FD7	1992	18	2,800	7.3%	7.3%	1.3
Dawson	DD1	1988	22	720	1.9%	1.9%	0.4
Dawson	DD2	1987	23	920	2.4%	2.4%	0.6
Dawson	DD3	1990	20	920	2.4%	2.4%	0.5
Dawson	DD5	1996	14	1,400	3.6%	3.6%	0.5
Mayo	MD1	1989	21	850	2.2%	2.2%	0.5
Mayo	MD2	1989	21	850	2.2%	2.2%	0.5
Whitehorse	WD1	1968	42	3,500	9.1%	9.1%	3.8
Whitehorse	WD2	1968	42	4,500	11.7%	11.7%	4.9
Whitehorse	WD3	1970	40	4,500	11.7%	11.7%	4.7
Whitehorse	WD4	1975	35	2,250	5.9%	5.9%	2.0
Whitehorse	WD5	1975	35	2,250	5.9%	5.9%	2.0
Whitehorse	WD6	1990	20	2,500	6.5%	6.5%	1.3
Whitehorse	WD7	1991	19	3,000	7.8%	7.8%	1.5
Mobile Diesels	YM1	1990	20	1,300	3.4%	3.4%	0.7
Mobile Diesels	YM2	1999	11	150	0.4%	0.4%	0.0
Mobile Diesels	YM3	unknown	n/a	n/a	n/a	n/a	n/a
Mobile Diesels	YM4	unknown	n/a	n/a	n/a	n/a	n/a
Total				**38,460**	**100%**	**100%**	**30.4**

Notes:

[1] Concluded weight is based on the MCR Rating of the generation equipment.

Main Transmission Facilities - Substations - Effective Age Calculation				
Site	In-Service Year	Chronological Age	Concluded Weight [1]	Effective Age Contribution
WAF - Aishihik	1975	35	12.5%	4.4
WAF - Takhini	1975	35	12.5%	4.4
WAF - Faro	1975	35	12.5%	4.4
WAF - MacIntyre	1975	35	12.5%	4.4
WAF - Riverside/S150	1990	20	12.5%	2.5
CSTP - Carmacks	2008	2	12.5%	0.3
CSTP - Minto Landing	2008	2	12.5%	0.3
Mayo Dawson - Calliston	2003	7	12.5%	0.9
Mayo	in progress	n/a	0.0%	0.0
Total			**100%**	**21.4**

Notes:

[1] Concluded weight is based equally by major substations.

TOPIC: **Depreciation**

REFERENCE: **Tab 10 – Depreciation Study – Results by Account, Table on Page 10-16**

PREAMBLE:

YECL is interested in more information in respect of the Depreciation Study report.

QUESTION:

a) Please provide the detailed calculations and/or computer printouts by "Number" supporting the development of the "Annual Accrual Amount", "Rate (%)", and "Calculated Accrued Depreciation" as provided on the table provided on Page 10-16.

b) Please provide the formulae used for each column of the table provided on Page 10-16.

c) Please provide what "A/D" refers to and the calculations to derive an "A/D Difference" as shown on the table provided on Page 10-16.

d) Please provide the calculations to derive an "Accumulated Depreciation of A/D Difference" as shown on the table provided on Page 10-16.

e) Please provide the calculations to derive the "Calculated Accrued Depreciation" as shown on the table provided on Page 10-16.

f) Please provide the calculations to derive the "Annual Accrual Amount" as shown on the table provided on Page 10-16.

g) Please provide the detailed calculations to derive the "KPMG Probable Remaining Life" as shown on the table provided on Page 10-16.

h) Please provide the detailed calculations to derive the "Accounting Effective Age" as shown on the table provided on Page 10-16. Please provide a definition of the "Accounting Effective Age".

i) Please provide the detailed calculations to derive the "KPMG Concluded Effective Age" as shown on the table provided on Page 10-16. Please provide a definition of the "KPMG Concluded Effective Age".

j) Please provide for all "Numbers" where "n/a" is shown (KPMG's Note [2] stated that n/a values reflect asset classes which KPMG reviewed, however a change was deemed unnecessary), the reasons why "no change was deemed necessary" and the applicable original date for such asset classes.

ANSWER:

(a)

Please see YECL-YEC-1-67.

(b)

Please see YECL-YEC-1-67.

(c)

"A/D" refers to accumulated depreciation. "A/D Difference" was provided by YEC Management.

(d)

This information was provided by YEC Management and accounts for the accumulated depreciation of the difference from the 2003 depreciation study when certain service lives were changed.

(e)

Please see detailed excel sheet provided as response to YECL-YEC-1-67(a).

(f)

Please see detailed excel sheet provided as response to YECL-YEC-1-67(a).

(g)

The KPMG Probable Remaining Life is calculated as the sum of the area underneath the survivor curve.

(h)

The Accounting Effective Age is a weighted effective age of the underlying assets based on its percentage of overall historical cost and year capitalized. The Accounting Effective Age is calculated by:

1. Finding the weighting of each year of capitalized costs over the total capitalized cost per class;

2. Multiplying the year by the weighting found in Step 1; and

3. Sum.

(i)

Please refer to excel sheet provided as Attachment 1 to this response. KPMG depended on the Accounting Effective Age where it did not perform a direct effective age analysis through conversations with YEC engineers.

(j)

Please see YECL-YEC-1-60(b).

Yukon Utilities Board
(YUB)

TOPIC: **2011 Resource Planning**

REFERENCE: **General Rate Application (Application), page 2**

Specifically, the 2006 Resource Plan used a long-term growth forecast of 1.85%/year, while 2011 resource planning forecasts use a 2.26%/year growth forecast.

PREAMBLE:

The Yukon Utilities Board (Board) requires further clarity regarding the 2011 resource planning forecasts.

QUESTION:

a) Please confirm whether the 2011 resource planning forecasts are included in YEC's 2012-13 GRA.

b) If the answer to part (a) is not confirmed, then please provide the 2011 resource planning forecast.

ANSWER:

(a) and **(b)**

Not confirmed.

Yukon Energy Corporation's 2011 Resource Plan Update load forecast was updated in the 2012/13 GRA application for industrial sales forecasts and for actual non-industrial sales. Subject to these updates, the Application reflects 2011 resource planning forecasts, as explained below.

The 2011 Resource Plan was prepared prior to mid-year 2011 based on information available at that time. Based on information available when the 2012/2013 GRA was prepared, non-industrial grid load growth is presently tending to exceed the updated 2011 forecast. For example, the 2011 Resource Plan Update forecast non-industrial load for 2011 was at 339.3 GW.h, while 2011 actual non-industrial load was 357.7 GW.h (including 8.7% losses), which is 18.4 GW.h higher than 2011 Resource Plan forecast.

However, the growth rate of 2.26%/year from the 2011 Resource Plan is used to forecast wholesales in the 2012/2013 GRA. This growth rate was developed in preparation of 2011 Resource Plan Update based on an average of the WAF average growth rate (2.18%) and 2.34% (reflecting Whitehorse residential use growth). The WAF average growth rate of 2.18% per year for 2001-2010 was calculated by excluding Pelly Crossing sales starting late 2008 (0.275 GW.h in 2008, 2.584 GW.h in 2009 and 2.691 GW.h in 2010) and including Faro site dewatering sales as after closure the Faro mine was charged as "Industrial" prior to 2005. The Whitehorse residential use growth rate of 2.34% per year was calculated based on City of Whitehorse population for the 2001-2010 period (averaging 1.8% per year based on Yukon Bureau of Statistics, Annual Reports - 2001-2008, Monthly Reports of Dec. 2009 and 2010) and the weather normalized average annual increase in residential usage per customer (0.52% per year based on Weather normalized UPC data for 2001-2007 as filed in Yukon Electrical 2008-2009 GRA; 2008-2010 data as provided by Yukon Electrical).

See Table 1 below for the grid generation load forecast from the 2011 Resource Plan, excluding Fish Lake hydro and any consideration of demand side management or supply side efficiency programs (DSM/SSE).

The 2011 Resource Plan load forecast was developed in three scenarios:

- **The Base Case** includes non-industrial load forecast at 2.26% per year (2010 actual as base year) plus connected industrial loads as then forecast (i.e., Minto and Alexco mines).

- **Scenario A** – **Base Case including Victoria Gold:** Given the possibility of new mines opening in Yukon, a near-term case that adds modest mine loads to the Base Case was assessed. This case combines the Base Case assumption for non-industrial (2.26%/year growth) and currently connected mines plus near-term development of the Victoria Gold mine starting in Q4 2013 (at 24 GW.h) and continuing for 7.3 years from 2013 through the end of 2020 at 13 MW.
    - The updated information shows changes in expected grid mine load forecasts since the 2011 Resource Plan forecasts were prepared, including delay in connection of Victoria Gold load until start of 2015 and expectation that this load will peak in summer and extend for a longer life than the seven years assumed earlier.

- **Scenario B – Base Case including Victoria Gold, Carmacks Copper and Whitehorse Copper Tailings:** Yukon Energy has also evaluated a sensitivity case that includes two new 10 MW to 15 MW range mines connecting to the grid system (as well as one smaller industrial load). This includes Victoria Gold (as described in Scenario A above) and Carmacks Copper starting in Q4 of 2014 with assumed load of 8 MW winter peak (10 MW in summer) and 52 GW.h/year for 6.5 years. Whitehorse Copper Tailings is included as an industrial load started in Q2 2013 with summer peak of 2 MW and approximately at 8.7 GW.h/year through to the end of 2018.

Table 1:
Yukon Energy Corporation's 2011 Resource Plan Update Load Forecast

Forecast Years	Non-Industrial Load forecast, incl. losses, without DSM/SSE (GW.h)	Industrial Load forecast, incl. losses (GW.h)		
		Base Case	Scenario A	Scenario B
2011	339.3	46.5	46.5	46.5
2012	347.2	68.4	68.4	68.4
2013	355.3	68.4	94.3	103.8
2014	363.5	68.4	171.0	194.6
2015	371.9	68.4	171.0	236.9
2016	380.6	61.7	164.3	230.2
2017	389.4	61.7	164.3	230.2
2018	398.4	61.7	164.3	230.2
2019	407.6	61.7	164.3	220.7
2020	417.0	38.3	140.9	197.4
2021	426.7			14.1
2022	436.5			
2023	446.6			
2024	456.9			
2025	467.5			
2026	478.3			
2027	489.3			
2028	500.6			
2029	512.1			
2030	523.9			

Please see Overview of 20-Year Resource Plan: 2011-2030, filed in response to YECL-YEC-1-18, which provides more detail on the 2011 Resource Plan forecasts as well as (see Appendix) the current update of these forecasts that reflect the 2012/2013 forecasts in the current GRA Application.

TOPIC: **Industrial Growth**

REFERENCE: **Application, page 3**

Industrial connected growth continues to be material – but industrial load growth to date also continues to bring higher revenues that tend to more than offset any related incremental costs.

QUESTION:

a) Please provide a schedule that demonstrates that revenues for incremental industrial load exceed incremental costs.

b) Please provide similar schedules showing incremental revenues and incremental costs for all remaining rate classes.

ANSWER:

(a)

Incremental load will add both incremental revenues and incremental (short term) operating costs to the system.

The impacts of industrial customer growth from 2009 GRA to 2013, is set out below. In summary these loads bring an incremental revenue of 11.8 cents/kW.h and incremental diesel costs (at long-term average hydro generation for forecast 2013 grid loads) of 7.65 cents/kW.h, or costs of only 4.51 cents/kW.h at the 59% of long-term average diesel generation included in the GRA for 2013.

Further detailed analysis is provided below.

Please see the attached Table 1 for the requested schedule, which shows industrial load growth as compared to 2009 GRA approved forecast and incremental cost of generation (focused on incremental diesel fuel costs) for the period since the 2009 GRA.

The 2013 forecast industrial sales is 33.3 GW.h higher than the 2009 approved amount, driving approximately 48.9% of the overall forecast grid energy sales growth (see Table

2.1 in Application). Assuming that no baseload diesel was in rates as approved in 2009[1], the growth in overall grid diesel generation over this same period (from 2009 to 2013) is 18.2 GW.h at 100% of long term average hydro generation (LTA, as per Appendix 3.2, Attachment 3.2). The impact of this added diesel generation fuel costs on overall rate revenue requirement in 2013 equals the portion of LTA diesel generation included in rates (approximately 59%) and the average diesel fuel cost per kW.h of diesel generation (28.68 c/kW.h), or $3.073 million (see Table 2.2 in Application for diesel generation numbers and Table 3.2 in Application for fuel cost in 2013). Total forecast rate revenue for industrial load in 2013 is $7.38 million at existing rates (average 11.8 c/kW.h - see Table 2.1 of Application).

As shown in Table 1 attached, the average incremental diesel fuel generation cost for industrial load growth from 2009 to 2013 translates into approximately 4.5 c/kW.h of incremental industrial sales. Compared to the average revenue at existing pre-GRA rates (11.8 c/kW.h), revenues for incremental industrial load exceed incremental costs[2].

This outcome reflects the existing rates charged to industrial customers, the extent to which incremental diesel generation at LTA supplies incremental generation[3], and the extent to which diesel at LTA is included in rates (approximately 59% proposed in 2013).

- If diesel generation is assessed at 100% of LTA, the incremental LTA diesel cost approximates 7.6 c/kW.h for incremental load growth from 2009 to 2013 (and average incremental diesel fuel generation cost for industrial load would still exceed incremental costs by a material margin). This cost reflects the average incremental diesel generation requirement for the overall load growth during the period.

- The highest incremental diesel requirement in 2013 (for the last 5 GW.h of load growth), is about 56% of new load (see Table 3.2-2 in Application) – on the margin, this incremental load results in incremental diesel generation cost of 16 c/kW.h at 100% LTA (i.e., in excess of incremental revenue) and 9.5 c/kW.h if

[1] As approved, the 2009 GRA included 945 MW.h of forecast diesel generation.

[2] This conclusion holds even if look only at the existing pre GRA energy charge of 8.291 c/kW.h (includes fixed Rider F charge), or if include 3.0 c/kW.h of diesel generation for non-fuel incremental diesel cost. Industrial load growth, however, is also subject to the existing pre-GRA demand charge of $15.94/kV.A per month.

[3] On average, 26.7% of new load results in new diesel generation in Table 1. In 2013, the overall load results in at most 56% of the last increment to load requiring LTA diesel generation.

59% of LTA diesel is included in rates (i.e., less than incremental revenue with demand charge included).

The above analysis for incremental costs related to industrial growth looks only at fuel costs – but in the case of industrial growth, PPA provisions have addressed separately direct recovery of incremental costs for connection of the new loads at transmission level of service. On this basis, the fuel-related costs (with some provision for incremental non-fuel O&M diesel costs) are a reasonable proxy for overall incremental costs related to current industrial load growth.

Please also see CW-YEC-1-1(a).

(b)

Beyond some high level comments provided below, YEC is not able at this time to assess the incremental costs and revenues for load growth associated with each of the non-industrial retail firm rate classes in Yukon (most of these customers are served directly by YECL).

Incremental fuel cost of diesel generation for all rate classes is currently approximately 7.65 cents/kW.h at long-term average water flow, or 4.5 cents/kW.h at GRA percentages of long-term average flows for overall load growth for the period from 2009 GRA to 2013 GRA (i.e., same as shown for industrial growth in Table 1). These diesel-related costs are affected for these classes in a broadly similar way as occurs for industrial customers, subject to differences in the share of annual loads focused in non-summer or fall periods when diesel use in typically concentrated in Yukon.

However, in the case of non-industrial retail load growth, incremental costs associated with load growth are expected to include several non-fuel elements that are not recovered directly from the customer through initial connection-related charges. Average rates to these other retail classes reflect added costs for distribution and other non-fuel services, e.g., average revenues at existing pre-GRA rates for YEC residential and general service forecast loads in 2013 approximate 14.6 c/kW.h and 16.5 c/kW.h respectively including the costs of distribution services. Based on Cost of Service analysis filed reflecting the Board's decisions in the 2009 Phase II GRA, in excess of 1/3 of residential customer costs relates to the distribution system, leaving only approximately 10 cents/kW.h to pay for the bulk power functions (generation and

transmission), which is comparable to (and in fact below) the incremental revenue effects of new industrial loads.

It is also important to note that, in the case of residential customers, cost of service studies for all Yukon (YEC and YECL consolidated) have consistently shown in the mid 1990s and more recently (2009) that existing rates do not recover even 85% of the average costs to serve these customers.

Table 1:

Industrial Load Incremental Cost of Generation Calculation since 2009 GRA

Description	2009 Approved	2013 Forecast	Growth	Share of Growth	Prorated Baseload Diesel Generation Growth	Prorated 2013 Forecast Baseload Diesel Cost in Rates	Incremental Cost of Generation for the Period
	MW.h	MW.h	MW.h	%	MW.h	$000	$/kW.h
Sales							
Residential	11,183	12,409	1,226	1.80%	327	55	
General Service	19,543	22,620	3,077	4.52%	820	139	
Industrial	29,023	62,364	33,341	48.94%	8,891	1,504	0.0451
Street lights	278	279	1	0.00%	0	0	
Space lights	15	15	-	0.00%	-	-	
Wholesale	267,747	298,228	30,481	44.74%	8,128	1,375	
Total	327,789	395,913	68,124	100.00%	18,167	3,073	
Losses	28,518	34,444	5,927				
Grid Load	356,306	430,357	74,051				
Baseload Diesel Generation at 100% LTA	-	18,167	18,167				
Diesel fuel generation cost in 2013 rates (58.978% of LTA diesel at 28.68 c/kW.h)			3,073				

TOPIC: **Hydro Generation Variability**

REFERENCE: **Application, page 3**

To mitigate the impact of incorporating full long-term average diesel costs into rates, the Application provides for diesel generation costs in the test years based on annual hydro generation forecasts slightly higher than forecast annual long-term average (with the result that forecast diesel generation is still less than long-term average).

QUESTION:

a) By mitigating the rate impacts, what is the effect of the impact on the economic and pricing signals to customers in the test years rather than the incorporation of forecast annual long-term averages? Please explain.

ANSWER:

(a)

The difference in rates for the test years between inclusion of the full long-term average diesel and YEC's proposed rates for the test years is approximately 1.4 to 2.0%/year or cumulatively over the two year about 3.6% overall[1]. The effect of the proposal is to reduce by this amount the rates that otherwise would be required in the test years, and thereby to reduce somewhat the "economic and pricing signals" to consumers in these years.

The nature of rate design criteria are that they are inherently competing, most notably "economic and price signals" (i.e., economic efficiency) versus rate stability and predictability. The system in Yukon to deal with water flow variation is intended to maximize rate stability and predictability and mute the harsh short-term economic

[1] For 2012, diesel fuel costs at 100% LTA would increase by approximately $1.134 million above the Application amount of $2.163 million (Table 3.2 of Application), resulting in an approximate 8.38% increase in average rates for 2012 (or 1.98 percentage points higher than 6.40% increase in Application). For 2013, diesel fuel costs would increase by approximately $2.14 million if diesel generation was at 100% of LTA rather than the proposed 59% (as shown in Table 3.2 of the Application). After including the 1.98% increase to proposed rates in 2012, a $2.14 million added increase to 2013 rates would equal 7.87% of the approximate $64.52 million consolidated retail revenue that would be forecast in 2013 at 2012 retail rates (see Table 4.2 in the Application for base sales numbers).

efficiency criteria, which would likely not adopt any DCF or similar mechanisms to stabilize costs but rather would provide for rates that are relatively low when water conditions are average or above average, but then impose harsh (and likely impractical) increased rates or special riders during periods of drought. In short, the very concept of including long-term average water and a DCF in the rate system is intended to increase the rate stability of the system and decrease the harshness of the short-term economic efficiency outcome. The premise of the DCF/rate setting method is that ideally ratepayers would pay the same during drought periods (when massive quantities of diesel maybe required) as they do during floods (when very small quantities of diesel, if any, are required).

The specific mitigation measures proposed for the test years reduces the overall diesel cost included in rates at this time to only 66% and 59% of long term average diesel generation. As explained in the Application, and in response to YUB-YEC-1-29 and YUB-YEC-1-12 and YUB-YEC-1-7(i), these measures are proposed to prevent a rate increase in 2013 in excess of 6.50% and to facilitate the transition from the 2009 GRA rates to what will be required in future when diesel costs are included in rates at 100% of LTA.

TOPIC: **Mayo Hydro Enhancement Project ("Mayo B")**

REFERENCE: **Application, page 3**

QUESTION:

(a) Please provide a table with the following information:

- Rated capacity of Mayo hydro (Mayo A) before the Mayo Hydro Enhancement Project (Mayo B).
- Average operating output of Mayo A (average or normal water flow years) before Mayo B.
- Rated capacity of Mayo B, not including Mayo A.
- Expected average operating output of Mayo B (average or normal water flow years), not including Mayo A.
- Rated capacity of the entire Mayo hydro plant, both Mayo A and Mayo B.
- Expected average operating output of the entire Mayo hydro plant (average or normal water flow years), both Mayo A and Mayo B.

ANSWER:

(a)

Please see table below with regards to capacity.

Table 1:
Mayo A and Mayo B Rated Capacity and Operating Output

Mayo Hydro (A) capacity before Mayo B	5 MW
Mayo B rated capacity	10 MW
The combined capacity of both Mayo Hydro (A) and Mayo B	15 MW

With respect to energy, in the test years the total output of the Mayo complex is shown in Table 2.2 in the Application at 59-60 GW.h. Assessments of Mayo A versus Mayo B outputs at the test year load levels have not been developed at this time - earlier assessments of this split, as provided below, provide an indication of what to expect.

LE-YEC-1-19 provides a copy of information filed in the Mayo B Part 3 hearing related to a 468 GW.h load level that shows the break down between Mayo A and Mayo B (total output of approximately 70 GW.h with no enhanced Mayo Lake storage). At a lower load level than 468 GW.h, Mayo A's output would be largely sustained at the level shown in LE-YEC-1-19 (as this is largely the required passage of fisheries in-stream flows) and the Mayo B output would be somewhat reduced. Under hypothetical ideal or infinite load conditions, the Mayo complex can generate closer to 80 GW.h/year, but this is unlikely to be achieved in practice and has not been the basis for Mayo B economic modeling at any time.

TOPIC: **Aishihik Third Turbine**

REFERENCE: **Application, page 4**

Completed and in service December 2011 at a net cost to ratepayers of $8.8 million after $5 million of third-party contributions.

QUESTION:

a) Please provide the original cost estimates for this project.

b) Please list any scope and cost changes to this project since the original cost estimates were provided.

ANSWER:

(a) and **(b)**

A detailed cost breakdown of the Original Budget estimates (April 2009), Construction Approval estimates (with tendered costs as of August 2010), and Final Cost Estimates (included in 2012/2013 GRA) is provided in Table 1 below.

Original Budget Cost Estimates noted in Table 1 below were not based on tendered costs. Differences between Original Budget (April 2009) and August 2010 were due primarily to adjustments needed to the estimates provided by AECOM. As indicated in the Application, after the tender process in February 2010, AECOM acknowledged that they had significantly underestimated the costs of the project and that the bids more accurately reflected the magnitude of the Aishihik Project costs. As a result of the high bids the tender was cancelled and AECOM and YEC had discussions with two separate contractors to refine project scope and achieve lower costs. However, these discussions did not materially alter the then estimated project costs or scope. Table 1 below indicates the estimated costs at the time a decision was made in August 2010 (the Construction Approval estimates) to proceed with the project based on these tendered costs.

Table 1:
Original Cost Estimates (April 2009 – before tendered costs were available) and Final Cost Estimates (2012/13 GRA)

Aishihik Third Turbine	Orginal Budget (April 2009)	Construction Approval (Aug 2010)	Final Cost Estimates (2012/13 GRA)
Building	5,000	$1,000	-
Rock Excavation	384,000	$1,177,054	1,132,765
Generating hall	397,000	$627,962	773,270
Turbine Generator	3989731	$3,989,731	4,056,114
Supply Electro-Mechanical	410,910	$400,000	713,994
Penstock Installation	245,000	$696,228	884,079
Turbine Generator Installation	268,800	$574,977	569,360
Auxillary System Installation	21,000	$828,204	821,815
Electrical Installation in Generating Hall	80,000	$333,327	322,673
Electrical Installation in Generating Control Room	50,000	$608,413	589,037
Testing and Commissioning	90,000	$79,812	114,735
Diesel Fuel	195,000	$653,000	636,759
Mobilizaiton - 4% of total	236,000	$185,336	386,152
Estimated Construction Field cost	**6,372,000**	**$10,155,044**	**11,000,753**
Contingency	750,000	$750,000	-
Preliminary Desing	567,537	$700,000	762,955
Detail Design	259,148	$400,000	609,702
Construction Management	273,927	$425,000	350,264
YEC Cost (Owner's Cost)	200,000	$250,000	843,580
Construction Financing Cost	387,261	$133,000	249,486
Sub-Total	**8,810,000**	**$12,813,044**	**13,816,740**
Yukon Government Contributions	-5,000,000	-$5,000,000	-$5,000,000
Total with Contributions	**3,810,000**	**$7,813,044**	**8,816,740**

As noted in LE-YEC-1-21(a) and (b), the overall scope of the project was not reduced or changed since tendered costs were provided in 2010. See response to CW-YEC-1-28(d) for a detailed explanation of +/-5% cost variances from August 2010 (when tendered costs were available) and final cost estimates.

TOPIC: **Faro Dewatering Account Funds**

REFERENCE: **Application, page 6**

Approval to apply $0.398 million of the remaining Faro Dewatering Account deferred regulatory liability amounts (related to earlier "de-watering sales" to the Faro mine site) against the current outstanding balance in the Yukon Energy Reserve for Injuries and Damages.

QUESTION:

a) Please explain the rationale for the application of these funds against the current outstanding balance in the Yukon Energy Reserve for Injuries and Damages.

b) Please identify what alternatives were considered and why the proposed application of these funds against the current outstanding balance in the Yukon Energy Reserve for Injuries and Damages was chosen over other alternatives.

ANSWER:

(a)

These funds were applied in the current GRA against the outstanding balance in the Yukon Energy Reserve for Injuries and Damages in accordance with past practice as approved by the Board and in order to reduce the revenue requirement and required rates in 2012 and 2013. The Faro Dewatering Funds were retained for the benefit of ratepayers, and application in this manner serves the intended purpose, by reducing the revenue requirement that is otherwise required from ratepayers.

Also note that the funds available from the Faro Dewatering Account have been applied to the benefit of ratepayers, including in this manner, in past proceedings as noted below:

- Prior to 2005, substantial Rate Schedule 34 collections (about $2 million by 2005) resulted from power sales for Faro mine dewatering and other shutdown activities; these collections were set aside in a deferred account to be used in future for ratepayer benefit subject to Board direction. Prior to Board direction,

the balance collected in the deferred Faro mine de-watering account was typically applied as an offset to ratebase. This benefited ratepayers over the 1999-2004 period by using the fund balance to avoid the need for new debt and equity (and to defer the need for rate increases).

- Following the 2005 Required Revenues and Related Matters hearing, Order 2005-12, directed that Yukon Energy address its 2005 revenue requirement shortfall of $0.292 million by way of an annual withdrawal from the Faro Dewatering Account regulatory liability that Yukon Energy maintained on behalf of ratepayers. That annual withdrawal was approved for a maximum of 3 years - 2005, 2006 and 2007.

- In the 2008/2009 GRA $0.463 million of the Faro Dewatering Account balance was applied against the Reserve for Injuries and Damages outstanding balance as is proposed in the current Application. Yukon Energy also sought (as required) approval of the Board to address (if and as required) specified income forecast contingencies related to final 2008 retail rate revenue requirements (i.e., offsetting, to the extent required to enable final approved forecast 2008 retail rate revenues, any net revenue losses due to delays in the final connection timing of Minto mine and Pelly Crossing loads to the CSTP from the October 1, 2008 connection date assumed in the Application) and secondary sales revenue losses, if any, arising due to below average water flows in any year after 2008.

- Subsequent to Order 2009-8, additional transfers from the Faro Dewatering Account were also used (as approved by the YUB) to address revenues deficiencies following the final Order on the GRA, i.e., $0.026 million in 2008 and $0.355 million in 2009.

(b)

As in past proceedings, it is recognized that an alternative would be for the full outstanding balance of the Reserve for Injuries and Damages to be included in rate base. As in past proceedings, it was recognized that this alternative provides much less benefit to ratepayers than the alternative proposed based on past practice.

TOPIC: **Electric Heat, System Sales and Generation**

REFERENCE: **Application, pages 2-2 to 2-17**

Since the 2008-09 GRA, ongoing events have demonstrated the depletion of surplus hydro generation and increasing relevance of diesel generation. As compared to the 0.95 GW.h diesel generation forecast for 2009 in the approved 2009 Compliance Filing, actual diesel generation exceeded 2.6 GW.h in 2009, 4.28 GW.h in 2010 and 10.55 GW.h in 2011 (excluding diesel requirements related to capital projects and hydro generation plant construction activities). Secondary sales have been interrupted on a sustained basis since September 2010 (except for temporary resumption in September 2011 due to high water in Aishihik Lake), and as a result of this sustained interruption a number of secondary sales customers have converted to primary supply for their electric heating loads.

With new major legacy assets in service by the end of 2011, the majority of grid generation requirements in the test years (over 97%) will continue to be met with hydraulic generation based on annual long-term average hydro generation capability. However, as reviewed in Tab 1 (Section 1.3) forecast diesel generation included in this GRA is considerably higher than the levels approved in the 2009 GRA and the Application marks a major transition in forecast annual long-term average baseload diesel generation needed to meet grid load growth. Anticipated continuing load growth beyond the test years is expected to result in continued material increases in diesel generation requirements, driving the need to secure new lower cost sources of supply by 2015 to displace continued increases in baseload diesel requirements.

PREAMBLE:

The Board would like additional information regarding electric heat.

QUESTION:

a) Are there alternative demand-side management (DSM) initiatives that the secondary sales customers who converted to primary supply for their electric heating loads could take advantage of?

b) Would these alternative means be viable as "new lower costs sources of supply"? Please explain.

c) Assuming that heating loads would peak in winter at a time when hydro capability is at a minimum, is the subject of electric heat appropriately addressed under the purview of DSM? Please explain.

d) Can YEC provide an estimate as to what percentage of the integrated grid load is electric heating load?

e) Regarding Table 2.1 on page 2-17, please explain the increase in lighting load for 2009 compared to other years in the table.

f) Has any customer given advance notice that it is electing to take service under Rate Schedule 39?

g) With respect to YEC's proposed audit pilot program, please provide the rationale and reasons for instituting such a program, including the related costs and the benefits to Yukon electric utility ratepayers. Are the costs to be paid by ratepayers in general or to be paid for by customers who agree to be audited?

h) Over a year, on average, how many GW.h of wind power is available to the integrated system?

i) What is the rationale underlying footnote 26 on page 2-12 where YEC notes the use of 66% (for 2012) and 59% (for 2013) of long-term average diesel generation requirements instead of 100% of annual long-term average hydro generation levels were included in rates? In your response, please indicate why another amount, e.g. 40% or 80%, would not be supported.

j) Please provide the basis for increasing forecast fuel prices by approximately 9 to 14 cents/litre as detailed on page 2-13.

k) Please explain how peak demand is determined and measured on the integrated system.

l) Please explain the statement on page 2-16: "the 25 km line L172 between Takhini and Whitehorse being appropriately reinforced." Please indicate whether this line is owned and operated by YEC. If it is owned by YEC, please explain the rationale, timing, and particulars of the line being reinforced. If it is not owned and operated by YEC, please explain the details of the line reinforcement and who owns and operates this line.

m) In the Application on page 2-14, YEC submitted that the results of a review by Doctors Billinton and Karki are being internally reviewed and assessed. Has YEC completed its internal review? If so, what are the results of YEC's review? If not, when does YEC expect to complete its internal review and assessment?

ANSWER:

(a) and **(b)**

The DSM Plan is being constructed to achieve the greatest savings for the lowest cost in each of the residential, commercial, and industrial sectors. Secondary sales customers that converted to primary supply for electric heating loads will be able to pursue the same DSM initiatives as every other primary supply customer. No special initiatives have been identified to date for these specific customers.

DSM is considered a "new, lower cost supply" option. As noted in the 2011 20-Year Resource Plan 2011:2030 Overview provided as an Attachment to YECL-YEC-1-18, DSM considered a resource option that will reduce diesel generation requirements at a LCOE <10c/kWh if fully utilized.

(c)

The Conservation and Demand Management Potential Review in 2011 undertaken collaboratively by the DSM working group consolidates data from multiple organizations and provides comprehensive research regarding Yukon Electricity use and opportunities to reduce consumption. This document is available for review on Yukon Energy's website at the link below:

http://www.yukonenergy.ca/energy/projects/dsm/#related_downloads.

Work to date has determined that between 50% and 70% of new residential and commercial construction (respectively) will be constructed with electric heat[1].

The DSM working group will continue to provide information about opportunities to reduce heating loads, and will include cost-effective programming where appropriate. Some programs conducted by members of the DSM working group will also address building envelope.

(d)

The following information regarding electric heating loads is available from the Conservation Potential Review:

- Exhibit ES5 of the Conservation Potential Review notes that (in the Base Year of 2010) domestic hot water and space heating each account for about 19% of total residential electricity use (approximately 146,000 MWh) (CPR Residential Sector Report, p.v)".

- "Space heating is expected to rise to 24% of residential electricity consumption" (p.vi).

- "Space heating is the second largest end use, accounting for 13% of Commercial sector electricity use" which totalled 166,133MWh in the base year of 2010 (Commercial Sector Final Report p.20, Exhibit 10 p.21).

(e)

The increased 2009 sales data for Streetlights compared to other years is due to an anomaly that occurred when the new Customer Information System (CIS) was implemented by YECL starting at November 1, 2008. Due to technical problems this anomaly could not be corrected until December 2009. During this period the monthly sales (kWh) were overstated but the revenues were correct.

[1] Based on working with YECL, and using historical data regarding new hook-ups.

(f)

Customers giving "advance notice" regarding taking service under Rate Schedule 39 (Industrial) since 2005 has typically only been provided by a customer indicating interest in negotiating a PPA with Yukon Energy for this service. To date, this has occurred for the existing Minto and Alexco mines (currently in service as Rate Schedule 39 customers), and potential future mines (Carmacks Copper, Victoria Gold, Whitehorse Copper Tailings, and Brewery Creek potential mines). Based on OIC 1995/90 and Rate Schedule 39, a customer will be charged this rate if it is connected to the grid and meets the criteria for a "Major Industrial Customer", i.e, in this sense, it is not up to a customer to "elect" to take service under this rate.

As noted in the Application (Tab 2), there are currently two industrial customers served under Rates Schedule 39: Minto mine and Alexco mine. At page 2-6, Whitehorse Copper Tailings is noted as an industrial load that is expected to require grid service commencing in July 2013. The Application also notes at page 2-7 that the Brewery Creek mine near Dawson City has informed YEC that it would like to discuss connection to the grid possibly as soon as mid-2013. This load was not included in test year load forecasts and Yukon Energy will update the Board at such time as there is more definitive information.

(g)

The reasons for instituting an auditing program are as follows:

- Energy audits provide a better understanding of how energy is used in the operation of a building or facility (i.e., how much energy is being used, where energy is being used, at what times and for what purposes). This type of information is essential to understand which projects and methods will be effective in reducing the energy usage of the building or operation in question.

- Audits generally provide recommendations regarding specific measures that can be undertaken to reduce energy use. Most audits outline the cost and anticipated kWh of energy savings that can be expected upon implementation of the recommendations.

- Energy audits provide a baseline of understanding which can be referenced during the verification process - thereby making audits an essential first step in any energy management program.

- Energy auditing can be a key element in demand side management as it provides a solid estimate of potential energy savings and the cost per kWh and kW saved. This allows a utility to compare the cost of conserving energy to the cost of building new supply to provide the energy. A building or facility owner is also able to understand the financial implications of the capital expenditure involved in implementation as well as the potential cost and energy savings.

- By conducting energy audits the utility builds general knowledge of the areas where there is a large potential to conserve energy in a broad sector. Some findings in an energy audit are very specific to the building or facility being examined, while many of the findings apply more generally to similar businesses, institutions or homes. Further benefits to the utility include an understanding of the hurdles and barriers to implementation that various sectors might anticipate as well as cost variances that might occur. These lessons inform and enhance the development of energy conservation initiatives or programs and their efficacy when delivered in the Yukon.

All audits have been completed under cost-sharing agreements where the audited customer is responsible for a greater portion of the costs if they do not implement recommendations and report savings within the first year following the audit. The audits that have been piloted to this point have resulted in identification of potential energy savings for the territory. As with all DSM programs, verifiable savings (in any sector) contribute to the most effective use of the current energy capacity of the Yukon thereby eliminating the need for, or at least postponing, the construction of new supply. See also response to CW-YEC-1-8.

(h)

The actual wind generator output available for the grid for 2009 was 0.238 GW.h, 0.085 GW.h in 2010 and 0.402 GW.h in 2011. The forecast amount of wind generation for 2012 is 0.239 GW.h and for 2013 is 0.238 GW.h.

(i)

The rationale for use in the test years of 66% (2012) and 59% (after 2012) of long-term average diesel generation requirements in rates, rather than 100%, is to mitigate rate impacts in these years and facilitate transition from 2009 GRA rates to once again setting rates based on revenue requirements of the full diesel generation costs based on forecast annual long term average hydro generation. The mitigation measure reduces expected contributions to the DCF during the test years and reduces rates charged. This approach takes advantage of current favorable water supply conditions, providing an opportunity to begin replenishing the DCF funds without immediately increasing rates as needed to reflect the cost of diesel generation requirements with hydro levels set at long-term average annual levels. This approach also allows for the potential future use of LNG at a materially lower fuel cost than diesel.

The amounts in the Application were finalized based on a balanced rate increase percentage for each of the two test years (6.40% in 2012 and 6.50% in 2013), and an overall objective to move meaningfully (e.g., one-half to one-third of the distance required) to reflect in rates 100% of long term average diesel generation requirements at the forecast grid loads. Lower amounts were not supported on the grounds that they would not materially move towards 100%. Higher amounts were not supported on the grounds that they would require rate increases in 2013 in excess of 6.50%.

See also response to YUB-YEC-12(a) and YUB-YEC-29(a).

(j)

The fuel price forecast for the 2012/13 GRA test years are based on actual diesel prices for Whitehorse, Faro, Mayo and Dawson effective February 1, 2012 provided by North 60 Petro Ltd. Actual prices effective this date were considered to be more appropriate for the current GRA than prices last approved by the Board for the 2009 GRA. The comparison referenced is to the fuel prices as last approved by the Board for the 2009 GRA.

The fuel price forecast levels approved in the 2009 GRA were as directed in Order 2009-08 (paragraphs 52 and 53) at $0.96 per litre for Whitehorse with differentials to other locations per YEC's application (+3.2 c/L for Faro, 1.5 c/L for Dawson City and 0.7 c/L for Mayo). The Board's direction reduced these fuel prices from the $1.149 per litre

forecast that YEC had provided in its 2009 GRA application, based on August 2008 NYMEX futures market crude oil prices adjusted for refining/shipping costs and exchange rate (please see Yukon Energy Corporation 2008-2009 General Rate Application, CW-YEC-1-16).

(k)

Peak demand on Yukon Integrated Grid is measured using hourly gross generation data from the Corporation's SCADA system. Hourly generation information is stored by SCADA system so is available for historical analysis and export to excel spreadsheets. Hourly customer load information is not recorded by SCADA.

Prior to connection of the grids in June 2011, peak demand was measured separately for WAF and MD grids.

Peak demand for the YEC grid generation is forecast based on the combined winter peak forecast for firm non-industrial load (based on estimated 2010-2011 average annual load factor for this load) and for firm industrial loads.

Table 1 below shows the calculation of the peak demand forecasts for the test years.

Table 1:
Yukon Energy Corporation 2012/13 GRA Peak Demand Forecast

Year	Total Generation (GWh) A=C+F	Total Peak MW B=D+G	Non-Industrial Generation (GWh) C	Non-Industrial Peak MW D	Load Factor E=C/8.76/D	Industrial Generation (GWh) F	Industrial Peak MW G
2010	371	74.1	338	67.3	57.35%	33	6.8
2011	400	76.9	353	70.0	57.60%	47	6.9
2012	416	80.1	359	71.3	57.48%	57	8.8
2013	430	81.1	363	72.0	57.48%	68	9.1

Notes:

1. Non-industrial peak for 2010 is estimated based on WAF and MD peak as shown in Table 2.2 of the 2012/13 GRA application (line 18 and 19) and minus estimated industrial peak.
2. Non-industrial peak for 2011 is estimated based on Integrated System peak occurred in November 2011 minus estimated industrial peak.
3. Non-industrial load factors for 2012 and 2013 are based average of 2010 and 2011 load factors.
4. Non-Industrial generation assumed non-industrial sales plus losses (calculated as non-industrial sales multiplied by % losses).
5. Industrial generation assumed industrial sales plus losses (calculated as non-industrial sales multiplied by % losses).
6. Higher than 2012 forecast peak, at 80.96 MW, was achieved in Integrated System in January 2012.

(l)

The system as currently configured meets the LOLE and N-1 tests when applied to the worst contingency of a failure of the Aishihik line. The system does not presently meet an N-1 test where the worst contingency test is applied to the L172 line that YEC owns and operates between Takhini and Whitehorse. This fact was well known in 2005, but at the time the Resource Plan highlighted that this line is short, and is close to trained crews, and as such it was not recommended to be adopted as the point of measurement for the N-1 test.

Since that time the load in Whitehorse has continued to grow, and the reliance on generation outside Whitehorse has increased. L172 has now become a critical point on the integrated grid and it is recognized that failure of this line means that all potential capacity from Faro, Mayo, Dawson and Aishihik is not available to Whitehorse.

There is no specific plan to reinforce or “twin” the line as of this time; currently, YEC is identifying and assessing the options available to achieve an equivalent outcome in this regard, including the option of lower voltage (35 kV) system reconfiguration or enhancement between the Takhini and McIntyre substations. It is expected that further

information and specific plans to provide the needed reinforcement will be known within the year.

See also response to YECL-YEC-1-31 and YECL-YEC-1-35.

(m)

Although certain conclusions are still being considered, including the implications noted in (l) above, the key results of the review by Doctors Billinton and Karki confirm continued use of the capacity planning criteria as previously adopted by Yukon Energy. Based on this review and the capacity planning criteria, updated capacity planning assessments for the grid assume that mine loads of about 13 MW will tend to result in the LOLE criteria being determinative rather than the N-1 criteria.

TOPIC: **Consultants**

REFERENCE: **Tab 3 Revenue Requirement**

QUESTION:

a) Please provide a table showing the amount YEC has spent and forecasts to spend on consultants for the years 2009 to 2012 inclusive. Within the table, provide a breakdown for each year based on the categories of Capital, Operation and Maintenance, Administration and General, and Regulatory, listing the individual and the organization that provided the service. Provide reference to any specific schedules containing these costs included in the Application.

b) For those individuals and organizations listed in part (a), for those instances where the costs exceed $50,000 in a given year, please provide the terms of reference of the consulting engagement, the related project, and the achieved results.

ANSWER:

(a)

Please see Attachment 1 to this response for the requested information.

(b)

Please see Attachment 1 to this response for the requested information.

Revised Response August 1, 2012

Since filing interrogatories July 27, 2012, the response to part (b) has been revised to correct one error in the description provided for 2011 Capital Projects (page 4 of 5 of Attachment 1 to this response). The version of Attachment 1 filed July 27, 2012 incorrectly attributed $321,000 of vendor costs for "Electricity Conservation and Demand Management Potential" to InterGroup Consultants Ltd. This has been corrected and these costs are attributed to ICF Marbek in the revised Attachment 1 to this response.

Further, on review it was noted that for some vendor costs there were descriptions that did not have total dollar amounts showing. This was due to the fact that total dollars were less than $1,000 and rounded to zero in presentation. Attachment 1 to this response has been revised to indicate that for these items the expense is < 1,000.

2009 Capital & Deferred	Amount ($000)
AECOM Canada Ltd.	1,679
BBA Inc.	27
Bluewater Biosciences	41
Chaos Electric Inc.	32
City of Whitehorse	65
CJ Consulting	29
Derek Crowe Photography	2
EBA Engineering Consultants Lt	832
Ecofor Consulting Ltd	28
eCorall Solutions Inc.	25
Environmental Dynamics Inc.	572
Fireweed Helicopters	10
Gerein Appraisal & Consulting	5
Government Of Yukon	75
H&N Enterprises	91
Hatch Ltd.	63
High Line Inspection Construct	3
Infomentat Inc.	30
Intergroup Consultants Ltd.	1,237
International Quest Engineerin	64
KGS Group	3,511
KPMG LLP	168
Laberge Environmental Services	10
M.P. Computing Ltd.	25
Maissan, John	9
Matrix Research Ltd.	9
MJ Solutions	11
N. A. Jacobsen P.Eng.	1
National Electrical Carbon Can	3
North/South Consultants Inc.	57
Northern Climate Engineering L	9
Orbis Engineering Field Servic	148
Peter Kiewit Sons Co.	49
Public Interest Advocacy Centr	29
R & D Environmental Management	12
Richard Huber Engineering Ltd.	<1K
Sadlier-Brown Consulting Ltd.	7
Technolise	5
Threlkeld Consulting Ltd.	98
Total North Communications	7
Underhill Geomatics Ltd.	16
Wardrop Engineering Inc.	655
Watt, Donald	10
Yukon Electrical Co. Ltd.	40
	9,798

2009 Administration O&M	Amount ($000)
AECOM Canada Ltd.	58
Aon Consulting Inc.	29
Archbould Photography	3
C.Caldwell Productions	10
Davis LLP	12
Design Group Staffing Inc.	20
eCorall Solutions Inc.	18
Environmental Dynamics Inc.	16
Gold Rush Inn	1
Government of Yukon	4
Greer, Lorrie	<1K
Hay Group Limited	26
Infomentat Inc.	80
Intergroup Consultants Ltd.	43
Jack Sekhon & Associates Inc.	9
Kim J. Lang	27
L.P. Kurach & Associates	6
M.P. Computing Ltd.	17
MAP Communications	2
MGCG Ltd.	2
Networkologist	33
Orbis Engineering Field Servic	14
R & D Environmental Manager	78
Riverspill Response Canada Lt	9
Subvert Marketing Inc.	10
Threlkeld Consulting Ltd.	6
UMA Engineering Ltd.	19
Underhill Geomatics Ltd.	3
Wordsworth & Associates	1
ZRG Canada Inc.	5
	561

2009 Regulatory O&M	Amount ($000)
Intergroup Consultants Ltd.	3
	3

2010 Capital & Deferred	Amount ($000)
AECOM Canada Ltd.	3,679
Waste to Energy Canada	100
Acuren Group Inc.	52
AmericanGovernor	5
Archbould Photography	5
BBA Inc.	174
BC Hydro	20
Bluewater Biosciences	19
Callow & Associates Mngmt Cons	12
CAP Engineering	162
CEATI International Inc.	35
City of Whitehorse	26
EBA Engineering Consultants Lt	438
ECI	56
Ecofor Consulting Ltd	90
eCorall Solutions Inc.	64
Edgewater Hotel	2
Environmental Dynamics Inc.	717
Frontier Geosciences Inc.	17
Glacier Drilling	2
Government Of Yukon	135
H&N Enterprises	51
Hatch Ltd.	76
Infomentat Inc.	8
Intergroup	1,120
International Quest Engineerin	9
JJRM Project Ltd.	186
KGS Group	696
Klohn Crippen	84
Kluane First Nation	<1K
Kobayashi & Zedda Architects L	10
KPMG LLP, T4348	105
Laberge Environmental Services	10
Lesley Cabott Consulting	64
Levelton Consultants Ltd.	<1K
M.P. Computing Ltd.	1
Matrix Research Ltd	12
Morrison Hershfield Limited	16
Natural Power Consultants Ltd.	22
North/South Consultants Inc.	14
Orbis Engineering Field Servic	6
Public Interest Advocacy Centr	16
Quest Engineering Group	16
Sadlier-Brown Consulting Ltd.	12
Sandwell Engineering Inc.	107
The Da-trol Group Inc.	46
Threlkeld Consulting Ltd.	265
Total North Communications	6
Underhill Geomatics Ltd.	2
Vector Research	17
Voith Hydro Inc.	6
Wardrop Engineering Inc.	1,938
WennSoft Inc.	1
Yukon Conservation Society	2
Yukon Engineering Services Inc	22
	10,758

2010 Administration O&M	Amount ($000)
AECOM Canada Ltd.	87
Access Mining Consultants Ltd	2
Aon Consulting Inc.	7
Aon Reed Stenhouse Inc.	8
Bellringer, Stephen	2
CMS Management Consulting	58
Design Group Staffing Inc.	16
E.A. Nunn Enterprises Ltd.	6
EBA Engineering Consultants L	2
eCorall Solutions Inc.	9
Environmental Dynamics Inc.	1
Hatch Ltd.	3
Hay Group Limited	21
Infomentat Inc.	53
Intergroup Consultants Ltd.	77
L.P. Kurach & Associates	2
Mainland Information Systems	18
Networkologist	17
Pekeles, Robert	1
R & D Environmental Manage	46
Underhill Geomatics Ltd.	9
Vandelay Systems	2
VCURA Canada Incorporated	12
Western Industrial Relations L	1
Aasman Design Inc.	2
Archbould Photography	3
	466

2010 Operations O&M	Amount ($000)
15878 Yukon Inc.	1
BBA Inc.	5
E.A. Nunn Enterprises Ltd	38
Stewart Hearing Health	<1K
	43

2010 Regulatory O&M	Amount ($000)
Intergroup Consultants Ltd.	36
	36

2011 Capital & Deferred	Amount ($000)
AECOM Canada Ltd.	3,004
Aasman Design Inc.	47
Access Mining Consultants Ltd.	1
Ajax Steel	43
American Governor Company	19
Archbould Photography	2
BBA Inc.	446
BC Hydro International Limited	12
Bluewater Biosciences	2
Borealis Geo Power Inc.	23
CAP Engineering	360
Challenger Geomatics	52
City of Whitehorse	25
Da-trol Group Inc., The	111
Demand Side Energy	40
Digital Boundary Group	38
Don Toews	16
Dr. Chilakammrri Rangacharyulu	2
Dr. Mark Jaccard	1
EBA Engineering Consultants Lt	153
ECI	21
Ecofor Consulting Ltd	5
eCorall Solutions Inc.	144
Environmental Dynamics Inc.	397
Fekete Associates	9
FSC Architects & Engineers	2
Government of Yukon	123
Hatch Ltd.	62
Howell-Mayhew Engineering Inc.	13
ICF Marbek	321
Intergroup Consultants Ltd.	1,049
JJRM Project Ltd.	198
Katopodis Ecohydraulics Ltd.	4
KGS Group	503
Kirkwood, Ron	10
Klohn Crippen Berger Ltd.	16
KPMG LLP, T4348	70
Lesley Cabott Consulting	177
Maissan, John	4
Mark Green	3
Matrix Research Ltd	1
McMahon, Patrick	8
Meerholz Canada	30
Morrison Hershfield Limited	116
Natural Power Consultants Ltd.	102
Normandeau associates, Inc	1
North American Construction (1	19
One Change Foundation	109
Public Interest Advocacy Centr	5
RSC Group, The	198
Sadlier-Brown Consulting Ltd.	10
Senes Consultants Limited	46
Stantec Architecture Ltd	95
Streicker, John	13
Survalent Technology	13
Thomas R. Payne & Associates	8
Threlkeld Consulting Ltd.	201
Total North Communications	5
Underhill Geomatics Ltd.	4
University Of Saskatchewan	10
Vanbibber, Pat	10
Vector Research	69
Wardrop Engineering Inc.	842
WennSoft Inc.	62
Yukon College	100
	9,605

2011 Administration O&M	Amount ($000)
A. Lanfranco and Associates In	6
Aasman Design Inc.	5
Access Mining Consultants Ltd	3
AECOM Canada Ltd.	47
AON Hewitt	25
Aon Reed Stenhouse Inc.	3
Archbould Photography	1
Arcrite Northern Ltd.	1
Bellringer, Stephen	6
Christian's Photography	<1K
Cliff Planning and Developmer	54
EBA Engineering Consultants L	14
eCorall Solutions Inc.	7
Environmental Dynamics Inc.	49
Golder Associates	12
Hay Group Limited	9
Infomentat Inc.	53
Intergroup Consultants Ltd.	148
Kennedy, Justin T	1
KGS Group	1
Kifinti Solutions inc.	50
L.P. Kurach & Associates	2
Levelton Consultants Ltd.	49
Lumos Energy	13
Mainland Information System:	11
Networkologist	5
R & D Environmental Manager	53
Red Seal Recruiting Solutions	15
Riverspill Response Canada Lt	5
Underhill Geomatics Ltd.	2
Vandelay Systems	12
Vincent L. Ready	4
Watson Advisors	48
Western Industrial Relations L	20
	733

2011 Operations O&M	Amount ($000)
Archbould Photography	<1K
Davis LLP	1
E.A. Nunn Enterprises Ltc	24
EBA Engineering Consulta	1
Innovative Fall Protectior	7
Rymad Engineering Inc.	27
	61

2011 Regulatory O&M	Amount ($000)
Intergroup Consultants Ltd.	32
KGS Group	7
	39

Year	Activity Type	Vendor	Total ($000)	Project Description
2009	**Capital**			
		AECOM Canada Ltd.	180	Renewable Resource Planning - Upper Pelly Large Hydro
		AECOM Canada Ltd.	366	Renewable Resource Planning - Marsh Lake Storage
		AECOM Canada Ltd.	2	Earth-Tech Canada - eng services for design and installation of the Wareham Dam Spillway bridge deck
		AECOM Canada Ltd.	498	Renewable Resource Planning - Gladstone Diversion
		AECOM Canada Ltd.	229	Renewable Resource Planning - Atlin Storage
		AECOM Canada Ltd.	134	Engineering partnership miscellaneous projects
		AECOM Canada Ltd.	37	System Protection & Coordination Study
		AECOM Canada Ltd.	13	Aishihik Fire Protection
		AECOM Canada Ltd.	12	Wareham Dam
		AECOM Canada Ltd.	135	AH3 Preliminary Design
		AECOM Canada Ltd.	9	Update Aishihik Drawings
		AECOM Canada Ltd.	14	Earth Tech Canada Contract'
		AECOM Canada Ltd.	48	AH3 Engineering design
		AECOM Canada Ltd.	4	Miscellaneous services
			1,679	
		City of Whitehorse	65	GRA cost award
		EBA Engineering Consultants Lt	7	Testing of Concrete Samples
		EBA Engineering Consultants Lt	5	Miscellaneous services
		EBA Engineering Consultants Lt	726	Geothermal Program
		EBA Engineering Consultants Lt	95	Geothermal Program
			832	
		Environmental Dynamics Inc.	18	CSTP Stage 2 Timber Salvage Management Plan
		Environmental Dynamics Inc.	514	Mayo B Environmental Assessment - Biophysical, Heritage and Arch Baseline Studies
		Environmental Dynamics Inc.	40	Aishihik Fish Monitoring
			572	
		Government Of Yukon	75	GRA cost award
		H&N Enterprises	91	CSTP Stage 2 on-site supervision
			91	
		Hatch Ltd.	63	Turbine Performance Testing
		Intergroup Consultants Ltd.	280	Support for Financial and Regulatory
		Intergroup Consultants Ltd.	17	Regulatory, Consulting Services
		Intergroup Consultants Ltd.	6	Mayo B Socio-Economic Consulting
		Intergroup Consultants Ltd.	285	Regulatory and Environmental Assessment
		Intergroup Consultants Ltd.	41	Mayo B Part 3
		Intergroup Consultants Ltd.	532	Mayo B Project Management
		Intergroup Consultants Ltd.	75	Resource Planning oversight services
			1,237	
		International Quest Engineerin	5	Aishihik Hydro Hoist Inspection
		International Quest Engineerin	5	Wareham Stoplog Hoist inspection
		International Quest Engineerin	54	Engineering Technical support
			64	
		KGS Group	36	Power Benefits Model Construction
		KGS Group	6	Mayo Lake Intake Gate Design Consulting
		KGS Group	7	Canyon Creek Heritage Bridge Design
		KGS Group	11	Aishihik River Icing
		KGS Group	1	Wareham Rock Face Assessment
		KGS Group	20	Seismic Study Mayo Dam
		KGS Group	444	Preliminary Engineering for Mayo B Project
		KGS Group	33	Support for Power Benefits Model
		KGS Group	2,831	Mayo B Phase 3a Preliminary Design
		KGS Group	114	Turbine Performance Testing on WH1,2 and 3.
		KGS Group	8	Modelling - Marsh Lake storage project
			3,511	
		KPMG LLP	168	IFRS Conversion Advisory Services
		North/South Consultants Inc.	42	Fisheries Consulting - Aishihik Fish Act Authorization
		North/South Consultants Inc.	16	2006 Aishihik Fish Monitoring
			57	
		Orbis Engineering Field Servic	148	Standing Agreement - various Electrical Engineering Consulting Services
		Threlkeld Consulting Ltd.	95	Engineering advisory services CSTP Stage 2
		Threlkeld Consulting Ltd.	3	Engineering advisory services CSTP Stage 1
			98	
		Wardrop Engineering Inc.	546	Final Engineering Design CSTP Stage 2
		Wardrop Engineering Inc.	31	Procurement Services CSTP 2
		Wardrop Engineering Inc.	10	CSTP Stage 2 System Study
		Wardrop Engineering Inc.	68	Preliminary Engineering Design CSTP Stage 2
			655	
	Admin			
		AECOM Canada Ltd.	11	Wind Assessment Study
		AECOM Canada Ltd.	47	Engineering partnership - miscellaneous projects
			58	
		Infomentat Inc.	4	IT Technical Support
		Infomentat Inc.	3	IT Technical Support
		Infomentat Inc.	2	IT Technical Support
		Infomentat Inc.	3	IT Technical Support
		Infomentat Inc.	69	IT Technical Support as and when required
			80	
		R & D Environmental Manageme	78	Fish Hatchery Management

Year	Activity Type	Vendor	Total ($000)	Project Description
2010	Capital			
		Acuren Group Inc.	52	Welding Preheat Services and Inspection WH4
		AECOM	93	Engineering partnership miscellaneous projects
		AECOM	53	Roop Lake
		AECOM	543	Marsh Lake
		AECOM	1,109	Atlin Lake
		AECOM	1,731	Gladstone
		AECOM	82	Large Hydro
		AECOM	21	System Protection and Coordination Study
		AECOM	11	Wareham Dame Bridge
		AECOM	23	Wareham Dam Construction Phase
		AECOM	13	Mayo Lake Control Structure Refurbishment design.
			3,679	
		BBA	21	Services for Operations and Mntce tech assistance
		BBA	15	Engineering Services Mayo Substation Assessment
		BBA	3	Engineering Services Mayo Substation Assessment
		BBA	8	Cost Estimate Interconnection
		BBA	15	Energy Storage Study
		BBA	20	Transmission Planning Costing Model
		BBA	4	Protection Event Collection System Preliminary Engineering Study
		BBA	15	Communications Needs Assessment
		BBA	73	Dam Safety Review
			174	
		CAP Engineering	115	PM & Inspection Services Civil Projects in and around Mayo
		CAP Engineering	15	Site project management AH3 civil work
		CAP Engineering	31	Wareham Dam Project Management
			162	
		EBA Engineering Consultants Lt	15	AH as and when reqd geotechnical assistance
		EBA Engineering Consultants Lt	19	
		EBA Engineering Consultants Lt	2	
		EBA Engineering Consultants Lt	40	Geothermal Project
		EBA Engineering Consultants Lt	1	
		EBA Engineering Consultants Lt	354	Geothermal Program
		EBA Engineering Consultants Lt	6	Geothermal Program
			438	
		Ecofor Consulting Ltd	5	Mayo B Additional Assessment and Monitoring
		Ecofor Consulting Ltd	50	Mayo Lake Historic Resource Impact Assessment
		Ecofor Consulting Ltd	34	Mayo Lake Heritage Recovery Excavation
			90	
		eCorall Solutions Inc.	19	JDE Consulting Services
		eCorall Solutions Inc.	45	Enterprise System Selection
			64	
		ECI	56	ROW Vegetation Assessment and Management
		Environmental Dynamics Inc.	25	CSTP ROW Revegetation
		Environmental Dynamics Inc.	8	Timber Salvage Management Plan
		Environmental Dynamics Inc.	7	Permitting for Bridge at Crooked Creek
		Environmental Dynamics Inc.	11	Timber Salvage Assessment for Mayo B
		Environmental Dynamics Inc.	54	Mayo B Nesting Assessment
		Environmental Dynamics Inc.	6	Timber Salvage Assessment for Mayo B
		Environmental Dynamics Inc.	54	Mayo River Fish Monitoring
		Environmental Dynamics Inc.	377	Mayo Lake Supplemental Studies
		Environmental Dynamics Inc.	102	Biophysical, Heritage and Arch Baseline Studies
		Environmental Dynamics Inc.	2	Aishihik FAA
		Environmental Dynamics Inc.	6	Aishihik Fish Monitoring
		Environmental Dynamics Inc.	65	2010 Aishihik Fish Monitoring
			717	
		Government Of Yukon	135	GRA cost award
		H&N Enterprises	51	CSTP Stage 2 on-site supervision
		Hatch Ltd.	9	Review construction requirement Mayo Lake Control Structure
		Hatch Ltd.	67	Cons & Eng Services to the 138 kV transmission line from Carmacks to Stewart
			76	
		Intergroup	11	Mayo B Water Board Ammendment
		Intergroup	224	Regulatory, Financial and Consulting Services
		Intergroup	86	Mayo B Part 3
		Intergroup	381	Mayo B Project Management
		Intergroup	6	Mayo B Water Board Amendment
		Intergroup	267	Regulatory and Environmental Assessment Services - Mayo B
		Intergroup	55	Mayo Lake Additional Storage
		Intergroup	90	Resource Planning Oversight Services
			1,120	
		JJRM Project Ltd.	40	Mayo B Project Coordinator
		JJRM Project Ltd.	147	Mayo B Project Coordinator
			186	
		KGS Group	4	AH3 modelling
		KGS Group	1	AH3 Operations plan
		KGS Group	169	Mayo Lake Intake Gate Consulting
		KGS Group	176	Engineering design for rock slope stabilization: Mayo Intake
		KGS Group	3	Aishihik River Icing - dike survey/drafting
		KGS Group	14	Canyon Creek Heritage Bridge Design

Year	Activity Type	Vendor	Total ($000)	Project Description
		KGS Group	238	Mayo B Phase 3a Preliminary Design
		KGS Group	49	Turbine Performance Testing on WH1,2 and 3.
		KGS Group	10	Marsh Lake Modelling
		KGS Group	4	Aishihik FAA - modelling
		KGS Group	20	Mayo and Wareham Dam liquefaction assessment
		KGS Group	9	Support for Power Benefits Model
			697	
		Klohn Crippen	22	P125 Bulkhead Gate Design
		Klohn Crippen	62	On-site Safety Review of three headgates WH1, WH2 and WH3
			84	
		KPMG	105	IFRS Consulting
		Lesley Cabott Consulting	64	Waste to Energy Project Management
		Sandwell Engineering Inc.	107	CSTP II Project Management
		Threlkeld Consulting Ltd.	265	CSTP Stage 2 Project Corrdinator
		Wardrop Engineering	1,818	CSTP Stage 2 Design
		Wardrop Engineering	120	Procurement Services
			1,938	
		Waste to Energy	100	Waste to Energy research
	Admin			
		AECOM Canada Ltd.	62	Environmental Management System Update and Implementation
		AECOM Canada Ltd.	25	Engineering Partnership - miscellaneous projects
			87	
		CMS Management Consulting Inc	58	Recruitment Services
		Infomentat Inc.	53	IT Support Services as and when req'd
		Intergroup Consultants Ltd.	77	Regulatory, Financial and Consulting Services

Year	Activity Type	Vendor	Total ($000)	Project Description
2011	**Administration**			
		Cliff Planning and Development	54	Board Chair Services
		Infomentat Inc.	49	IT Support Services
		Infomentat Inc.	4	IT Support Services
			53	
		Intergroup Consultants Ltd.	147	Financial & Regulatory Consulting
		Intergroup Consultants Ltd.	<1K	Resource Planning Oversight Services
			148	
		R & D Environmental Manageme	53	Fish Hatchery Management
	Capital	AECOM Canada Ltd.	30	Roop Lake Water Gauging
		AECOM Canada Ltd.	10	Charrette Participation
		AECOM Canada Ltd.	20	System Protection and Coordination Study
		AECOM Canada Ltd.	551	Renewable Resource Planning - Marsh Lake Storage
		AECOM Canada Ltd.	663	Renewable Resource Planning - Atlin Storage
		AECOM Canada Ltd.	361	Renewable Resource Planning - Gladstone Diversion
		AECOM Canada Ltd.	16	Renewable Resource Planning - Upper Pelly Large Hydro
		AECOM Canada Ltd.	85	AH3 Prelim Engineering
		AECOM Canada Ltd.	1	AH3 Detailed Design and Construction
		AECOM Canada Ltd.	5	Roop Lake Water Gauging
		AECOM Canada Ltd.	1,068	Marsh lake
		AECOM Canada Ltd.	(10)	Atlin
		AECOM Canada Ltd.	191	Gladstone
		AECOM Canada Ltd.	7	Upper Pelly
		AECOM Canada Ltd.	7	Update Mt. Sumanik Wind Study
			3,004	
		BBA Inc.	20	Engineering Services Mayo Substation Assessment
		BBA Inc.	281	Mayo A Substation Detailed Design
		BBA Inc.	15	Charrette Participation
		BBA Inc.	29	Energy Storage Study
		BBA Inc.	37	Transmission Planning Cost Model
		BBA Inc.	63	Communications Needs Assessment
		BBA Inc.	2	Costing Model Training
			446	
		CAP Engineering	360	AH3 Project Management
		Challenger Geomatics	43	CSTP Stage 2 Legal Survey
		Challenger Geomatics	9	CSTP Stage 2 Legal Survey
			52	
		Da-trol Group Inc., The	111	CMMS Project Manager Roll-out #1
		EBA Engineering Consultants Lt	3	Aishihik Switchgear Foundation
		EBA Engineering Consultants Lt	1	AH as and when reqd geotechnical assistance
		EBA Engineering Consultants Lt	2	Aishihik Switchgear Slab testing
		EBA Engineering Consultants Lt	27	Mayo Sub testing
		EBA Engineering Consultants Lt	11	Soil Testing, site assessment
		EBA Engineering Consultants Lt	7	Geotech - Takhini Substation
		EBA Engineering Consultants Lt	101	Geothermal Project
		EBA Engineering Consultants Lt	<1K	Mayo River Icing study
			153	
		eCorall Solutions Inc.	144	Enterprise System Implementation Project Management
		Environmental Dynamics Inc.	17	Mayo River Fish Monitoring
		Environmental Dynamics Inc.	174	2010 Aishihik Whitefish Monitoring
		Environmental Dynamics Inc.	<1K	Wareham Rock Scaling
		Environmental Dynamics Inc.	<1K	Mayo A Tailrace
		Environmental Dynamics Inc.	49	Mayo B Permitting Assistance
		Environmental Dynamics Inc.	63	Workplan to Complete Mayo River Monitoring
		Environmental Dynamics Inc.	2	Mayo B Nesting Survey
		Environmental Dynamics Inc.	79	Mayo Lake Supplemental Studies
		Environmental Dynamics Inc.	12	Feasibility of Fisheries Enhancement
		Environmental Dynamics Inc.	<1K	Climate change Study Map Update
			397	
		Government of Yukon	123	GRA Cost Award
		Hatch Ltd.	4	System Stability Study
		Hatch Ltd.	59	System Stability Study - assess CSTP Intertie
			62	
		ICF Marbek	5	Electricity Conservation and Demand Management Potential
		ICF Marbek	316	Electricity Conservation and Demand Management Potential
			321	
		Intergroup Consultants Ltd.	41	Mayo B Project Management
		Intergroup Consultants Ltd.	59	Regulatory and Environmental Assessment
		Intergroup Consultants Ltd.	63	Mayo B Water Board Amendment
		Intergroup Consultants Ltd.	44	Mayo Lake Additional Storage
		Intergroup Consultants Ltd.	72	Resource Planning oversight services
		Intergroup Consultants Ltd.	44	Phase II GRA ($9,418.25); Rider F Policy Review
		Intergroup Consultants Ltd.	496	Resource Plan Update 2010
		Intergroup Consultants Ltd.	200	Mayo Lake Additional Storage
		Intergroup Consultants Ltd.	28	Mayo Lake Additional Storage
		Intergroup Consultants Ltd.	3	Mayo River Salmon Enhancement
			1,049	
		JJRM Project Ltd.	198	Mayo B Project Coordinator

Year	Activity Type	Vendor	Total ($000)	Project Description
		KGS Group	35	Mayo B Contract Administration
		KGS Group	106	Mayo Intake Gate Consulting
		KGS Group	<1K	Permitting + Hydro Mayo B
		KGS Group	43	Eng design, production of tender drawings for Wareham Core Raise Phase I
		KGS Group	52	Canyon Creek Heritage Bridge Flood Proofing
		KGS Group	13	Turbine Performance Testing
		KGS Group	25	Wastewater Handling
		KGS Group	118	Mayo River Ice Study
		KGS Group	7	Mayo Lake Bathymetric
		KGS Group	42	Support for Power Benefits Model
		KGS Group	63	Mayo B Final Design Services
			503	
		KPMG LLP, T4348	70	IFRS Advisory Services
		Lesley Cabott Consulting	69	WTEC Program Management
		Lesley Cabott Consulting	108	Energy Charette
			177	
		Morrison Hershfield Limited	10	Charrette Participation
		Morrison Hershfield Limited	106	WTEC Tech Advisory Support
			116	
		Natural Power Consultants Ltd.	12	Charrette Participation
		Natural Power Consultants Ltd.	5	Engineering Assessment Ferry Hill Site
		Natural Power Consultants Ltd.	85	Mt Sumanik Feasibility
			102	
		One Change Foundation	4	Charrette Participation
		One Change Foundation	22	DSM Program
		One Change Foundation	83	Demand Side Management Program
			109	
		RSC Group, The	170	Financial Software Implementation
		RSC Group, The	28	Financial Software Implementation
			198	
		Stantec Architecture Ltd	95	Facilities Energy Audit
		Threlkeld Consulting Ltd.	201	CSTP Stage 2 Project Coordinator
		Vector Research	47	Charrette Planning, delivery, reporting
		Vector Research	11	Gladstone Business Case Analysis
		Vector Research	10	Bioenery Case Study
		Vector Research	1	WTEC Economics & Envir Assessment
			69	
		Wardrop Engineering Inc.	726	CSTP Design
		Wardrop Engineering Inc.	116	Procurement Services CSTP Stage 2
			842	
		WennSoft Inc.	62	Design and Implementation of CMMS and job cost modules - Financial info system
			62	
		Yukon College	7	Prepare and present course on climate change
		Yukon College	94	Study on the effect of climate change on glaciation - resource plan
			100	

TOPIC: **Forecast Fuel and Purchase Power Costs**

REFERENCE: **Application, page 3-2**

These increases reflect higher loads, adjusted fuel prices (small increase), and provisions for diesel being required based on a percentage of long-term average hydro generation.

QUESTION:

a) Please provide a cost breakdown of the increase based on higher load, adjusted fuel prices, and provisions for diesel being required based on a percentage of long-term average hydro generation.

b) Please provide what forecast fuel prices would be if the assumptions and calculations used were those that existed before the proposed changes to the Diesel Contingency Fund (DCF) and the changed definition of "diesel on the margin".

ANSWER:

(a)

The reference is to the increase in forecast Fuel and Purchase Power costs by 526% from 2009 approved to the 2013 forecast, with a $1.70 million increase from 2009 approved to the 2012 forecast and a further $0.91 million increase in 2013 over 2012 forecast.

Because the DCF was not activated prior to 2012, Yukon Energy's ROE was impacted directly by diesel fuel and incremental diesel non-fuel O&M costs during 2009, 2010 and 2011 to the extent that, due to lower-than-expected water conditions, these costs materially exceeded the 2009 forecast that the YUB approved for inclusion in YEC's 2009 revenue requirement and rates. Compared to 2009 approved Fuel forecast of $0.443 million, actual Fuel cost (at 2009 GRA approved forecast fuel prices) for diesel generation required for operations (excluding generation costs assigned to capital projects) was $0.623 million in 2009, $1.145 million in 2010 and $2.708 million in 2011.

The 2009 GRA diesel forecast as approved included 1.262 GW.h of diesel generation (350,600 litres fuel) and a further 100,700 litres for diesel maintenance activities at an average approved fuel price of approximately 98.1 c/litre. Please see Tables 1 and 2 below for fuel cost breakdown of the approximate increases in fuel costs since 2009 approved based on higher loads, adjusted fuel prices and average fuel efficiencies (calculations are done by location, and reflect impact of changing mix of diesel generation by location).

Forecast diesel generation in the 2009 GRA was not based on long term average hydro (as noted at footnote 5, page 3-4 of the 2012/13 GRA, long term average (LTA) diesel generation based on approved 2009 loads would approximate 4 GW.h, implying that forecast diesel was only about 32% of LTA).

Forecast diesel generation in the 2012/13 GRA approximates 66% of LTA for 2012 (7.5 GW.h versus LTA of 11.5 GW.h at LTA) and 59% of LTA for 2013 (10.7 GW.h versus 18.2 GW.h at LTA).

Table 1:
2012 Fuel Cost at 2009 GRA and 2012/13 GRA
Fuel Efficiencies and Fuel Prices

Line #	Description	($000)
1	Fuel cost in 2009 GRA Compliance Filing	443
2	Estimated 2012 fuel cost at 2009 GRA fuel efficiency and fuel prices	2,005
3=2-1	Increase in fuel cost due to higher diesel generation	1,562
4	Estimated 2012 fuel cost at updated fuel efficiencies and 2009 GRA fuel prices	1,944
5=4-2	Decrease in fuel cost due to updated fuel efficiencies	(60)
6	2012 fuel cost in 2012/13 GRA (updated fuel efficiencies and fuel prices)	2,163
7=6-2	Increase in fuel cost due to updated fuel prices	158

Note:
1. The fuel cost in Line 6 is from Table 3.2 of the GRA application.

Table 2:
2013 Fuel Cost at 2009 GRA and 2012/13 GRA
Fuel Efficiencies and Fuel Prices

Line #	Description	($000)
1	Fuel cost in 2009 GRA Compliance Filing	443
2	Estimated 2013 fuel cost at 2009 GRA fuel efficiency and fuel prices	2,848
3=2-1	Increase in fuel cost due to higher diesel generation	2,405
4	Estimated 2013 fuel cost at updated fuel efficiencies and 2009 GRA fuel prices	2,762
5=4-2	Decrease in fuel cost due to updated fuel efficiencies	(86)
6	2013 fuel cost in 2012/13 GRA (updated fuel efficiencies and fuel prices)	3,073
7=6-2	Increase in fuel cost due to updated fuel prices	225

Note:
1. The fuel cost in Line 6 is from Table 3.2 of the GRA application.

(b)

2012/13 GRA forecast fuel prices would not change. The 2012/13 GRA fuel prices are actuals effective February 1, 2012, and are not related to assumptions or calculations used for the DCF or definitions adopted for "diesel on the margin".

TOPIC: **Fuel and Purchased Power**

REFERENCE: **Application, Section 3.2**

Fuel and Purchased Power costs as set out in Table 3.2 for 2012 and 2013 test years increase to $2.203 million and $3.113 million respectively (from $0.497 million in 2009 approved), reflecting higher loads, adjusted fuel prices and provisions for diesel being required based on annual long-term average hydro generation. Due to low water conditions and non-activation of the DCF, fuel costs in 2011 were material, at levels higher than the 2012 forecast and comparable to the 2013 forecast.

Diesel generation in late 2010 and early 2011 reflected below average water conditions and non-activation of the DCF.

Due to reduced surplus hydro generation caused by material increases in load, diesel is forecast in the test years to be on the margin at annual long-term average hydro generation levels.

However, these test year forecasts are adopted to address the transition to annual long-term average levels and potential future use of LNG at a materially lower cost than diesel and are consequently lower in each year than the levels that would be required assuming annual long-term average hydro generation.

QUESTION:

a) Please explain how non-activation of the DCF contributed to diesel generation in late 2010 and early 2011.

b) Please explain what is meant by “diesel is forecast in the test years to be on the margin” — i.e. is diesel on the margin a majority of the time?

c) In terms of length of time and as it relates to the DCF, please explain what is meant by “long-term average hydro generation levels”.

d) Have changes respecting the length of time used to calculate long-term average generation levels remained the same over the period when the DCF was, and was not, in use up to the current test years?

ANSWER:

(a)

Non-activation of the DCF did not contribute to diesel generation in late 2010 or early 2011.

The quoted reference was intended to address diesel generation fuel cost impacts related to non-activation of the DCF, i.e., diesel generation as such is not affected by the DCF.

The references to fuel costs being material in 2011, and "diesel generation" in late 2010 and early 2011 reflecting non activation of the DCF, are explaining fuel costs as shown on YEC's income statements for those years. Below average water conditions lead to the requirement to use diesel generation - and non activation of the DCF at that time meant that all diesel generation costs incurred in this regard went directly to YEC's fuel costs.

When the DCF is activated, diesel generation fuel costs are charged to YEC fuel costs based solely on the DCF-specified diesel generation requirement (e.g., diesel generation assuming long-term average hydro, if this is what the DCF specifies) and are not affected by changes in water conditions that affect hydro generation.

Accordingly, non-activation of the DCF contributed to the higher diesel generation costs shown as YEC fuel costs in late 2010 and early 2012 to the extent that such higher costs reflected low water conditions.

(b)

In the context of Section 3.2, the phrase "diesel is forecast in the test years to be on the margin" simply means that the reactivated DCF will apply during these years for determination of YEC diesel fuel generation costs.

The Application assumes that the DCF, as updated in Attachment 3.2, is reactivated effective January 1, 2012. On this basis, starting January 1, 2012 and thereafter, diesel generation will be charged to YEC fuel costs based on the reactivated DCF.

As reviewed in Section 2.3.2 of the Application, and in Appendix 3.2, the term "diesel on the margin" is a concept that in the past triggered the DCF as well as other cost recovery and rate mechanisms. As explained in Attachment 3.2 (page 3.2-4), the updated DCF would be permanently switched "on" through a formulaic approach that automatically adjusts forecast long-term hydro generation and related diesel (or other non-diesel fossil fuel) generation to reflect actual grid generation load. Accordingly, under the updated DCF there would no longer be a "diesel on the margin" test for activating the DCF.

(c)

The term "long-term average hydro generation levels" as applicable to the updated DCF is the average annual YEC hydro generation on the grid under a given set of assumed grid generation load and generation capacity and licence conditions based on 28 years of water record ("water years" 1981-2008) for the interconnected grid. More specifically, it is the long-term average hydro generation under a given set of assumed grid generation load and other conditions as estimated by the simulation model "YECSIM" developed for the integrated grid by KGS Group.

As reviewed in Attachment 3.2 of the Application which addresses the DCF as updated for the Application, Tables 3.2-1 and 3.2-2, the long-term average hydro generation levels for the test years are determined by the YECSIM simulation model that develops expected hydro generation for each load scenario. The model reviews, by week, the 28 "water years" of record and 20 "load years" (each examines a different hypothetical scenario to reflect different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this deletes cases where starting or ending year volumes can distort results).

(d)

No. The current YECSIM model was developed after the 2006 Resource Plan and was used in the assessment of the Mayo B Project (see Mayo B Part 3 Application hearing). The earlier DCF as approved in the 1996/97 GRA reflected an earlier model and different water year information.

TOPIC: **Forecast Fuel Costs**

REFERENCE: **Application, page 3-5**

However, these test year forecasts are adopted to address the transition to annual long-term average levels and potential future use of LNG at a materially lower cost than diesel, and are consequently lower in each year than the levels that would be required assuming annual long-term average hydro generation.

QUESTION:

a) Please provide a net present value (NPV) analysis that supports YEC's proposed "future use of LNG at a materially lower cost than diesel." Is it YEC's intention to use LNG generation to complement diesel generation during the test years?

b) In respect of the integrated system, please provide a list of all generating units and their respective efficiencies.

ANSWER:

(a)

YEC is not currently intending to use LNG generation during the test years.

The opportunities today to develop LNG use in Yukon are still in the resource assessment stage and based on available information at the time of filing 2012/13 GRA Application the earliest in-service date is estimated to be 2014. Available analysis from the 2011 Resource Plan indicates potential LCOE (2010$) for LNG use at Whitehorse under Scenario A loads at 18.4 cents/kW.h (compared to diesel fuel and O&M costs at 28 cents/kW,h). Please see Overview of 20-Year Resource Plan: 2011-2030, as provided in response to YECL-YEC-1-18, Table 8-2.

Subject to securing LNG supply, LNG/Natural Gas is recognized as a reliable resource option for power generation that offers many of the same attributes as diesel generation,

but at lower overall cost, GHG emissions and air pollutants than diesel. Key related features include[1]:

- Natural gas power plants are intended to be operated only when required and (subject to securing fuel supply) can be relatively easily integrated into the Yukon system as conversion or replacement of the current diesel generation plant. New equipment and retrofit of existing diesel engines can provide a range of options for LNG/natural gas use, including options for dual fuel (diesel/natural gas) operation.

- Natural gas power plants require relatively low capital costs, with options for "scalable" generation over a wide range of sizes, as well as options for combined cycle and cogeneration (with associated higher capital costs).

- Natural gas power plant operating costs are mostly composed of fuel cost that is subject to ongoing inflation and market price uncertainty, although natural gas prices in North America have tended to show more moderate swings than diesel prices.

- Natural gas power units can be permitted, purchased and installed within reasonably short time periods (i.e., usually well under two years) using proven technology that is readily available from multiple vendors and be reliably operated over an economic life of 20-25 years; units can also be located at load centres (minimize transmission requirements).

Depending on load level and LNG supply options (from Kitimat or from Fort Nelson) [2]:

- Estimated unit grid power generation costs with simple cycle generation ranged from 15.7 to 17.9 cents/KWh (compared to approximately 28 cents/KWh diesel fuel cost).

[1] LNG Workshop. Whitehorse, January 18, 2012. http://yukonenergy.ca/downloads/db/1102_LNG%20Background%20Paper%20January%202012.pdf.
[2] LNG Workshop. Whitehorse, January 18, 2012. http://yukonenergy.ca/downloads/db/1102_LNG%20Background%20Paper%20January%202012.pdf.

- Estimated unit power generation cost with combined cycle generation was lower than with simple cycle generation, from 14.2 to 16.4 cents/kWh depending on load level and LNG supply options (compared to approximately 28 cents/KWh diesel fuel cost).

(b)

Please see Attachment 1 to this response for Yukon Energy's Generation Inventory for 2011. This provides the gross fuel efficiency in kWh per litre for each diesel unit.

Yukon Energy diesel units typically have an overall efficiency rating in the range of 85%. However, Yukon Energy typically uses the gross fuel efficiency. The gross fuel efficiency in conjunction with the fuel availability, cost, load and area requirements determines which units will be run at a given time.

YEC GENERATION INVENTORY *2011*

LOCATION	***UNIT NO.***	***PRIME MOVER TYPE***	***NAME PLATE CAPACITY***	***MCR RATING (kW)***	***GEN. RATING (KVA)***	***GEN. VOLTAGE (V)***	***IN-SERVICE DATE***	***PLANNED RETIREMENT DATE***	***Gross Fuel Eff. (KWh/ltr)***
Aishihik				37,000					
	AH1	hydro	15,600	15,000	19200	13800	1975	none	
	AH2	hydro	15,600	15,000	17000	13800	1975	none	
	AH3	hydro	7,200	7,000	8250	13800	2011	none	
Faro				8,850					
	FD1	diesel	5,150	4,000	6000	12000/6900	1970	2021	3.7
	FD3	diesel	1,000	850	1250	4160	1989	2019	3.7
	FD5	diesel	1,400	1,200	1800	4160	1990	2020	3.7
	FD7	diesel	3,000	2,800	3750	4160	1992	2027	3.9
Dawson				3,960					
	DD1	diesel	800	720	1000	2400/4160	1988	2018	3.7
	DD2	diesel	1,000	920	1250	4160	1987	2017	3.7
	DD3	diesel	1,000	920	1288	4160	1990	2020	3.7
	DD5	diesel	1,500	1,400	1875	4160	1996	2031	3.9
Mayo				17,100					
	MD1	diesel	1,000	850	1250	4160	1989	2019	3.7
	MD2	diesel	1,000	850	1250	4160	1989	2019	3.7
	MH1	hydro	2,620	2,600	2550	6900	1957	none	
	MH2	hydro	2,840	2,800	2550	6900	1951	none	
	MBH1	hydro	5,693	5,000	5,693	6900	2011	none	
	MBH2	hydro	5,693	5,000	5,693	6900	2011	none	
Whitehorse				62,500					
	WH1	hydro	5,800	5,800	5800	6900	1958	none	
	WH2	hydro	5,800	5,800	5800	6900	1958	none	
	WH3	hydro	8,400	8,400	8400	6900	1969	none	
	WH4	hydro	20,000	20,000	2360	6900	1984	none	
	WD1	diesel	3,920	3,500	4250	6900	1968	2014	3.7
	WD2	diesel	5,150	4,500	6000	6900	1968	2015	3.7
	WD3	diesel	5,150	4,500	6000	6900	1970	2021	3.7

	WD4	diesel	2,500	2,250	3000	4160	1975	2025	3.6
	WD5	diesel	2,500	2,250	3000	4160	1975	2025	3.6
	WD6	diesel	2,700	2,500	3125	4160	1990	2025	3.7
	WD7	diesel	3,300	3,000	4125	4160	1991	2026	3.9

Haeckel Hill				810					
	WW1	wind		150			1993	2018	
	WW2	wind		660			2000	2025	

Total Co 4 Capacity **130,220**

Mobile Diesels				1,610					
	YM1	diesel	1,400	1,300		4160	1990	2015	3.7
	YM2	diesel	150	150	150	347/600	1999	2024	
	YM3	diesel	125	125		277/480			
	YM4	diesel	35	35		277/480			

TOPIC: **Forecast Fuel Costs**

REFERENCE: **Application, page 3-5**

However, these test year forecasts are adopted to address the transition to annual long-term average levels and potential future use of LNG at a materially lower cost than diesel, and are consequently lower in each year than the levels that would be required assuming annual long-term average hydro generation.

QUESTION:

a) Please explain why a transition to annual long-term average levels is required.

b) Please comment on the likelihood of using LNG instead of diesel during the test period.

c) If the use of LNG is likely, then please explain how fuel costs will be adjusted to reflect that use.

ANSWER:

(a)

A transition is proposed to move materially closer to 100% of LTA while mitigating current impacts on rates such that the 2013 rate increase does not exceed 6.5%; the transition also recognizes the potential future use of LNG at a materially lower cost than diesel.

It is recognized that 2009 GRA rates included grid diesel at well under 100% of long-term average (LTA), i.e., at about 32% of LTA (see response to YUB-YEC-9(a)), and that future rates will also need to provide for fossil fuel generation forecasts at 100% of LTA requirements. As reviewed in Table 3.2-1 and 3.2-2 in Appendix 3.2, Attachment 3.2, higher load scenarios at this time are leading to increased pressure.

- For example, at the forecast loads for 2013 of approximately 430 GWh, LTA diesel generation is approximately 18.1 GW.h (this reflects the average impact of severe drought years of record combined with many years when water conditions

would result in no diesel being required at this forecast load). Diesel at 59% or more of LTA [10.7 GW.h or more] occurs at this load only about 54% of the 28 water years of record. In short, at current load levels, about half the time diesel will be below the GRA proposed level (10.7 GW.h) where funds will be deposited into the DCF, and about half the time it will be above this level, where funds are withdrawn from the DCF – however when diesel generation is above the 10.7 GW.h level, it will occasionally be far above (severe droughts).

- In contrast, as grid loads increase and require higher LTA diesel generation, diesel at 59% or more of LTA will occur much more frequently, e.g., over 70% of the water years at a grid load of 485 GW.h/year, and over 95% of the water years at a grid load of 585 GW.h/year. Based on past practice and DCF rate stability principles, this shift in will require that diesel (or any other fossil fuel generation that responds flexibly to load and hydro generation conditions) be included in rates based on 100% of LTA. If this were not done, in 70%-95% of the years, the DCF would be expected to pay for some portion of the diesel generation, and in only 5%-30% of years would there be any deposits to the DCF to fund these frequent draws.

Please also see response to YUB-YEC-29(a).

(b) and **(c)**

LNG supply is not currently expected to be available in the test years. Further, it is not currently considered likely that suitable gas-fired generation facilities could be permitted and in service in the test years.

Based on current information, LNG is being seriously considered as a potential supply option for gas-fired generation at Whitehorse as soon as is feasible, which is currently thought to in 2014 at the earliest. No decisions have been made at this time. Ongoing assessments are reviewing the LNG option. Before such time as LNG is used, Yukon Energy will provide the Board with a proposal to adjust costs to reflect the use of LNG rather than diesel. Operation of the DCF as such, however, would still be applicable to determine LTA expected LNG generation requirement at any given Grid Load.

TOPIC: **Employee Complement History**

REFERENCE: **Application, page 3-6**

Full Time Equivalent (FTE) positions are forecast to increase by 12.26 FTEs in 2013 compared to 2009 approved with most of the increase in 2010 (7.38 FTEs). The average annual increase in salaries per FTE is 4.3% from 2009 approved to 2013 forecast.

QUESTION:

a) What duties performed by employees in the additional FTE complement were previously performed by consultants or contractors?

b) What are the incremental costs of bringing on the additional FTEs to complete these duties compared to utilizing contractors or consultants?

c) Of the new employees represented by the additional FTE complement, how many are currently performing new roles or duties not previously performed by contractors or consultants?

d) What are these new duties/roles? Please explain why these new duties and roles are required.

e) How does the average annual increase in salaries per FTE compare to CPI increases for the Yukon?

f) How many FTE complements were allocated to the Yukon Development Corporation (YDC)?

g) Please provide an organizational chart of all positions in YEC and indicate whether any of the positions are shared with other organizations such as YDC.

ANSWER:

(a) through **(d)**

Please refer to section 3.3.5 of the Application for a detailed explanation and justification of each position.

(e)

CPI increases for Whitehorse according to the Yukon Bureau of Statistics (Yukon statistics not published) are as follows:

- 2009 0.4%;
- 2010 0.8%; and
- 2011 3%.

(f)

Approximately 0.55 FTEs are allocated to YDC on a forecast basis.

(g)

Organizational charts are provided in response to YECL-YEC-1-46. There are two positions shared with YDC: President, (30%) and Corporate Secretary (25%).

TOPIC: **Labour Costs**

REFERENCE: **Application, page 3-6**

Table 3.3 Non-Fuel Operating and Maintenance Expenses

QUESTION:

a) Are the costs for contractors and consultants included in the labour expense category?

b) Please explain the increase in labour costs for the 2009 actual from the labour costs provided in the 2009 GRA compliance.

c) Please provide a breakdown of the increases in labour costs as shown in Table 3.3 between step increases, negotiated settlements, and new positions.

d) Does YEC employ a variable pay program (VPP) (bonus)?

e) If the answer to part (d) is affirmative, please provide a breakdown of total labour costs between base salary and VPP.

f) If YEC does employ a VPP, please provide the criteria that must be met in order for employees to qualify for the VPP.

ANSWER:

(a)

No.

(b)

The 2009 actual labour expense was higher than the 2009 GRA Compliance labour expense for the following reasons:

- Budgeted labour had a 5% vacancy rate factored into the cost. There was an actual vacancy rate of 3% for the company as a whole.

- There was 1.5 FTE increase over the course of the year. This was mostly temporary or casual plant operators to accommodate the increase in diesel generation required to meet peak demand.

- There was a $100,000 payout to a senior employee upon his leaving of the corporation.

- There was a $40,000 pension adjustment to labour costs in production to reflect the drop in the market in 2008.

(c)

Steps or increment increases in labour costs were as follows:

- 2009 Actual: 3.50%;
- 2010 Actual: 3.50%;
- 2011 Actual: 3.00%; and
- GRA 2012 and 2013: 2.25%.

The only negotiated settlement was in 2009, for the payout listed in part (a) above.

The list of new positions added is provided below:

- **2009:** 1.5 FTE increase in casual and temporary plant operators.

- **2010:** 6.75 FTE increase: SQL/Sharepoint Administrator, Communications Protection & Control Technologist, Director of Major Projects, Electrical Engineer, Capital Mechanic, Capital Electrician and a 0.75 FTE Plant Operator in Faro.

- **2011:** 6.0 FTE increase: Manager of Energy Conservation, Environmental Coordinator, Resource Planning Engineer, Term SCC Operator, Energy Conservation Administrator and a Backfill Controller. Also Director of Major Projects position was cancelled and a new position of Manager Resource Planning was added.

- **2012 GRA:** 0 FTE increase: the Electrical Engineer position was cancelled and a new position of Financial Administrator was added.

- **2013 GRA:** 0 FTE increase: no new positions forecast.

(d) through **(f)**

YEC does not currently employ a variable pay program.

TOPIC: **Production Costs**

REFERENCE: **Application, page 3-7**

Table 3.5 Production Costs

QUESTION:

a) Please explain the increase in wind costs from 2011 to 2012.

b) Please explain the volatility in Operation Supervision costs for the years included in Table 3.5.

c) Please explain the increase in Diesel costs in 2011.

d) Please explain the increases in Hydro costs for the years included in Table 3.5.

ANSWER:

(a)

Wind costs increased from 2011 to 2012 due to the following electrical maintenance work scheduled to be undertaken in 2012:

- WW1 – maintenance work scheduled with regard to the gearbox, PLC, propeller, generator, protection units and transformers.

- WW2 – maintenance work is also scheduled to be completed on WW2.

Mechanical maintenance work is also scheduled to be completed in 2012.

(b)

Operation Supervision costs are reduced to $0.006 million in 2011 FYF compared to $0.038 million in 2010 Actual and $0.059 million in 2012 Forecast due to the fact that the position was vacant for most of 2011.

(c)

Table 3.5 in Tab 3 provides the costs for production and consists of labour and non-labour components, excluding fuel and purchased power costs. As indicated on Table 3.5, Diesel Production costs increased by 107%, from $0.297 million in 2010 Actual to $0.615 in 2011 FYF. This increase in production costs was due to the fact that there was increased use of the diesel generation to meet demand in 2011 compared to 2010.

As noted in Tab 3, page 3-4 diesel generation increased by 146%, from 4.28 GW.h in 2010 to approximately 10.55 GW.h in 2011 actual (excluding diesel requirements related to hydro generation plant construction activities).

(d)

Hydro production cost increases noted in Table 3.5 are reviewed below:

- **2009 Actual:** Increase of $0.042 million in 2009 Actual over 2009 GRA Compliance is due mainly to an increase in maintenance expense related to the intakes.

- **2010 increase:** of $0.293 million in 2010 actual over 2009 actual is due to further expenditures on the intakes as well as further expense related to hydro structures.

- **2011 increase:** Hydro expense decrease slightly in 2011 and generally tracked with 2010 expense.

- **2012 increase:** Hydro expense increased by $0.086 million in 2012 forecast over 2011 actual due to scheduled generator work to be undertaken on Whitehorse Hydro Units #1 to #4 and Mayo Hydro Units MH#1 and MH#2. There is also work required on the switchgear for WH#4 scheduled for 2012, and new maintenance costs associated with having the new hydro units at Aishihik and Mayo.

- **2013 increase:** 2013 forecast expense decreased by $0.029 million over 2012 forecast and is expected to follow in line with 2012 expense for regular maintenance on the units.

TOPIC: **Production Labour Costs**

REFERENCE: **Application, page 3-7**

Table 3.5 Production Costs

QUESTION:

a) Please provide the reason(s) for actual labour production costs being 28% higher than approved labour production costs in 2009.

b) Please explain the reasons for the approximately 56% increase in forecast labour costs in 2012 over 2009.

ANSWER:

(a)

Actual 2009 production labour is higher than 2009 GRA Compliance production labour for the following reasons:

- Budgeted labour had a 5% vacancy rate factored into the cost. There was little vacancy in this area and there was an actual vacancy rate of 2.5% for the company as a whole.

- There was 1.5 FTE increase in this area over the course of the year. This was mostly temp or casual plant operators to accommodate the increase in diesel generation required to meet peak demand.

- There was a $0.100 million payout to a senior employee upon leaving the Corporation in 2009.

- There was a $0.040 million pension adjustment to labour costs in production to reflect the drop in the market in 2008.

(b)

The increase in forecast labour costs for Production in 2012 over 2009 Compliance is 38%, not 56% (as noted in the Application at page 3-7, this increase is 56% of the overall increase in Production costs during this period).

The reason for this increase in forecast labour costs in 2012 Forecast over 2009 Compliance is largely due to an increase in FTE of 12.26 over that time frame (increases in staff positions are discussed and described at Tab 3 pages 3-13 to 3-17 of the Application), as well as the following across the board wage increases:

- 3.5% in 2010;
- 3.0% in 2011 (comprised of 1.5% increase from January 1, 2011 to June 30, 2011; and 1.5% increase July 1, 2011 to December 31, 2011); and
- 2.25% for Forecast 2012/2013.

TOPIC: **Transmission Costs**

REFERENCE: **Application, page 3-8**

Table 3.6 Transmission Costs

QUESTION:

a) Please explain how the completion of the Carmacks-Stewart Transmission Project (CSTP) Stage 2 and the connection of the Mayo-Dawson and Whitehorse-Aishihik-Faro grids causes higher transmission costs.

b) Please explain the increased costs for brushing activities. Please explain how costs are related to the annual brushing plan. Are first-time brushing costs capitalized?

c) Please provide the costs for the brushing study.

ANSWER:

(a)

The addition of any new transmission asset (such as CSTP Stage 2) will increase costs in the following manner:

i. Costs related to increased line patrols
ii. Increased brushing costs
iii. Additional annual maintenance costs (e.g. substation breaker and transformer maintenance)

(b)

Since the 2009 compliance filing, transmission brushing costs have increased $128,000 to $505,000 in 2012 (forecast).

In 2012, management intends to advance one of the key recommendations in the brushing study, namely herbicide application. Budgets permitting, a study will be completed to select the appropriate herbicide (for Yukon flora affecting transmission

rights of way) and several test plots will be sprayed to measure effectiveness of this approach. The results of this work will form part of the brushing policy to be developed in 2013. The study has also identified several risk areas for lines that will need immediate attention in 2012. Over the period 2009-2011, increased budget was required to deal with high rates of growth on key lines (i.e. L170 between Faro and Carmacks, L177 between Dawson and Stewart Crossing and L250 from Mayo to Keno).

First time brushing costs are capitalized as part of the related capital project.

(c)

There are two aspects to the brushing program reviewed conducted by the company:

1. Work completed by ECI to assess current conditions and review and recommend improvements to the existing brushing program – this cost $105,022 with $27,190 in additional costs for helicopter fees for aerial surveys.

2. YEC participated in a jointly-funded multi utility survey of best practices in brushing conducted by the Centre for Energy Advancement through Technological Innovation (CEATI) International which cost an additional $25,000.

TOPIC: **Transmission Costs/Brushing Study Costs**

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

In 2012 Yukon Energy is field testing the recommendations (e.g., herbicide treatments) prior to developing the formal policy. Costs for these activities are included in 2012 forecast amounts. The noted studies are provided in Tab 12, Appendix 12.1 and Appendix 12.2.

-and-

Additionally, the study also recommended investigating Integrated Vegetation Management (IVM) methods to reduce the long-term cost of brushing YEC's transmission network.

QUESTION:

a) What are the third-party costs involved with the brushing studies and field testing?

b) How are these costs allocated among the three expense categories in Table 3.6?

c) Are any portions of the costs related to the brushing studies and field-testing also allocated to the Distribution Costs in Table 3.7?

d) Please explain how, and by what amount, the use of IVM methods will reduce transmission brushing costs.

ANSWER:

(a)

Third party costs in 2012 relate to the forecast expense for herbicide selection and test plotting (between $0.030 million and $0.100 million) for the brushing studies and field selection.

(b)

The cost of the work described (a) above is included in the transmission line brushing forecast.

(c)

No. There are no costs related to the brushing studies and field-testing allocated to Distribution Costs in Table 3.7.

(d)

IVM methods control new growth and re-growth of tall, fast growing plant species (e.g. Aspen, Poplar, Pine) that are incompatible with safe transmission and distribution operations, and encourage the growth of low growing native plant species in the ROW. IVM methods can reduce transmission brushing costs over time by reducing the density and type of vegetative re-growth after mechanical brushing (thus reducing workload at the next brushing cycle). In addition to simply reducing the cost of mechanical brushing, these practices also have a number of valuable ancillary benefits in terms of improved accessibility, reduced environmental impact, better worker safety and ultimately increased asset value.

The expected savings from IVM were calculated by the consultant in their report (see Appendix 12.2, pages 12.2-33 and 34). Using a high and low cost estimate for herbicide application, IVM will generate NPV savings over both 10 and 20 year versus conventional mechanical control practices.

In the short term, annual brushing costs may increase somewhat as the policy and program are developed and implemented; it is normal to expect that cost intensity is higher in early years and savings accrue later in the cycle.

TOPIC: **General Operation and Maintenance**

REFERENCE: **Application, page 3-10**

Table 3.8

QUESTION:

a) Please explain the labour increase in FYF for 2011 to the proposed numbers in 2012.

b) Please explain the 51% increase (2012 over 2009) in Maintenance of Company Owned Property and the rationale for this increase.

c) Please explain why costs for Maintenance of Company Owned Property were $650,000 in 2011 compared to previous years. Given that the forecast test years are also lower than this amount, is the reason for higher costs for Maintenance of Company Owned Property in 2011 likely to recur, or was it a one-time occurrence?

ANSWER:

(a)

The increase in these labour costs from 2011 FYF to 2012 Forecast is based on the following factors:

- A vacancy in this area due to a retiring employee; and

- Two employees that normally code labour to this area were assigned to work major capital projects in 2011 (i.e. Mayo B, CSTP Stage 2 and Aishihik Third Turbine). These projects were forecast to be complete by year-end 2011. These two employees are expected to return to normal duties coded under General Operation and Maintenance for 2012.

(b)

Maintenance of Company Owned Property expense increased by $0.197 million from 2009 Compliance to 2012 Forecast due to the following expenditures over the period:

- A $0.087 million increase from 2009 Compliance to 2009 Actual due to the following increased expenditures:
  - $0.020 million increase in expense related to snow removal.
  - $0.024 million expense for crane inspection.
  - $0.020 million increase for parts and services, including work required related to the electrician's trailer and an increase in utilities (including sewage pump outs, garbage hauls and rodent control).

- A $0.067 million increase in rent/lease payment related to the requirement for more space rental charge increases.

- A $0.021 million increase in materials and supplies and a $0.011 million increase related to the drafting trailer. These trailers were added to accommodate additional requirements for space for both staff and documents.

- A $0.011 million increase related to an electrician trailer due to increases in prices.

(c)

The 2011 FYF expense for Maintenance of Company Owned Properties was $0.650 million. This was a $0.161 million over 2010 actual, and there is a $0.069 million decrease in expense in the 2012 Forecast. The increase in 2011 FYF relates to the following expenses:

- $0.014 million for repairs to the fish ladder undertaken in that year;

- $0.017 million for work on the company house in Mayo (including painting, carpets, underlay and porch repair);

- $0.020 million for heating fuel used in 2011 for the Dawson plant (this amount is not budgeted for 2012 or 2013 due to a budgeting oversight); and

- $0.005 million for work on the single wide trailer to accommodate employees moved into the trailer in 2011.

TOPIC: **Administration/Communications Costs**

REFERENCE: **Application, pages 3-11 and 3-12; and Table 3.9 Administration**

Increased costs relate to implementation of an on-going public information campaign which accounts for approximately $0.2 million of the total budget and $0.05 million for upgrading YEC's website.

QUESTION:

a) The Public information campaign is referred to as "on-going". Please confirm if the public information campaign is a recurring or one-time expense. Is the $0.2 million allocated for the information campaign a permanent communications budget item going forward? Please explain the justification for why the public information campaign is necessary for YEC to provide utility service to the public.

b) Do any of the costs under the communication expense category overlap with the "information programs and advertising" costs that are accounted for under the new DSM administration expense category? If there is an overlap, please explain the overlap and supporting rationale for the overlap.

c) Please explain the increases in 2011 costs for the following categories and the effect of these increases on the forecast costs for the test years:
    a. Resource Planning;
    b. General;
    c. Board of Directors; and
    d. Regulatory Affairs.

d) On page 3-12 the increases for the General expense are provided. What is the basis for these increases?

e) Please explain the legislative authority(ies) for the inclusion of YEC's DSM policy in this Application.

f) Please explain how YEC's DSM policy provides service to the public.

g) As YEC has indicated that some of these expenses may not be directly attributed to a DSM program, if the Board were to deny DSM, would the administrative expenses related to DSM still be required to be included in YEC's 2012 and 2013 forecasts? Why or why not?

h) The proposed increases in administrative labour include several new positions. Will the hiring of a Manager, Resource Planning and a Resource Planning Engineer reduce consultant costs for YEC? Please provide the rationale and any supporting information.

i) Please provide the expected return to YEC due to the hiring of the Manager, Energy Conservation and Energy Conservation Administrator, in terms of MW.h of energy and MW of capacity to be saved by YEC through its energy conservation programs. Please provide the timeline of the expected savings.

ANSWER:

(a)

No decision has been made as to the level of funding beyond 2013; however, it is expected that the current level of effort in communications will be an ongoing Corporate commitment.

With regard to justification for the current level of expense, it is noted that Yukon Energy is a publicly owned utility that is operated for and by Yukoners. Surveys undertaken by Yukon Energy in 2011 identified that Yukoners want to remain engaged in discussion around the territory's energy issues and the Corporation's objectives. The Corporation has also recognized the need to do more to distribute information to, and communicate with, the public, stakeholders and governments. In this vein, Yukon Energy's 2012 Strategic Plan includes as one of the Corporation's principles a commitment to "operate in a manner that ensures we are transparent and accountable to all of our customers and Yukon residents[1]."

[1] The 2012 Strategic Plan also states: "Yukon Energy communicates with and engages stakeholders in a transparent and timely manner."

An ongoing communications program benefits Yukon Energy and ratepayers as public input helps Yukon Energy make decisions regarding energy investments and strategic planning and also provides valuable input towards project planning. Ratepayers and the public also benefit through the ability to ensure stakeholder and other perspectives are incorporated into utility decision-making processes.

In this respect, approximately $198,000 was identified and invested in a public information campaign aimed at helping Yukoners better understand Yukon Energy and its future plans.

- Yukon Energy shared its strategic plans and priorities through ads, a household mailer, community signage and by enhancing its website, and sharing information about specific projects.

- Other communications initiatives included actively engaging Yukoners by asking for their views, opinions and concerns through public surveys and our social media sites.

- Yukon Energy created an 'Ask Janet' section on its blog to encourage questions and conversation. A Facebook and Twitter page was set up and a YouTube channel established with simple videos that provided information about major projects.

(b)

No. There is no overlap with 'information programs and advertising' costs accounted for under the DSM department.

(c)

Increases in 2011 costs and the effect of these increases on the forecast costs for the test years are as follows:

i. **Resource Planning** - increase in 2011 expense due to a $70,000 increase in contractor expenses. A $14,000 increase in consultants. And a $6,000 increase in travel.

ii. **General** - increase in 2011 expense due to the following:
   a. Unforeseen damages that occurred in 2011 that due to their nature were not eligible to be charged to the Reserve for Injuries and Damages and were instead expensed. This type of expenditure did not occur in 2010.
   b. An increase in the copying expense, telephone expense and equipment rental expense during the 2011 year.

iii. **Board of Directors** - increase in expense in 2011 due to a $56,000 increase of in legal expenses, a $55,000 increase n consultant expenses and a $65,000 increase in honoraria.

iv. **Regulatory Affairs** - an increase in 2011 expense relates to an $18,000 increase in legal expenses and a $63,000 increase of in consultant/contractor expenses.

(d)

As indicated on page 3-12 there is a forecast increase of $0.176 million by 2012 over 2009 approved expense with an increase of $0.189 million in 2013 over 2012. The increases in the test year are due to the following:

- A $0.050 million increase in promotions in 2012 for Arctic Winter Games support.
- A $0.012 million increase in interviewing costs 2012 over 2009 approved.
- A $0.050 million increase in recruitment costs over 2009 approved.
- A $0.250 million increase related to First Nation relations agreements in 2012 and 2013.

(e)

The Application includes accounting policy proposals for dealing with DSM costs, but does not otherwise propose a specific YEC DSM policy.

Focusing on DSM plans and programs, the legislated basis for a DSM program in the context of a regulated utility such as YEC comes directly from YEC's obligation to serve

its customers. As with all regulated utilities involved in locating alternatives to meet growing demand -- especially given cost of new supply -- DSM is a very important supply option which needs to be aggressively pursued in the best interests of ratepayers. A policy in this regard is crucial for success and it is important that the YUB and intervenors be allowed to review such a policy in a public process such as this GRA.

(f)

To be clear, Yukon Energy and the DSM Steering Committee have over the course of the past year determined it more effective to focus on development of a DSM Plan rather than a DSM policy. The basis for this change was concern over the time and investment required for policy development. Development of a Plan (with supporting partnership agreements from committed parties) was considered to provide a better vehicle for development and implementation of DSM in Yukon. It is understood that the development of a specific DSM policy for Yukon would be the responsibility of the Yukon Government.

With regard to how the development of a DSM Plan provides service to the public, as indicated in (e) above, in order to continue to meet demand on the integrated grid in a Yukon Energy is required to review economically and technically feasible supply options. DSM has been identified as a key supply option to be aggressively pursued in the best interests of ratepayers as it is a low cost source of supply that reduces the requirement for more costly diesel generation on the grid as well as associated greenhouse gas emissions.

In this regard, the DSM Plan will provide a well researched roadmap toward pursuit of specific projects that can provide verifiable DSM savings in Yukon.

The Yukon Energy 2011 20-Year Resource Plan Overview (provided as Attachment 1 to YECL-YEC-1-18) examines the extent to which this resource option may affect the evaluation of other potential near term resource supply options. However, development and evaluation of specific DSM plan and program options has been carried out by Yukon Energy in collaboration with the DSM Steering Committe, separate from the Yukon Energy 2011 Resource Plan process.

The CPR 2011 confirms that significant cost-effective electric energy and peak load savings opportunities exist in both the Residential and Commercial sectors" (page 11).

The potential savings available from DSM are described in detail in the Conservation Potential Review ("CPR") available on Yukon Energy's website at the link below.

http://yukonenergy.ca/energy/projects/dsm/

(g)

Were expenses for specific DSM projects or programming (reviewed in Tab 5) to be denied, the administrative costs (included in O&M costs in Tab 3) would still need to be reviewed on their own basis to determine whether the expenses were prudently incurred. These expenses are not directly tied to a specific program or project and must be assessed on their own merits, assuming that any DSM plan and programs are to be developed and implemented by Yukon Energy during the test years.

(h)

In the absence of these positions, ongoing planning projects would either require additional outside consultants to oversee this work or the projects would not be advanced.

Both of the referenced positions were required to boost the capacity of the planning group at YEC. As referenced throughout the Application document, YEC is undertaking unprecedented levels of planning including but not limited to LNG, storage enhancement, geothermal, etc.. The Resource Planning Engineer also works with modeling tools to assist in the analysis of business cases, load and generation forecasting, economic dispatch and reserve capacity requirements which enhance Yukon Energy's ability to oversee and coordinate planning project work, including ongoing system forecasting related analysis.

(i)

YEC has committed to an intensity target of 5GWh in 5 years. Savings will be slow during test years. The first major savings from DSM should be recordable by 2013/2014. Please see YUB-YEC-1-20(f) for Review of Yukon's Conservation Potential 2012 for projected savings at milestones out to 2030.

TOPIC: **Manager of IT**

REFERENCE: **Application, page 3-13**

Consequently, the Network Administrator was moved to a new position as Manager of IT.

QUESTION:

a) Please describe in greater detail the difference between roles and responsibilities of the Manager of IT and the Network Administrator, and any overlap between these two positions.

ANSWER:

(a)

In addition to all of the Network Administrator responsibilities, the Manager of IT assumed the overall managerial responsibilities for the IT department (performance management, budget preparation, short and long term planning, job assignments, etc).

TOPIC: **SQL/SharePoint Administrator**

REFERENCE: **Application, page 3-13**

Yukon Energy was dependent on one database technician to run all critical systems (e.g., SharePoint, ERP, SCADA). This is not considered sufficient from a risk perspective – especially considering current and expected future operational requirements.

QUESTION:

a) Please confirm that the rationale for adding an SQL/SharePoint Administrator is for risk purposes. Please describe the risks that Yukon Energy considers that are not acceptable under current and future operational requirements.

b) Is there a more cost-effective method of managing this risk? Please explain your response.

c) Please confirm that the roles and duties currently being completed by the SQL/SharePoint Administrator were previously completed by the "one database technician."

d) How has adding an SQL/SharePoint Administrator affected the database technician's role and duties? How has the addition of the SQL/SharePoint Administrator affected the database technician's workload? If the database technician's workload has decreased, by what percentage has the workload decreased?

ANSWER:

(a)

Confirmed. This is considered a critical function for the company, and dependence on one individual to support and maintain main corporate systems is considered very risky. No other employee had the corporate knowledge or sufficient SQL technical skills to perform backfill functions when required. Further, the workload is considered too great for one individual.

Yukon Energy's intranet utilizes Microsoft SharePoint to house corporate information. This product is very complex and is massive in its scope and scale. Because of its complexity it can be very challenging to manage, and if not managed correctly can start to have serious issues.

The Corporation launched Microsoft Dynamics GP, a new enterprise resource planning (ERP) system in 2012. This system integrates financial information across an entire organization. The purpose of ERP is to facilitate the flow of information between all business functions. This is another massive and complex system.

In addition to supporting the two major systems described above, the same individual was tasked with developing and supporting critical programming which is used for analysis for our Systems Control Centre (water levels at various sites, temperatures, capacity, etc).

(b)

The most cost-effective method was to increase the employee complement by one person year instead of outsourcing to a third party consultant that on average would charge $100+ per hour. It was more advantageous for the Corporation to staff the position rather than outsource the work in order to keep the corporate knowledge and skills in-house since the job requirements was deemed to be ongoing.

(c) and **(d)**

In 2009, the IT department consisted of 3 employees:

- 2 Network/Systems Administrators; and
- 1 Database Administrator.

The overall development and support for the Corporation's two major systems has now been split between the two positions.

- One individual has the primary responsibility for developing, maintaining, supporting the SharePoint system; and

- One individual is tasked primarily with developing, maintaining and supporting the ERP system.

Both incumbents are expected to have sufficient knowledge and experience to support either system as and when required. The need to develop, maintain and support both major systems is sufficient to keep both incumbents busy on a full time basis.

TOPIC: **Administration/Backfill Controller**

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

The former Controller moved to a new position focused on the implementation of the new financial system. A Backfill Controller is required as a backup to cover the Controller for the Enterprise System Conversion during the period when the new financial system is being implemented.

QUESTION:

a) Did YEC examine whether it would have been more cost effective to hire a consultant or new employee to manage the implementation of the new financial system instead of moving the former Controller to this new position and hiring a Backfill Controller?

b) Please describe any change in the former Controller's compensation, or overlapping compensation between the former Controller and the Backfill Controller, due to the move to the new position.

c) Once the Enterprise System Conversion process is over, will both the former Controller and the Backfill Controller be retained? If so, in what capacity will each individual serve?

d) With the CSTP Stage 2, Mayo B and Aishihik third turbine projects substantially completed, and no other major projects identified in the test period, why is the Financial Administrator position required?

ANSWER:

(a)

It would not have been cost effective to hire a consultant or new employee to manage the implementation of the new financial system. The Controller has over 10 years experience with Yukon Energy and therefore was able to provide valuable insight to the implementation consultant designing the system. It would not be possible for a recruit or

consultant to provide the level of Yukon Energy-specific knowledge required for this implementation.

(b)

There was no change to the former Controller's compensation as a result of the move to the new position. Outside of a brief (less than one week) overlap for training purposes, there was no overlap in compensation.

(c)

The former controller has accepted a position as the Supervisor of Reporting and the Backfill Controller has accepted a permanent posting to the Controller position.

(d)

While several large projects are now complete, Yukon Energy has several future years of higher than historical capital plans. These projects include maintaining existing assets as well as planning for next generation of supply. With respect to large, multi-stage planning projects (e.g. Marsh Lake, Gladstone), the accounting is quite complicated; consequently, financial resources are required to support project managers. As well, the material spending necessitates more frequent oversight of corporate cash flows which in turn requires increased financial capacity.

TOPIC: **Planning Activities**

REFERENCE: **Application, page 3-22 – Footnote 16**

Further, the Board notes that YEC's obligation to serve does require it to plan the system to meet these expected loads and any other requirements that may arise.

QUESTION:

a) Given the Board's findings in Section 5.3.2.1 of Board Order 2009-8, what factors does YEC expect the Board to apply in reaching a determination on the deferred planning costs incurred by YEC for the current and future applications?

ANSWER:

(a)

It is expected that the YUB will apply the same prudency test for deferred costs included in current and future applications as considered for capital projects or other expenses prior to being included in rates, i.e., were the costs prudently incurred with a business case objective to provide some form of enduring benefit.

As the Board noted in Section 5.3.2.1 of Board Order 2009-8, there is considered to be enduring value for YEC and its ratepayers from planning and studies work or regulatory and licencing work undertaken. This value reflects the long planning times for certain projects, the range of ongoing benefits from feasibility work undertaken, and the need to have projects or research "shelf-ready" to address future load requirements as they occur, even if a project does not proceed.

The new Planning Cost Accounting Policy provided as Appendix 5.1 notes projects will be internally scrutinized by YEC as part of the year-end financial review to ensure the requirement for annual milestones and close-outs is being met; as part of this review tangible products or reports will be required in order to demonstrate a useful "asset" and if there is no demonstrable tangible product or report, the costs incurred to date will be closed out and the balances will be written off to income in that year.

TOPIC: **Planning Costs and Planning Cost Accounting Policy**

REFERENCE: **Board Order 2009-8, Appendix A – Reasons for Decision (paragraphs 245 to 248)**

However, the Board finds intervenor comments regarding the lack of business cases for each of the individual projects and hence the absence of significant and material information to be justifiable.
…
Therefore, the Board directs YEC to keep written documentation of any and all deferred cost project review meetings that occur (e.g. agendas, materials presented for discussion, minutes, etc.) and have available for review for those items YEC wishes to include in its revenue requirement.

-and-

Further, with respect to each deferred project, YEC is to prepare a business case that highlights the project status and the underlying reasons for its status. Additionally, the progress of the various stages of the project development should highlight and explain significant variances respecting project costs that may occur and what steps might be employed, if any, to mitigate these variances. The business case with the progress updates is to be supplied at the time YEC requests to include any of the costs in its revenue requirement. Amounts in deferred costs are not to be included in rates without Board approval and will be subject to a prudency review.

QUESTION:

a) For each deferred-cost item that YEC wishes to include in rate base in this Application, please provide the business cases for those items and explain how those business cases meet the directions given by the Board in Board Order 2009-8.

b) Please explain how the new Planning Cost Accounting Study incorporates all the directions given by the Board in Board Order 2009-8.

ANSWER:

(a)

Business Cases for Deferred Cost Projects

"Business cases" in the context of deferred cost projects, as described Board Order 2009-8, Appendix A, paragraph 248 has a different meaning than "business cases" to be provided for major capital cost projects (as required by Directive #14 of Board Order 2009-8, and as addressed in response to YUB-YEC-1-32(c)).

The factors that YEC expects the Board to apply in reviewing deferred planning costs are addressed in response to YUB-YEC-1-24.

As reflected in Board Order 2009-8 as referenced above, "business cases" for deferred cost projects are to highlight "the project status and the underlying reasons for its status". Additionally "the progress of the various stages of the project development should highlight and explain significant variances respecting project costs that may occur and what steps might be employed, if any, to mitigate these variances."

Deferred costs are incurred (at least with regard to possible future capital projects) to develop the "business case" that allows the Corporation to have reasonable assurance that it can proceed with a specific capital project. Accordingly, there is only limited capability to describe a project (rather than a concept), provide economic or engineering analysis, discuss outcomes regarding alternatives or risks, etc. prior to undertaking a deferred project.

In summary, deferred cost initiatives are typically initiated to define an opportunity for a capital project, e.g., assess broad range of alternatives for a specific resource option in order to identify a preferred alternative.

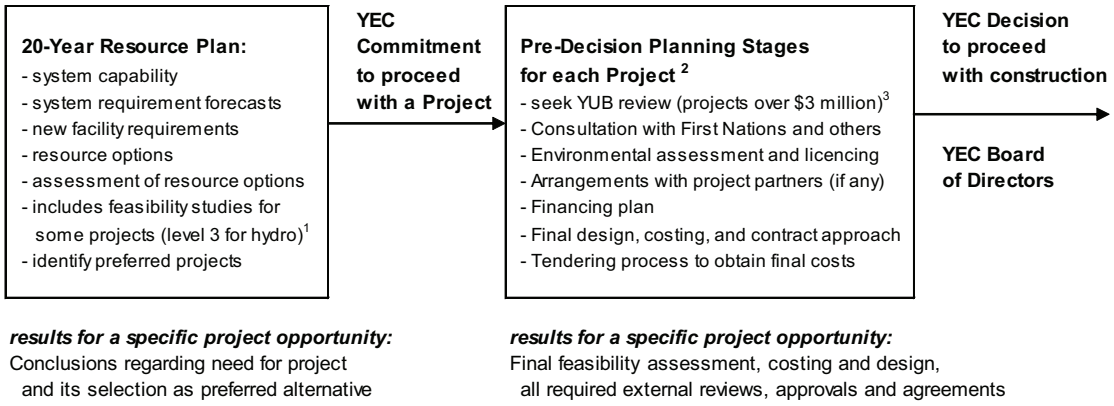
In some cases, deferred cost projects advance to the point of prefeasibility or feasibility work to define a specific project and its initial business case.

To set the context for considering the business cases for deferred cost projects, Yukon Energy's planning process is reviewed below.

Overview of Yukon Energy Planning Process

Yukon Energy described its overall planning process in the 2006 Resource Plan (see Figure 1 below), noting the role of the overall planning process in identifying specific project opportunities versus what occurs after YEC has committed to proceed with seeking approvals for a specific project opportunity.

Figure 1.1 from 2006 20 Year Resource Plan: 2006-2025



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.

The following are noted regarding deferred cost studies:

- Deferred studies work (often undertaken as part of the resource planning process) is required to define near term and longer requirements (i.e., existing system capability and future requirements); assess resource options available to meet near term and longer term requirements and to make determinations regarding the need for a project and its selection as a preferred alternative.

- As part of this process a particular supply option may be studied to determine technical and economic feasibility. To do this sufficient pre-feasibility work (preliminary engineering, baseline environmental studies and economic analysis)

is required to be undertaken to define the specific project and ensure there are no specific showstoppers to proceed with further development work.

- This work is required to develop the case for YEC to make a commitment to proceed with further work. Once a sufficient case is established, i.e., that there is a need for a project and a preferred option to address the need, Yukon Energy can make a decision to proceed to further pre-decision planning stages work, including consultation regarding project concept; preparation and filing of Project Proposal with YESAB and related licencing and permitting activities; arrangements with partners and financing arrangements; determine final costing, design and contract approach; tender process to obtain final costs.

Please see response to YUB-YEC-1-40(b) for a review of the general development phases that YEC currently considers for a project prior to tendering or construction, and the general relation of such phases to engineering estimates.

Business Cases for Deferred Cost Projects in Application

As set out in Section 5.3.1 of the Application, nine major deferred cost projects are identified. Business case information as directed in Board Order 2009-08 is provided in this section to highlight project status, the underlying reasons for this status, and the progress on various stages of the project development[1]. Please also see response to YUB-YEC-1-40(b) regarding documentation on review processes and project stages for these nine major deferred cost projects. This list excludes the 2012-13 GRA deferred costs where the basic rationale and status is apparent.

[1] Section 5.3.2 of the Application provides brief similar information on deferred cost projects costing between $0.1 and $1.0 million. These projects are updated under four groups to help highlight the differing purposes for these projects: feasibility (includes studies on potential supply options to displace diesel, and studies to ensure continued reliability or determine requirements for business improvements for existing assets), deferred overhauls, relicensing and dam safety review, and rate case.

In addition to what is provided in Section 5.3.1 of the Application, a summary is provided below, under three groups for the nine major deferred cost projects, of additional information provided in response to IRs:

1. **Hydro Enhancements (identified in the 2006 Resource Plan)** – Yukon Energy has continued since 2006 to focus on cost effective projects to enhance output of existing hydro generation facilities at Aishihik, Whitehorse and Mayo. During the 2008/2009 GRA Marsh Lake Storage was described as one of a number or potential hydro enhancements that could be developed at an attractive cost compared to developing new greenfield hydro (or other) supply options. Gladstone Diversion, Atlin Storage and Mayo Lake Enhanced Storage have all been previously identified as other potential hydro enhancements that could cost-effectively displace diesel generation at current and future forecast grid loads. The key risk associated with development of these small hydro enhancement projects in Yukon Energy's inventory relates not to economic justification for the project but to the schedule risk related to planning and licence requirements - accordingly, deferred cost planning work for these projects has focused on addressing project definition, baseline environmental studies and initial consultation, and feasibility/conceptual engineering as required to assess permitting issues and requirements. Identifying and addressing "show stopper" issues as soon as is feasible, and prior to spending all costs needed for environmental assessment submissions, is one of the key points of focus regarding these studies. Overall, $13.55 million in deferred cost is forecast to go into rate based by the end of 2013 for the following hydro enhancement deferred cost projects:
    a. **Marsh Lake Storage** – Section 5.3.1.1 of the Application reviews the project concept and changes since the 2006 Resource Plan review, project risks costs and benefits, planning work undertaken to date (including public consultation, extensive work on shoreline erosion and groundwater issues and hydraulic modeling) and next steps. An LCOE (2010$) is estimated at 8.5 cents/kWh assuming a capital cost (2010$) of $10.5 million, full utilization of annual generation of 6.4 GWh on average over a 65 year life, focused in winter months at current Whitehorse plant, and annual operating cost (2010$) of $8/MWh. Marsh Lake is assumed to provide 1 MW of added reliable winter peak. The project remains at a prefeasibility stage and prior to a decision to prepare any regulatory filings to secure approvals. The Application forecasts $4.8 million going into rate

base on or before the end of 2013. Please see the following responses for additional information on this project:

i. YUB-YEC-1-42 - various details relating to the project status and current stage of development.
ii. YECL-YEC-1-38 - additional details regarding capital cost expected and any additional generation upgrades needed.
iii. YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030 recommends completion of the required environmental, engineering and remediation studies related to the project in order to make a determination whether it is feasible and cost-effective to proceed.

b. **Gladstone Diversion** – Section 5.3.1.2 of the Application reviews the project concept, risks, costs and benefits, review work undertaken to date and provides an LCOE (2010$) over the 65 year estimated project life of 6.3 cents/kWh (assuming an estimated cost of $40 million and full utilization of added energy generation of up to 36.6 GWh/year). The project remains at a prefeasibility stage and prior to a decision to prepare any regulatory filings to secure approvals. The Application forecasts $4.4 million going into rate base on or before the end of 2013. Please see the following responses for additional information on this project:

i. YUB-YEC-1-43 - various details relating to the project status and current stage of development.
ii. YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030 recommends that YEC plan within the next 6 to 12 months to reach a final determination regarding whether the project is feasible to pursue at this time, based on discussions with local First Nations and regulators.

c. **Atlin Lake Storage** – Section 5.3.1.3 of the Application reviews the project concept, risks, costs and benefits and costs incurred to date and rationale for decision not to proceed with further work at this time. The discussion notes potential benefits of 10.5 cents/kWh LCOE (2010$) over the 65 year project life with an estimated cost of $30 million (2010$). The Application forecasts $2.2 million going into rate base on or before the end of 2013. Please see the following responses for additional information on this project:

i. YUB-YEC-1-44 - information on total costs to date.

d. **Mayo Lake Enhanced Storage** – Section 5.3.1.4 of the Application reviews the project concept, work completed to date (including environmental and socio-economic field work activities, analysis and assessment, project proposal preparation, engineering support, and public consultation), and project risks, costs and benefits. This project is included under Relicensing rather than Feasibility Study deferred cost projects, reflecting the central objective to modify the current water licence affecting water storage at Mayo Lake. The discussion in the Application notes total project costs over the life of the project of $5.4 million (2012$) (including mitigation and monitoring costs) with an LCOE (2010$) of 6.3 cents/kWH for approximately 4 GWh/year of added average hydro grid energy with 1 metre of added storage at Mayo lake. The project is in the final steps of preparing a submission to YESAB for regulatory review, and the Application notes the earliest potential project in-service estimated to be during 2013. The Application forecasts $2.1 million going into rate base on or before the end of 2013. Please see the following responses for additional information on this project:
    i. YUB-YEC-1-45 - various details relating to the project LCOE and costs.
    ii. YECL-YEC-1-39 -sought a copy of the Project Agreement with NNDFN (which is confidential and cannot be provided).
    iii. YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030 notes, in updated grid load scenarios Appendix A (page A-4), that more recent information suggests that this project's earliest in-service date is now winter 2014/15.

2. **Other Near Term Generation Options** – Yukon Energy has been examining other non-hydro potential near term opportunities as potential options to meet near term grid load diesel displacement. The four major deferred cost projects in this category each involve very different resource options. In each instance, the deferred cost work has initially focused on the preliminary studies needed to define an opportunity for a capital project, e.g., assess the broad range of alternatives for the specific resource option in order to identify a preferred alternative or alternatives that may be optimal and feasible for near term development. For some of these resource options, deferred cost projects have advanced to the point of prefeasibility or feasibility work to define a specific project and its initial business case. In addition to the major deferred cost

projects, feasibility studies also were conducted on wind resource options and on Atlin grid connection.

a. **Demand Side Management (DSM)** – Section 5.3.1.5 of the Application reviews the context underlying proceeding with a robust DSM plan at this time, the project concept, work being undertaken to prepare a plan and project cost. The Application forecasts approximately $3 million (net of contributions) going into rate base on or before the end of 2013. Please see the following responses for additional information on this project:
    i. YUB-YEC-1-52 - details on YEC Energy Conservation office costs, consultations, objectives and deliverables.
    ii. YUB-YEC-1-7(a) to (c), (g) - DSM potential re: secondary sales customers who converted to firm, subject of electric heating under purview of DSM, proposed audit pilot program
    iii. LE-YEC-1-24 (and CW-YEC-1-35(a)) - update and progress on filing a DSM plan (YEC and YECL)
    iv. LE-YEC-1-12 (and YCS-YEC-1-26) - reductions in forecast sales in test years due to DSM
    v. CW-YEC-1-8; CW-YEC-1-35(b) - details on YEC's audit study with Alexco mine facilities, and YEC's LED Streetlight project
    vi. UCG-YEC-1-18 and 61 - details on YEC DSM efforts, audit processes, impacts, and expenditures and cost recovery from ratepayers.

b. **Waste to Energy/ Biomass –** Section 5.3.1.6 of the Application reviews the project concept (both Waste to Energy and Biomass), provides references to publically available reports and feasibility work to date on Yukon Energy's website, and reviews project risk, costs and benefits. These projects remain at a prefeasibility stage and prior to a decision to prepare any regulatory filings to secure approvals. The Application forecasts approximately $1.6 million (net of contributions) going into rate base on or before the end of 2013. Please see the following responses for additional information on these projects:
    i. YUB-YEC-1-47 - additional details on the project cost -benefit assessments, work being done, requested approvals, and timeline for determining when viable and feasibility level work proceeds.
    ii. YCS-YEC-1-16 - details on costs spent.
    iii. UCG-YEC-1-62 - details on programs, expenditures, costs and benefits expected, and how costs recovered from ratepayers.

iv. YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030 recommends that YEC identify and pursue opportunities for small scale (e.g., 2 to 3 MW) wood biomass pilot project, potentially in association with existing wood operations at Haines Junction, and seek funding support for this pilot project.

c. **District Heating** – Section 5.3.1.7 of the Application reviews status of work on this project, which remains at a prefeasibility stage with feasibility work being planned. The Application forecasts approximately $0.5 million (net of contributions) going into rate base on or before the end of 2013. Please see the following responses for additional information on this project:
   i. YUB-YEC-1-48 - additional details on study findings to date, non-utility/private sector implementation option, benefits, requested approvals, and expected basis for viability.
   ii. YCS-YEC-1-17 - details on costs spent.
   iii. UCG-YEC-1-63 - details on programs, expenditures, costs and benefits expected, and how costs recovered from ratepayers.

d. **LNG -** Section 5.3.1.8 of the Application reviews the status of work on this project, which remains at feasibility assessment stage with consideration for near term development. The Application forecasts approximately $1.7 million spending during the test years with none of these amounts going into rate base before the end of 2013. Please see the following responses for additional information on this project:
   i. YUB-YEC-1-49 - additional details on feasibility studies to date, suggested role of LNG, basis for incurring additional costs to further feasibility work, fixed asset expenditure forecast and expectation to meet reasonable assurance before end of 2012 (and related implications for accounting treatment of costs).
   ii. YECL-1-YEC-1-44 - details on plans for LNG use, net impact on fuel costs, and basis for projecting LNG and diesel prices.
   iii. YCS-YEC-1-21- explain why non-renewable LNG option taking precedence over other alternatives
   iv. YCS-YEC-1-22 - details of commitments, contracts and feasibility studies undertaken
   v. LE-YEC-1-27 - details on studies and plans and contracts; LNG plant timing, location, capacity; plans for combined heat and power.

vi. UCG-YEC-1-64 - details on programs, expenditures, costs and benefits expected, and how costs recovered from ratepayers.
vii. YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030 recommends that, subject to completion of current assessments, determine whether Yukon Energy is able to establish LNG generating capability in Whitehorse prior to 2015 with sufficient capacity to displace grid diesel generation under current Base Case grid load forecasts, and determine the feasibility of utilizing LNG in the event that material additional near-term grid loads occur such as those assessed under Scenarios A and B.

3. **Long term Generation Options** – Yukon Energy has worked on appropriate planning activities required over the near-term to protect the ability to proceed with potential longer term legacy resource development options when loads are sufficient to justify proceeding. Deferred cost projects in this category address preliminary studies needed to define an opportunity for a future capital project, e.g., assess the broad range of alternatives for the specific resource option in order to identify a potential preferred alternatives that may be optimal and feasible for future development as grid loads continue to grow. Geothermal is the one major deferred cost project in this category - large hydro feasibility studies have also been conducted regarding potential greenfield hydro site alternatives.
    a. **Geothermal** – Section 5.3.1.9 of the Application reviews the status of work on this project, which remains at prefeasibility stage. The Application forecasts approximately $2.6 million going into rate base on or before the end of 2013. Please see the following responses for additional information on this project:
        i. YUB-YEC-1-50 - additional details on work to date, tendering of work done by contractor.
        ii. YECL-YEC-1-40 - details on study findings, LCOE, and sites.
        iii. UCG-YEC-1-65 - details on programs, expenditures, costs and benefits expected, and how costs recovered from ratepayers.
        iv. YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030 recommends that YEC carry out scaled down geothermal investigations and look for funding support for geothermal exploration and studies, and seek funding support for these activities.

(b)

The new Planning Cost Accounting Study policy was developed to update the previous policy for the reasons set out in the Application. Yukon Energy is not aware of any specific directions given in Board Order 2009-08 that relate to the accounting matters addressed specifically in this policy.

Please also see response to YUB-YEC-1-39.

TOPIC: **Cost of debt – Canada Flex Term Note/YDC Flexible Promissory Note**

REFERENCE: **Application, page 3-25**

QUESTION:

a) Based on current forecasts, when would the Canada Flex Term Note be expected to expire?

b) Based on current forecasts, when would the YDC Flexible Promissory note be expected to expire?

ANSWER:

(a)

The previous Canada Flexible Term Note was refinanced during 2011. At the time the balance on the note was over $24 million, with flexible payments based on WAF load to a maximum of $1 million per year. While the definition of "WAF load" becomes problematic following the interconnection of the Mayo Dawson and WAF systems, under a reasonable interpretation the current integrated system load levels exceed the levels where the full $1 million per year principal payment were required. In short, had this note been retained, it would have operated as a 7% loan over the next 24-25 years.

(b)

The previous YDC Flexible Promissory Note was refinanced during 2011. The YDC Flexible Promissory Note was set up for the Mayo Dawson interconnection, with fixed annual principal payments of $0.450 million per year, terminating in 2043. Given the material degree to which the savings from the Mayo-Dawson line now exceed the costs, had this note been retained, it would have operated as a 6.55% loan through 2043.

TOPIC: **Rider F/ DCF**

REFERENCE: **Application, page 3-28**

Based on proposed changes to the DCF whereby any secondary sales revenues after January 1, 2012 would be credited directly to the DCF (and thereby not affect Yukon Energy revenues or income), it is proposed that Rider F no long (sic) be affected by variations in the ongoing quarterly adjustments to the prices of secondary sales, i.e., any secondary sales revenues after January 1, 2012 would be credited to the DCF without any Rider F related adjustment or impact for price changes.

QUESTION:

a) Please provide a numeric example of the before- and after-effect of the proposed change.

b) Would this change also require an amendment to YEC's existing Rider F? If yes, is YEC concurrently seeking approval to amend its Rider F policy?

ANSWER:

(a)

In the examples below, for the illustration of the before- and after-effect of the proposed change, 2010 actuals have been used:

- 2010 actual Rider F calculations (please see Yukon Energy and Yukon Electrical Rider F Policy, YUB-YEC-YECL-2-2(e), October 2011).

- 10.5 GW.h secondary sales and $0.644 million secondary sales revenues (please see Table 2.2 of the 2012/13 GRA application).

- DCF balance is $0.891 million as of December 31, 2010.

Before the proposed change

The 2010 ending balance of Rider F is $0.0376 million (YEC only) as shown in Table 1 below, no change in DCF balance, YEC reports $0.644 million secondary sales revenues in its income statement.

Table 1. Rider F - Fuel Adjustment Rider
Diesel Fuel Price Variances and Rider F Surcharges
Before Proposed Change ($)

	YEC					
	Fuel Price Variance	SS Adjustment	Rider F Surcharge - Industrial	Rider F Surcharge - CIS	Inter-company Transfer	Balance
Dec-09						**(0)**
Jan-10	9,601	(9,969)	(7,642)	(11,823)	19,833	(0)
Feb-10	1,686	(10,746)	(7,731)	(10,052)	26,843	(0)
Mar-10	609	(12,815)	(9,337)	(9,138)	30,681	(0)
Apr-10	5,088	(9,410)	(7,404)	(9,179)	20,906	(0)
May-10	1,420	(7,763)	(8,207)	(8,748)	23,298	(0)
Jun-10	1,088	(6,411)	(6,215)	(11,551)	23,089	(0)
Jul-10	11,546	(5,050)	(2,034)	(1,205)	-	3,258
Aug-10	19,174	(4,249)	(2,306)	(2,565)	-	13,312
Sep-10	4,166	(2,538)	(2,313)	(2,845)	1,037	10,819
Oct-10	6,530	-	(2,049)	(2,469)	(922)	11,910
Nov-10	9,741	-	(3,270)	(2,349)	(2,201)	13,831
Dec-10	**40,699**	**-**	**(4,633)**	**(2,479)**	**(9,854)**	**37,565**

After/with the proposed change

The 2010 ending balance of Rider F would be $0.106 million (YEC only) as shown in Table 2 below, $0.575 million ($0.644 million as in income statement minus $0.069 million Rider F secondary sales adjustment) sales revenues would go into DCF account increasing DCF balance to $1.466 million, YEC would not report the revenues from the secondary sales in its income statement and no Secondary Sales Adjustments in Rider F.

Table 2. Rider F - Fuel Adjustment Rider
Diesel Fuel Price Variances and Rider F Surcharges
After Proposed Change ($)

	YEC				
	Fuel Price Variance	Rider F Surcharge - Industrial	Rider F Surcharge - CIS	Inter-company Transfer	Balance
Dec-09					**(0)**
Jan-10	9,601	(7,642)	(11,823)	19,833	9,969
Feb-10	1,686	(7,731)	(10,052)	26,843	20,715
Mar-10	609	(9,337)	(9,138)	30,681	33,530
Apr-10	5,088	(7,404)	(9,179)	20,906	42,940
May-10	1,420	(8,207)	(8,748)	23,298	50,702
Jun-10	1,088	(6,215)	(11,551)	23,089	57,113
Jul-10	11,546	(2,034)	(1,205)	-	65,421
Aug-10	19,174	(2,306)	(2,565)	-	79,724
Sep-10	4,166	(2,313)	(2,845)	1,037	79,769
Oct-10	6,530	(2,049)	(2,469)	(922)	80,860
Nov-10	9,741	(3,270)	(2,349)	(2,201)	82,781
Dec-10	**40,699**	**(4,633)**	**(2,479)**	**(9,854)**	**106,515**

(b)

The proposed treatment would not require an amendment to the existing Rider F Rate Schedule, but would require an amendment to delete Section 1.2 of the Rider F – Fuel Adjustment Rider & Deferred Fuel Price Variance Policy as at January 1, 2012.

As noted on page 3-28 of Tab 3 of the General Rate Application, based on proposed changes to the DCF whereby any secondary sales revenues after January 1, 2012 would be credited directly to the DCF (and thereby not affect Yukon Energy revenues or income), it is proposed that Rider F no long be affected by variations in the ongoing quarterly adjustments to the prices of secondary sales, i.e., any secondary sales revenues after January 1, 2012 would be credited to the DCF without any Rider F related adjustment or impact for price changes.

TOPIC: **Study on the Reserve for Injuries and Damages**

REFERENCE: **Application, Appendix 3.1 Yukon Energy RFID Policy**

QUESTION:

a) Please provide the amount YEC paid for the Study on the reserve for injuries and damages.

b) Section 4.1 of Appendix 3.1 lists the criteria for Finance Policy FA-014. Please confirm whether all of these criteria would be have to be met, or whether YEC considers that only one or more of the criteria would have to be met.

c) Please provide YEC's definition of "The incident was of significance to the operation of the unit."

d) Please provide a definition and examples of what YEC would consider to be "low probability, not normally expect to occur in a typical operating year".

ANSWER:

(a)

Yukon Energy paid $42,500 for the Study on the Reserve for Injuries and Damages.

(b)

All of the listed criteria would need to be met.

(c)

Any event that affected the capacity of equipment to meet its full rated output would be considered a significant incident.

(d)

Events that are “low probability, not normally expect to occur in a typical operating year” would in the context of managing the utility’s operations, refer to events that would not be expected to occur in an annual operational cycle (and consequently cannot be budgeted for).

For example, YEC would not normally, budget for damage from lightning strikes as this type of event normally does not happen at a level where material costs would result i.e. the system has protection from these events, but an event that is so severe it overcomes this protection and causes significant damage would not be expected or budgeted for.

This definition may also refer to any piece of equipment that fails well before end of its normal service life. Newer assets that prematurely fail and may have recourse against the vendor (i.e. warranty) and failures on assets that are end-of-life would not be captured by this definition.

TOPIC:

REFERENCE: **Application, Appendix 3.2 Update to Diesel Contingency Fund (DCF)**

QUESTION:

a) Please explain why the proposed update to the DCF is required as part of the current Application.

b) Does the DCF have the potential to mask market signals to consumers? Is there a potential effect that consumers of electrical energy would not adjust consumption patterns based on price signals if the updates to the DCF were approved? Please explain your response.

c) What effect will the proposed update to DCF have on any potential DSM?

ANSWER:

(a)

As noted at page 3.2-1 of Appendix 3.2, the proposed update to the DCF is required as part of the current Application because this was so directed by the Board when, in Order 2011-15, it directed Yukon Energy to "to address any changes necessary to the operating rules, administration and revised revenue requirements pertaining to the DCF in its next GRA." The Board also directed that YEC do this at the earliest of its next GRA or July 1, 2012.

Separate from the above Board direction, Yukon Energy had already committed to address all DCF issues in its next GRA. The following were noted in this regard at page 3.2-1 of Attachment 3.2:

- The proposed update is required at this time to address changes needed to the DCF to reflect new conditions (integrated grid) as well as new long-term average hydro generation simulations required to estimate expected diesel generation at any grid load.

- The available information confirms the need to address diesel generation costs today as an important element of any new GRA, and in this regard to update and reactivate DCF mechanisms to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro generation.

Please also see response to YUB-YEC-12(a).

(b)

The DCF has an inherent potential to mask short term cost signals to consumers when the DCF masks the extent to which current water conditions are limiting or expanding the need for diesel generation. However, secondary sales availability and rates, which are not affected by DCF determinations, are available to address this as regards secondary customers able to respond most significantly to such short term price signals.

For firm rate sales, the purpose of the DCF as initially established was to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro generation, i.e., the DCF was established specifically to prevent such short term price variability and to instead provide firm rate customers with appropriate longer term price signals. Due to lack of any interconnection with external grids, there is no "market" signal as such to be communicated to consumers.

The updates as proposed to the DCF do not change the above fundamentals - the updates simply go to ensuring that long term average annual diesel costs for any specific grid load level are more accurately reflected in the costs included in rates and in the costs charged to YEC. In this regard, the DCF update as provided in Attachment 3.2 is differentiated from the GRA proposal to include 66% of LTA costs in 2012 rates and 59% of LTA costs in rates after 2012, i.e., the reduced cost included in rates was done as a transition measure, and clearly masks the full LTA cost signals to consumers during the test years.

(c)

YEC is not aware that the proposed update to the DCF will have any effect on any potential DSM program. This conclusion reflects the following:

- That the DCF, as such, was established in the 1996/97 GRA as part of the regulatory regime for YEC;

- That the update, as proposed, does not change the fundamentals applicable to the DCF;

- That potential DSM (beyond secondary sales) will be proposed to secure long term efficiency and conservation for electricity use based on long-term average savings that may be secured in incremental diesel or other sources of generation supply; and

- That, generally, it is not feasible to establish longer-term DSM programming to address essentially very short-term and unpredictable water variability issues caused by a drought.

TOPIC: **Energy Reconciliation Adjustment (ERA)**

REFERENCE: **Application, page 4-12**

On this basis, charges to Yukon Electrical will be adjusted when changes in actual Yukon Electrical wholesale purchases (relative to Yukon Energy's most recent test year forecast for such purchases) result in changes to Yukon Energy costs incurred for diesel generation, whether such costs are incurred through adjustments in actual diesel generation or through adjustments in DCF payments or recoveries.

QUESTION:

a) Has YEC consulted with and received buy-in from Yukon Electrical Company Ltd. (YECL) with respect the DCF, the definition of diesel on the margin, and the ERA? Please provide details of any consultations with YECL.

b) Please provide a sample calculation with formulae intact showing how the ERA in Rate Schedule 42 works, including the calculations before the proposed change and after the proposed change.

ANSWER:

(a)

Yukon Energy has not consulted with Yukon Electrical Company Ltd. specifically with respect to the submissions in the current Application regarding the DCF, the definition of diesel on the margin, or the ERA. These matters were addressed in part with YECL during the recent Rider F proceeding. The current Application, however, required that Yukon Energy provide an updated DCF for review by the Board and the ERA proposals were developed concurrent with the updated DCF submission.

(b)

Please see Attachment 1 to this response for the requested calculation. Note that the calculation shows a number of hypothetical scenarios, and shows the related impacts on the DCF and the ERA. Also see YECL-YEC-1-16 for further scenarios.

The Excel spreadsheet includes 4 tabs.

Tab 1 sets out the description of the 4 hypothetical 2013 cases, the loads and generation assumed for each case, and the resulting distribution of actual diesel between that portion charged to the DCF, the portion charged to YECL via the ERA, and YEC's own income statement. Negative numbers in the diesel allocation mean credits to the respective transaction (i.e., a deposit into the DCF, or a refund to YECL).

Tab 2 shows the calculations supporting the DCF transfers. As indicated, this tab relies on the information in Table 3.2-2 of the GRA filing, and also reflects the proportion of the long-term average diesel in rates (e.g., approximately 59% in 2013). This Tab shows annual calculations – for an example of the monthly calculations that would be performed to track the fund (prior to year-end adjustments to reconcile to the proper annual balances) please see CW-YEC-1-24(b).

Tab 3 shows the proposed ERA approach. Consistent with the proposed rate schedule, this approach indicates the variation in wholesale purchases (indicated as "Incremental Wholesale Sales"), the modification of YEC diesel generation overall (indicated as "Incremental Diesel in Base Rates" – net of DCF transfers), and the degree to which the Incremental Wholesale Sales drove the Incremental Diesel, by applying the same overall percentage growth in diesel to all load changes by any customer class. The table also shows at the bottom the reconciliation of what would have been paid by YECL as wholesale charges during the base year, and what net impact the Incremental YECL Wholesale Sales had on YEC's costs (impact on diesel generation costs, less added/less revenue from changes in Rider J/R revenue).

Tab 4 shows, for comparison, the operation of the previous ERA mechanism as applied to the current context, assuming diesel is "on the margin" under the old definition. This approach similarly credits YECL with incremental revenues from riders that are related to the load growth that drives the ERA charge.

Case descriptions for 2013 scenarios:

Case #1: Actual Total Load at GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected
Case #2: Actual Load Above GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected
Case #3: Actual Load Below GRA Forecast; Wind below forecast; Actual Diesel Generation Above Expected
Case #4: Actual Load Below GRA Forecast, Wind Generation at forecast; Actual Diesel Generation Below Expected

		Cases (possible actual loads and diesel generation)			
	GRA	**Case #1**	**Case #2**	**Case #3**	**Case #4**
Retail and Industrial (MW.h)	97,685	92,685	100,476	96,677	96,677
Wholesale (MW.h)	298,228	303,228	305,228	295,228	295,228
Total Sales (MW.h)	395,913	395,913	405,704	391,904	391,904
Losses (MW.h)	34,444	34,444	35,296	34,096	34,096
Total Generation (MW.h)	430,357	430,357	441,000	426,000	426,000
Hydro (MW.h)	419,405	416,119	417,762	413,800	416,762
Diesel (MW.h)	10,714	14,000	23,000	12,000	9,000
Wind (MW.h)	238	238	238	200	238
Total Generation (MW.h)	430,357	430,357	441,000	426,000	426,000
Diesel MW.h	10,714	14,000	23,000	12,000	9,000
Proposed ERA Determination & related DCF determinations					
In Base Rates Excluding ERA MW.h (YEC's Income Statement)	10,714	10,714	11,790	10,348	10,348
Charged/credited via ERA (MW.h)	0	0	2,698	-1,091	-1,091
Total in Rates (Expected Diesel)	10,714	10,714	14,488	9,257	9,257
Charged/credited via DCF (MW.h)	0	3,286	8,512	2,743	-257
Total Diesel	10,714	14,000	23,000	12,000	9,000

DCF Formulaic Approach Operation Sample for 2013 Cases

Variable cost of diesel calculation

Line No				Notes
L1	Fuel Price	28.68	kW.h	DCF diesel price as forecast in GRA for 2013 (average for YEC grid)
L2	Variable O&M cost	3.000	kW.h	
L3=L1+L2	Variable cost of diesel	**31.681**	cents/kW.h	2009 GRA approved

Calculation of Diesel Cost to Charge (Refund) DCF

GRA Load

L4	2013 GRA Forecast Load (YEC grid load excluding Fish Lake generation	430,357	MW.h	Table 2.2 of GRA
L5	Grid Load for DCF (2013 GRA Forecast Load net of Wind Generation)	430,119	MW.h	Table 2.2 of GRA (wind generation at 238 MW.h)
L6	Expected Base Diesel Generation at 430 GW.h	18,100	MW.h	Derived from Table 3.2-2 of GRA
L7=(L5-430 GW.h)x56%	Expected Incremental Diesel Generation at 119 MW.h above 430 GW.h	67	MW.h	56% of Grid Load between 430 GW.h and 435 GW.h is diesel - Derived from Table 3.2-2 of GRA
L8=L6+L7	Total Expected Diesel Generation	18,167	MW.h	
L9=L8x59%	Expected Diesel Generation in Rates	10,714	MW.h	GRA proposes to include in rates 59% of Expected Diesel Generation - see Table 2.2

Case #1 - Actual Load at GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected

Assumptions

	Hydro	416,119		
	Diesel	14,000		
	Wind	238		
L10	Total Actual YEC Supply	430,357	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	430,119	MW.h	Assumed (430.357 GW.h less 238 MW.h)
L12	Expected Base Diesel Generation at 430 GW.h	18,100	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-440 GW.h)x56%	Expected Incremental Diesel Generation at 119 MW.h	67	MW.h	56% of Grid Load between 430 GW.h and 435 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	18,167	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	10,714	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	14,000	MW.h	Assumed
L17=L16-L15	Diesel Generation to be Included in DCF	3,286	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)	$1,041		

Case #2 - Actual Load Above GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected

Assumptions

	Hydro	417,762		
	Diesel	23,000		
	Wind	238		
L10	Total Actual YEC Supply	441,000	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	440,762	MW.h	Assumed (441 GW.h less 238 MW.h)
L12	Expected Base Diesel Generation at 440 GW.h	24,100	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-440 GW.h)x61%	Expected Incremental Diesel Generation at 762 MW.h	465	MW.h	61% of Load between 440 GW.h and 445 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	24,565	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	14,488	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	23,000	MW.h	Assumed
L17=L16-L15	Diesel Generation to be Included in DCF	8,512	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)	$2,697		

Case #3 - Actual Load Below GRA Forecast; Wind below forecast; Actual Diesel Generation Above Expected

Assumtpions	Hydro	413,800		
	Diesel	12,000		
	Wind	200		
L10	Total Actual YEC Supply	426,000	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	425,762	MW.h	Assumed (426 GW.h less 238 MW.h)
L12	Expected Base Diesel Generation at 425 GW.h	15,300	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-440 GW.h)x61%	Expected Incremental Diesel Generation at 762 MW.h	396	MW.h	52% of Load between 425 GW.h and 430 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	15,696	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	9,257	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	12,000	MW.h	Assumed
L17=L16-L15	Diesel Generation to be Included in DCF	2,743	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)	$869		

Case #4 - Actual Load Below GRA Forecast, Wind Generation at forecast; Actual Diesel Generation Below Expected

Assumtpions	Hydro	416,762		
	Diesel	9,000		
	Wind	238		
L10	Total Actual YEC Supply	426,000	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	425,762	MW.h	Assumed (426 GW.h less 238 MW.h)
L12	Expected Base Diesel Generation at 425 GW.h	15,300	MW.h	Attachment 3.2 Table 3.2-2
L13=(L11-440 GW.h)x61%	Expected Incremental Diesel Generation at 762 MW.h	396	MW.h	52% of Load between 425 GW.h and 430 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	15,696	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	9,257	MW.h	59% of Expected Diesel Generation
L16	Actual Diesel Generation	9,000	MW.h	Assumed
L17=L16-L15	Diesel Generation to be Included in DCF	-257	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)	($82)		

Case descriptions:

Case #1: Actual Total Load at GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected
Case #2: Actual Load Above GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected
Case #3: Actual Load Below GRA Forecast; Wind below forecast; Actual Diesel Generation Above Expected
Case #4: Actual Load Below GRA Forecast, Wind Generation at forecast; Actual Diesel Generation Below Expected

Inputs

	Cases				
	GRA	**Case #1**	**Case #2**	**Case #3**	**Case #4**
Retail and Industrial (MW.h)	97,685	92,685	100,476	96,677	96,677
Wholesale (MW.h)	298,228	303,228	305,228	295,228	295,228
Total Sales (MW.h)	395,913	395,913	405,704	391,904	391,904
Losses (MW.h)	34,444	34,444	35,296	34,096	34,096
Total Generation (MW.h)	430,357	430,357	441,000	426,000	426,000
Change from GRA Forecast					
Retail and Industrial (MW.h)		-5,000	2,791	-1,008	-1,008
Wholesale (MW.h)		5,000	7,000	-3,000	-3,000
Total Sales (MW.h)		0	9,791	-4,008	-4,008
Losses (MW.h)		0	852	-349	-349
Total Generation (MW.h)		0	10,643	-4,357	-4,357
Hydro (MW.h)	419,405	416,119	417,762	413,800	416,762
Diesel (MW.h)	10,714	14,000	23,000	12,000	9,000
Wind (MW.h)	238	238	238	200	238
Total Generation (MW.h)	430,357	430,357	441,000	426,000	426,000
Diesel MW.h	10,714	14,000	23,000	12,000	9,000
less: DCF	0	3,286	8,512	2,743	-257
Total in Rates (Expected Diesel)	10,714	10,714	14,488	9,257	9,257
Incremental Diesel in Base Rates (MW.h)		-0	3,773	-1,457	-1,457
Incremental Diesel in Base Rates (% of Total Gen'n Change)		0%	35%	33%	33%

Proposed ERA Approach

Proposed 2013 Wholesale Rate	8.298	cents/kW.h	current wholesale rate (Appendix 4.1)
Average proposed rider revenue per kW.h	2.088	cents/kW.h	89.23% of non-industrial rider revenue of $6.98 million (Table 4.2)
ERA Rate Calculation:			
Fuel Price	28.681	kW.h	DCF diesel price as forecast in GRA for 2013 (average for YEC grid)
Variable O&M cost	3.000	kW.h	2009 GRA approved
ERA rate (var cost of diesel)	**31.681**	cents/kW.h	

The **Energy Reconciliation Adjustment** is calculated as follows:

a) **sales below GRA forecast**: no adjustment for sales more than 10% below GRA forecast
b) **sales above GRA forecast:** all sales in excess of GRA forecast are subject to the adjustment

	Cases					
	GRA	**Case #1**	**Case #2**	**Case #3**	**Case #4**	
Incremental Wholesale Sales (MW.h)	0	5,000	7,000	-3,000	-3,000	
Incremental Wholesale Related Generation (MW.h)	0	5,435	7,609	-3,261	-3,261	at 8.7% losses (Table 2.2 of GRA)
Incremental Diesel Generation Subject to ERA Charge (MW.h)	0	0	2,698	-1,091	-1,091	
Incremental Wholesale Sales Subject to ERA Credit (MW.h)	0	0	2,482	-1,003	-1,003	sales equivalent of diesel gen.
Amount paid under normal ongoing billing ($000s)	$ 24,747	$ 25,162	$ 25,328	$ 24,498	$ 24,498	
ERA Adjustment to be Paid (Refunded) ($000s)	$ -	$ -	$ 597	($241)	($241)	
Total Amount Paid after ERA	$ 24,747	$ 25,162	$ 25,925	$ 24,257	$ 24,257	

Note:
Calculations are to be done on a monthly basis, however in practice the adjustment and calculations would be addressed periodically (and made final based on a year-end reconciliation processes).

Case descriptions:

Case #1: Actual Total Load at GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected
Case #2: Actual Load Above GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected
Case #3: Actual Load Below GRA Forecast; Wind below forecast; Actual Diesel Generation Above Expected
Case #4: Actual Load Below GRA Forecast, Wind Generation at forecast; Actual Diesel Generation Below Expected

Inputs

	Cases				
	GRA	**Case #1**	**Case #2**	**Case #3**	**Case #4**
Retail and Industrial (MW.h)	97,685	92,685	100,476	96,677	96,677
Wholesale (MW.h)	298,228	303,228	305,228	295,228	295,228
Total Sales (MW.h)	395,913	395,913	405,704	391,904	391,904
Losses (MW.h)	34,444	34,444	35,296	34,096	34,096
Total Generation (MW.h)	430,357	430,357	441,000	426,000	426,000
Hydro (MW.h)	419,405	416,119	417,762	413,800	416,762
Diesel (MW.h)	10,714	14,000	23,000	12,000	9,000
Wind (MW.h)	238	238	238	200	238
Total Generation (MW.h)	430,357	430,357	441,000	426,000	426,000
Diesel MW.h	10,714	14,000	23,000	12,000	9,000
less: DCF	0	3,286	8,512	2,743	-257
Total in Rates (Expected Diesel)	10,714	10,714	14,488	9,257	9,257
Incremental Diesel in Base Rates (MW.h)		-0	3,773	-1,457	-1,457
Total Diesel	10,714	14,000	23,000	12,000	9,000

Existing ERA Approach

Proposed 2013 Wholesale Rate	8.298	cents/kW.h	current wholesale rate (Appendix 4.1)
Average proposed rider revenue per kW.h	2.088	cents/kW.h	89.23% of non-industrial rider revenue of $6.98 million (Table 4.2)
ERA Rate Calculation:			
Fuel Price	28.681	kW.h	DCF diesel price as forecast in GRA for 2013 (average for YEC grid)
Variable O&M cost	3.000	kW.h	2009 GRA approved
ERA rate (var cost of diesel) at sales	**31.681**	cents/kW.h	

The **Energy Reconciliation Adjustment** is calculated as follows:

a) **sales below GRA forecast**: no adjustment for sales more than 10% below GRA forecast
b) **sales above GRA forecast:** all sales in excess of GRA forecast are subject to the adjustment
c) **sales when diesel not on margin:** no adjustment when diesel not on the margin at average water flows

	Cases					
	GRA	**Case #1**	**Case #2**	**Case #3**	**Case #4**	
Incremental Wholesale Sales (MW.h)	0	5,000	7,000	-3,000	-3,000	
Incremental Wholesale Related Generation (MW.h)	0	5,435	7,609	-3,261	-3,261	at 8.7% losses (Table 2.2 of GRA)
Amount paid under normal ongoing billing ($000s)	$ 24,747	$ 25,162	$ 25,328	$ 24,498	$ 24,498	
ERA Adjustment to be Paid (Refunded) ($000s)	$ -	$ 1,203	$ 1,684	($722)	($722)	
Total Amount Paid after ERA	$ 24,747	$ 26,364	$ 27,011	$ 23,776	$ 23,776	

Note:

Calculations are to be done on a monthly basis, however in practice the adjustment and calculations would be addressed periodically (and made final based on a year-end reconciliation processes).
All cases for the "existing approach" assume diesel is on margin.

TOPIC: **Capital Spending**

REFERENCE: **Application, page 5-1**

Coordinated with these initiatives, Yukon Energy has also completed projects to enhance safety and reliability at the existing Mayo, Aishihik and Whitehorse hydro facilities.

QUESTION:

a) For each of the projects referred to in the above quote, please provide the details of completed project safety and reliability measures compared to any current or proposed safety and reliability measures. If the proposed safety and reliability measures are not yet available, please provide YEC's best estimates of those measures.

ANSWER:

(a)

Most of the following projects were completed to ensure the continued operation of the identified equipment was safe and reliable – however, some projects were completed to meet new legal safety requirements or licencing requirements. There are very few individual safety or reliability measures available as most of the projects were completed to maintain the original design requirements.

Aishihik Projects

The following projects provide for improvements in the protection systems and SCADA installed at Aishihik and will aid in reducing the overall area and impact of a failure event on equipment at the Aishihik plant. These projects will also provide information and data for analysis to provide for quicker restoration of the plant in the event of an outage. The estimated improvement in reliability is the two to three hours to travel to the plant to analyze the event and complete the necessary switching to isolate any faulted equipment.

- Aishihik Generation Redundancy; and

- Aishihik Substation Upgrades.

While there are aspects of public safety and flood mitigation, the primary reason for undertaking this work is to comply with water licence requirements.

- Aishihik River Icing Study Mitigation – Bridge; and
- Aishihik River Icing Study – Berm.

The following project was required to bring the equipment back to original design requirements for safety and reliability as mandated by legal safety requirements. There are not considered to be safety or reliability measures undertaken for this project as it was required to meet legal safety requirements.

- Aishihik Elevator Modernization.

Mayo

The following project provides for improvements in the protection systems and SCADA installed at Mayo. It will aid in reducing the overall area and impact of a failure event on equipment at the plant. As well, it will provide information and data for analysis to provide for quicker restoration of the plant in the event of an outage. The estimated improvement in reliability is the four to five hours to travel to the plant to analyze the event and complete the necessary switching to isolate any faulted equipment.

- Mayo Hydro – Substation Enhancement.

The following projects provide for public safety or are required to meet YEC's regulatory requirements (i.e. Dam Safety). These projects were required by licensing or regulatory agencies.

- Wareham Intake Rock Scaling;
- Wareham Spillway Upgrades;
- Mayo Lake Control Structure;
- Wareham Bridge – to provide access of equipment to complete Core Raise and Dam Water Barriers;
- Wareham Dam Core Raise and Improvements;

- YEC Fall Arrest System;
- Mayo Gate House Rock Removal; and
- Dam Water Barriers.

The following projects provide for maintaining equipment to the original design requirements for safe and reliable operation or to improve its operability to ensure its reliable operation under adverse conditions, such as winter weather/temperatures or emergency events (i.e. penstock failure). These projects were required to maintain original design specifications or in the event of an emergency.

- Mayo Head Gate Repairs;
- Install Jack Screws at Mayo Spill Gates;
- MH2 Upper Guide Bearing Replacement; and
- Mayo Stop Log Hoist.

Whitehorse

The following projects provide for improvements in the protection systems and SCADA installed at Whitehorse. They will aid in reducing the overall area and impact of a failure event on equipment at the plant. As well, they will provide information and data for analysis to provide for quicker restoration of the plant in the event of an outage. The estimated improvement in reliability is the hour to travel to the site or plant to analyze the event and complete the necessary switching to isolate any faulted equipment.

- WH4 Spillgate PLC and RTU Upgrade; and
- Lewes Gate Structure – SCADA

The following projects provide for maintaining equipment to the original design requirements for safe and reliable operation or to improve its operability to ensure its operation under adverse conditions, such as winter weather. These were not considered to be safety or reliability as they were required to maintain original design specifications.

- Whitehorse Spillway Improvements;
- WH West Gate Gearboxes and VFD;
- WH East Gate Gearboxes;
- WH4 Governor System Hydraulic Upgrade;
- P125 Trash Racks and Heater Rebuild;

- WH1 Commutator Upgrade;
- WH2 Commutator Upgrade;
- Fish Ladder Lewes Control Structure; and
- WH4 Digital Governor Retrofit.

The following projects provide for improving equipment to the meet new legal requirements for the safe and reliable operation or maintenance of the equipment. These are not considered to be safety or reliability measures as they were required to meet legal requirements.

- Hydro Unit Platforms for Working in Draft Tubes; and
- P125 Bulkhead Gate (Stop Logs).

TOPIC: **Aishihik Third Turbine**

REFERENCE: **Application, Section 5.2.1; An application by Yukon Energy Corporation for a review of its 20-year resource plan 2009-2025 - Board Recommendation, page 29; Board Order 2009-8, paragraph 193**

The Board also notes that until this Application, final costs and the final scope of the project were not known. The Board has concerns that the final costs of the project were materially greater than the high estimate that the Board had the last opportunity to review (during the Part 3 review process) and that this cost overrun (when compared to the estimates provided to the Board) in conjunction with the cost overruns of the Mayo-Dawson transmission project display a trend of underestimation by YEC. (Board Order 2009-8 Appendix A, Paragraph 193).

-and-

To alleviate existing concerns regarding YEC's ability to estimate, the Board directs YEC, in future, to file any Part 3 applications before this Board only when preliminary engineering estimates are available and included as part of the application. Further, in future GRA applications, the Board directs YEC to include business cases for major capital items, including electronic models. Business cases will include:

- Descriptions of the project;
- Economic analysis including preliminary engineering estimates;
- Discussion of alternatives and how the chosen option was determined;
- Discussion of the risks of proceeding with the chosen alternative;
- Discussion of risks of not proceeding with the chosen alternative; and
- Discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs. (Board Order 2009-8 Appendix A, Paragraph 196).

PREAMBLE:

Estimated costs of the Aishihik third turbine $7.0 million, 20-Year resource plan; $8.5 million, Board Order 2009-8; $13.8 million.

QUESTION:

a) Aishihik third turbine costs appear to be 97% above the originally estimated costs and 62% above the estimates provided in YEC's 2008-09 GRA. Please explain and reconcile the cost estimates provided in YEC's 2008-09 GRA with the costs provided in the current Application.

b) Given the directions in Board Order 2009-8, please explain what steps YEC has taken to address large variances in estimates for capital projects and cost overruns from application to application.

c) How does YEC propose that such variances in estimates or cost overruns be addressed in order to address the potential impacts to the utility and to customers — e.g. recovery of costs, rate shock? Please provide the business cases, including the information as directed in Board Order 2009-8, for all capital projects listed in the Application.

d) Please provide a copy of all written documentation of all project review meetings that have occurred (e.g. agendas, materials presented for discussion, minutes, etc.) for all of the capital projects included in the Application.

ANSWER:

(a)

Overview of Changes to Cost estimates

The vast majority (over 80%) of the $5.3 million cost estimate variance from the 2008-09 GRA to December 2011 reflects the variance between the preliminary engineering cost estimate and actual tendered cost estimate.

The cost estimates provided in the 2006 Resource Plan and in the 2008-09 GRA were preliminary engineering estimates. This was made clear in both proceedings.

The Original Budget Cost Estimate of $8.8 million was prepared in April 2009 using the estimates provided to YEC by its engineering consultant AECOM which was retained specifically to provide a cost estimate for tendering purposes.

As noted in the Application, the Construction Approval Cost Estimate of $12.8 million was based on actual tendered costs and the increase in budget to reflect this more accurate estimate of costs was not approved until August 2010 after an extensive review was undertaken by both AECOM and YEC.

Final cost estimates are $1 million (approximately 8%) higher than the tendered cost estimate. Please see the response to YUB-YEC-1-5 for a review of costs by component for the Original Cost Estimates, the Construction Approval Cost Estimates, and the Final Cost Estimates,

In summary, as in the case of many complex projects, project costing cannot be confirmed with reasonable certainty until the project is tendered.

Detailed review of process leading to actual tendered cost estimate

As reviewed in the Application (pages 5-7 and 5-8), in 2008/2009, as a result of a tendered process, Yukon Energy retained AECOM Engineering (AECOM) to provide general engineering services to Yukon Energy. At that time Yukon Energy did not have the internal engineering capability to carry out many of the projects facing the utility at the time.

One of the first projects AECOM undertook on Yukon Energy's behalf was the Aishihik Project. Yukon Energy requested AECOM prepare preliminary engineering costing estimates for budget and tender evaluation purposes.

AECOM prepared such an estimate and based on that estimate in August 2009 Yukon Energy set a budget of $8.810 million.

AECOM was also hired to undertake the tender process and in February 2010, under AECOM's direction the construction related work was tendered. Unfortunately the two bids received were each materially higher than the estimate prepared by AECOM. As a result an in depth review of all bids was undertaken, and after lengthy discussion with AECOM including with AECOM's senior management, AECOM acknowledged that they had significantly underestimated the costs of the Project. AECOM informed YEC that the bids more accurately reflected the magnitude of the Aishihik Project costs.

As a result of this review, Yukon Energy cancelled the tender process, and undertook various additional steps to confirm the tendered project cost estimates. Yukon Energy also undertook a review of the project's feasibility based on the new estimate and concluded that the Project was economic. As a result, in August 2010 a decision was made to proceed with the Project. The budget was adjusted upwards to $12.813 million to reflect the more up to date tendered Project cost estimate.

Please see CW-YEC-1-28(d) for an explanation of +/-5% cost variances from August 2010 (when tendered costs were available) and final cost estimates (December 2011).

(b)

Based on the Board's directions, and the experience it has gained in undertaking numerous major capital projects over the last decade, YEC has instituted a number of additional controls to better manage project budgets:

1. On larger projects, the Company has hired experienced owner's representatives who act as the Company representative overseeing construction, and providing advice on design and contracting on the project. For example experienced owner's representatives were hired for CSTP Stage 2 and for Mayo B.

   Funding for large projects is also staged; for large projects, the owner's representative or project manager regularly reports to senior management based on approved budgets for each stage -- he is required to report on deliverables expected and explain any variances prior to release of the next tranche of funding. For each stage a new budget is prepared for review by senior management and once approved it is then brought to the Board of Directors for its approval. Although the exact definition of each phase may vary somewhat depending on the nature of the project, the stages are phased to encompass preliminary planning through to the final decision to proceed to construction.

2. Major projects also employ weekly minuted meetings between YEC representatives, contractor reps and project engineers. These meetings cover all aspects of the project including work site activities, costs incurred and forecast, timing of key equipment delivery, etc. These meetings are crucial to YEC not only for monitoring individual project performance but also this information is critical for planning coordinated outages between projects.

3. Project management on large projects are also required to provide written status reports to YEC management on a prescribed schedule.

4. In addition to the above -- on a quarterly basis -- all capital projects are reviewed internally by senior management who then report to the Board about the status of the project including any budget variances.

This process was followed in relation to the major capital projects including Mayo B, CSTP Stage 2 and the Aishihik Third Turbine projects.

As demonstrated by the Aishihik Third Turbine project, notwithstanding steps taken by Yukon Energy, material cost variances can occur between preliminary engineering cost estimates and cost estimates after tendering. Such variances can reflect risks related to project complexities, and market conditions and variances can occur even though such estimates are provided by qualified major engineering consultants. In all such cases, Yukon Energy's focus (as demonstrated by the Aishihik Third Turbine Project) is to take all reasonable steps to confirm the reasonableness of tendered cost estimates, and to only proceed with construction after senior management and YEC's Board confirm that the project remains economic and justified in the circumstances.

(c)

Addressing Cost Variances

Pursuant to generally accepted principles of rate regulation, if utility costs are determined to be reasonable and prudently incurred than the utility is entitled to recover such costs through rates.

In the circumstances of Aishihik Third Turbine, the appropriate test is not whether the costs were materially higher than forecast based on earlier engineering cost estimates, but whether such costs were prudently incurred and necessary to complete the project.

The fundamental reason why the 2008/09 GRA estimate of project costs was materially lower than what it has cost Yukon Energy to complete the Project is because AECOM underestimated what those costs would be. As noted, a review of the bids received after tender both by AECOM and Yukon Energy determined that the more accurate estimates were approximately $13 million, not $8.8 million.

Notwithstanding final estimated costs were higher than the original engineering cost estimates, the Aishihik Third Turbine Project remains very attractive relative to diesel generation and therefore it is economic and good for ratepayers. It will help to materially reduce ratepayer costs.

As noted in the Application -- at the revised forecast net capital cost and a wide range of grid loads (i.e., 4.5 GW.h/year and higher) -- the levelized cost of energy (LCOE) for the project approximates 9 to 11 cents/kW.h over an assumed 65 year economic life.[1]

Accordingly, this Project is forecast to provide a net economic benefit to Yukon ratepayers over its economic life solely on the basis of its expected displacement of diesel generation. This was the test that the Board adopted in Board Order 2009-8, (Appendix A, paragraph 195) when it approved the final costs for the CSTP Stage One Project (notwithstanding -- as in the case of this Project -- there were increases in CSTP Stage One final estimated costs relative to earlier pre-tendered cost estimates).

Business Cases for Capital Projects

In relation to the request for business cases for all capital projects listed in the Application, Yukon Energy notes that it addressed this (as directed by the Board in Board Order 2009-8, Appendix A, paragraph 196) in the Application for all **major** capital (defined in this Application, as in past GRA applications, as capital projects costing more than $1 million). This level of information has also been addressed in the Application, at a very broad level (and to the extent practicable), for smaller capital project costing between $0.1 and $1 million during 2012 and 2013.

In an effort to be responsive, outlined below is further information on each of the major capital projects. Unfortunately, given the number of IRs, the large number of capital projects and the extraordinary broad nature of this question -- it is simply not possible in the time available to provide similar detailed information on "all capital projects listed in the Application". Once the Board has had a chance to review Yukon Energy's response to this and other IRs relating to capital projects Yukon Energy is willing to work with Board staff if more detail on any specific capital project is needed.

[1] Please see response to YECL-YEC-1-32 for a more in depth review of the sensitivity of this LCOE estimate to variations in the assumed grid loads.

Further information on Major Capital Projects listed in the Application

Business case analysis on major capital projects is primarily directed at the justification for proceeding with the construction of a major project.

Depending on the nature of the Project a so called business case analysis can take on different forms. For example a so called business case analysis for projects may be very different when the reason for undertaking the project is for reliability or safety purposes versus projects intended to add supply or reduce costs to the system. When dealing with the former there is typically no option but to undertake the project, and often limited options for how the project must be undertaken (e.g., YEC requires a financial system and there are limited vendors who can provide a system that meets YEC's needs). In contrast, when dealing with the latter type of major projects -- a reasonable business case can include a description of the proposed project, economic analysis (including preliminary engineering estimates), discussion of alternatives (including the "do not undertake the project" option) and how the preferred option was chosen, discussion of risks (of proceeding or not proceeding with the chosen alternative, including the risks associated with foregone opportunities), and discussion of assumptions included in the analysis and sensitivities on these assumptions (including escalation factors, loading, financial measures, term of project and associated ancillary costs).

As set out in Section 5.2.1 of the Application, eleven major capital projects are identified. Business case information is provided in this section for each of these projects using four separate categories of major projects.

1. **Major Projects subject to prior major YUB review processes**: - The business cases for these projects have been subject to prior YUB review. Overall, the net rate base increase from these projects approximates $43.8 million related to approximately $172.3 million capital costs (less approximately $128.5 million of government/YDC contributions) for projects in-service prior to December 31, 2011.
    a. **Carmacks-Stewart Transmission Project Stage 2** - As reviewed in Application section 5.2.1.1, the business case for this project was reviewed by the YUB in the 2006 Resource Plan review, in the 2007 Part 3 review of CSTP, and in the 2008-09 GRA (response to YECL-YEC-1-8 REVISED [provided as Attachment 1 to CW-YEC-1-27]. As proposed in the Application, the $41.9 million forecast contributions will fully offset the

$41.9 million final estimated costs and there is no impact on requested rates. Please also see response to CW-YEC-1-26 and UCG-YEC-1-49.

b. **Mayo Hydro Enhancement Project (Mayo B)** - As reviewed in Application section 5.2.1.2, the business case for this project was reviewed by the YUB in the 2008-09 GRA (response to YECL-YEC-1-5 REVISED provided as Attachment 1 to this response) and in the subsequent Part 3 review. As proposed in the Application, the net rate base cost forecast at $35 million reflects forecast project costs of approximately $116.6 million that are forecast to be offset by federal and Yukon Government/YDC contributions of approximately $81.6 million. Please see the following responses for additional information:
   i. YUB-YEC-1-4 - provides Mayo A and Mayo B Rated Capacity and Operating Output
   ii. CW-YEC-1-27 - provides the following additional information in response:
      1. A side-by-side comparison of the cost breakdown provided as CW-YEC-1-5 Table 1 in the Mayo B Facilities hearing (attached) and the $116.6 million actual costs and an explanation of any variance greater than ±5%.
      2. An analysis of the costs and benefits of the Mayo B project based on actual costs, contributions and forecast sales in the same format as YUB-YEC-25 Attachment 1 in the Mayo B hearing.
   iii. YUB-YEC-1-33 - references scope and provides explanation why Mayo Head gate was not included in scope and only $0.750 million allocation of Mayo Substation was included in scope.
   iv. YECL-YEC-1-33 - confirms Mayo Substation cost allocation included in Mayo B costs per kW.h comparisons.

c. **Aishihik Third Turbine Project** - As reviewed in Application Section 5.2.1.3, the business case for this project was reviewed by the YUB in the 2006 Resource Plan review, in the 2007 Part 3 review of CSTP, and in the 2008-09 GRA. As proposed in the Application, the net rate base cost is forecast at $8.8 million, after $5 million Yukon Government contributions. In addition to the responses provided above in this IR

(Sections (a) and (b)), please see the following responses for additional information:

i. YUB-YEC-1-5 - provides the original cost estimates for the project and scope and cost changes since the original cost estimates were provided.
ii. YUB-YEC-1-34 - discusses steps YEC has taken to avoid past issues relating to estimating and the recourse Yukon Energy has taken against AECOM for the underestimation of project costs.
iii. CW-YEC-1-28 - provides peaking capacity and "long-term average hydro energy supply" added to the system by this project (page 5-6, lines 25-26); provides the NPV analysis of the benefits of this project mentioned in footnote 3, page 5-7 of Application (analysis from 2007 CSTP Part 3 hearing); provides the analysis that led YEC to conclude in August 2010 that this project was still beneficial (page 5-8, lines 16-19 of Application); provides the original costs of this project as of August 2010 by component and the actual costs in the same detail with explanations for variances greater than ±5% between estimated and actual.
iv. LE-YEC-1-21 - notes completed scope did not change from project scope contemplated initially. Provides detailed cost listings of the projected final cost by component and by contractor (including YEC internal costs).
v. YECL-YEC-1-35 - addresses LCOE sensitivity to grid loads. Also provides the following additional info:
    1. When the grid is expected to reach 450 GW.h/year.
    2. The LCOE previous to the year determined (when grid reaches 450 GWh/year)
    3. Detailed calculations for (1) and (2) above
    4. Whether Mayo B is included in the LCOE. If not, the levelized cost of energy including Mayo B.
    5. The annual diesel displacement with Mayo B in operation.

2. **Major Projects required to ensure system safety and reliability**: The business cases for these projects relate to requirements to ensure system safety and reliability, and address the need and thorough estimation of costs rather than a cost benefit assessment. Overall, the net rate base increase from these four projects is forecast at approximately $19.1 million:

a. **Mayo Hydro - Substation Enhancement** - As reviewed in Application section 5.2.1.4, the project was undertaken to ensure system reliability and safety and to accommodate forecast loads. The facility is 50 years old and in need of major refurbishment and upgrades to continue operating in a safe and reliable manner, and to address (among other matters) outstanding concerns documented in the June 2004 BC Hydro Engineering report No Es94 and the need to maintain appropriate service for the Mayo A generators, Dawson and Elsa transmission Lines, and the local Mayo town distribution. In addition, many ongoing changes on the Yukon grid require material investment in the Mayo substation to ensure that it is equipped and fully capable of addressing those changes including interconnection of WAF and MD grids, the addition of Mayo B, and the addition of industrial loads in 2010 and beyond. The project is not specifically driven by any of these factors alone, but is a needed system improvement to address the confluence of all of these factors at this point in time. The Application reviews why the work was undertaken now, and how overall efficiencies were gained through coordination with other projects being undertaken (Mayo B and CSTP Stage 2). The net rate base cost is forecast at approximately $10.15 million for completion in 2012. Please see the following responses for additional information:
    i. YUB-YEC-1-33; CW-YEC-1-29; LE-YEC-1-22 – Explains why only a portion of this project's costs was allocated to Mayo B project and justification for allocation.
    ii. UCG-YEC-1-51
        1. Notes the timing for this project was primarily driven by existing system requirements.
        2. Notes the completion of the CSTP2 and Mayo Hydro Enhancement (Mayo B) Projects advanced the Mayo Substation Project by approximately one to two years in advancing the project also allowed Yukon Energy to take advantage of the tendering process on CSTP2 to purchase the bulk of the substation equipment (i.e. switches, breakers) through that tendering process – saving the cost of that work. With regard to Mayo B, this allowed YEC to take advantage of, and gain efficiencies from, the contractors being on site (i.e. PKI, etc.) and to

utilize the outages planned for the Mayo B work to complete some of the Mayo Substation work.

3. Provides a component breakdown by year for the Mayo Hydro Substation Enhancements for 2010, 2011, 2012 and 2013.

b. **Mayo Head Gate Repairs** - As reviewed in Application section 5.2.1.5, the project was undertaken to ensure plant reliability and safety. The existing reinforced concrete intake was constructed in the 1950s. In order to ensure continued safe and reliable operation, it needed replacement and upgrading to address ongoing deterioration and to ensure the intake gate is brought into compliance with current standards. The Application reviews the outcomes of an outside third party expert inspection of the intake gate in 2009, and the steps initially taken in response that inspection including the assessment of options and the reasons behind choosing the preferred alternative. It also describes why this work was required now, and why it was coordinated with Mayo B. As proposed in the Application, the net rate base cost is forecast at approximately $1.3 million for completion in 2012. Please see the following responses for additional information:

   i. YUB-YEC-1-33 - confirms that this project was not part of the original scope of the Mayo B project.

c. **Aishihik Generation Station Redundancy** - As reviewed in Application section 5.2.1.6, the project was undertaken to rectify a serious system reliability issue identified as a result of a major system outage on January 29, 2006. This outage identified very serious security of supply issues to Whitehorse during peak winter times. Attachment 1 to LE-YEC-1-18 provides a copy of the April 11, 2006 letter to the YUB setting out Yukon Energy's Outage Response and Reliability Plans following the January 29, 2006 event. YEC was asked by the YUB to provide a response that outlined the circumstances of the outage, how YEC responded to the emergency, the likelihood for the event recurring, what emergency plans YEC had in place for such an event, and what other system vulnerabilities were present (and how they were being addressed). This letter provided the detailed information to the YUB and interested parties and was filed as part of the interrogatory responses in the 2008/2009

GRA (LE-YEC-1-5). It is also provided as Attachment 1 to LE-YEC-1-18 in the current proceeding. As proposed in the Application, the net rate base cost is forecast at approximately $6.4 million for completion in 2011. Please see the following responses for additional information:

i. CW-YEC-1-30 -
    1. Provides a breakdown of the original estimated cost and a detailed explanation of the changes in costs.
    2. Provides a detailed history of the estimated costs of this project showing how each factor in the quote above increased costs from $2.9 million to $6.356 million.

ii. LE-YEC-1-23 - provides detailed listing of the projected final cost by component and by contractor (including YEC internal costs).

d. **Whitehorse Spillway Improvement** - As reviewed in Application section 5.2.1.7, the project was undertaken to ensure plant reliability and safety. The dam, including the spillway and spill gates, are over 50 years old and absent refurbishment/upgrades, the gates were becoming less reliable and more prone to failure. In an outage or any other times that large quantities of water must be spilled, loss of control of the gates may cause overtopping of the dam. In May 2011, an external advisor was retained to prepare a condition assessment of the gates. He identified areas where the spill gates needed to be upgraded and their related budgetary costs (see the Application for more details on the process leading to the approved budget). As proposed in the Application, the net rate base cost is forecast at approximately $1.25 million for completion in 2013. Please see the following responses for additional information:

i. UCG-YEC-1-54 - provides a component breakdown of the Whitehorse Spillway Improvements project expenditures by year.

3. **Other Major Projects**: The business cases for the following two projects relate to specific Yukon Energy needs as noted in the Application:

a. **Enterprise System (JDE)** - As reviewed in Application section 5.2.1.9, the project was undertaken to replace the current JDE enterprise business system (on which YEC's financials, inventory management and procurement functions are operating) with an integrated system that includes a computerized maintenance management system module for

operations that is currently operating manually. The Application reviews the business case for this project. As proposed in the Application, the net rate base cost is forecast at approximately $3.2 million for completion in 2013. Please see the following responses for additional information:

i. UCG-YEC-1-56(c) - provides savings and productivity gains from the installation of these programs.

ii. YUB-YEC-1-36

1. Provides business cases provided in the 2008-09 GRA [provided as Attachment 1 to YUB-YEC-1-36**.** This includes summary of the RFP responses with evaluation criteria and related scoring, and the criteria, evaluation process and scores from the product demonstrations.
2. Explains why the costs estimate changed from the 2008-09 GRA.
3. Provides the economic benefit of the enterprise system as proposed by YEC versus a continuation or update of the previous system.
4. Provides a breakdown of costs for Roll-out #1
5. Provides review of scope and costs for the work remaining after Roll-out #1, and expected total cost of the enterprise system, including all costs after Roll-out #1.
6. Provides a breakdown of the costs for the selection process totaling $300,000.

b. **Whistle Bend Subdivision Supply** - As reviewed in Application section 5.2.1.8, the project is being undertaken in collaboration with YECL. It relates to the issue of how and when Whistle Bend should be connected to the system to ensure adequate supply and overall system reliability and protection. This project will not be in service before 2014 and therefore will not impact rates in the test years. As proposed in the Application, no net rate base cost is forecast in the test years - although the forecast total spending in the test years is $5.23 million, this number is a preliminary number and the final estimate will depend on the discussions with YECL. Please see the following responses for additional information:

i. YECL-YEC-1-31 and YECL-YEC-1-32 - describes available business case information for this project.

4. **Mine grid connections Major Projects to be offset by customer contributions**: The business cases for these two projects relate to initial estimated costs for connecting two specific new mines to the grid (Victoria Gold and Western Copper), based on each mine providing a customer contribution to fully offset all capital costs for this connection. Overall, no net rate base increase is forecast during the test years - the $10.0 million estimated capital cost for potential work during the test years is forecast to be fully offset by customer contributions. No agreements currently exist to provide for connection of either of these mines.

(d)

Unfortunately -- as noted above in relation to business cases -- given the number of IRs (over 900), and the large number of capital projects (well in excess of 100 projects) -- it is simply not possible in the time available to provide the detailed information requested on "all capital projects" included in the Application. Once the Board has had a chance to review Yukon Energy's response to this and other IRs relating to capital projects Yukon Energy is willing to work with Board staff if more detail on any specific capital project is needed.

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).

TOPIC: **Major Projects Required to Ensure System Safety and Reliability**

REFERENCE: **Application, page 5-3**

Mayo Hydro – Substation Enhancements, Mayo Head Gate Repairs

QUESTION:

a) Please confirm if either of the two projects listed above were part of the original scope of the Mayo B project.

b) Please provide the original scoping document for the Mayo B project.

ANSWER:

(a) and **(b)**

The Mayo Hydro Substation Enhancements and the Mayo Headgate Repairs were never considered part of the Mayo B Project.

The above-noted projects were required to be undertaken to ensure continued safe and reliable operation of the existing Mayo plant infrastructure and were not planned to be undertaken as part of the original scope of the Mayo B project.

The two key original scoping documents for the Mayo Hydro Enhancement Project (Mayo B) are the YESAB Project Proposal filed with the Executive Committee February 27, 2009 and the Part 3 Application filed with the Minister December 10, 2009 and reviewed by the YUB at an oral hearing April 6-9, 2010.

Both documents are publically available at the link below.

http://yukonenergy.ca/energy/projects/mayob/.

TOPIC: **Aishihik Third Turbine**

REFERENCE: **Application, page 5-8**

In discussion with AECOM — after an in depth review of the bids — AECOM acknowledged they had significantly underestimated the costs of the Project, and the bids more accurately reflected the magnitude of the Aishihik Project costs.

QUESTION:

a) Has YEC undertaken a review of how to prevent a recurrence of the difference of the bids and the project costs? If so, what was the result of YEC's review? What steps has YEC taken to avoid this situation occurring in the future? What recourse, if any, has YEC taken against AECOM for the underestimation of project costs?

b) Please provide the amount YEC compensated AECOM for estimating the costs of the Aishihik third turbine project.

ANSWER:

(a)

Yukon Energy over the past several years has been engaged in major planning and construction processes related to Mayo B, CSTP Stage 2, and Aishihik Third Turbine, as well as other capital investments (Mayo Substation, Aishihik Redundancy etc) and ongoing studies. These intensive activities have informed and refined Yukon Energy's tendering and purchasing policies. In effect, Yukon Energy over the past 5 years has learned from all major projects it has undertaken and is improving its practices and methods based on this collective effort.

The following issues related to the Aishihik Third Turbine project are noted – along with how the Corporation has adjusted its practices pursuant to the experience with Aishihik Third Turbine as well as other projects undertaken recently.

- **Contract Approach** – During 2008, Yukon Energy pursued a strategic alliance with an engineering firm to provide a full suite of engineering services. At that

time, the Company was challenged to hire sufficient experienced engineering staff to address a backlog of projects. After an intensive tender process including thorough on-site interviews, AECOM (formerly UMA) was selected. The Aishihik Third Turbine construction management package was outsourced to a major engineering firm as a full design engineering, tendering and construction management contract. Going forward, based on the experience with the Aishihik Third Turbine project:

- Yukon Energy would not normally contract all of these components to one contractor and would typically split tendering and construction management from other tasks.
- Based on the experience with AECOM on Aishihik Third Turbine, Yukon Energy would not implement this type of model for major projects without higher degree of oversight by the company, either directly with staff or through an external coordinator (as was employed with Mayo B and CSTP).

- **Cost Estimating Process** – Yukon Energy retained AECOM to do cost estimating and tendering work on the Aishihik Third Turbine project as it did not have the capacity at the time the estimates were prepared to undertake a peer review of the cost estimates and expected that AECOM would undertake this work as part of their contract. AECOM did not do a peer review of the cost estimates before issuing tenders, and only completed this review after the tender process was complete. Yukon Energy elected to hire a large firm with internal resources and comprehensive quality control mechanisms with the expectation that such a firm would have the internal capacity to undertake this type of rigourous review.
  - Since this occurred, Yukon Energy's tendering and contracting processes have become more refined and robust – this includes adding staff to oversee these issues.
  - The situation with this project has highlighted for YEC that peer review of estimates, especially for unusual and/or large projects is a critical control measure that needs to be considered.

- **Oversight** –Yukon Energy expected on the Aishihik Third Turbine project that a firm with the resources of AECOM would have the internal capacity and quality control measures to successfully undertake this work. Other project development

and construction processes of the same period have highlighted the value of implementing project oversight mechanisms.

- Mayo B and CSTP Stage 2 processes both highlighted the value of an ongoing project Steering Committee to provide oversight and overall direction as the project proceeds.
- The Mayo B and CSTP Stage 2 construction processes have highlighted the value of hiring an experienced owner's representative (as well as an administration construction project manager) to oversee all elements of the project during the construction period.
- Future projects will see more significant input from YEC staff through all stages.

Yukon Energy has not taken legal recourse against AECOM. Yukon Energy rigourously reviewed the tendered cost estimates after they were provided in February 2010. This intensive review determined that the tendered cost estimates reflected the true costs to undertake and complete this work. In effect, the underestimation of costs by AECOM did not change the actual costs reasonably required to do the project (beyond costs for checking the estimates) but merely misrepresented the true costs to complete this work. Prior to a decision to proceed Yukon Energy reviewed the costs and benefits and determined that the project still provided substantial benefits despite the higher than anticipated costs.

AECOM did agree to perform certain additional services to complete the project for no additional cost.

(b)

This task was completed as part of preliminary engineering but was not separately identified as such. Preliminary engineering was $0.584 million.

TOPIC: **Mayo Hydro – Substation Enhancements**

REFERENCE: **Application, page 5-10**

The Mayo Substation at 50 years old was in need of major refurbishment and upgrades to continue operating in a safe and reliable manner.

-and-

Added to the requirement to refurbish the substation, many ongoing external changes on the Yukon grid required material re-investment be done to the Mayo substation to ensure that it is equipped and fully capable of addressing the fundamental changes to the grid system at this time including:

…

- Additional new industrial loads in 2010 (i.e. Alexco mine) and anticipated potential future loads.

QUESTION:

a) Please explain whether the described Mayo B substation enhancements should have been undertaken in conjunction with either the Mayo B project or the CSTP Stage 2.

b) If this project is partially driven by new industrial loads, should there be customer contributions to partially offset the costs? Please explain.

ANSWER:

(a)

The substation was required to be refurbished due to the age of the infrastructure and the need to address pre-existing concerns to ensure that an appropriate level of service is maintained for Mayo 1 and 2 generators, Dawson and Elsa Transmission Line and the local Mayo town distribution (also see UCG-YEC-1-51(b)). As noted in the GRA, many ongoing external changes on the Yukon grid also required material re-investment to

ensure that it is equipped and fully capable of addressing the fundamental changes to the grid system at this time.

- Interconnection of the Whitehorse-Aishihik-Faro grid and the Mayo Dawson grid through the completion of the Carmacks Stewart Transmission Project - Stage 2;

- Addition of a new generation station and generating capacity at Mayo (i.e., Mayo B); and

- Additional new industrial loads in 2010 (i.e., Alexco mine) and anticipated potential future loads (e.g., Victoria Gold).

As noted in Tab 5, page 5-10, these external requirements were coordinated with the work being undertaken at the Mayo Substation to secure overall efficiencies for the project as well as cost savings in design, equipment specifications and procurement; however, each project is justified on a separate basis from the Mayo Substation Enhancement. See also response to UCG-YEC-1-53.

(b)

No. There is no basis to directly charge any such costs solely to the industrial class or one specific customer, except in the case where the costs were incurred directly as a component of extending new service to the customer or relating to infrastructure that solely serves the customer (e.g., the Minto spur was directly charged to Minto). The costs in question related to overall system improvements and, similar to all other system improvements, ultimately affects all classes.

TOPIC: **Enterprise System**

REFERENCE: **Application, pages 5-19 to 5-21**

QUESTION:

a) Footnote 32 on Page 5-19 notes that issues with the software configuration have prevented optimum functionality and system capabilities are minimally used. Please explain if the system has the capability but is not being used to in relation to that capability, or if there is another reason for the system not operating optimally. Since YEC has stated that the system is at its end of life, is this a result of the configuration of the software or is it related to staffing or training issues? Would all the ad hoc files and spreadsheets be eliminated by the new system?

b) Please provide the business cases provided in the 2008-09 GRA and the business case prepared for the current proceeding. Explain why the costs changed for the estimate of approximately $1 million in the 2008-09 GRA to $3,240,000 in 2010 with more work to be completed. In addition, provide a cost-benefit analysis showing the economic benefit of the enterprise system as proposed by YEC versus a continuation or update of the previous system.

c) Please provide a breakdown of costs for Roll-out #1 — software license, implementation (internal and external), training, customization and enhancements, and support (one-time and ongoing).

d) What is the scope and costs for the work remaining after Roll-out #1? What is the expected total cost of the enterprise system, including all costs after Roll-out #1?

e) Please provide the summary of the RFP responses with evaluation criteria and related scoring.

f) Since the RFP was issued to 11 vendors, please explain why there were only four software product proposals received?

g) Please provide the criteria, evaluation process and scores from the product demonstrations.

h) What is the relationship between Microsoft Dynamics and Wennsoft?

i) Please provide a breakdown of the costs for the selection process totaling $300,000.

ANSWER:

(a)

The system generally was capable of this functionality, however, certain design set up did not occur in the initial implementation and could not be retrofitted – a new installation of the software would have been required. Also, the version YEC runs is not well supported by the vendor. A key objective of the new install was the elimination of manual workarounds and this was accomplished in a number of areas. The existing system also did not have a CMMS which was a key objective for the new system install.

(b)

For business case provided in the 2008/2009 GRA please see Attachment 1 to this response which provides a copy of YUB-YEC-1-37(c) from that proceeding. Due to the age of the current system, a simple update was not possible and a new installation would have been required. Continuation was not an option as the vendor had effectively ceased to support the version YEC employs. The costs for this, based on discussions with the vendor, would not have materially varied from the selected option.

The $1 million budget item in the last GRA was a placeholder budget based on the last installation in 1999. At this point, YEC had not sourced a replacement system nor had they developed detailed budgets for the implementation. The last installation also did not include a CMMS which was a significant component of the new installation. Despite the increased costs, the justification for the project remains largely the same – the existing system was end of life and required replacement; the solution selected was the most cost effective available given the market available (see also response to part (e) below).

(c)

Please see Table 1 below which provides a breakdown of costs for Roll-out 1.

Please note YEC does not track costs by the categories provided in the interrogatory (i.e., software licence, implementation (internal and external), training, customization and enhancements, and support. To provide some indication of where these costs fit in the cost categories tracked by YEC the following is noted:

- Licence costs would be in software (not broken out);
- Implementation includes all consulting and some internal costs; support is not part of implementation; and
- Training, customization and enhancements are not tracked separately.

Table 1:
Roll-out #1 Total Expense

	Fcst Final Estimate (2012/13 GRA)
System selection (includes current/future state analysis and procurement of system and implementation consultants)	344
Hardware purchase	135
Software	291
Consulting	
- project management	241
- Financial module implementation consultant	606
- Job Cost/CMMS implementation Consultant	176
- CMMS project advisor	165
YEC Internal Costs	449
Total	2407

(d)

YEC has budgeted $500,000 in 2012 and $250,000 in 2013 to accomplish the following:

1. Populate the CMMS module with data related to balance of assets (Roll-out #1 configured the module for use and loaded limited location data to ensure functionality).

2. Automate employee timesheet processing (currently manually entered).

3. Develop automated reporting of capital and operational results.

4. Automated budgeting processes.

5. Investigate and implement where feasible automation of capital approvals and customer billing data.

(e)

RFP responses were evaluated and scored in accordance to YEC's priority and closeness of product fit to YEC's requirements. Responses were evaluated by the project team and the overall results are provided in Table 2 below.

Table 2:
Evaluation of RFP Responses

	Microsoft GP	IFS	Lawson	Oracle
Overall Product Fit Expectation: 70% to 80% [1]	91.9% Met base requirements	95.6% Met base plus non-mandatory	98.0% Met base plus non-mandatory	96.5% Met base plus non-mandatory
Technology Compliance [2]	100.0%	55.4%	82.1%	82.1%
Price [3]	$693,998	$694,091	$2,046,368	$956,406
Annual maintenance	$82,697	$72,537	$182,783	$17,000
Short-listed	**YES**	NO	NO	**YES**

Note 1 - The overall product fit is a consolidated score of fitness for use and ease of use by core business areas, namely, Accounting, Inventory, Procurement and Maintenance. The non-mandatory requirements were "nice to have" features.

Note 2 - The technology compliance was primarily based on compliance with YEC's current technology infrastructure platform. YEC is a Microsoft shop and uses Microsoft's operating systems and database.

Note 3 - Price" is proponent's estimate of only software and consulting costs and does not include all other costs associated with an ERP implementation such as hardware cost, client's internal resource cost, travel cost, project management cost, etc.

Short-list Derivation

Product functionality fit, technology platform compliance and price were the main elements in determining the proponent short-list; as indicated in the table above.

- **IFS** was eliminated as the product only runs on an Oracle database. YEC is a Microsoft "shop" and the current database platform in use for all applications is Microsoft SQL Server. Implementing IFS will require YEC to be staffed with two different technical skill-sets.

- **Lawson** was eliminated on its price point. The price reflected the sophistication of the richness in product functionality which was felt to be more than what YEC needed. The level of sophistication will require internal in-depth skills to support the product.

- **Oracle** was short-listed on functionality fit, price and based on the fact that YEC is currently running an old release of Oracle's EnterpriseOne applications.

- **Microsoft GP** was short-listed on functionality fit and price. It met the minimum of both criteria.

Short-listed proponents were subsequently advised and invited to proceed to the next stage which was to demonstrate their proposed solutions.

Vendor Demonstrations

Demonstration (demo) scripts were developed by the project team based on business needs from the future state analysis in phase 2 of the FIS project and issued to the short-listed vendors. The purpose of the demo scripts was to ensure that vendors structured their demos accordingly so that the demos flowed in accordance to YEC's operations and showcased what YEC wants to and needs to see. Prior to the demonstrations, discovery sessions were held with each vendor to clarify demo requirements and expectations.

- **Oracle Demo -** Product demonstrations were conducted by Oracle, on-site, on September 23 to 24, 2009. Oracle was unable to complete their demo within their requested timeframe of 2 days. Therefore, Accounts Payable, Accounts Receivable, General Ledger, Budgeting & Forecasting and Fixed Assets were not demonstrated. After the demo, Oracle advised that since the modules that

were not demonstrated are already in use by YEC, what would probably suffice are follow-up remote demos to clarify existing functionality and net-new changes between YEC's release of JDE and the latest product release. After a series of follow-up emails with Oracle to arrange for the follow-up demos, Oracle eventually advised that they did not have any resources and not even within the next few months to stage the demos. This somewhat reinforced YEC's concern with the level and availability of JDE expertise currently in place in Oracle. Since the JDE product had gone through two acquisitions, staff turnovers are typical. YEC, therefore, had to proceed without Oracle in the selection process.

- **Microsoft Dynamics GP & Wennsoft Maintenance Demo -** The Dynamics GP and Wennsoft demonstrations were conducted on November 9 and 10, 2009. A list of follow-up items requiring further clarification was compiled by the YEC team. Follow-up demonstrations to address this list was conducted from January 25 through to 27, 2009. With the exception of the Wennsoft Maintenance product, most items on the list were cleared to YEC's satisfaction whereby the Dynamics GP product was deemed to have no "show-stoppers". YEC was able to obtain a more in-depth Wennsoft demonstration during the week of April 12, 2010. Albert Schwarz, Operations Lead, from YEC attended the prototype demo and was able to gain a better understanding of "fitness for use" for YEC. A further confirmation of "fitness for use" was expedited by a subsequent demo on July 26, 2010 by Wennsoft for YEC's maintenance advisor (consultant), Roger Davies of the Da-trol Group. Wennsoft's score by Roger Davies was over 86% with shortfalls related to minor requirements only and no "show-stoppers". This was documented in Roger Davies Site Report dated July 29, 2010.

Evaluation after demonstrations

The final evaluation after product demonstrations was an overall 78% fit which is within the expected range of 70% to 80% for fitness for use.

Reference Checks

Product and vendor references, consisting of conference calls and site visits, were conducted from March to October 2010 on five (5) references. A substantial amount of time and effort was expended in working with vendors to source client references that were applicable to YEC's business and coordinating schedules amongst all participants. Prior to expediting each reference check, objectives were internally reviewed and a list

of questions compiled and forwarded to the client in advance of the reference call or site visit.

The five references were:

- Northwest Territories Power Corporation (Yellowknife, Northwest Territories);
- Pristine Power (Calgary, Alberta);
- CityWide (Melboune, Australia);
- Advanced Technology Construction (Toronto, Ontario); and
- Delta Controls (Cloverdale, British Columbia);

The feedback from all references was overall positive with no show-stopper issues or concerns.

As a result of the FIS system sourcing project, the recommended solution to replace the current JDE system was with a combination of products from the Microsoft Dynamics GP and the Wennsoft suite of products. Wennsoft's suite of products is tightly and seamlessly integrated to Dynamics GP which meets YEC's system objective of an integrated business system.

Table 3:
Dynamics GP & Wennsoft Recommendation

Dynamics GP & Wennsoft Recommendation		
Requirement	**Met**	**Rationale**
Integrated System which includes a CMMS system for Operations.	√	Wennsoft's Maintenance and Job Cost modules were built specifically to integrate to Dynamics GP Financials. Dynamics GP includes Inventory Management and Procurement modules which are integrated to the Financial modules.
Technology Platform Compliance	√	Both Wennsoft and Dynamics GP run on Microsoft operating systems and database which is currently in place in YEC.
Product Functionality Fit of 70% to 80%	√	After product demonstrations, the overall product fit was evaluated to 78%.
Extensive vendor support	√	In addition to direct vendor support, both Microsoft and Wennsoft have a substantial worldwide network of business partners that resell and implement their products.
Ease of use	√	Dynamics GP and Wennsoft scored 75 out of a 100. Oracle scored 20.
Process Efficiency	√	Dynamics GP and Wennsoft scored 65 out of a 100. Oracle scored 20.
Product Documentation	√	Dynamics GP and Wennsoft scored 70 out of a 100. Oracle scored 35.

(f)

The non-responding vendors did not provide reasons for their decision not to participate.

(g)

See response to part (e) above.

(h)

Microsoft is the owner of the core financial system called GP Dynamics. Wennsoft is a business partner of Microsoft and develops asset and equipment management software products that seamlessly integrates to the Microsoft Dynamics GP suite of products.

(i)

Please see Table 4 below for a breakdown of costs for the selection process.

Table 4:
Breakdown of Costs for Selection Process

Component	Cost ($)
Labour	67
Travel	23
Misc	2
Legal	13
Consulting	182
Hardware	23
Overhead/Interest	34
Total	**344**

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.

TOPIC: **Aishihik Business Improvements**

REFERENCE: **Application, page 5-23**

Include provision for icing studies and mitigation work to address the effects of Aishihik operation on infrastructure downstream.

QUESTION:

a) What information does YEC hope to obtain by undertaking icing studies? How would the provision of icing studies be implemented?

b) Why is this study required for this capital project?

c) Is this item better suited as a deferred cost?

ANSWER:

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

The Aishihik Icing Study was required to ensure compliance with Yukon Energy's licensing requirements and obligations, and provides the following benefits:

1. Further information regarding the potential impacts of ice build-up on smaller rivers such as the Aishihik River. This is considered important as the majority of previous icing studies have been undertaken on larger rivers, such as the Yukon River (where the processes for ice build-up are now well documented).

2. To determine possible areas where remedial actions related to icing effects are required. The studies have identified two areas of remediation and the following recommendations: (1) to raise the heritage bridge located at Canyon; and (2) to construct an earthen berm at the low ground level area.

The Aishihik Icing Study was undertaken as a feasibility study; when it was determined that capital works were required to address the issues identified, these costs were transferred to generation asset construction for the earthen berm project (Aishihik River Icing Study – Berm). As indicated in response to LE-YEC-1-29 the Aishihik River Icing

Study - Bridge project is in design and evaluation as the completion of the Aishihik Third Turbine project allows Yukon Energy to maintain a consistent flow of water in the Aishihik River which provides for the establishment and improved maintenance of ice cover. Once this evaluation is complete, YEC will assess whether capital works are required.

It is appropriate in some instances for studies that do not result in physical construction to be treated as deferred costs. However, as noted, in this instance there was an expectation (that is being realized) that there will be construction related activities, so the costs of the study is being included in the cost of the asset built and amortized over the appropriate asset class life.

In the event that a study such as this did not result in asset construction, the study will be amortized over 5 years similar to other deferred study costs.

TOPIC: **Demand-side Management (DSM) Accounting Policy**

REFERENCE: **Application, page 5-26 and Appendix 5.2**

The Application includes, as Appendices to this section for approval by the YUB, Yukon Energy's … DSM Accounting Policy (Appendix 5.2) to address amortization of these costs for regulated revenue requirement purposes.

-and-

The purpose of this policy is to outline the accounting policy for costs incurred in relation to Demand Side Management (DSM) activities.

DSM is defined as "options available to electric utilities to alter the volume and pattern of electricity end-use, so as to improve or increase the efficiency of electricity production and system performance". **This includes any improvements in Corporation "end use" such as insulation in its buildings,** but does not include Supply Side Enhancements that the Corporation does to improve efficiency of generation and transmission activities.

The intent of DSM programming is to implement programs or rate structures designed to influence electricity consumption patterns by reducing and/or shifting loads. The primary benefits of DSM for the Yukon were seen to be lower costs of providing electrical service and enhanced customer relations. [Emphasis added]

QUESTION:

a) Please provide the impetus respecting YEC's proposed DSM finance policy, including corporate and regulatory considerations.

b) Please explain how "improvements in Corporation end use such as insulation in its buildings" will influence Yukon electric utility ratepayers to reduce and/or shift loads. Please explain how such improvements are to the benefit of Yukon electric utility consumers.

c) If YEC's proposed DSM accounting policy is approved, please explain how Interveners and the Board are to judge/examine future DSM program-related

expenses, such as those alluded to in Section 2.2 of the proposed policy, as being prudent and/or include benefits to Yukon electric utility ratepayers.

d) As an expenditure item, how would an improvement, such as the addition of insulation in YEC's buildings, be treated under YEC's capitalization policy? Please explain and provide a copy of YEC's capitalization policy.

e) Please explain the underlying rationale of how an amortization period of 10 years was determined to be appropriate in respect of the DSM accounting policy.

ANSWER:

(a)

The impetus underlying the DSM accounting policy was to ensure there was a clearly defined practice for treatment of these costs, i.e., which costs should properly be deferred and amortized and which costs should properly be expensed as O&M in the year incurred. In addition, in Order 2009-8 the Board had directed (Directive #4) that an appropriate treatment of deferral accounts in support of DSM initiatives be proposed at the next GRA[1].

The last time Yukon Energy had initiated material DSM programming in Yukon was in the early 1990's. There was a DSM accounting policy developed and in place at that time. Similar to the Planning Cost Accounting policy it was recognized that this accounting policy should be reviewed and updated to ensure it reflects current practice. In this respect, Yukon Energy reviewed DSM accounting policies and practice from other jurisdictions in order to determine an appropriate accounting treatment. The proposed policy builds on the past practice and also is considered to be consistent with accounting practice in other jurisdictions with robust DSM programming such as Manitoba and British Columbia.

[1] Directive #4 notes "The Board finds UCG and LE proposals for deferral accounts in support of the DSM initiatives acceptable and both YEC and YECL can propose appropriate treatment of these accounts at the time of their next GRA."

(b)

Improvements in Corporate end use are not directly designed to influence choices of ratepayers (i.e., either to reduce or shift loads); however, this does provide a positive example for the community regarding efforts that can be made by all consumers in order to be more efficient. Yukon Energy is itself an end user of electricity, consequently, conservation efforts by Yukon Energy within its own facilities helps to reduce loads and requirements for costly baseload diesel generation on the grid – which benefits all ratepayers.

(c)

Before expenditures are included in rates they must be approved by the YUB as prudent. As such the YUB will have an opportunity to review all deferred DSM costs prior to such costs being included in rates. With regard to amounts expensed in the year incurred (Section 2.2) – where this occurs in a test year the YUB will have the opportunity to review the O&M expense as part of the GRA filing and determine whether the test year amounts are reasonable and prudent. Outside of test years, such amounts will be expensed and go to the utility's bottom line.

(d)

The project would be classified as a betterment and would consequently be capitalized provided it met the following criteria:

a. Increase the service life of the existing asset by at least 25% of the original estimated useful life or depreciation class to which it belongs;
b. Reliability and/or quality improvements above original design standards;
c. Increase the previously assessed physical output or service capacity;
d. Reduce operating costs of the existing asset by a substantial and quantifiable amount over a period of at least three years.

This above criteria is included in the Criteria for Capitalization policy provided as Attachment 1 to this response.

(e)

Overall, DSM expenditures are recognized as being made to provide benefits over many years and therefore to be appropriately treated by way of amortization. In order to determine the appropriate amortization period, a utility might be expected to conduct a detailed study to determine the appropriate benefit period over which to amortize these costs for its specific programs. In Yukon, based on the size of the operation, this was not considered to be cost effective as there is no reason to believe the benefits accruing from these programs will materially vary from other Canadian utilities. Accordingly, the amortization period noted was derived from a review of similar programs at other Canadian utilities, including Manitoba Hydro and BC Hydro.

At the time this review was undertaken, prior to preparing the GRA, it was understood that both Manitoba Hydro and BC Hydro had 10 year amortization periods for DSM costs. On more recent review for the purpose of responding to this IR, updates are noted below:

- BC Hydro has recently updated its amortization period for DSM from 10 years to 15 years to reflect the increase in average persistence of DSM program savings - see BC Hydro draft 2012 Integrated Plan, page 3-23, which is available publicly at the web site below:
  http://www.bchydro.com/energy_in_bc/irp/document_centre/reports/draft_irp.html

- Manitoba Hydro has stated in its latest GRA filing that, due to IFRS, it now proposes to expense all DSM costs for financial reporting purposes. See, page 21 of the International Financial Reporting Standards – Update Report (April 30, 2012) provided as part of Manitoba Hydro's 2012/13 and 2013/14 GRA is available at the link below:
  http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_5_5.pdf
  However, Manitoba Hydro has previously noted that in the event DSM expenditures were required to be expensed for financial reporting purposes, the Corporation would consider alternative regulatory treatments to permit rates to be set more consistent with the earlier practice. Manitoba Hydro has yet to complete a regulatory review with the new provision, so it is not yet clear what regulatory approach the utility will adopt.

Notwithstanding these updates, Yukon Energy continues to propose a 10 year amortization as appropriate for Yukon conditions, particularly during the initial years of the Yukon DSM activities (based on BC Hydro experience, a longer period may be appropriated at some future time if an increase in average persistence of DSM program savings is then established).

YUKON ENERGY		DEPARTMENT:	INQUIRIES TO:	TOPIC:
	Finance Accounting Practice	All	Finance	Criteria for Capitalization
		ISSUED:	**REVIEW DATE:**	**APPROVED BY:**
	FX-001			Chief Financial Officer

1.0 Purpose

To provide guidelines for determining whether expenditures should be capitalized or expensed.

2.0 Criteria for Capitalization

Expenditures are considered capital in nature if one or more of the following criteria are met:

a) If they have been incurred to acquire, construct, or develop assets that will be used on a continuing basis for longer than one year.
b) The resulting asset will be held for use in the production or supply of goods or services, for rental to others, for administrative purposes, for the development, construction, maintenance or repair of other property, plant and equipment;
c) To ensure achievement of life or an extension of the life of the asset.
d) To increase the capacity of an existing asset.
e) A substantial improvement in the facility affecting quality of output or reduce operating costs.
f) When a building or structure is substantially renovated or refurbished to ensure that the asset will attain its expected useful life.
g) The cost is significant, relative to the total capital cost of the particular asset. In the case of new assets, the cost must exceed $1,000 (except for office furniture and fixture purchases for 2005, which will be capitalized when the cost is greater than $300**.)**

Acquisition Costs for capitalization include; but are not limited to:

a. outright purchase cost of the asset
b. engineering costs
c. material, supplies
d. per diems
e. consulting, contractor fees
f. freight, brokerage, duty

g. labor, including the cost of benefits
h. vehicle operating costs
i. travel costs
j. training costs associated with the new asset
k. equipment rentals
l. project insurance
m. legal costs
n. feasibility study costs related to the fixed asset being constructed
o. brokers' commissions
p. installation costs
q. site preparation costs
r. incremental costs related to power supply to customers during construction or installation of a new asset
s. warranties purchased with initial purchase or during project construction
t. ES&G (see definitions) and
u. AFUDC (see definitions).

The Corporation capitalizes revenue generating meters, regardless of the cost of each meter.

The Corporation capitalizes streetlights, regardless of the cost of each streetlight.

The Corporation capitalizes transformers and breakers, regardless of the cost of each transformer and breaker.

The Corporation capitalizes all initial cost expenditures, except the following:

a) office furniture and general office items with a value of $1,000 or less per item. Such items include desks, chairs, computer equipment, shelving, etc.
b) household furniture and appliances with a value of $1,000 or less per item. Such items include fridges, stoves, microwaves, table, chairs, couches, etc
c) operating items with a value of $1,000 or less per unit, per kit or per set. Such items include hand tools, chains, shop items, etc. Where such items form part of a construction project, however, they are to be recorded in the relevant work order for that project, which, on completion, is charged to fixed assets.
d) Software licenses and software upgrades items with a value of $1,000 or less.

3.0 Betterments to Existing Assets

Betterments must meet one of the following criteria to be capitalized:

a) Increase the service life of the existing asset by at least 25% of the original estimated useful life or depreciation class to which it belongs;
b) Reliability and/or quality improvements above original design standards;
c) Increase the previously assessed physical output or service capacity;
d) Reduce operating costs of the existing asset by a substantial and quantifiable amount over a period of at least three years.

4.0 Addition, Replacement, or Removal of Major Components

4.1 Units of Property If the expenditure is related to the replacement or addition of one or more Units of Property, the expenditure will be capitalized, when the expenditure is greater than $1,000.

4.2 Components of Units

a) Additions (not replacements) of Components of Units; the cost of installing component parts which did not previously exist (e.g. guys or cross arms) will normally be capitalized

b) Replacement of component parts will be **expensed** when:

i) Component parts are replaced independently and not in conjunction with the replacement of a Unit of Property; and

ii) A substantial betterment is not effected; and

iii) A component is replaced because it has reached the end of its useful life (normal wear and tear). **OR**

iv) A component is replaced due to premature failure, or technological reasons with no intent to improve the asset and the cost of the replacement is less than the materiality limits listed below.

Replacement of component parts will be **capitalized** when:

i) Component parts are replaced in conjunction with the replacement of the Unit of Property with which it is associated. (The new component parts need not be physically similar to those replaced as long as it performs the same function as the replaced part.) **OR**

ii) A substantial number of component parts are replaced; and the cost of the replacement meets the following minimum materiality limits:

• Wind Generation	$15,000
• Hydro Generation	$25,000
• Transmission Lines	$20,000
• Distribution	$10,000
• Diesel Generation	$15,000
• Substations	$15,000
• Combustion Turbines	$50,000
• SCADA & Communications	$20,000
• General Property	$ 1,000
• Vehicles	$ 5,000
• Land Improvements & Buildings	$10,000
• Computer Software	$ 1,000

c) The cost of removing component parts, which are not replaced, will be charged against the Future Removal and Site Restoration provision.

5.0 Computer Software

If computer software is purchased with the initial purchase of new computer hardware then the software is capitalized with the cost of the computer hardware.

Software packages purchased for an existing computer costing more than $1,000 are capitalized, while packages costing less than $1,000 are expensed in the period that they are acquired.

In-house software development (costs related to the direct and indirect design, programming, testing, and implementation costs for new applications) and enhancement (costs related to the direct and indirect design, programming, testing and implementation costs for improvements to an existing system) projects including implementation and testing costs for packaged products costing in excess of $1,000 are capitalized and amortized over the estimated useful life of the software package.

TOPIC: **YEC Planning Cost Accounting Policy (PCAP)**

REFERENCE: **Application, page 5-26 to 5-27 and Appendix 5.1**

The Application includes, as Appendices to this section for approval by the YUB, Yukon Energy's Planning Cost Accounting Policy (Appendix 5.1) … to address amortization of these costs for regulated revenue requirement purposes.

-and-

Due to the unprecedented levels of planning costs incurred since 2009, a new planning cost accounting policy (provided in Appendix 5.1 to Tab 5) is included in this Application to ensure that these costs are addressed and included in rates in a manner that moderates near-term rate impacts for ratepayers.

-and-

The purpose of this policy is to outline the accounting policy for costs incurred in relation to Planning activities.
…

Planning costs deferred without amortization must meet a "Reasonable Assurance Test":

a. Future expenditures will not be recognized as work-in-progress assets until such time as there is reasonable assurance that a Corporation commitment to construction will be made. [original footnotes omitted]
b. In the event a project is abandoned after this step, accrued costs will be amortized over 10 years.

QUESTION:

a) Please provide the rationale and supporting reasons for proposing a planning cost accounting policy.

b) Please explain what is meant by the statement that YEC's proposed PCAP will ensure that "these costs … are included in a manner that moderates near-term rate impact for ratepayers."

c) Please explain what is meant by the phrase “reasonable assurance test”.

d) Please explain the reasons and rationale underlying the amortization period of 10 years for projects that have met the reasonable assurance test but are later abandoned. Please provide examples of past projects with descriptions and the reasons that the project was later abandoned.

e) Please explain the reasons and rationale underlying the amortization period of five years for major projects that do not meet YEC’s reasonable assurance test. Please provide examples of such projects with descriptions and the reasons that the project did not meet the reasonable assurance test.

f) Please explain the reasons and rationale underlying the short carry-over period of approximately 12 months.

g) Please explain how the Board and Interveners are to examine future deferred costs that are included in YEC’s proposed PCAP to ensure that the costs that were incurred, were prudent and to the benefit of customers.

h) How should it be determined whether an expenditure is prudent and to the benefit of ratepayers?

i) Please explain what is meant by “a major project” versus “a project”.

j) Please provide capital expenditure continuity tables for YEC generation and feasibility study projects for the period 2007 to 2013. The tables are to include 2007 projects in addition to those listed in tables 5.2 to 5.7. Please use the attached Excel workbook that includes tabs for generation and feasibility study projects as a guideline.

ANSWER:

(a)

Yukon Energy had an existing planning cost accounting policy reviewed by the YUB as part of the 1993/94 General Rate Application; however, it was determined that it would be prudent to review and update this policy to ensure it reflected the current

circumstances of the Corporation. This concern and requirement was largely driven by the unprecedented levels of planning costs incurred since 2009; the new policy was developed to ensure that these costs are addressed and included in rates in a manner that moderates near-term rate impacts for ratepayers.

Yukon Energy is aware that other utilities have come under scrutiny and criticism due to extensive reliance on deferral mechanisms. In the specific case of BC, the provincial Government and Auditor General have made detailed comments, but the issue also extends more broadly to other jurisdictions where concerns have been raised by regulators and the public. The cited concerns relate to excessive reliance on deferral/regulatory accounts, and to the risks posed to the utility and ratepayers over the long term due to continued deferral of costs. Such criticisms relate to the large number of accounts, the growing balances in each account, the lack of transparency (in current rates and in current financial reporting) to the costs and the financial impacts of deferrals, and the uncertainty regarding any clear plan to reduce growing deferral balances in the future and potential future rate pressures when large amounts of deferred costs are eventually brought into ratebase.

Yukon Energy has also been engaged in an unprecedented level of planning activities (both to ensure continued safe and reliable operation of the existing system due to aged and end of life infrastructure and to provide new supply in order to meet growth on the integrated grid). In this regard it was determined that pushing significant deferred costs to the future would shift risks and cost burden to future ratepayers in a manner that may not be viewed as equitable.

The following principles were applied in development of the new Planning Cost Accounting Policy in order to address the above noted concerns:

- Yukon Energy's planning cost accounting policy must recognize and provide a clear decision-making framework to address rate stability, transparency/accountability and intergenerational equity concerns that can arise where material deferred studies costs continue to accumulate over long periods.

- Yukon Energy's planning cost accounting policy should recognize that deferring material amounts over time without a process or framework for their disposal may serve to undermine the precise objective for deferring the costs - instead of benefiting rate stability, the deferral accounting treatment may become a further

cause of rate instability (i.e., near term rate impacts are avoided with more material impacts required at some future date).

- The need to ensure the existing policy (developed in 1992) reflects, and is sensitive to, the existing requirements or challenges faced by Yukon Energy (related to the need to undertake planning studies to ensure resource options are shelf-ready and can be developed as needed to ensure YEC can meet the generation needs for this non-interconnected system). In this regard,
    - The policy must recognize the requirement to undertake planning studies work prior to developing credible information and plans for a project to the point of meeting a "reasonable assurance" test and (provided the costs are prudently incurred) the basis for recovering these costs through rates as prudent expenditures that benefit all ratepayers.
    - The policy should recognize the need to ensure rate stability over time (i.e., through deferring and amortizing costs over a defined period instead of expensing such costs in the year incurred).

Please also see the response to UCG-YEC-1-40(a) regarding details of other jurisdictions that Yukon Energy reviewed that have allowed planning costs to be amortized.

(b)

Please see part (a) above regarding concerns related to long term rate impacts for rate payers. In terms of moderating near term rate impacts, the one-time transition provision is designed to moderate rate impacts in the test years by allowing for a 10 year (rather that 5 year) amortization period for deferred cost projects that have not reached reasonable assurance in the current test years and that are greater than $1 million. In the future, the new policy will tend to prevent such costs from accumulating to levels that would require such mitigation measures.

(c)

Please see the Planning Cost Accounting Policy provided as Attachment 5.1 to the Application.

Reasonable assurance is generally consistent with Yukon Energy's *Commitment to Proceed* with a specific project. This would be consistent with the following specific types of activities:

- A decision by YEC to define a specific project location, approach, technology;
- Prepare and file a YESAB Project Proposal;
- Enter into substantive negotiations with First Nations or other project partners;
- Preparation of engineering designs and tender materials; and
- Arrangement of project financing where needed.

Recent experience with CSTP and Mayo B has indicated "Commitment to Proceed" or "Reasonable Assurance" at time of a decision to prepare a YESAB filing. As noted for these projects when such filings were made, a filing with YESAB is not a final decision to proceed with a project - such final decision requires a number of other subsequent steps, including: securing necessary permits and approvals; completing engineering design, costing and tendering as required for a final construction contract award; completion of any required agreements with First Nations or other project partners; arrangement of project financing where needed.

(d)

An amortization period of 10 years is proposed for projects that have met the reasonable assurance test but are later abandoned in order to mitigate and smooth rate impacts when such prudent and reasonably incurred costs are included in ratebase. This reflects the reality that at any decision point in the project planning phases up to the point of the *Decision to Construct* there may also be a decision not to proceed with a project. It also reflects the reality that the further along in the planning stages a project proceeds, the greater likelihood that significant costs will be incurred related to assessment, licencing, engineering and tendering costs.

It is difficult to apply a currently developed standard for the new policy to past projects; however, Yukon Energy cannot cite an example of any of its prior projects that

developed beyond pre-feasibility stages of development (into effects assessment or licencing stages) that were later abandoned.

(e)

The amortization period of five years is retained for planning study cost projects that do not meet YEC's reasonable assurance test in order to retain continuity with past amortization policy for such projects and to be sensitive to the existing requirements or challenges faced by Yukon Energy (related to the need to undertake planning studies to ensure resource options are shelf-ready and can be developed to meet generation needs for a non-interconnected system). In this regard, five year amortization of such costs reflects the following requirements:

- Yukon Energy's requirement to undertake planning studies work prior to developing credible information and plans for a project to the point of meeting a "reasonable assurance" test and (provided the costs are prudently incurred) the need for a clear basis for recovering these costs through rates as prudent expenditures that benefit all ratepayers.

- The need to ensure rate stability over time (i.e., through deferring and amortizing costs over a defined period instead of expensing such costs in the year incurred).

The five year amortization period for such costs also reflects current policy for the Northwest Territories Power Corporation.

For the test years a one-time transition approach of 10 years is also applied for specific existing major deferred cost projects over $1 million that do not meet the reasonable assurance test in order to mitigate or smooth rate impacts in the test years. Projects less than $1 million were deferred and amortized based on the current 5 year practice.

Major projects that did not meet reasonable assurance and that were deferred and amortized over 10 years are noted in footnote 4 of the Planning Cost Accounting Policy and are noted below. Detailed descriptions for each of these projects are provided in Section 5.3.1 of the Application and in interrogatory responses noted, including the rationale for each project.

- Marsh Lake Storage; Tab 5, pages 5-30 to 5-33; YUB-YEC-1-42; YECL-YEC-1-38; YCS-YEC-1-11.

- Atlin Storage; Tab 5, pages 5-35 to 5-36; YUB-YEC-1-44; YCS-YEC-1-13.

- Gladstone Diversion; Tab 5 pages 5-33 to 5-35; YUB-YEC-1-43; LE-YEC-1-25; YCS-YEC-1-12.

- Geothermal; pages Tab 5 pages 5-46 to 5-47; YUB-YEC-1-50; YECL-YEC-1-40.

- Waste to Energy; Tab 5 pages 5-41 to 5-44; YUB-YEC-1-47; YCS-YEC-1-16.

None of the above projects has completed project definition (Phase 1 as reviewed in response to YUB-YEC-1-40(b)). None of the reasonable assurance tests have been met for any of the above projects:

- Preparation of environmental assessment applications for filing with YESAB (i.e., YESAB Project Proposal) or other regulatory/ permitting process have not commenced;

- Substantive negotiations with First Nations or other project partners regarding the defined project have not commenced;

- Engineering designs or other tender materials have not been prepared;

- Project financing has not been secured.

The reasons that a project has not yet met the reasonable assurance test can vary. In the above example, Marsh Lake Storage and Gladstone Diversion have not yet completed the studies and assessments needed for such a decision to be made; geothermal remains at an even earlier stage of assessment; in contrast, the decision has been made, based on the planning study work done, not to proceed further at this time on the Atlin Storage or Waste to Energy projects.

(f)

See response to part (a) above. A 12 month carry over period was deemed appropriate in order to formalize a process for a systematic annual internal review of deferred costs.

(g)

Deferred costs incurred to date are provided for review in the current Application and the Board may assess prudence of current costs and forecast test year costs for each deferred project. Future deferred costs will need to be reviewed by the Board prior to being included in rates. At that time the Board and intervenors will have the opportunity to review the prudence of such expenditures.

(h)

Please see response to YUB-YEC-1-24.

(i)

As noted in Tab 5 of the Application, Major Projects are considered to be capital projects greater than $1 million. This definition is only relevant to the one-time transition provisions.

(j)

Please see Attachment 1 to this response which reviews Feasibility Projects and Major Generation as requested.

Please note that the continuity schedule corrects 2009 WIP opening balances for feasibility study projects (please see notes in the excel file). There is no impact on the projects' 2009 closing balances due this corrections.

2007 as provided in 2008/09 GRA

Feasibility Study	WIP Opening Balance	Expenditures	Transfers/ Adjustments/Write-offs	Additions	WIP Closing Balance
Carmacks-Stewart Transmission Line	995	(995)			-
Resource Plan Phase 2	678,818	(450,247)		(228,570)	-
L170 Line Assessment	6,947	207,040		(213,987)	-
2006 Dam Safety Upgrades	62,158	73,547		(27,141)	108,564
Carmacks-stewart Transmission Line Phase 2	784,940	(784,940)			-
Western Copper Aerial Photo Mapping & Route Sele	28,513	(3,313)			25,200
Minto Copper Distribution Line	171,109	(171,109)			-
Marsh Lake Fall Storage	51,255	11,323		(62,578)	-
Southern Lakes Hydrology Study	10,358	90,103			100,461
2006 Yukon River Downstream Icing	20,020	126,592		(146,612)	-
Wareham Spillway Wall Raise	-	8,588		(8,588)	-
Customer Billing System Replacement	-	51,724		(51,724)	-
Carmacks-stewart Trans Line Phase 3	138,264	(138,264)			-
Hydro Storage & Generation Pre-feasibility	-	501,222			501,222
Wareham Intake Rock Face Assessmt	-	583			583
Minto Mine PPA	-	767,856			767,856
Mayo Wareham Liqufaction Analysis	-	98,711			98,711
Total	1,953,379	388,419	-	(739,202)	1,602,596

2007 Actual

Feasibility Study	WIP Opening Balance	Expenditures	Transfers/ Adjustments/Write-offs	Additions	WIP Closing Balance
Carmacks-Stewart Transmission Line	995	(995)		-	0
Resource Plan Phase 2	678,818	(450,247)		(228,570)	-
L170 Line Assessment	6,947	207,040		(213,987)	-
2006 Dam Safety Upgrades	62,158	73,547		(27,141)	108,564
Carmacks-stewart Transmission Line Phase 2	784,940	(784,940)		-	-
Western Copper Aerial Photo Mapping & Route Sele	28,513	(3,313)			25,200
Minto Copper Distribution Line	171,109	(171,109)		-	0
Marsh Lake Fall Storage	51,255	11,323		(62,578)	-
Southern Lakes Hydrology Study	10,358	90,103		-	100,461
2006 Yukon River Downstream Icing	20,020	126,592		(146,612)	-
Wareham Spillway Wall Raise	-	8,588		(8,588)	-
Customer Billing System Replacement	-	51,724		(51,724)	-
Carmacks-stewart Trans Line Phase 3	138,264	(138,264)		-	(0)
Hydro Storage & Generation Pre-feasibility	-	501,222		-	501,222
Wareham Intake Rock Face Assessmt	-	583		-	583
Minto Mine PPA	-	767,856			767,856
Mayo Wareham Liqufaction Analysis	-	98,711		-	98,711
	1,953,379	388,419	-	(739,202)	1,602,596

	2008 per 2008/09 GRA				
Feasibility Study	**WIP Opening Balance**	**Expenditures**	**Transfers/ Adjustments/Write-offs**	**Additions**	**WIP Closing Balance**
Aishihik Runner Up-rate Study		110,000		(110,000)	-
Aishihik River Icing Study		58,900		(58,900)	-
Wareham Dam Reliability Study		55,000		(55,000)	-
2006 Dam Safety Upgrades	108,564	2,000		(110,564)	-
Western Copper Transmission Line	25,200	-			25,200
Southern Lakes Hydrology Study	100,461	60,000		(160,461)	-
Hydro Storage & Generation Pre-feasibility	501,222	130,000		(631,222)	-
Wareham Intake Rock Face Assessmt	583	100,000		(100,583)	-
Minto Mine Ppa	767,856	8,435		(776,291)	-
Mayo Wareham Liqufaction Analysis	98,711	4,000		(102,711)	-
Mayo B		1,700,000			1,700,000
Other Generation Feasibilities		800,000			800,000
Investigate International Financial Reporting Standards		45,700			45,700
Total	1,602,596	3,074,035	-	(2,105,731)	2,570,900

2008 Actual

Feasibility Study	WIP Opening Balance	Expenditures	Transfers/ Adjustments/Write-offs	Additions	WIP Closing Balance
2006 Dam Safety Upgrades	108,564	1,680		(110,244)	-
Southern Lakes Hydrology Study	100,461	69,782		(170,243)	-
Hydro Storage & Gen Pre-Feas	501,222	93,196		(594,418)	-
Wareham Intake Rock Face Assessmt	583	9	(592)		-
Mayo Whrm Liqufaction Analysis	98,711	(25,835)		(72,876)	-
Hydro Storage and Generation		-			-
Aishihik River Icinng		27,114			27,114
International Financial Reporting Standards		18,823			18,823
Aishihik Unit Up-rate Study		5,169			5,169
Wareham Rock Face Feas. Phase 2		52,294			52,294
Warham Liquefication Assessment		40,755		(37,904)	2,851
Warham Dam Reliability		19,328			19,328
Mayo B		1,880,211			1,880,211
Resource Plan Oversight		163,296			163,296
Gladstone		39,063			39,063
Marsh		46,666			46,666
Large Hydro & Other		81,255			81,255
Geothermal		208,443			208,443
CSTL Stage 2		938,444			938,444
Western Copper Aerial Photo Mapping & Route Sele	25,200				25,200
Minto Mine PPA	767,856	1,201		(769,057)	-
L170 transmission Line Asses. Carmarcks		206,721		(206,721)	-
Total	1,602,596	3,867,613	(592)	(1,961,462)	3,508,156

2009 per 2008/09 GRA

Feasibility Study	WIP Opening Balance	Expenditures	Transfers/ Adjustments/Write-offs	Additions	WIP Closing Balance
Diesel Seismic Study - Dawson, Whitehorse, Faro		70,000		(70,000)	-
Customer Billing System		75,000		(75,000)	-
Mayo Lake Dam Assessment		100,000		(100,000)	-
Western Copper - Grid Connection YESAA & PPA	25,200	1,000,000			1,025,200
Western Copper - Grid Connection YESAA & PPA (cust Contribution)		(1,000,000)			(1,000,000)
Mayo B	1,700,000	6,500,000			8,200,000
CSTP Stage II		1,000,000			1,000,000
Other Generation Feasibilities	800,000	4,300,000			5,100,000
Alexco Mine - Feasibility & Permitting		300,000			300,000
Alexco Mine - Customer Contribution		(300,000)			(300,000)
Feasibility Studies And Engineering Assesments		50,000			50,000
Investigate International Financial Reporting Standards	45,700	105,500			151,200
Total	2,570,900	12,200,500	-	(245,000)	14,526,400

2009 Actual

Feasibility Study	WIP Opening Balance	Expenditures	Transfers/ Adjustments/Write-offs	Additions	WIP Closing Balance
Wareham Liquefaction Assessment (note 4)	2,851	170		(3,021)	-
Wareham Dam Reliability (note 4)	19,328	2,038		(21,365)	-
Aishihik Unit Up-rate Study (note 4)	5,169	285		(5,454)	-
Wareham Rock Face Feasibility Phase 2 (note 4)	52,294	3,608		(55,902)	-
Mayo Lake Structure Integrity Assessment		25,467		(25,467)	-
Wareham Liquefaction Assessment		22,117		(22,117)	-
Wareham Spillway Hoist Upgrade		41,617		(41,617)	-
Metering Audit 2009		30,510		(30,510)	-
Protection Event Collection System		28,154		(28,154)	-
Aerial Photo Mapping & Route Selection	25,200	5,033			30,233
Aishihik River Icing	27,114	42,901			70,015
International Financial Reporting Standards	18,823	236,283			255,107
Geothermal	208,443	1,099,142			1,307,584
Power Benefit Model Development		1,724			1,724
Wareham Consequence Category Assessment		50,375			50,375
AH0 Deluge System		22,863			22,863
WAF/MD Modeling and Stability		215,203			215,203
Hydro Unit Performance Test		251,777			251,777
Study P126 Heating System		4,228			4,228
Metering Audit 2009		35			35
Alexco Resource Corporation PPA		39,989			39,989
Resource Plan Oversight (notes 1 and 2)	163,296	(163,296)			
Marsh Lake Storage (note 1)	46,666	400,501			447,167
Atlin Storage		446,195			446,195
Gladstone (note 1)	39,063	972,936			1,011,999
Large Hydro (note 1)	81,255	250,608			331,863
Mayo B	1,880,211	5,560,658	(7,440,869)		-
CSTP2 (note 3)	938,444	-	(938,444)		-
Total	3,508,156	9,591,121	(8,379,313)	(233,606)	4,486,358

Note:

1. These projects were components of one project in 2008. In 2009 these projects were assigned their own projects accounts with the associated balances being transferred to their respective accounts (i.e. the balance related to Marsh Lake was transferred to the newly created Marsh Lake Storage project). Table 5.3 in error rolled the opening 2009 WIP balances for these projects into the 2009 expenditures. This is a presentation error and as such there is no impact on the projects' closing balances due this error.

2. The cost is allocated to Marsh Lake, Atlin, Gladstone and Large Hydro projects.

3. Corrected WIP and transfer balance.

4. Table 5.3 in error rolled the opening 2009 WIP balances for these projects into the 2009 expenditures. This is a presentation error and as such there is no impact on the projects' closing balances due this error.

2010 Actual

Feasibility Study	WIP Opening Balance	Expenditures	Transfers/ Adjustments/ Write-offs	Additions	WIP Closing Balance
Protection Event Collection System		33		(33)	
AH0 Deluge System	22,863	2,656		(25,519)	-
P125 Headgates Single Point		50,419		(50,419)	-
Aerial Photo Mapping & Route Selection	30,233				30,233
Aishihik River Icing	70,015	18,042			88,057
International Financial Reporting Standards	255,107	178,841			433,948
Geothermal	1,307,584	278,341			1,585,925
Power Benefit Model Development	1,724	(1,724)			0
Wareham Consequence Category Assessment	50,375	11,955	(62,330)		-
WAF/MD Modeling and Stability	215,203	261,918			477,121
Hydro Unit Performance Test	251,777	65,219			316,996
Study P126 Heating System	4,228	49	(4,276)		-
Metering Audit 2009	35	(35)			0
Alexco Resource Corporation PPA	39,989	6,702	(46,691)		-
Wind Feasibility- Ferry Hill		36,124			36,124
Mayo/Wareham Geotechnical Investigation		44,565			44,565
WH4 (Rotor) Investigation		28,771			28,771
Waste To Energy		235,777			235,777
Communications Stategy Study		16,684			16,684
P125/126 Hydrocarbon Containment		26,396			26,396
Study of Ice Processes in the Mayo River at Mayo		12,067			12,067
Marsh Lake Storage	447,167	1,035,711			1,482,879
Atlin Storage	446,195	1,616,254			2,062,448
Gladstone	1,011,999	2,077,573			3,089,572
Large Hydro	331,863	149,042			480,905
Mayo B		2,422,837	(2,431,581)		(8,744)
Mayo Lake Project		613,764	(613,764)		-
Total	4,486,358	9,187,981	(3,158,642)	(75,971)	10,439,726

2011 Full Year Forecast

Feasibility Study	WIP Opening Balance	Expenditures	Transfers/ Adjustments/ Write-offs	Additions	WIP Closing Balance
Wareham Consequence Category Assessment		62,882		(62,882)	-
Mayo/Wareham Geotechnical Investigation	44,565	(3)		(44,562)	-
Geothermal	1,585,925	361,485		(1,947,410)	-
WAF/MD Modeling and Stability	477,121	(29,585)		(447,536)	-
Hydro Unit Performance Test	316,996	23,204		(340,200)	-
WH4 (Rotor) Investigation	28,771	69,196		(97,967)	-
Communications Strategy Study	16,684	63,892		(80,576)	-
P125/126 Hydrocarbon Containment	26,396	1,176		(27,572)	-
Study of Ice Processes in the Mayo River at Mayo	12,067	167,197		(179,265)	-
IT Security Audit		38,071		(38,071)	-
Mayo River Salmon Enhancement		7,212		(7,212)	-
Mayo Lake Control Structure - Fish Passage		2,569		(2,569)	-
Atlin Storage	2,062,448	168,204		(2,230,652)	-
Wind Feasibility- Ferry Hill	36,124	391,917		(428,041)	-
International Financial Reporting Standards	433,948	131,821		(565,769)	-
System Stability Review		99,961		(99,961)	-
Western Copper - Aerial Photo Mapping & Route Sele	30,233			(30,233)	-
Short Term Energy Storage Feasibility		44,200		(44,200)	-
Atlin Grid Connection Feasibility Study		109,941		(109,941)	-
Mayo Lake Outlet Channel Bathymetry & Water Output Analysis		13,250		(13,250)	-
Climate Change Study		106,659		(106,659)	-
Large Hydro	480,905	190,852		(671,757)	-
Aishihik River Icing - Berm	88,057	10,829	(98,886)		-
District Heating		70,449			70,449
District Heating - Contributions		(530,000)			(530,000)
Waste to Energy	235,777	505,226			741,003
Waste to Energy - Contributions		(112,500)			(112,500)
LNG (Liquified Natural Gas)		168,905			168,905
Mayo B	(8,744)	-	8,744		-
Marsh Lake Storage	1,482,879	1,748,029			3,230,907
Gladstone	3,089,572	604,052			3,693,624
Total	10,439,725	4,489,091	(90,142)	(7,576,285)	7,262,389

2012 Forecast

Feasibility Study	WIP Opening Balance	Expenditures	Transfers/ Adjustments/ Write-offs	Additions	WIP Closing Balance
Geothermal		385,755		(385,755)	-
WH4 (Rotor) Investigation		175,310		(175,310)	-
Study of Ice Processes in the Mayo River at Mayo		50,000		(50,000)	-
District Heating	70,449	460,000		(530,449)	-
District Heating - Contributions	(530,000)				
Large Hydro		200,000		(200,000)	-
International Financial Reporting Standards		101,307		(101,307)	-
Atlin Grid Connection Feasibility Study		50,000		(50,000)	-
Mayo Lake Outlet Channel Bathymetry & Water Output		55,500		(55,500)	-
Climate Change Study		50,000		(50,000)	-
Wind Feasibility- Ferry Hill		100,000		(100,000)	-
System Stability Review		150,000		(150,000)	-
Waste to Energy	741,003	612,500		(1,353,503)	-
Waste to Energy - Contributions	(112,500)	(112,500)		225,000	-
Aishihik Hydro - Turbine-rerunnering		150,000		(150,000)	-
Faro FD1 Mirrlees Generator Assessment Rad Repair		50,000		(50,000)	-
Hydraulic Wood Removal System for Spill Gates at WH		75,000		(75,000)	-
Wareham Spillway Hoist Upgrade		100,000		(100,000)	-
Whitehorse Dam Break and Mapping		80,000		(80,000)	-
Marsh Lake Storage	3,230,907	800,000		(4,030,907)	-
Gladstone	3,693,624	200,000		(3,893,624)	-
LNG (Liquified Natural Gas)	168,905	1,500,000			1,668,905
Total	7,262,389	5,232,872	-	(11,356,356)	1,668,905

2013 Forecast

Feasibility Study	WIP Opening Balance	Expenditures	Transfers/ Adjustments/ Write-offs	Additions	WIP Closing Balance
Geothermal		300,000		(300,000)	-
District Heating		500,000		(500,000)	-
Large Hydro		100,000		(100,000)	-
Wind Feasibility- Ferry Hill		100,000		(100,000)	-
Waste to Energy		500,000		(500,000)	-
Wareham Spillway Hoist Upgrade		650,000		(650,000)	-
Marsh Lake Storage		800,000		(800,000)	-
Gladstone		500,000		(500,000)	-
Condition Assessment of Selected YEC Assets		150,000		(150,000)	-
VOIP Assessment		35,000		(35,000)	-
Diesel Seismic Study - Dawson, Whitehorse, Faro		70,000		(70,000)	-
LNG (Liquified Natural Gas)	1,668,905		(1,668,905)		-
Total	1,668,905	3,705,000	(1,668,905)	(3,705,000)	-

	2007 Actual			
Generation	**CWIP Opening Balance**	**Capital Expend.**	**Capital Additions**	**CWIP Closing Balance**
FD-1 (Note 1)		608,825		608,825

Note:
1. Includes cost for subcomponents.

2008 Decision

Generation	CWIP Opening Balance	Capital Expend.	Capital Additions	CWIP Closing Balance
FD-1	407,162	1,158,240		1,565,402
WD3		1,100,000		1,100,000
Aishihik Third Turbine Construction		750,000		750,000

	2008 Actual			
Generation	**CWIP Opening Balance**	**Capital Expend.**	**Capital Additions**	**CWIP Closing Balance**
FD-1	608,825	920,098		1,528,923
WD3		915,448		915,448
Aishihik Third Turbine Construction		279,280		279,280

Note:
1. Minto Diesels Phase 1 cost is sum of the project subcomponents.

2009 Decision

Generation	CWIP Opening Balance	Capital Expend.	Capital Additions	CWIP Closing Balance
FD-1	1,565,402		(1,565,402)	
WD3	1,100,000		(1,100,000)	
Aishihik Third Turbine Construction	750,000	3,500,000		

2009 Actual

Generation	CWIP Opening Balance	Capital Expend.	Capital Additions	CWIP Closing Balance
Mayo B - Construction		7,440,869		7,440,869
Aishihik Third Turbine Construction (note 1)	279,280	3,794,712		4,073,992
Aishihik Generation Station Redundancy		101,567		101,567
Mayo Head Gate Repairs		61,666		61,666
Whitehorse Spillway Improvements		-		-
FD-1	1,528,923	822,535		2,351,458
WD3	915,448	702,317	(1,617,765)	-

Note:

1. Table 5.2 in error rolled the opening 2009 WIP balances for Aishihik Third Turbine Construction into the 2009 expenditures. This is a presentation error and as such there is no impact on the project's closing balance due this error.

2010 Actual

Generation	CWIP Opening Balance	Capital Expend.	Capital Additions	CWIP Closing Balance
Mayo B - Construction	7,440,869	41,199,822		48,640,691
Aishihik Third Turbine Construction	4,073,992	4,742,490		8,816,482
Aishihik Generation Station Redundancy	101,567	706,076		807,643
Mayo Head Gate Repairs	61,666	204,347		266,014
Whitehorse Spillway Improvements	-	-		-
FD-1	2,351,458	626,487	(2,977,945)	

2011 Full Year Forecast

Generation	CWIP Opening Balance	Capital Expend.	Capital Additions	CWIP Closing Balance
Mayo B - Construction	48,640,691	60,721,436	(109,362,127)	-
Aishihik Third Turbine Construction	8,816,482	5,000,257	(13,816,739)	-
Aishihik Generation Station Redundancy	807,643	5,300,244	(6,107,887)	-
Mayo Head Gate Repairs	266,014	428,430		694,444
Whitehorse Spillway Improvements	-	96,440		96,440

	2012 Forecast			
Generation	**CWIP Opening Balance**	**Capital Expend.**	**Capital Additions**	**CWIP Closing Balance**
Mayo B - Construction	-	7,226,144	(7,226,144)	-
Aishihik Third Turbine Construction	-			-
Aishihik Generation Station Redundancy	-	257,313	(257,313)	-
Mayo Head Gate Repairs	694,444	639,956	(1,334,400)	-
Whitehorse Spillway Improvements	96,440	575,000		671,440

	2013 Forecast			
Generation	**CWIP Opening Balance**	**Capital Expend.**	**Capital Additions**	**CWIP Closing Balance**
Mayo B - Construction				-
Aishihik Third Turbine Construction				-
Aishihik Generation Station Redundancy				-
Mayo Head Gate Repairs				-
Whitehorse Spillway Improvements	671,440	575,000	(1,246,440)	-

TOPIC: **Major Projects Over $1 Million**

REFERENCE: **Application, Section 5.3, pages 5-26 and 5-27**

Yukon Energy must continue to plan to meet potential future loads (both expected near-term developments as well as over the longer term) in a cost effective manner that ensures continued reliable and low cost supply that is also environmentally responsible.

…

Progression through the planning process on each major deferred cost project has been carefully monitored and controlled by staged approvals for expenditures that apply to each project phase. In effect, each phase requires an approval to define the scope of work and the deliverable to be completed before progressing to the next stage.

…

Due to the unprecedented levels of planning costs incurred since 2009 a new planning cost accounting policy (provided in Appendix 5.1 to Tab 5) is included in this Application to ensure that these costs are addressed and included in rates in a manner that moderates near-term rate impacts for ratepayers.

QUESTION:

a) Please explain what is meant by "environmentally responsible" and provide examples of such projects in the past and going forward.

b) In Order 2009-8, the Board set out the following:

> The evidence suggests that YEC has a review process in place wherein concerns are identified, tested and reviewed by YEC's Board of Directors. The Board considers that the review process itself should document more clearly what materials are actually reviewed and how decisions that affect the status of studies and projects are made. Therefore, the Board directs YEC to keep written documentation of any and all deferred cost project review meetings that occur (e.g. agendas, materials presented for

discussion, minutes, etc.) and have available for review for those items YEC wishes to include in its revenue requirement.

In respect of each of the nine major deferred cost projects (excluding the 2012-13 GRA deferred costs), please provide documentation that indicates that each project has been carefully monitored and controlled by staged approvals for each project that apply to each project phase. Moreover, in general terms, please describe the project phases related to these major projects.

c) Please explain what significant event(s) in the Yukon environment has given rise to the unprecedented levels of planning costs that YEC has incurred since 2009.

ANSWER:

(a)

The 2011 Resource Plan discusses resource options in the context of four planning principles, one of which is "environmental responsibility" (the other principles are reliability, affordability and flexibility). Please see Overview of 20-Year Resource Plan: 2011-2030, as provided in response to YECL-YEC-1-18.

Environmentally responsible projects have one or more of the following traits:

- Responsible planning to mitigate and manage socio-economic and environmental impacts as required by various regulatory authorities.

- Planning for energy solutions that reduce greenhouse gas emissions (GHGs), and meet Yukon, national and global climate change action plans, and that follow the Yukon Government's Energy Strategy.

- Planning that supports a shift towards cleaner, renewable sources of energy, and seeks to increase energy production from renewable resources and reduce fossil fuel use and GHG emissions through replacing fossil fuels with cleaner, renewable energy sources where possible.

Past examples of environmentally responsible projects include the following:

1. ***Mayo Dawson Transmission Line –*** provided for interconnection of Dawson with the Mayo grid and allowed for surplus hydro available at Mayo to be used to displace baseload diesel requirements at Dawson (reducing diesel costs and GHG emissions).

2. ***Carmacks-Stewart Transmission Project – Stage 1*** - provided for interconnection of the Minto mine and Pelly Crossing with the WAF grid. This project allowed for sale of surplus hydro generation on WAF (that would otherwise be spilled) to be used to displace diesel generation occurring at the Minto mine (approximately 29 GWh/yr in 2009) site and at Pelly Crossing (approximately 2.2 GWh/year in 2009).

3. ***Carmacks-Stewart Stage 2*** - The completed CSTP provides for the "reinforcement, expansion of existing and construction of new transmission grids to transmit clean electricity" through the interconnection of two previously isolated electricity grids in order to transmit clean hydro generation.

4. ***Aishihik Third Turbine Project*** - This project provides enhanced hydroelectricity generation from an existing generating station, enhancing clean, renewable energy generation and displacing diesel generation that would otherwise be required.

5. ***Mayo Hydro Enhancement Project*** - Mayo B provides additional renewable electricity generation facilities in Yukon through the enhancement of an existing hydro facility to increase hydro-electric generation capability. This enhancement to the existing Mayo hydro generating facility generates up to twice as much electricity using the same amount of water, increasing Yukon's renewable electricity generation capability to displace diesel generation that would otherwise be required to meet projected needs of Yukon's mine and non-industrial power users.

Potential future environmentally responsible projects include:

1. ***Demand Side Management*** – efficiency measures have potential to reduce energy requirements (and related diesel or GHG emissions) without added GHG emissions or environmental footprint.

2. ***Enhancements to Existing hydro infrastructure*** – provide renewable energy option with low GHG emissions and overall lower footprint (due to enhancement of existing infrastructure) compared to greenfield developments.

3. ***Biomass or Waste to Energy*** – is considered potential renewable source of supply with low GHG emissions.

4. ***Liquefied Natural Gas*** – has many of the same positive characteristics of diesel (i.e., reliable and flexible) but lower GHG emissions.

(b)

In order to review "staged approval" monitoring for the nine major deferred cost projects, an overview is provided of general development phases that YEC currently considers for a project prior to tendering or construction, and the general relation of such phases to engineering estimates (see Table 1 below).

In practice, development phases are defined as appropriate for each project, and are specific to the project[1].

[1] Project phases or stages were broadly discussed in the 2006 Resource Plan, both in terms of overall planning versus selection of specific project opportunities for development (see Figure 1.1, for example, in response to YUB-YEC-1-25 in the current proceeding) and in terms of more specific planning stages for any given hydro project opportunity.Chapter 5, pages 5-32 and 5-33 of the 2006 Resource Plan reviewed three levels or stages for planning of hydro projects prior to any decision to proceed to licensing, based on the 1992 Resource Plan, e.g., Level 1/Stage 1 - River Reconnaissance/Inventory (all sites); Level 2/Stage 2 - Site Reconnaissance/Pre-Feasibility; and Level 3/Stage 3 - Feasibility Studies (includes consultations and impact assessment studies).

Table 1: Pre-Tendering Project Phases and Engineering Activities

Development Phase	Environmental/permits	Engineering	Phase Deliverables
Phase 1 – Project Definition, Initial Business Case	Baseline environmental studies, begin consultation	Feasibility/conceptual engineering; +50-30%	Sufficient info to prepare project description for EA
Phase 2 – Effects Assessment	Complete effects assessment, mitigation design & project description, consultation agreements	Preliminary engineering; +30-20%	Ready to file EA project description, signed consultation agreements
Phase 3 – Regulatory review & business case	EA regulatory review process Complete & submit permit application, on-going consultation	Design & order long lead equipment where needed & prepare business case for YEC Board and YUB approval; +20-15%	EA final report, YEC Board approval, submit business case for YUB review (if energy certificate required), identify financing requirements
Phase 4 – Permitting	Obtain permits and land acquisition if needed, Confirm and begin EA commitments	Pre-tender detailed engineering; +15-10%	Issuance of permits/approvals and YG authorization for construction, if required

Deferred projects are many times at a "pre-Phase 1" stage, as defined in Table 1, in that work is still proceeding to define a potential project opportunity sufficient to prepare an initial business case, to define baselines environmental studies and to begin initial consultations.

- Such work is an essential first step to assess and define specific new resource options, and to confirm at a broad level which types of resource options merit more attention at this time.

- Much of the work to date on major deferred cost projects relating to non-hydro generation options could be classified this way, e.g., work to define potential generation project opportunities regarding waste to energy, wood biomass, district heating, or geothermal resources, and initial studies to define wind generation site opportunities.

- Comparative assessments of potential hydro sites could also be classified in this way.

- Work at this “pre-Phase 1” stage is monitored and controlled to provide results that will assist in defining, where appropriate, a specific project opportunity that merits a Phase 1 work plan.

Based on "pre-Phase 1" work to date, the following non-hydro generation option deferred cost projects have progressed to Phase 1 and/or Phase 2 work (see Overview of 20-Year Resource Plan; 2011-2030 as provided in response to YECL-YEC-1-18 - the waste/biomass and LNG options are included in major deferred cost projects in the Application, while wind is included in the lower deferred cost project category of $0.1 to $1.0 million costs):

- **Waste to Energy and Wood Biomass**: A 2.2 MW waste to energy project (among other similar scale options) at Whitehorse was examined and a determination made not to pursue this option further at this time; following review of wood biomass options, the Overview recommends that a small scale (2-3 MW) wood biomass pilot project opportunity be indentified and pursued, potentially in association with existing wood operations at Haines Junction, and that funding support be sought for this pilot project.

- **LNG**: Various scale LNG project options have been identified at Whitehorse; the Overview recommends that, subject to completion of current assessments, work proceed to determine whether Yukon Energy is able to establish LNG generating capability in Whitehorse prior to 2015 with sufficient capacity to displace grid diesel generation under current Base Case grid load forecasts, and to determine the feasibility of utilizing LNG in the event that material additional near term grid loads occur such as those assessed under Scenarios A and B. Based on this, Phase 2 work could be underway during 2012.

- **Wind:** 10 to 20 MW wind options at the Ferry Hill and Mount Sumanik sites. As reviewed in the Overview, initial business case assessments have been developed; ongoing monitoring at Ferry Hill is recommended to be completed as required to have the project shelf ready to proceed with Phase 2 work (i.e., to pursue through regulatory submissions and other development activity at such time as grid loads and other relevant conditions indicate that this project would

be cost-effective to implement; it is also recommended that YEC continue to examine for initial development the feasibility of smaller wind projects in the range of 10 MW to meet suitable grid loads).

Major deferred cost projects beyond those reviewed above include DSM and hydro enhancements (Marsh Lake Storage, Gladstone Diversion, Atlin Storage and Mayo Lake Enhanced Storage).

The **DSM** work is in Phase 2/3, preparing the business cases for specific program activities. Aside from the **Mayo Lake Hydro Enhancement** (which is in the midst of Phase 2/3 work including preparing a YESAB submission and other regulatory application preparations), the hydro enhancement projects are each at Phase 1 level:

- **Marsh Lake Storage** - The Overview recommends completion of the required environmental, engineering and remediation studies related to the project in order to make a determination whether it is feasible and cost-effective to proceed. The next step in proceeding would be to prepare the required YESAB and other regulatory submissions.

- **Gladstone Diversion** - The Overview recommends that YEC plan within the next 6 to 12 months to reach a final determination regarding whether the project is feasible to pursue at this time, based on discussions with local First Nations and regulators. The next step in proceeding would be to prepare the required YESAB and other regulatory submissions.
- **Atlin Storage** - Based on work to date, a decision has been made not to pursue this project further at this time. This decision was made prior to preparing any regulatory submissions.

Major deferred projects are monitored and controlled by the Corporation through Board of Directors review and approval of the annual capital budget as prepared by senior management (and any material revisions to this budget), and through periodic project update reports (major capital projects can be subject to update reports to the Board on a quarterly basis when warranted, and when any approvals required for a new stage of activity or budget). The Corporation also monitors commitments and performance as regards all related contracting, and by annual audit reviews all expenditures. At the project specific level, project steering and/or review committees are used as required to provide overall ongoing oversight of project activities.

As noted in the above review, the nine major deferred cost projects have not typically proceeded to date through many distinct staged approvals similar to those faced by major capital projects such as CSTP or Mayo B. Monitoring and control has accordingly often focused on annual budget and project reviews by the senior management and YEC Board.

- Renewable Energy Planning Projects Updates were provided to the YEC Board on a regular basis on hydro projects being examined by AECOM such as Marsh Lake Storage, Atlin Storage, Gladstone and large hydro project review projects (Board Updates were provided in March, April, August and December of 2010; in February, March, and August of 2011; and in May of 2012).

- Demand Side Management project updates were provided to the YEC Board in December 2010, February 2011, May 2011 and August 2011.

- Mayo Lake Storage Enhancement project updates were provided to the YEC Board as part of the regular quarterly Mayo B project updates.

- A briefing note on the Waste to Energy project was provided to the YEC Board in May 2010.

- LNG project updates were provided to the YEC Board in February, May and July of 2012.

Although the type of written documentation referenced in this question for these Board related meetings is available, documentation provided to Yukon Energy's Board (including minutes of Board meetings and board resolutions) has never been provided in previous YUB proceedings. The reasons for this include issues relating to Board confidentiality, proprietary information, and privacy. However, if after reviewing the information that Yukon Energy has provided in response to this question, and the many other responses on each of the individual projects, the YUB staff is in need of more specific information Yukon Energy is willing to work the staff to provide the information needed on any specific project as long as the above noted concerns can be accommodated in an appropriate manner.

(c)

The underlying changes in the Yukon environment that give rise to the unprecedented levels of planning costs that YEC has incurred since 2009 relate to significant load growth and the related impacts on expected long-term average annual diesel requirement costs in the near as well as longer term, combined with the costs and increasing complexity of project options examined to displace future diesel requirements.

As identified with respect to load growth in the 2006 and 2011 Resource Plans, and in each GRA and Part 3 proceedings since 2006 --the Yukon system has seen significant load growth. In fact the 2011 Resource Plan specifically highlights expected challenges related to near and longer term growth in the coming years and the related default diesel generation requirements and costs. For further information on this topic, please see YECL-YEC-1-18.

As reviewed in the 2011 Resource Plan, planning cost requirements since 2009 result from work to address the potential near term requirements for significant new generation to displace expected diesel requirements under potential load scenarios that assume connection of Victoria Gold and/or Carmacks Copper mine loads by as soon as 2015/16.

With respect to the complexity of projects, during the period from 1987 to 2008, Yukon Energy undertook few major capital projects and typically expended much lower costs for planning studies for the following reasons:

- From 1987 to 1998, the main load driver was the on-and-off nature of the Faro mine. While material planning costs were incurred leading up to the 1992 Resource Plan to identify and scan many resource supply options, the nature of the Faro mine load meant that there was excessive load risk to actually move any of these projects from a conceptual stage into true feasibility and licencing stages. The major capital investment of that era (e.g., rebuilding of the Whitehorse Substation) were for projects that did not require a high degree of planning costs, consultation, environmental licencing, etc. In addition, while developing renewable resource supply options would have been preferable to the then status quo (which involved running up to 100 GW.h of diesel generation per year), the costs of diesel were less than 1/3 of today's costs such that the diesel option was not prohibitively expensive, and economics of new renewable projects

to displace diesel were typically quite challenging (in part due to the great uncertainties about the life remaining for the Faro mine).

- From 1998 leading up to the 2005 Resource Plan surplus hydro was available on both YEC grids. For this reason little work was conducted on new supply options. The major projects undertaken were not complicated from a planning perspective and were limited in number (e.g., rebuilding the Whitehorse Generating Station after the 1997 fire, and the Mayo-Dawson line which already had all needed environmental approvals and a considerable amount of earlier work completed from the early 1990s).

- From 2005 to 2008, planning costs increased reflecting the need for new supply – first for capacity reasons (per Chapter 4 of the 2006 Resource Plan) and then for energy reasons. These bulk power projects began with the more straight-forward and relatively well-understood options:
  - Aishihik 3rd turbine already had regulatory approvals;
  - CSTP Stage I had been studied a number of times in the past and as a transmission line had a simpler regulatory process (no need for Water Board hearings, no DFO Fish Act Authorization required, etc.); the complexities arose in addressing the Minto mine PPA and related need to complete the project quickly if it was to proceed;
  - Mirrlees Life Extension required little planning costs and no new regulatory approvals.

- Beginning in about 2008 the next tier of options to bring new supplies to the system by 2011/12 to meet potential new load growth began to get more complicated due to the depletion of the grid hydro surplus and the need to develop new generation as well as to complete CSTP Stage 2.

- Attention focused on enhancements to existing hydro generation plus initial consideration of possible new other renewable resources:
  - Each of Marsh Lake Storage, Gladstone Diversion and Atlin Storage hydro enhancement options were well known going back to when YEC bought the NCPC assets as potential projects with excellent financial characteristics, but each had challenging licencing characteristics. As a result, none of these could be relied upon to address near term load growth.

- The concept of a "Mayo B" was long identified as a potential resource with a material potential addition to hydro generation, but there was no single identified preferred scheme, and little planning work had been conducted as the Mayo system which had long been in surplus and had no major likelihood of needed new power sources for many years. It was not until CSTP was advanced that the Mayo B option became a preferred generating source for an integrated Yukon grid; securing federal and YG funding to reduce risks and costs -- and then completing this major $120 million project within the set timelines and budget then became the key challenges.

- Given the apparent limitations on continued hydro enhancements, longer-term renewable resource development options also needed to be examined, including wind site options, greenfield hydro options, and geothermal resource options.

- Positive Geothermal characteristics were known to exist in Yukon, but there was no resource definition for the purposes of electricity generation. Initial work was needed to scope out potentials for future generation development.

The material increase in planning costs starting in the 2008-2009 period had been identified as a requirement in the 2006 Resource Plan, which noted that for major projects a reasonable working approximation is that 10% of the project cost needs to be committed and spent before decisions can even be made to proceed with the project (although there are exceptions – such as Marsh Lake, where the planning costs likely account for well over 50% of the project cost that must be spent before the project can be committed). For Mayo B, with a total budgeted project cost of $120 million, this working approximation proved to be reasonably accurate – approximately $10 million was spent on planning costs leading to the decision to commit to the project in early to mid 2010 (following receipt of all initially required regulatory approvals, etc)[2].

The 2006 Resource Plan further noted that new greenfield developments of a scale that is typical in Yukon (e.g., hydro at 30-40 MW), in the event these become required, could

[2] In the case of Mayo B the expedited development sequence required by the Government of Canada funding required the land based development activities to be initiated prior to completion of activities to secure all needed water-based permits. This meant that planning and licencing costs were still in progress after the decision to commit to construction had been made. The typical project development approach seeks to avoid this sequencing complication (although this is not always successful).

readily require $18 to $42 million in planning costs before the project could be committed (in 2005$)[3].

The planning process for the 2011 Resource Plan, including the three day Charrette in March 2011, highlighted added complexities related to involvement of the public and external experts to ensure that all potentially relevant resource options are being considered. In addition to DSM/SSE options, consideration of wood biomass and waste to energy options (in combination with district heating) was added to the near term alternatives being considered, and a wide range of longer-term generation and transmission connection options were also highlighted for ongoing consideration.

[3] Similar ratios likely exist for Geothermal, while projects that do not involve water-based activities (e.g., wind or LNG) may be somewhat lower in planning costs.

TOPIC: **Mayo B Flexible Note / Interest Costs**

REFERENCE: **Application, Attachment 5.3 page 5.3-1**

If the Maximum Interest Payable under this Note is a negative number, then YDC will pay to Yukon Energy the positive dollar amount of that number on or before March 31 of the next calendar year.

QUESTION:

a) Please confirm that YDC will pay YEC interest since forecasted grid loads for 2012 and 2013 are below the Minimum Grid Loads (GW.h) set out in Schedule 1 of Attachment 5.3.

ANSWER:

(a)

Not confirmed.

Per Schedule 1 of the Mayo B Promissory Note (Attachment 5.3 to the YEC's 2012/13 GRA application) the Minimum Grid Load (GW.h) for 2012 is 415 GW.h and for 2013 is 413 GW.h. YEC's total generation forecasts for the 2012 and 2013 test years are at 415.9 GW.h and 430.4 GW.h respectively, i.e. higher than Minimum Grid Loads (GW.h) set out in Schedule 1. Based on these load forecasts Mayo B interest payments are forecast $0.011 million for 2012 and $0.212 million for 2013.

TOPIC: **Major Projects, Marsh Lake Storage**

REFERENCE: **Application, Section 5.3.1, pages 5-28, 5-31 and 5-33**

For the current test years approximately $13.55 million in deferred cost is forecast to go into rate base by the end of 2013 for the following hydro enhancement projects:

- Planning and feasibility costs to the end of 2011 are $3.231 million with forecast spending over the test years of $1.6 million.
  …
  By the end of 2012 it is anticipated that a decision will be made on proceeding with the project …The forecast cost to complete the project is currently estimated at $10.5 million.

…

QUESTION:

a) Please provide a description of, and explain, any mitigation work that is yet to be completed.

b) Please explain what is meant by “completion of baseline work.”

c) Please explain what is meant by “effects assessment.”

d) YEC notes that “the actual costs for mitigation cannot be known with any certainty” at this time. Please explain the basis for the uncertainty and provide a range of forecast cost estimates for mitigation.

e) Please provide the cost estimates for this project that were presented in the business case reviewed as part of the 2006 20-Year Resource Plan.

f) Please provide the 8.5 cents per kW.h full utilization LCOE analysis (lines 9-12, page 5.33 of the Application) in Excel format with all formulae intact and including all underlying assumptions.

g) Please provide an explanation and analysis on how management will consider whether this project is no longer viable.

h) Please provide a cost-benefit analysis for the Marsh Lake project that includes alternative generation comparisons.

i) With respect to this project, please provide total costs incurred to date, broken down by category (consultant, consultation, water application, etc.) with accompanying descriptions and related costs.

ANSWER:

(a)

The extent of any required mitigation work will be determined as part of an environmental effects assessment process. The environmental effects assessment process has yet to be carried out; consequently, the full extent or requirement for mitigation measures is not known at this time.

The following effects are being reviewed and as part of a future environmental effects assessment may require mitigation:

1. Sub-surface improvements adjacent the lakeshore, such as septic fields (due to higher fall groundwater levels);

2. Heritage resources adjacent the lakeshore (due to shoreline erosion and accretion); and

3. Surface improvements/features such as docks, beaches, private property, and buildings/structures (due to higher fall water levels and potential erosion).

For preliminary project cost estimating purposes, approximately $4 million has been earmarked for mitigation to address any potential effects should a project proceed after the studies, environmental and socio-economic assessments are completed.

Detailed characterization of such things as the extent, duration, magnitude, and frequency of potential effects has yet to be completed for the effects identified above.

This is the major focus of the current studies underway and is expected to be completed over the course of the next year.

(b)

Baseline Work refers to the planning and study that is conducted as part of an environmental assessment in order to establish the baseline environmental and socio-economic conditions within the project study area, i.e., the conditions that exist without the new project.

The "*completion of baseline work*" marks the point at which sufficient information has been collected in order to initiate the environmental and socioeconomic assessment exercise of comparing the future with the project and the future without the project under study. The purpose of the assessment is to understand potential project environmental and socio-economic effects, whether those effects might be significant (in an environmental assessment context), and if so, what economically and technically feasible mitigation measures might be available to address the significant adverse effects were they to occur.

(c)

Effects assessment is the systematic analysis of the likely effects a potential project will have on components of the human and physical environments. This assessment is carried out, in part, to meet regulatory requirements for any project, e.g., review of environmental and socioeconomic effects as required by the Yukon Environmental and Socio-economic Assessment Board (YESAB), permitting as required by government decision bodies, and any water licensing review required by the Yukon Water Board (YWB).

(d)

The uncertainty stems from the fact that the potential effects of the concept under study are not yet fully known. As such, determinations as to what potential effects would require mitigation, or the technical and economic feasibility of mitigating them, have not yet been made. For planning purposes approximately $4 million has been earmarked for mitigation to address any potential effects should a project emerge from the studies currently underway.

(e)

As summarized on page 8 of the 2006 20-Year Resource Plan the description of the Marsh Lake project was as follows:

> This project … will increase the firm winter capacity of the Whitehorse Rapids hydro facility by about 1.6 MW and increase long-term average hydro energy from this facility by about 7.7 GW.h/year at a capital cost of no more than $1 million.

This estimate was provided prior to YEC undertaking project planning activities, including consultation and environmental licencing. As noted in the GRA Application at page 5-30, Yukon Energy provided an update on November 9, 2006 and indicated that it would not be pursuing Marsh Lake at that time (as a near term project) due to local resistance, high water level impacts in low lying areas and related impacts to the environmental. Project cost increases since the 2006 Resource Plan are outlined and explained in section 5.3.1.1 of the GRA.

The early estimate provided in 2006 was based on a relatively simple concept and approach to the project. After further work was undertaken it was determined that the project was more complex and Yukon Energy would need to do a substantial amount of work to advance through the licencing process. The overall concept for the project is the same, but the regulatory process to secure approvals is expected to be more complex.

(f) and **(h)**

Please see Attachment 1 for the requested information.

Table 1 below provides an overview that compares the Marsh Lake project to default diesel option at Scenario A load of 2011 Resource Plan Update (please see YUB-YEC-1-1 (b) and YECL-YEC-1-18 for Overview of 20-year Resource Plan: 2011-2030). The Overview of the 2011 Resource Plan includes cost-benefit analysis comparing this project to other non-diesel near term resource options.

Table 1:
Marsh Lake Project over 20-year planning period

	Capital (2010$ million)	Capacity (MW)	Energy Capability (Average GWh/yr)	2015-2019 Diesel Required/ Displaced (GWh/yr)	2015-2019 Annual Costs (cents/kW.h diesel displaced)	Forecast LCOE (2010 c/kWh) Scenario A[1]	LCOE (2010 c/kWh) Extend 2019 load to 2030	LCOE (2010 c/kWh) Full Utilization
Default Diesel Requirement	56	37	292	85	29-31 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)
Marsh Lake Storage	10	NA	6.7	6.4	15-16	11.4	NA	8.5

Note:
1. Forecast LCOE = Levelized Cost of Energy (cents/ kW.h of forecast diesel displaced [2010$]) over project life at Scenario A load scenario.

(g)

YEC will continue over the next year to assess the results of ongoing assessment analysis and consultations to determine if this project is likely to secure regulatory approvals to yield the benefits as currently projected within the budget costs currently projected. If a decision is made within this time period to proceed to the next stage, the necessary regulatory submissions will then be prepared and submitted. A final decision on the project would be made only after receipt of all necessary permits and approvals.

(i)

Please see Table 3 below for a breakdown of expenditures to the end of 2011 by task by Consultant for the Marsh Lake Storage Project.

Table 2:

Total Expense to end of 2011 by Contractor by Task: Marsh Lake Storage Project

Vendor	Task	Expense to end of 2011
AECOM Canada Ltd.	Project Management and Baseline Environmental Data Collection	2,699,083
Aasman Design Inc.	Public Awareness Campaign	123,330
KGS Group	Power Benefit Model Development Simulation Modeling	31,918
Canpac Divers Inc.		36,669
Klondike Welding Ltd.		23,800
Total Vendor Costs		**2,914,800**
YEC - Owners Costs		316,107
Total		**3,230,907**

AECOM retained sub-consultants to undertake some if its work on the project including, Ardea Biological Consulting, Ecofor Consulting, EDI Environmental Dynamics, Normandeau Associates Inc., Palmer Environmental Consulting Inc., Northwest Hydraulic Consultants, Northsense Management Consulting, T.E. Keopke Consulting Services Ltd, Underhill Geomatics Ltd and Vector Research.

The GRA forecasts additional test year spending of an additional $1.6 million ($0.800 million in each test year to complete baseline work, effects assessment and mitigation design.

Marsh Lake project LCOE

Capital ($000)	**2010**	**$10,500**	
Capital ($000)	**2015**	$11,593	
O&M (Fixed)	**2010**	**$52.5**	$000/yr
O&M (Variable)	**2010**		$/MWh
Life		**65**	years
Salvage cost		0%	

Cost of Capital			6.56%
Discount Rate			6.56%
Inflation Rate			2.00%
Real discount rate			4.47%
Fuel Inflation rate			2.00%
	Rate of Return	Ratio	Rate
Debt	60%	5.28%	3.17%
Equity	40%	8.49%	3.40%
Total	100%		6.56%

	2015$	2010$
PV Cost $000's (Combined)	12,701	11,504
Project LCOE		$0.085

Marsh Lake project LCOE

Year	Rate Base	Depr	Return	O&M	Total $000	Annual Energy GW.h
2013						
2014	11,593					
2015	11,414	178	755	58	991	6.40
2016	11,236	178	743	59	981	6.40
2017	11,058	178	732	60	970	6.40
2018	10,879	178	720	62	960	6.40
2019	10,701	178	708	63	949	6.40
2020	10,523	178	697	64	939	6.40
2021	10,344	178	685	65	928	6.40
2022	10,166	178	673	67	918	6.40
2023	9,988	178	661	68	908	6.40
2024	9,809	178	650	69	897	6.40
2025	9,631	178	638	71	887	6.40
2026	9,453	178	626	72	877	6.40
2027	9,274	178	615	74	866	6.40
2028	9,096	178	603	75	856	6.40
2029	8,918	178	591	76	846	6.40
2030	8,739	178	579	78	836	6.40
2031	8,561	178	568	80	826	6.40
2032	8,383	178	556	81	816	6.40
2033	8,204	178	544	83	806	6.40
2034	8,026	178	533	84	795	6.40
2035	7,847	178	521	86	785	6.40
2036	7,669	178	509	88	775	6.40
2037	7,491	178	498	90	766	6.40
2038	7,312	178	486	91	756	6.40
2039	7,134	178	474	93	746	6.40
2040	6,956	178	462	95	736	6.40
2041	6,777	178	451	97	726	6.40
2042	6,599	178	439	99	716	6.40
2043	6,421	178	427	101	707	6.40
2044	6,242	178	416	103	697	6.40
2045	6,064	178	404	105	687	6.40
2046	5,886	178	392	107	678	6.40
2047	5,707	178	380	109	668	6.40
2048	5,529	178	369	111	659	6.40
2049	5,351	178	357	114	649	6.40
2050	5,172	178	345	116	640	6.40
2051	4,994	178	334	118	630	6.40
2052	4,815	178	322	121	621	6.40
2053	4,637	178	310	123	612	6.40
2054	4,459	178	299	125	602	6.40
2055	4,280	178	287	128	593	6.40
2056	4,102	178	275	131	584	6.40
2057	3,924	178	263	133	575	6.40
2058	3,745	178	252	136	566	6.40
2059	3,567	178	240	139	557	6.40
2060	3,389	178	228	141	548	6.40
2061	3,210	178	217	144	539	6.40
2062	3,032	178	205	147	530	6.40
2063	2,854	178	193	150	521	6.40
2064	2,675	178	181	153	513	6.40
2065	2,497	178	170	156	504	6.40
2066	2,319	178	158	159	496	6.40
2067	2,140	178	146	162	487	6.40
2068	1,962	178	135	166	479	6.40
2069	1,784	178	123	169	470	6.40
2070	1,605	178	111	172	462	6.40
2071	1,427	178	100	176	454	6.40
2072	1,248	178	88	179	445	6.40
2073	1,070	178	76	183	437	6.40
2074	892	178	64	186	429	6.40
2075	713	178	53	190	421	6.40
2076	535	178	41	194	413	6.40
2077	357	178	29	198	405	6.40
2078	178	178	18	202	398	6.40
2079	- 0	178	6	206	390	6.40
PV					12,701	

TOPIC: **Major Projects, Gladstone ($4.4 million)**

REFERENCE: **Application, Section 5.3.1, page 5-28 and page 5-34**

For the current test years approximately $13.55 million in deferred cost is forecast to go into rate base by the end of 2013 for the following hydro enhancement projects:

Planning and feasibility costs to the end of 2011 are $3.694 million with forecast spending over the test years of $0.700 million. Third party environmental assessment, engineering and project management costs comprise approximately 90% of the project costs to date.

…

Based on feasibility studies to date, project cost was estimated at $40 million …

QUESTION:

a) Please provide the 6.3 cents per kW.h full utilization LCOE analysis (lines 17-20, page 5.34 of the Application) in Excel format with all formulae intact and including all underlying assumptions.

b) Have negotiations been initiated with the local First Nation groups? Please explain your response on why negotiations have or have not been initiated.

c) In respect of this project, please provide future milestones at which point in time discussions will take place and decisions will be made as to whether or not to proceed with the project.

d) Please provide total costs incurred to date, broken down by category (consultant, consultation, water application, etc.) with accompanying descriptions and related costs.

ANSWER:

(a)

There is an error (line 18, page 5-34) in the 2012/13 GRA Application regarding Gladstone project full utilization LCOE (6.3 cents/kW.h). The correct full utilization LCOE is 5.7 cents/kW.h with estimated project cost at $40 million (2010$).

Please see Attachment 1 to this response for the Gladstone project full utilization LCOE analysis.

(b) and **(c)**

Consultation has taken place with the two local First Nations (Champagne and Aishihik First Nations) from the project inception in late 2009. Consultation has taken place at political leadership level (Chief and Council) and at the First Nations membership level (community meetings).

Specific issues raised by one of the local First Nations in late 2010 led to a reduction of 2011 field studies and engineering work until the issues were better clarified and a path forward identified to bring resolution to the issues. Most of the issues identified related to the original construction and operation of the Aishihik hydro development and the renewal of the Aishihik Water license in 2002. Discussions in early 2011 led to the signing of a protocol agreement with the First Nations (provided as Attachment 2 to this response). This agreement was intended to signal the start of a new relationship between Yukon Energy and these First Nations on all energy matters, including the Gladstone Project. Meetings involving representatives from Yukon Energy and the First Nations have been held on a bi-weekly basis since the protocol agreement was signed and are continuing.

Aside from ongoing hydrological monitoring on the site, no further field work is planned on the Gladstone Project until there is a positive response on this project from these First Nations.

Discussions are on-going with these First Nations and are expected to continue on several potential energy projects.

With respect to the Gladstone project, Yukon Energy is committed to working with the local First Nations until they make a decision as to whether or not they will oppose the project. This is expected to take until the end of 2012. Following this, it is expected that in 2013 Yukon Energy will make a decision as to whether to defer the project or proceed with the field and engineering studies needed to prepare an Environmental Assessment application.

(d)

Please see Table 1 below for a breakdown of expenditures to end of 2011 by task by Consultant for the Gladstone Diversion Project.

Table 1: Total Expense to Year End 2011 by Contractor by task for Gladstone Diversion Project

Vendor	Task	Expense to end of 2011
AECOM Canada Ltd.	Project Management and Baseline Environmental Data Collection	3,082,104
Aasman Design Inc.	Public Awareness Campaign	126,853
Champagne & Ashihik First Nation	Accountable advance towards CAFN capacity and participation	60,000
Kluane First Nation	Accountable advance towards KFN capacity and participation	40,474
Underhill Geomatics Ltd.	Aerial Photography	33,338
KGS Group	Power Benefit Model Development Simulation Modeling	12,447
EBA Engineering Consultants Ltd.	Baseline Hydrology	6,103
Total Vendor Costs		**3,361,319**
YEC - Owner Costs		332,306
Total		**3,693,624**

Spending is forecast to be $0.200 million in 2012 and $0.500 million in 2013. This spending relates to continued gathering of environmental baseline data (including pathogen studies which require a minimum two years of data) in preparation for YESAA filing. This also includes provision for stakeholder consultation activities.

DATED FOR REFERENCE the 1st day of April 2011

PROTOCOL AGREEMENT

AMONGST:

YUKON ENERGY CORPORATION a publicly owned electrical utility that operates at arms length from the Yukon Government.

(YEC)

and

CHAMPAGNE AND AISHIHIK FIRST NATIONS a self-governing First Nation in the Yukon Territory;

(CAFN)

and

DAKWAKADA DEVELOPMENT CORPORATION a privately held investment firm, located in Whitehorse, Yukon wholly owned by the Champagne and Aishihik Trust.

(DDC)

Hereafter referred to as the "Parties".

WHEREAS:

A. YEC desires to identify new sources of renewable energy to meet the growing needs of its customer base;
B. There is an interest by the parties to explore renewable energy production potential within the Champagne and Aishihik First Nations traditional territory (TT);
C. There is an interest in building a collaborative and respectful working relationship between the parties to move the Parties towards a partnership in renewable energy;
D. CAFN and DDC are exploring economic opportunities associated with renewable energy production in CAFN TT.

THEREFORE THE PARTIES AGREE TO the following:

Shared Principals

1. The Parties agree to the following principle:

   To build a strong and lasting relationship there must be open and effective communication that respects and promotes the sharing of information, ideas and opportunities in an equitable manner while respecting the distinct mandates of each of the Parties.

Objectives

2. The objectives of this agreement are:
    a. To work together to develop a renewable energy development strategy for the CAFN TT that respects and reflects the economic, environment and communities interests within the TT;
    b. To promote an equitable relationship that fosters a dialogue that enhances the assessment of energy potential and the identification of priorities for the production of renewable energy in the CAFN TT;
    c. To enhance renewable energy economic opportunities for CAFN in their TT;
    d. To develop a respectful and mutually beneficial relationship between the three parties to this agreement.

Priorities

3. The Parties will work together to identify potential energy projects based on a dialogue that will identify project priorities and planning including indentifying, as required, the individuals who will be primarily responsible for coordinating and overseeing specific projects.
4. The Parties agree to assess the projects and to prioritize the projects based on community dialogue, the capacity of the parties and their affordability, flexibility, reliability and environmental responsibility. The parties agree that they will make efforts to develop preliminary timelines that reflect to ability of each party to effectively engage.
5. Parties commit to open communication. To this end each party agrees to identify primary contacts that will be responsible for being the point of contact for each party:

CAFN contact is:

Ian Robinson
Economic Development Manager
Champagne and Aishihik First Nations
304 Jarvis Street
Whitehorse, YT
Y1A 2H2
867-456-6878

DDC contact is:

Murray Arsenault
General Manager
Dakwakada Development Corporation
409 Black Street
Whitehorse, YT
Y1A 2N2
867-668-5831

YEC contact is:

Hector Campbell
Director, Resource Planning & Regulatory Affairs
#2 Miles Canyon Road
Box 5920
Whitehorse YT
Y1A 6S7

6. The Parties will ensure that there is an on going effort to identify training and employment opportunities for CAFN Citizens related to the development of renewable energy in the TT that is affordable, flexible, reliable and environmentally responsible.
7. The Parties commit to identify and support for funding requests related to capacity development and engagement of CAFN and DDC in the development of renewable energy in the TT.
8. The Parties agree to develop an action plan to ensure that the objectives and priorities set out in this Agreement are actively pursued and that the action plan will be included as an appendix to this agreement.

General

9. The Parties understand that this agreement is principally intended to promote and build a positive relationship and as such is not intended to be a legally binding agreement.
10. The Parties acknowledge that this agreement does not create or assume any support or commitment to any particular energy project in the CAFN TT.
11. The Parties agree to review this agreement in eighteen months.

THE PARTIES HEREBY commit to this new relationship on this the 01 day of APRIL _____, 2011.

James Allen
Chief
Champagne and Aishihik First Nations

Piers McDonald
Chair, Board of Directors
Yukon Energy Corporation

Richard Jamieson
Chair, Board of Directors
Dakwakada Development Corporation

TOPIC: Major Projects, Atlin Lake Storage ($2.2 million)

REFERENCE: Application, Section 5.3.1.3, page 5-28 and pages 5-35 and 5-36

For the current test years approximately $13.55 million in deferred cost is forecast to go into rate base by the end of 2013 for the following hydro enhancement projects:

…

The control structure would need to be located entirely within British Columbia and consequently would be assessed and permitted under BC and Federal Regimes.

…

In 2011, when the BC Government designated Atlin River as a Class A park (with expectation that the designated park would include the river), a decision was made by Yukon Energy to discontinue work on the Atlin Storage project.

QUESTION:

a) With respect to this project, please provide total costs incurred to date, broken down by category (consultant, consultation, water application, etc.) with accompanying descriptions and related costs.

ANSWER:

(a)

Please see Table 1 below for a breakdown of expenditures by task by Consultant for the Atlin Lake Storage Project.

Table 1:

Total Expense by Contractor by Task for the Atlin Lake Storage Project

Vendor	Activity	Expense
AECOM Canada Ltd.	Project Definition	111,504
	Environmental Assessment & Consultation Activities	1,640,668
	Project Management	143,162
Aasman Design Inc.	Public awareness campaign	79,000
BBA Inc.	Preliminary Engineering	14,782
Davis LLP	Permitting, Regulatory & FN Consultation	66,244
Environmental Dynamics Inc.	Environmental Assessment & Consultation Activities	1,320
KGS Group	Preliminary Engineering	6,716
Underhill Geomatics Ltd.	Environmental Assessment & Consultation Activities	11,731
YEC	Owner Costs	155,525
Total Expense		**2,230,652**

TOPIC: **Major Projects, Mayo Lake Enhancement Storage**

REFERENCE: **Application, Section 5.3.1.4, page 5-28 and page 5-37**

For the current test years approximately $13.55 million in deferred cost is forecast to go into rate base by the end of 2013 for the following hydro enhancement projects:

…

The Mayo Lake Enhanced Storage project was originally included as a component of the Mayo Hydro Enhancement Project proposal. During the 2009 adequacy review process, YESAB informed Yukon Energy that the proposal was adequate with the exception of the Mayo Lake storage component. As a result, YEC made the decision to withdraw the Mayo Lake storage component from the original project proposal and file the Mayo Lake Enhanced Storage Project as a separate project at a later date.

...

A Project Proposal is currently being prepared and is expected to be filed with the relevant YESAB Designated Office in 2012. In order to address the information requirements identified by YESAB during the 2009 Mayo B adequacy review process, additional environmental and socio-economic fieldwork was conducted 2008 through 2011.

QUESTION:

a) Please provide the 6.3 cents per kW.h full utilization LCOE analysis (lines 17-19, page 5.38 of the Application) in Excel format with all formulae intact and all underlying assumptions.

b) Please provide total costs incurred to date, broken down by category (consultant, consultation, water application, etc.) with accompanying descriptions and related costs.

ANSWER:

(a)

Please see Attachment 1 for Mayo Lake Hydro Enhancement Project LCOE analysis.

(b)

Project activities to date include project management; environmental and socio-economic studies (including substantive field level studies); effects assessment, mitigation design and testing, monitoring and adaptive management plan development, First Nation, regulatory, stakeholder, and public consultation and engagement.

Public engagement has included the following activities:

- Two public dinners, open houses, and presentations with questions and answers in Mayo;

- Hundreds of person hours of direct, often in-person, engagement with representatives and technical advisors of the First Nation of Na-Cho Nyak Dun government to evaluate various aspects of the project and effects assessment; and

- Engagements with Yukon Government resource managers, the Mayo Renewable Resource Council, the Mayo Designated Office of YESAB, and other individual stakeholders (e.g., placer miners).

As a Project Proposal has not yet been submitted to the Mayo Designated Office for review costs related to the regulatory review process have not been incurred.

Please see Table 1 below for total expense for the Mayo Lake Enhancement Project by contractor and by task.

Table 1:
Total Expense to end of 2011 for Mayo Lake Enhancement Project

Resource	Scope of Work	2011 YTD Expenditures
EDI	Approx. 80% of expenditures for baseline ecological field studies, mitigation trials, and monitoring. Approx. 20% for impact assessment and planningn and design, stakeholder engagement.	$651,000
InterGroup	Project management and coordination, baseline socio-economic studies, stakeholder engagement.	$357,000
AECOM	Roop Lakes & Wetlands Hydrology Studies	$105,600
Ecofor	Traditional Land use, Traditional Knowledge, and Archaeological Studies, Impact Assessment, Heritage Site Protection, and Artifact Dating and Cataloging.	$78,600
FN NND	Participation in project study design, execution of ecological field studies, impact assessment, monitoring and adaptive management plan design.	$58,500
KGS	Project Hydrological Modelling, Engineering, Geomorphology Studies.	$49,900
Horizon Helicopters	Field Study Support	$31,900
Don Toews	Senior Aquatic Sciences Advisor (2011- present)	$25,300
Bluewater Biosciences	Senior Aquatic Sciences Advisor (pre-2011)	$11,600
Total Consultants & Contractors		**$1,369,400**
Internal Labour & Owner Costs		$64,800
Estimated Project Total		**$1,434,200**

The GRA forecast $0.660 million to be expensed in 2012 for project activities. These preliminary estimates for remaining work are under active review at this time. Activities include continuance of fieldwork and analysis; preparation of YESAB Designated Office Project Proposal (including participation by NND); and preparation of Yukon Water Board Licencing Amendment Application (and review process) and preparation and review of DFO Fisheries Act Authorization.

Please note that there was a typographical error in GRA Application on page 5-28 (line 16), the spending to end of 2011 is $1.43 million as shown in the table above, not $1.46 million. This correction will not affect any other numbers in GRA Application.

Mayo Lake Hydro Enhancement Project Benefit/Cost Analysis

Regulatory Cost at $2012	2012	$2,167.9
Assumed close-out year	2012	end of the year
Assumed amortization	13	years
Present Value Cost 2012 $000's		$5,406.1
Present Value of Benefits 2012 $000's		$24,627.6
LCOE at $2012, cents/kW.h		6.3
Benefit/Cost ratio		4.6
Average GW.h diesel displaced		4.0

Key Assumptions:

6.56% - Return on Ratebase (ROR), blended cost of debt and equity (approved for YEC's 2009 GRA)
4.47% - real Return on Ratebase based on ROR above and general inflation at 2% per year
2.00% - inflation rate per year
28.78 - Diesel Fuel & O&M cost at $2012/kW.h

		Project Cost ($000)						Estimated Benefits	
Years	Project Year	Monitoring & Reporting Cost	Regulatory Cost	Amortization	Return	Total Regulatory Cost $000	Total Cost $000	Displaced Diesel Generation GW.h	$000
2012		258	2,168				258		
2013	1	316	2,001	167	137	304	620	3.55	1041.9
2014	2	291	1,834	167	126	293	583	4.43	1327.4
2015	3	297	1,668	167	115	282	578	4.34	1325.0
2016	4	314	1,501	167	104	271	585	4.31	1344.2
2017	5	289	1,334	167	93	260	549	4.19	1332.7
2018	6	318	1,167	167	82	249	566	4.05	1312.9
2019	7	242	1,001	167	71	238	480	3.88	1283.5
2020	8	235	834	167	60	227	462	4.13	1392.0
2021	9	240	667	167	49	216	456	3.43	1181.1
2022	10	257	500	167	38	205	462	3.71	1303.1
2023	11	295	334	167	27	194	489	3.92	1403.3
2024	12	318	167	167	16	183	501	4.07	1486.3
2025	13	216	0	167	5	172	388	4.18	1557.1
2026	14	206					206	4.27	1620.5
2027	15	210					210	4.34	1680.5
2028	16	214					214	4.41	1740.8
2029	17	218					218	4.47	1803.2
2030	18	223					223	4.54	1867.9
2031	19	243					243	4.61	1932.2
2032	20	232					232	4.65	1987.6
2033	21	288					288	4.44	1935.8
2034	22							4.24	1887.1
2035	23							4.06	1842.3
2036	24							3.98	1840.8
2037	25							3.89	1838.4
2038	26							3.89	1875.2
2039	27							3.89	1912.7
2040	28							3.89	1950.9
2041	29							3.89	1990.0
2042	30							3.89	2029.7
2043	31							3.89	2070.3
2044	32							3.89	2111.8
2045	33							3.89	2154.0
2046	34							3.89	2197.1
2047	35							3.89	2241.0
2048	36							3.89	2285.8
2049	37							3.89	2331.5
2050	38							3.89	2378.2
2051	39							3.89	2425.7
2052	40							3.89	2474.3
2053	41							3.89	2523.7
2054	42							3.89	2574.2
2055	43							3.89	2625.7
2056	44							3.89	2678.2
2057	45							3.89	2731.8
2058	46							3.89	2786.4
2059	47							3.89	2842.1
2060	48							3.89	2899.0
2061	49							3.89	2957.0
2062	50							3.89	3016.1
2063	51							3.89	3076.4
2064	52							3.89	3138.0
2065	53							3.89	3200.7
2066	54							3.89	3264.7
2067	55							3.89	3330.0
2068	56							3.89	3396.6
2069	57							3.89	3464.6
2070	58							3.89	3533.8
2071	59							3.89	3604.5
2072	60							3.89	3676.6
2073	61							3.89	3750.1
2074	62							3.89	3825.1
2075	63							3.89	3901.6
2076	64							3.89	3979.7
2077	65							3.89	4059.3
PV		3,285				2,121	5,406		24,628

TOPIC: **Major Projects, DSM**

REFERENCE: **Application, Section 5.3.1.5, pages 5-39 to 5-41**

A significant amount of DSM related planning and consultation work has been undertaken by Yukon Energy individually and by Yukon Energy in coordination with Yukon Government, Yukon Development Corporation and Yukon Electrical in order to implement a robust and aggressive DSM/SSE program, and to meet the Yukon Utilities Board directive.

…

Planning and feasibility costs to the end of 2011 are $1.037 million – however, with offsetting contributions, net costs in 2011 are $0.303 million… Forecast spending over the test years is $2.709 million.

…

A material portion of DSM costs incurred to date, and expected to be incurred in the test years, relate to internal DSM within YEC. This includes feasibility, study, planning and implementation of conservation improvements at Yukon Energy's existing buildings and facilities…The benefit of this form of DSM is that since Yukon Energy is carrying out the changes there is assurance that the activities will be undertaken and targeted savings achieved.

QUESTION:

a) Please explain YEC's submission that a full utilization LCOE of less than 10 cents per kW.h is a relatively low cost. What is it relatively compared to?

b) Please provide background and details regarding YEC's submission that it considers DSM a key supply option to help address near-term and longer-term energy requirements. Moreover, does YEC undertake, or propose to undertake, a cost-benefit analysis respecting its proposed key supply options? As with other projects, are business cases provided to YEC's management for consideration to ensure options are closely monitored? Please explain your response.

c) Please provide details regarding the internal DSM activities to be undertaken in the test years. Please provide a description of the activity, the associated savings and any known assurances that the targeted savings will be achieved.

d) Please provide a detailed description of costs incurred to date and those to be incurred over the test years, broken down by category (consultant, project, etc.) with accompanying descriptions and related details. Moreover, please provide a description of the benefits that should accrue to customer both in the short term and the long term.

e) Does YEC's capitalization for this project clearly indicate that the proposed internal DSM activities are to be capitalized and not included as operations and maintenance activities? Please explain your response.

ANSWER:

(a)

At this time a full utilization LCOE of 10 cents per kWh for this resource option would be compared to the existing marginal cost of supply being displaced (i.e., diesel generation at a cost of approximately 30 c/kWh). However, this is also a relatively low cost supply option compared to other available near term supply options being reviewed. Further detail regarding near term resource options is provided in the 2011 20-Year Resource Plan: 2011-2030 Overview provided as Attachment 1 to YECL-YEC-1-18.

(b)

DSM is scrutinized as regards cost-benefits both on a per-project basis and as a portfolio.

Projects are approved by YEC's management on a case by case basis and monitored closely for efficacy. The DSM plan consists of programs developed with a set reduction target and cost of conserved energy (CCE). These targets, agreed to by the working group, provide a backbone of savings to the territory. Programs are individually analyzed for the greatest cost/benefit ratio.

With regard to reporting to the YEC Board – please see response to YUB-YEC-1-32. The portfolio as a whole adheres to the targets set out in the YEC Business Plan.

(c)

A detailed energy audit was conducted of the diesel plant, hydro plant and office in Whitehorse and the diesel plant and office in Dawson. The audit identified almost a full GWh of potential savings with payback periods ranging from less than a year to over 75 years. The audit also identified areas where more detailed data could be collected to help better understand specific energy uses.

Currently Yukon Energy is developing a workplan to implement some of the low cost measures with short payback periods, such as light change-outs, and to collect the additional energy use data as recommended. The audit will provide a basis for planning future energy conservation projects at Yukon Energy.

The audit was conducted by an independent engineering firm and reviewed by senior engineers at Yukon Energy to ensure accuracy of the cost and energy saving estimates.

(d)

Please see Attachment 1 to this response for a review of cost by project to end of 2011 FYF, and provides and overview of forecast activities for the test years.

(e)

Please see the DSM Accounting Policy provided as Appendix 5.2 of the Application. This includes internal DSM in Section 1.2: “This [DSM] includes any improvements in Corporation “end use” such as insulation in its buildings…” These are specific expenditures whose primary goal is to improve ongoing end use of energy at YEC – as such they would not be budgeted or accounted for as O&M expenditures.

Table 1: Detailed Costs for DSM-related Activities by Project and Contractor to end of 2011 FYF

Project	Vendor		Cost ($000)
DSM-LED Streetlight Project	Aasman Design Inc.		8.0
	ACR Systems Inc.		5.6
	Archbould Photography		1.0
	Copy		0.7
	Courier / Freight		1.9
	EECOL Electric Ltd.		6.5
	Intergroup Consultants Ltd.		8.2
	Ruud Lighting Canada		0.6
	YEC - Owners Costs		20.7
	Yukon Electrical Co. Ltd.		4.0
	DSM Reallocations		4.4
		Subtotal	**61.5**
DSM-Focus Group Session	Vector Research		5.9
	YEC - Owners Costs		0.7
		Subtotal	**6.6**
DSM-Residential Pilot Project	Aasman Design Inc.		0.0
	Klondike Broadcasting Co. Ltd.		0.0
	Northern Native Broadcasting Y		0.0
	YEC - Owners Costs		0.9
	DSM Reallocations		0.4
		Subtotal	**1.3**
DSM-Commercial Pilot Project			
	Aasman Design Inc.		5.8
	YEC - Owners Costs		0.9
	DSM Reallocations		3.1
		Subtotal	**9.8**
DSM-Industrial Pilot Project			43.7
		Subtotal	**43.7**
DSM-Schools Pilot Project	Aasman Design Inc.		0.2
	Archbould Photography		0.5
	Phone & Cell		1.3
	YEC - Owners Costs		0.6
	DSM Reallocations		0.9
		Subtotal	**3.5**
DSM-Conservation Potential Review	Aasman Design Inc.		8.6
	Courier / Freight		0.0
	ICF Marbek		316.0
	Lesley Cabott Consulting		2.0
	Northern Native Broadcasting Y		0.0
	Phone & Cell		2.3
	YEC - Owners Costs		19.1
	DSM Reallocations		19.0
		Subtotal	**367.0**
DSM-O/C Misc/Program	Aasman Design Inc.		10.5
	ACR Systems Inc.		7.6
	Government of Yukon		8.3
	Office Rent		9.5
	Phone & Cell		2.5
	Spectrum Security Sound Ltd.		4.5
	Woodbine Window Coverings		2.1
	YEC - Owners Costs		119.6
	DSM Reallocations		-145.8
		Subtotal	22.6

Project	Vendor		Cost ($000)
DSM-Community Engagement	Aasman Design Inc.		42.4
	Archbould Photography		0.6
	Klondike Broadcasting Co. Ltd.		1.4
	Northern Native Broadcasting Y		1.3
	One Change Foundation		187.0
	YEC - Owners Costs		5.5
	Yukon Electrical Co. Ltd.		4.7
	DSM Reallocations		2.8
		Subtotal	**245.6**
DSM-Working Group	YEC - Owners Costs		0.0
	DSM Reallocations		4.1
		Subtotal	**4.1**
DSM-Residential End Use Survey			
	Aasman Design Inc.		72.6
	Klondike Broadcasting Co. Ltd.		0.7
	Northern Native Broadcasting Y		0.9
	YEC - Owners Costs		0.7
	DSM Reallocations		0.4
		Subtotal	**75.2**
DSM - Municipal Pilot Project	Natural Resources Canada		8.1
	YEC - Owners Costs		2.4
	Course Revenues		-0.4
	DSM Reallocations		0.4
		Subtotal	**10.6**
DSM - ESC Fridge/Freezer Pilot			-4.5
	Aasman Design Inc.		
	YEC - Owners Costs		4.5
		Subtotal	0.0
DSM - Public Ed/Communication			
	Aasman Design Inc.		4.5
	YEC - Owners Costs		58.1
	DSM Reallocations		1.7
		Subtotal	**64.2**
IDSM-Energy Audit & Mngmt Plan	YEC - Owners Costs		9.4
	Stantec Architecture Ltd - internal audit		95.0
	DSM Reallocations		15.4
	FSC Architects & Engineers		1.7
		Subtotal	**121.4**
Total Expense to 2011 Year End			**1037.1**

Table 2: DSM-related Activities by Project, 2012 Forecast

Project	Description	Cost ($000)
Admin/Prgm Dev/ Misc	Administrative costs associated with the planning, execution, measurement, and evaluation of DSM programs.	165.1
Policy/Planning	In keeping with the directions given by the Yukon Utilities Board (YUB), the Demand Side Management (DSM) working group has collaborated throughout 2011 and 2012 to complete a Demand Side Management (DSM) plan. Based on the findings of the Conservation Potential Review (CPR) (completed as a partnership between the Yukon Government, YECL and YEC in 2011) as well as multiple stakeholder and public consultation events, YEC and YECL have engaged ICF Marbek to build a portfolio of cost effective programs (including evaluation, measurement, and verification) for implementation over the next five years. YEC staff have been pulled into the project to reduce costs and apply technology/knowledge transfer during the process. Upon completion of this work the DSM working group has committed to submitting a five-year DSM plan to the YUB.As an input to the CPR, Aasman completed a Residential Electricity End Use survey on behalf of YEC in 2011. In order to properly monitor the efficacy of DSM programs, a Residential Electricity End Use survey and a Commercial Electricity End Use Survey will be completed on a bi-annual basis starting in 2013.	246.1
Communication/ Engagement	A community engagement tour was conducted by One Change during the June 2011. This tour was focused on getting Yukoners talking about energy conservation and collecting their input on future DSM programs. Upon completion of the DSM plan a second community tour will be conducted to hear how communities are developing conservation, provide stakeholder education, and talk about new utility led DSM programs. Yukon Energy has engaged Aasman to produce the InCharge brand for DSM program delivery and is continuing this work as a potential public education campaign to be delivered in concert with the programs in the five-year DSM plan.	82.8
LED Pilot	2011 Pilot is complete and report is available. Due to issue with data a second pilot will be undertaken through the winter of 2012/2013 to test four different brands of lights throughout an entire winter. YEC is coordinating with YECL to ensure that efforts are not being duplicated. YECL will provide lights and participate in the findings of the study. The 2012/2013 study will include a third party lighting engineer to make recommendations based on data provided by YEC.	16.7
Commercial/ Institutional	Commercial programs to date have included multiple offerings of Natural Resource Canada's Dollars to $ense workshop. This course walks business owners through the basics of electricity, electricity usage in a commercial setting and how to start evaluating potential electricity saving measures. YEC has partnered with the City of Whitehorse and is supporting their 2012 energy audit with financial and human resources.	124.2
Industrial	An energy audit of Alexco's Bellekeno mine has been completed with a 50/50 cost sharing agreement. An agreement for an additional 25% contribution from YEC is still pending the implementation of recommendations. YEC staff are working with the mine operations staff to inform decisions and assist in implementation.	48.3
Education	Yukon Energy and Yukon Electrical have partnered with the department of Education to support a pilot project installing energy dashboards in four schools. Work has commenced regarding the development of a school curriculum for Yukon schools teaching about electricity generation and conservation as well as safety. Resources from BC Hydro's PowerSmart program will be heavily involved in curriculum delivery. This material is expected to be delivered to schools in the Fall of 2012.	138.2
Residential	Residential programs to date have included partnering with ESC on a fridge/freezer collection program (2011 and 2012) and completing a Residential Electricity End Use survey. The fridge/ freezer collection is a program delivered by ESC. The goal of which is to replace older fridges and freezers with newer, more energy efficient models. The program also aims to reduce the number of households that have an older fridge or freezer in operation as a second unit.	48.1
Internal DSM	An internal energy audit has been completed and has informed a suite of projects for 2012/2013. 2012 will include multiple small monitoring projects aimed at filling information gaps identified in the original audit. The recommendations from the audit will be implemented according to the annual budget - measures with the greatest cost-benefit ratio will be given priority. All projects will be subject to approval from senior management so as to ensure organizational consistency and potential equipment lifetime concerns. In addition to technical upgrades, the IDSM project will include a program aimed at educating and engaging employees In DSM activities at work and at home.	200.6
Total 2012 Forecast Expense		**1070.1**

Table 3: DSM-related Activities by Project, 2013 Forecast

Activity	Description
Admin/Prgm Dev/ Misc	Administrative costs associated with the planning, execution, measurement, and evaluation of DSM programs.
Policy/Planning	Efficiency standards and building codes; support for Yukon government DSM related policies such as Climate Change, Energy Strategy, etc.; Residential and Commercial End Use surveys to support evaluation and verification of DSM Plan programs
Communication/ Engagement	InCharge messaging; website storefront; community outreach; program advertisement; public education
LED Pilot	LED pilot completion; streetlight implementation (pending results of pilot)
Commercial/ Institutional	Commercial programs as per DSM plan (eg. lighting, building optimization including operations and HVAC)
Industrial	Customized support for industrial customers; efficiency standards
Education	Grade school curriculum delivery and support; trade education; lunch and learn/breakfast technology sessions
Residential	Residential programs as per DSM plan (eg. appliances and lighting, block heater timers, programmable thermostats, low flow showerheads, new home construction, etc.)
Internal DSM	Employee education; implementation of efficiency upgrades to YEC buildings and equipment (as per audit recommendations)

TOPIC: **Major Projects, Waste-to-energy/Biomass/Biogas**

REFERENCE: **Application, Section 5.3.1.6, pages 5-41 to 5-44**

In assessing potential future supply options Yukon Energy has looked beyond diesel and hydro resources that have formed a significant portion of its supply portfolio to date and has also considered generation options that could be locally developed (based on local sources of supply) and that would provide firm, reliable power. These thermal biomass resources can be developed with conventional technology but require development of relatively more capital intensive high pressure steam generation plants that would typically be intended for year round operation in order to secure cost efficient use of the facilities. Accordingly, such options are potentially relevant under increased grid loads that provide sufficient opportunity for the biomass generation to displace default diesel generation. Such options have been considered at a pre-feasibility stage (where there is no decision to proceed with the project).

…

Total forecast feasibility costs to the end of 2012 are $1.383 million with a $0.225 million offsetting contribution from CANNOR.

QUESTION:

a) Considering that options have been considered at a pre-feasibility stage, have preliminary cost-benefit analyses been undertaken? If a cost-benefit analysis has been undertaken, please provide the net present value analysis and underlying assumptions. If a cost-benefit analysis has not been undertaken, please explain why not.

b) What is CANNOR?

c) Please provide the benefits that would accrue to electrical customers of the Yukon as a result of this project.

d) Please explain the meaning of “environmental baseline work and data collection required for a feasibility level of assessment.”

e) Is YEC requesting Board approval to proceed with "environmental baseline work and data collection required for a feasibility level of assessment?"

f) Considering the costs of the project and the LCOEs submitted (lines 2 – 7, page 5-43), please provide a timeframe for when this project is viable and when the "environmental baseline work and data collection required for a feasibility level of assessment" will proceed?

ANSWER:

(a)

Please see Table 1 below for Waste to Energy and Biomass thermal projects present value (PV) analysis prepared as part of 2011 Resource Plan Update (see YECL-YEC-1-18).

Table 1:
Overview of Resource Options - Capabilities & Costs

	Capital ($2010 million)	Capacity (MW)	Energy Capability (Average GWh/yr)	2015-2019 Diesel Required/ Displaced (GWh/yr)	2015-2019 Annual Costs (cents/kW.h diesel displaced)	Forecast LCOE (2010 c/kWh) Scenario A[1]	LCOE (2010 c/kWh) Extend 2019 load to 2030	LCOE (2010 c/kWh) Full Utilization
Default Diesel Requirement	56	37	292	85	29-31 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)
Waste to Energy	39	2.2	17	14	27-31	31.5	19.0	13.5
25 MW Wood Biomass	114	25	199	85	48-51	55.4 [3]	42.8	16.6
15 MW Wood Biomass	86	15	120	72	33-35	40.1 [3]	28.8	15.8
3 MW Wood Pilot (Haines J.)	19	3	24	18	28-29	23.1 [3]	24.7	17

Note:

1. Forecast LCOE = Levelized Cost of Energy (cents/ kW.h of forecast diesel displaced [2010$]) over project life at Scenario A load scenario.

(b)

CanNor is the acronym for the Canadian Northern Economic Development Agency.

(c)

The referenced spending covers a range of projects, as set out in YUB-YEC-1-47(a) above. Each of these projects can provide energy at a levelized cost of energy (LCOE) below diesel if all of the output of the plant can be fully utilized to displace diesel ("Full Utilization"), which would (if feasible) benefit ratepayers. In addition, each of the options provides renewable power which in itself a goal where feasible.

After review of the studies, Yukon Energy is not currently pursuing waste-to-energy options and has focused current biomass resource option planning efforts solely on a 2-3 MW wood biomass pilot option (see Section 8, Overview document). Given the grid loads forecast to occur ("Scenario A") in the 2011 Resource Plan, the LCOE is below diesel costs for the 3 MW Wood Biomass Pilot project.

(d)

Under the general stages of project development, "environmental baseline work and data collection required for a feasibility level of assessment" refers to activities occurring to collect environmental and socio-economic data and public consultation activities related to preparing a YESAB Project Proposal (but does not yet include the actual consultation and Environmental Assessment work needed to complete the YESAB Proposal) as well as cost and engineering data to confirm sufficient feasibility to commit further stages of activity and funding to the project.

(e)

No. There is no provision for the YUB to review and/or approve project feasibility assessment activities that a utility is required to carry out to maintain its ability to serve customers.

Yukon Energy is seeking approval to include the costs incurred for the studies in rate base, and the amortization of the studies starting in 2013, as set out in Table 5.6 and 5.7.

(f)

Lines 2-7 of page 5-43 solely refer to one of the options included in this project (the Municipal Waste-to-Energy concept). The remainder of the LCOEs are set on the remainder of page 5-43 and in YUB-YEC-1-47(a) above. As noted in YUB-YEC-1-47(c) above, the primary concept for development at this time is a 3 MW Wood Biomass pilot at Haines Junction that could generate up to 24 GW.h per year and displace up to 18 GW.h of diesel generation based on Scenario A loads starting in 2015. No formal in-service date target has yet been established for the project, nor has any specific target date been set to determine when this project is viable. Current attention is focused on seeking external funding support.

TOPIC: **Major Projects, District Heating**

REFERENCE: **Application, Section 5.3.1.7, pages 5-44 to 5-45**

Yukon Energy is currently exploring various thermal supply options that produce waste heat, including liquefied natural gas, biomass and waste to energy. For these projects, a developed district heating market in Whitehorse may provide added value through generation of additional revenues that may lower costs for thermal supply options and consequently reduce impacts on ratepayers. Very preliminary findings to date indicate promising market potential of 3 to 4 MW of district heat applications within the core areas of Whitehorse.

QUESTION:

a) Please provide the recommendations and findings of the study "prepared in partnership with the Energy Solutions Centre, Property Management, Yukon Government and City of Whitehorse" that resulted in YEC's decision to "proceed with a full feasibility study."

b) Please explain why such a project is not better suited for a non-utility/private venture.

c) Please provide the benefits that would accrue to Yukon electrical customers if it was included as a regulated utility project.

d) Is YEC requesting Board approval for the costs of the feasibility study or is YEC seeking approval for the project in order for it to proceed? Please explain your response.

e) At which price point does the project become viable and at what time in the future does YEC speculate that the project would become viable?

ANSWER:

(a)

Please see study at link below (Section 7 provides conclusions, recommendations and next steps).

http://www.energy.gov.yk.ca/pdf/whitehorse_des_prefeasibility_study.pdf

(b) and **(c)**

The current studies have been to assess the potential added energy efficiency and cost savings benefits that Yukon electrical customers might secure in the event that thermal based power generation options (e.g., renewable options such as biomass or waste to energy, or fossil fuel options such as diesel or LNG) are utilized and/or developed at Whitehorse. YEC has not made any assessments or determinations as to the optimum institutional options for actual development of district heating.

(d)

YEC is seeking YUB approval for including the study feasibility costs in rates as provided for in the Application. The YUB does not have jurisdiction to approve specific capital projects.

(e)

YEC will assess on an ongoing basis with each thermal generation options under consideration at Whitehorse, including potential near term LNG development, the opportunity to reduce its costs through local uses of waste heating by YEC and sale of waste heat to others through district heating developments.

TOPIC: **Major Projects, Liquefied Natural Gas (LNG)**

REFERENCE: **Application, Section 5.3.1.8, pages 5-45 to 5-46**

The feasibility of thermal generation using LNG is being considered by Yukon Energy for near-term development (i.e., before 2015) as it is expected to provide a reliable, abundant, low cost, and flexible source of supply with reduced greenhouse gas emissions and costs compared to using existing diesel generation.

…

Forecast feasibility costs are approximately $1.7 million to the end of 2012. The Table 5.2 forecast in 2013 shows a further $1.0 million expenditure in fixed assets in 2013, plus transfer of $1.669 million from feasibility study costs.

QUESTION:

a) Please provide the LNG feasibility study conducted by Braemar Wavespec.

b) Provide a summary, highlighting the underlying assumptions of the LNG feasibility study and the rationale that underpins YEC's assertion that LNG "is expected to provide a reliable abundant, low cost, and flexible source of supply with reduced greenhouse gas emissions and costs compared to using existing diesel generation."

c) Is YEC suggesting that diesel generation in the Yukon be replaced with LNG? Please explain your response.

d) Please explain why additional costs should be incurred related to further feasibility work referenced to in lines 18 – 19, page 5-45 of the Application. How would this further feasibility work be conducted and what would be the parameters of the feasibility work?

e) Please provide details regarding the proposed $1 million fixed-asset expenditure in 2012 and the proposed $1.669-million transfer from feasibility costs for which YEC is requesting approval.

f) Please explain what is meant by YEC's submission "that this project will meet reasonable assurance before the end of 2012, and that the costs to date (and ongoing costs) will be included in construction WIP as the project is developed."

ANSWER:

(a)

The requested study was undertaken jointly between Yukon Energy and Western Copper and Gold, contains commercially sensitive information and is confidential to those two parties. The major elements of this study that are public are reflected in response to (b) below.

(b)

A summary of the assumptions and rationale that underpin YEC's conclusions on LNG to date is addressed in the Summary Conclusions of YEC's Overview of the 20-Year Resource Plan: 2011-2030 (see YECL-YEC-1-18), and in the LNG Background Paper-January 2012 presented at YEC's January 2012 workshop on LNG (see link below).

http://www.yukonenergy.ca/downloads/db/1120_LNG%20Workshop%20Report%20January%202012.pdf.

It is assumed in the referenced documents that LNG is supplied in the near-term by truck haul to Whitehorse from supply sources to be developed in northern British Columbia (Fort Nelson or Kitimat) for use at YEC's Whitehorse site (assumes simple cycle or combined cycle gas fired generation). Cost of LNG fuel was assessed at assumed natural gas prices (after inflation) in BC at $6.07/MMBTU in 2015, $8.05/MMBTU in 2020 and $11.07/MMBTU in 2030, assuming combined cycle generating units at 50% energy conversion efficiency (about 6.56 Mcg/MW.h), a 22 MW plant under Scenario A loads with DSM/SSE and an average annual plant capacity factor of 44%.

The following is a summary of the related conclusions in the Overview:

- LNG is identified as the only option that can totally displace Default Diesel on the grid during 2015-2019 with forecast Scenario A or B loads (e.g., with forecast diesel generation ranging from 85 to 143 GW.h/year with DSM/SSE).

- Excluding the relatively small energy impact Marsh Lake Storage hydro enhancement option (approximately 6 GW.h/year) and DSM/SSE, LNG is also the lowest cost near term option, with costs per kW.h of diesel displaced less than half the cost of diesel. Wood Biomass ranks second behind LNG in diesel displacement capability, but (at development scales beyond a pilot plant) is the highest cost near term option (with costs per kW.h of diesel displaced higher than the cost of diesel).

- The only other near term option with potential ability to displace more than 50% of Scenario A diesel generation requirements (i.e., Wind) has 2015-2019 costs per KWh only slightly lower than diesel, and forecast LCOE costs that are higher than diesel under Scenario A or B loads with the assumed DSM/SSE.

In summary, the 2011 Resource Plan indicates that the LNG Transition Portfolio option provides a range of potential benefits relative to the other near-term grid generation options available for potential commitment before 2015:

- LNG is superior to diesel in terms of cost (affordability) and emissions (environmental responsibility); relative to near-term renewable resource options, LNG is less costly while also providing high reliability, flexibility and diversity of potential Yukon uses on and off-grid.

- Where established, LNG would displace diesel as the default option in Yukon (although dual fuel units could also cost effectively retain flexibility to use diesel if and when advantageous). Lower cost LNG fuel would affect the assessment of future resource choices and also incremental pricing and rate setting in the rate zones where it is utilized, i.e., run out rates for higher use levels could be set based on LNG costs rather than diesel fuel costs.

- Other potential development benefits include:
  - LNG is the only option to offer material reductions in near-term rate increase impacts relative to diesel under Scenario A or B loads, as well as the non-diesel option with the lowest rate impacts in the event that currently assumed mine closures reduce grid loads after 2020.
  - LNG provides a cost effective contribution to grid capacity planning requirements, and the planned retirements of all of YEC's diesel plant over the 20-year planning period.

- As a result of the above impacts, LNG is the only option to offer opportunity to reduce present value diesel costs during the planning period under Scenarios A and B (projected reductions at 35% under Scenario A and 41% under Scenario B).
- Overall, LNG offers high flexibility with ability to be turned off and ability to accommodate load changes; it can provide cost effective baseload generation and backup capacity, and can be cost effectively developed concurrently with hydro enhancements such as Marsh Lake Storage and Gladstone Diversion.
- The LNG Transition Option can accommodate optimum timing for Gladstone diversion, other potential hydro enhancements or greenfield developments, and wind development in response to confirmation of longer-term grid loads needed to secure reduced Forecast LCOE for these various renewable resource options.
- LNG is the only portfolio option that can be used off-grid to reduce reliance on diesel (i.e., off-grid communities such as Watson Lake and mines at various off-grid locations). This option can also be used to reduce GHG emissions in other sectors where GHG emissions impacts are more significant (e.g., transportation).

(c)

Yukon Energy is examining its ability to displace diesel generation on the Yukon grid with LNG, as set out in the Overview to the 20-year Resource Plan: 2011-2030 (see response to YECL-YEC-1-18). The 2011 Resource Plan also notes the potential for LNG to displace diesel at off grid generating sites in Yukon.

Subject to successful completion of current feasibility assessments, the Overview recommends that Yukon Energy determine whether it is able to establish LNG generating capability in Whitehorse prior to 2015 with sufficient capacity to displace grid diesel generation under current Base Case grid load forecasts, and that Yukon Energy also determine the feasibility of utilizing LNG in the event that material additional near-term grid loads occur such as those assumed in Scenarios A and B. This action is being undertaken to implement LNG as a transition option that is able to meet current forecast loads with the least cost option available for near-term implementation, i.e., prior to 2015, and with reduced GHG and other emissions relative to diesel generation.

(d) through **(f)**

Yukon Energy has not included any LNG costs in the proposed revenue requirements for 2012 or 2013.

In order to pursue the LNG option for near-term development for power generation in Yukon by late 2014, the Application notes that Yukon Energy is pursuing further feasibility work to determine the optimum way to secure the LNG, the required timing and all related costs (including assessment of potential options for LNG supply chain development jointly with other interests to meet broader near and longer term Yukon opportunities). Feasibility work is also being pursued to optimize the specific Yukon Energy generation capacity and technology for power generation using LNG (including assessment of the optimum combination of combined cycle and simple cycle units in response to different potential load scenarios).

This further feasibility work is being conducted as follows in 2012:

- **LNG supply options:**
  - **General:** YEC and Western Copper and Gold (WC&G) jointly carried out a confidential Request for Interest Proposal (RFIP) process in late 2011 and early 2012 for potential LNG suppliers, which resulted in five submissions and related meetings with potential proponents. This RFIP process helped to guide subsequent joint activities.
  - **Fort Nelson, BC:** YEC is working jointly with WC&G and Spectra Energy to investigate the feasibility of developing an LNG supply facility on Spectra Energy's existing major gas processing site at Fort Nelson for initial in-service by late 2014/early 2015 for Phase 1 (YEC supply of 250 to 300 m^3 per day) and by 2018/19 for Phase 2 (WC&G supply of an added 1,000 m^3 per day), with provision for added LNG development when and if other local or Yukon or NWT interests confirm additional LNG requirements. Pre-FEED work, including plant technology selection and cost scoping sufficient for budgetary feasibility assessment and development of key commercial contract terms, is expected to be completed during summer 2012.

- **Other supply options:**
  - YEC is completing examination of all other potential near term LNG supply options in British Columbia, including Fortis BC [LNG supply facility in Surrey BC], Shell Canada [developing a 1,600 m^3 per day LNG facility at Jumping Pound near Calgary for in-service planned in late 2013], and potential new LNG developments to be located at Kitimat, BC. Yukon Energy is assessing options to secure LNG supply initially from one or more of these sources, until such time as LNG supply becomes available at Fort Nelson.
  - Yukon Energy is also examining available information on potential future LNG supply from future Eagle Plains natural gas development in Yukon or from other Yukon sources of natural gas such as potential developments in the south east corner of Yukon.

- **LNG transportation:** YEC and WC&G are individually and jointly examining options and costs to haul LNG to Yukon as required from Calgary, Vancouver, Kitimat or Fort Nelson, including assessment of requirements to secure any additional permitting.

- **LNG power generation at Whitehorse:** Yukon Energy has engaged the Kwanlin Dun First Nation and the Ta'an Kwacha'an First Nation in discussion of potential partnership arrangements with YEC regarding LNG facility development at Whitehorse. Yukon Energy has also retained consultants to examine the following elements of the requirements for LNG power generation at Whitehorse:
  - LNG power generation option assessment;
  - LNG unloading, storage and vaporization requirements assessments;
  - Site options assessment.

The forecast feasibility study costs in the Application are $1.669 million to the end of 2012 to address the planning activities outlined above (including activities in 2011). As part of this stage YEC intends to develop work plans and budgets as required to develop LNG use to displace default diesel generation as soon as is feasible throughout the range of potential Yukon Energy near-term grid loads. Based on information to date, Yukon Energy expects that work to be done in 2012 will confirm an ongoing work plan later in 2012 (with appropriate decision stages) with “reasonable assurance” that a

Corporation commitment to construction will be made at some point in the future[1]. The term “reasonable assurance” is an accounting policy term that reflects how costs are expected to be treated. It does not suggest that a final decision to develop LNG would be made before the end of 2012.

Absent such confirmation, Yukon Energy has not currently forecast further planning expenditures on LNG; however, in the event that the "reasonable assurance" test is met in 2012 as expected, a specific work plan will be established and the costs to date and future costs will be included in construction WIP. At this time, pending completion of the current planning work, YEC has no reliable budget cost estimate for the post-2012 work for LNG, i.e., the $1.0 million expenditure shown in the Application for fixed assets in 2013 is simply a preliminary budget until the relevant budgets are developed and approved.

As noted, costs related to LNG do not affect the revenue requirements or rates currently included in the Application.

[1]As set out in Appendix 5.1 of the Application, section 2.2 of the finance policy for costs incurred in relation to Planning activities states that "future expenditures will not be recognized as work-in-progress assets until such time as there is reasonable assurance that a Corporation commitment to construction will be made". It is noted that such assurance would be consistent with a decision by YEC to define a specific project location, approach, technology, etc. and/or to prepare and file a YESAB Project Proposal, enter into substantive negotiations with First Nations or project partners, preparation of engineering designs and tender materials, and arrange project financing where needed.

TOPIC: **Major Projects, Geothermal**

REFERENCE: **Application, Section 5.3.1.9, pages 5-46 to 5-47**

Geothermal opportunities offer future potential to provide significant low cost, clean, and reliable long-term electricity supply in Yukon if successful exploration can define appropriate opportunities close to the grid.

Due to the potential significant benefits of this resource, geothermal opportunities in Yukon have been subject high level review since the 2008/2009 GRA in order to ascertain geologic and economic potential for development for heat and electricity production at the following locations: Haines Junction, Volcano Mountain, Whitehorse, McArthur, Nash Creek and Larson Creek.

A preliminary resource assessment and prioritization of sites was subsequently undertaken for Yukon Energy by Borealis Geopower. This assessment indicates that, while unconfirmed, there is clearly a material and significant potential at the sites identified.

Future consideration of geothermal sites is dependent on successful exploration that defines appropriate opportunities close to the grid.

…

Forecast feasibility study costs of $1.95 million to the end of 2011 are closed and amortized over 10 years starting in 2012. A further $0.38 million of feasibility study costs are forecast in 2012 and $0.30 million in 2013, to be amortized over 5 years.

QUESTION:

a) Please provide details of YEC's high-level review of geothermal opportunities and YEC's decision to move ahead with the preliminary resource assessment undertaken by Borealis Geopower.

b) Please provide the Borealis Geopower assessment.

c) Was the resource assessment undertaken by Borealis Geopower tendered? Please provide details.

d) Please describe the unconfirmed potential significant benefits of this project that would accrue to Yukon ratepayers if implemented.

e) Please provide a detailed description of the total project costs by category with related totals that have been or will be incurred in the test years.

f) YEC submitted that deferred costs total approximately $2.633 million: $1.95 million to the end of 2011 and forecast spending of $0.686 million for the test years. With respect to test year expenditures, if "results of 2012 studies are favorable" will YEC be requesting further approval for an additional $7 million in expenditures related to additional baseline studies and permitting work expected to total approximately $1.5 million while costs for exploration and drilling would increase to $5 million (lines 15-16, page 5-47)? Please explain your response including an explanation of the expected timing of approvals related to this project.

g) Will Borealis Geopower be assessing the results of the 2012 studies? Are there other third-party consultants who will assist in the assessment of results? Please explain your response.

h) Knowing that "exploration activities typically comprise approximately 10% of the total capital cost of a geothermal project", at what point in time would this project not be prudent or in the best interests of YEC or Yukon electric utility ratepayers?

ANSWER:

(a)

YEC's initial review confirmed that Yukon is located on the Circum-Pacific volcanic belt (also known as the "Ring of Fire"), and that there are a number of areas in Yukon in reasonable proximity to the grid with geological evidence for the type of geothermal resource that could be used to produce electricity. As a result, Yukon Energy proceeded with further high level review of the resource potential in areas near the current grid.

An overview of YEC's high level review of geothermal opportunities is provided below. Yukon Energy's decision to move ahead with the preliminary resource assessment undertaken by Borealis Geopower was driven by the need to prioritize which sites to focus on for further review (i.e., which sites have best potential for developing resource given material effort, cost and risk associated with further exploration).

- **Jarvis Creek** – this site is located within the Shakwak Valley, approximately 31 km north of the Village of Haines Junction. Geochemistry and isotopes analysis suggest the water from the spring has a deep source with little interactions with shallow groundwater. Geothermometry data indicate the resource temperature varies between 72 oC and 76 oC; however, this doesn't provide an indication of the depth of the resource. A thermal gradient of 40 oC/km was estimated using well data from the Village of Haines Junction municipal well. In an attempt to obtain deep temperature data, drilling was undertaken in 2010. Activities ceased shortly after beginning when an artesian aquifer in surficial deposits was encountered. The geological context (graben structure) makes the site encouraging from a geothermal development standpoint. However, the combined effect of significant distance from major loads, high technical challenges associated with exploration work, and requirement for new transmission line to Haines Junction contributed to significantly increase the overall project risk and impact.

- **Larson Creek/Beaver River** – The proposed geothermal play is located in the south-east corner of the Territory, near Watson Lake. The springs are associated steeply dipped thrust faults within limestone bedrock. The temperature at surface at the Larsen and Pool springs reach 50 oC. Geothermometry analysis suggests water at source reached temperatures ranging between 167 oC and 232 oC. Isotope analyses suggest the residence time of the spring water in the ground is greater than 50 years. The site showed promising results but was not retained for further investigations due to its remoteness and the lack of transmission infrastructures between Watson Lake and Whitehorse, where major loads are.

- **McArthur Hot Spring** – The site is located approximately 75 km south of the Village of Mayo, within the Ddhaw Ghro Habitat Protection Area. Only limited exploration work was completed at the site as no agreement could be reached to undertake a thermal gradient drilling program. Extensive faulting in the area and potential seismic activity suggest an encouraging setting for a geothermal play.

The lack of bedrock outcrops and thick overburden cover makes difficult the mapping of subsurface structures. Spring water temperature of 52 oC at surface was recorded. Geothermometry analysis suggests water temperature at the source ranges between 120 oC and 165 oC and potentially understated due to mixing with shallow groundwater. Although promising, the site was not considered for further assessment due to its remoteness and location within a protection area.

- **Nash Creek** – The Nash Creek Hot Springs are located approximately 110 km northeast of the Village of Mayo, within the Peel River Watershed. Early exploration work suggests the thermal system includes at least 27 springs potentially sourced from a single well associated with nearby fault structures. The water temperature of 47 oC was measured at surface. Isotopes analysis suggests deep water mixing with shallow groundwater. Extensive faulting in limestone bedrock is encouraging for geothermal development. The Nash Creek Hot Springs was not retained for further assessment because of its remoteness.

- **Partridge Creek** – The Partridge Creek site is located 15 km east of the North Klondike Highway near McQueston River crossing. The warm spring pool covers an area of 95 m2 and is 10 cm deep. The site is located within the Tintina Trench that is known for its steeply dipping structural features. The heat is inferred to originate from two nearby granitic intrusions. A temperature of 25 oC at surface was recorded and combined with structural geology context, suggest shallow groundwater mixing. Geothermometry indicate source temperature ranging between 75 oC and 110 oC. The low temperature of the source and distance to major loads contribute to increase the overall project risk associated with this site.

- **Volcano Mountain** – The Volcano Mountain site is located 40 km west northwest of Pelly Crossing. No thermal springs were observed and water chemistry did not support deep upwelling of geothermal resource. The lack of subsurface information and surface expression of geothermal resource contributed to discard this site from the list of potential opportunities.

- **Whitehorse** – Several sites with the Whitehorse area are considered as prospects and include the Takhini Hot Springs, Alligator Lake, Versluce Lake and Stinky Lake. A temperature at surface of 47 oC was measured at the Takhini Hot

Springs. Geothermometry analysis suggest a source temperature at depth ranging between 96 oC and 170 oC. Geological mapping suggest extensive faulting in the Whitehorse area and is encouraging for the development of geothermal resource. Based on available groundwater temperature data, a thermal of 60 oC/km was calculated. Although deep drilling would likely provide a reduced thermal gradient, it still provides a good first estimate of the depth of the geothermal resource and associated drilling costs. The Whitehorse play has the advantage of being close to major electrical loads and existing transmission infrastructures. In addition, a portion of the heat from geothermal resource could be integrated as part of a district energy system. The combined effect of favourable geological context, ease of access, minimal transmission requirements, potential for additional usage of heat resource and proximity to major electrical loads contributed to focus future exploration activities on the Whitehorse play.

(b)

This report includes proprietary information, is considered confidential and cannot be publically released. If the YUB wishes to review this information Yukon Energy is willing to make it available for review on a confidential basis.

(c)

The resource assessment was awarded to Borealis Geopower without tender. Yukon Energy is aware of no other firms in Canada that perform this type of work.

The Corporation determined Borealis Geopower to be the best resource available to undertake the review based on the following:

- Borealis Geopower staff have a high level of specialized and technical skills that would be difficult to secure elsewhere.

- Borealis Geopower is a leader in the exploration and understanding of the geothermal systems in Canada. For example, several members of this organization are heavily involved with the development of the Canadian

Geothermal Energy Association (CanGEA) and were actively involved in the development of the Canadian Geothermal Code for Public Reporting (the Code[1]).

The Corporation also recognized that Borealis Geopower can provide material financial resources to advance the development of the geothermal potential in the Whitehorse area. This partnership would allow a reduction of the financial pressure on the Corporation associated with exploration efforts, as well as other project components up to plant construction. As the capital investment requirements can be prohibitive, the Corporation currently has the option to assume the entire risk or share it with a partner such as Borealis Geopower.

(d)

Geothermal opportunities offer future potential to provide significant low cost, clean and reliable long term electricity supply in Yukon if successful exploration can define appropriate opportunities. This is a potential legacy resource that if proven and developed would provide long-term, low cost power for ratepayers.

As indicated in the Application at page 5-46 and 5-47, Whitehorse has been identified as a potential site with proximity to power infrastructure and markets. Estimate of potential capacity and cost per kWh for the Whitehorse site range from 30-45 MW and 9.3 to 12.6 c/kWh. Given a location close to the grid and to major loads, any such legacy resource option of this magnitude and low potential cost (relative to diesel) could provide material longer term power cost savings to Yukon ratepayers.

(e)

The Table 1 below provides a detailed description of actual expense incurred from 2008 to 2011. This notes that Yukon Cold Climate Innovation Center provided $19,354 in funding for the project in 2009 which reduced total expense that year.

[1] The Code is similar to those in mining (43-101) and oil and gas reservoir analysis (51-101) and provides a framework for the analysis of the risk and subsurface potential associated with geothermal energy resources.

Table 1
Actual Geothermal Project Expense 2008-2011

Vendor	2008	2009	2010	2011	Total 2008-2011
Borealis Geo Power Inc.				27,500	27,500
EBA Engineering Consultants Ltd	149,890	850,637	434,472	202,319	1,637,318
Horizon Helicopters				6,903	6,903
Sadlier-Brown Consulting Ltd.	24,039	15,602	9,897		49,537
YEC - Owners Cost	34,513	252,257	- 166,028	124,764	245,507
Yukon Cold Climate Innovation Center	-	19,354		-	19,354
Accruals	22,373	218,670	- 230,942	- 10,102	-
Total	230,816	1,317,812	47,399	351,384	1,947,411

Table 2 below provides forecast expense for the test years.

Table 2:
Forecast Geothermal Project Expense for 2012 and 2013 Test Years

Test Year	Proposed Activity	Amount
2012	Preliminary Exploration including non intrusive advanced exploration	$300,000
	Geothermal Mini –Workshop	$50,000
	YEC Internal Cost (Labour, Travel, Materials, Admin, AFUDC)	$35,755
2013	Advanced Exploration (Drilling)	$275,000
	YEC Internal Cost (Labour, Travel, Materials, Admin, AFUDC)	$25,000

(f)

Yukon Energy is implementing a staged approach to complete the geothermal project development (see response to (h) below).

Future exploration activities in the Whitehorse area will be reviewed at the end of the year to determine whether additional resources should be assigned to more advanced exploration. The Corporation currently intends to complete early exploration activities and non-intrusive exploration over the test years. The Corporation does not expect to request additional budget of up to $6.5 million to complete permitting and exploration drilling over the test years. Exploration drilling is scheduled to occur in 2015 at earliest.

(g)

In 2012, EBA Engineering Consultants Ltd., a Tetra Tech Company will undertake preliminary assessment of the Vista Mountain warm spring, located north of Whitehorse. No decision has been made at this time regarding whether or not Borealis Geopower will be retained to assess the results of the 2012 studies.

(h)

Yukon Energy recognizes the risks related to development of geothermal resource, even under the attractive conditions noted to date in Yukon

The Overview of 20-Year Resource Plan: 2011-2030 recommends as follows regarding future geothermal resource activity (see response to YECL-YEC-1-18):

> "Carry out scaled down geothermal investigations and look for funding support for geothermal exploration and studies, and seek funding support for these activities."

TOPIC: **Projects Between $100,000 and $1 Million**

REFERENCE: **Application, Section 5.3.2, pages 5-47 to 5-49**

The projected total 2012 and 2013 spending on deferred cost activities outside of major projects over $1 million (as described in Section 5.3.1) totals $2.89 [million] in 2012, as set out in detail in Table 5.6, and a total of $2.7 million for 2013 as set out in detail in Table 5.7.

QUESTION:

a) In terms of the Aishihik hydro turbine re-runnering feasibility, is YEC or a third party performing the tests referred to on page 5.5-2? Please provide the details of performance of these tests in your response.

b) In terms of wind feasibility, please explain what YEC is stating when it submits that wind-related projects can be developed with minimal regulatory risk? Please provide a cost-benefit analysis (NPV) respecting the Ferry Hill site alluded to on page 5.5-2, wherein YEC submits that the scope of work to date includes sizing, location, effects of rime icing and connection to the grid.

c) In terms of large hydro feasibility, please provide a detailed description and breakdown of the 2012 costs, totaling $671,757.

d) In terms of the Atlin grid connection feasibility study, what capacity is available from the Pine Creek hydro facility? Is this a BC Hydro facility? Please provide any relevant details regarding the proposed assessment.

e) In terms of the AH1 and AH2 10-year unit overhauls, to which units do the acronyms AH1 and AH2 refer?

ANSWER:

(a)

Efficiency tests on the Aishihik units were conducted in 2010/2011 by external consultants. The results of these tests and the data provided by them will form the basis

for the evaluation planned for this year to determine if there is a business case to re-runner these units. This evaluation will be completed by an external consultant who is yet to be determined.

(b)

Regulatory and development risks are key considerations that affect whether or not an option may be considered to be reliable for development (i.e., licenced and constructed in time to meet a particular grid load requirement). For example, while hydro enhancements are options that may be pursued in the near-term, these options are not considered reliable to meet any specific in-service near-term target date due to the high degree of regulatory risk involved in development of each enhancement project. During the Mayo B Part 3 hearing, Mayo B was considered a more reliable option to proceed with at that time as there was greater certainty that the project could be licenced and constructed within the time period required to meet demand in 2012. Other options such as Gladstone, Marsh Lake and Altin storage were noted at that time to be lower cost and technically simpler options, but there was no assurance at that time that any of these options could be developed and licenced within the required time period. In this sense, these options were not reliable for development timing requirements.

In this respect, wind is considered to be an option where, once project feasibility is established, there is expected to be low regulatory risk, i.e., it could reliably be licenced within a reasonably short period of time.

Please see Table 1 below for Ferry Hill 21 MW wind project present value analysis prepared as part of 2011 Resource Plan. The analysis confirms that the project could be attractive at such time as there is sufficient sustained grid load that this resource could supply to displace diesel generation.

Table 1:
Overview of Resource Options - Wind Capabilities & Costs
(based on Table 8-1, Overview of 20-year Resource Plan: 2011-2030)

	Capital ($2010 million)	Capacity (MW)	Energy Capability (Average GWh/yr)	2015-2019 Diesel Required/ Displaced (GWh/yr)	2015-2019 Annual Costs (cents/kW.h diesel displaced)	Forecast LCOE (2010 c/kWh) Scenario A[1]	LCOE (2010 c/kWh) Extend 2019 load to 2030	LCOE (2010 c/kWh) Full Utilization
Default Diesel Requirement	56	37	292	85	29-31 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)	28 (fuel + O&M only)
Wind with 5 MW DRUPS	93	26*	56	45	26-29	40.0	21.3	14.8

* 21 MW wind not firm capacity
10.5 MW wind option was slightly less cost-effective at forecast loads.

Note:
1. Forecast LCOE = Levelized Cost of Energy (cents/ kW.h of forecast diesel displaced [2010$]) over project life at Scenario A load scenario.

(c)

Please see Table 2 below for a breakdown and description of $671,757 spent to date for Large Hydro Feasibility (differences due to rounding).

Table 2:
Total Expense by Component and by Contactor for Large Hydro Feasibility

Vendor	Description of activities	Total Spending 2009-2011 ($)
AECOM Canada Ltd.	Project Definition - Initial Evaluation - Review of Homan Lake - Review of potential hydro project near Faro - Slate Rapids and Finlayson mapping	364,742
Receiver General for Canada		2,000
KGS Group	Preliminary engineering and modeling	71,031
InterGroup Consultants Ltd.		4,504
Aasman Design Inc.	Public Information & awareness campaign	79,000
YEC - Owners Cots		150,482
Total Expense		**671,758**

The 2012 forecast budget for the Large Hydro feasibility is $200,000. From the total amount, $125,000 will be used to cover the equipment and labor cost associated with the installation of hydrological monitoring equipment at two sites. The budgetary allocation will also cover the annual maintenance of the two gauging stations.

A $50,000 amount is earmarked for holding a mini-workshop on the future of hydroelectric generation in the Yukon Territory. The workshop is intended to gather

information from experts in the field, stakeholders, regulators, utilities and interest groups and discussed how best proceed with the development of hydroelectric potential in the Yukon. The remaining amount ($25,000) is intended to cover Yukon Energy's administration costs (labor, AFUDC, etc.).

(d)

The current capacity of the Pine Creek Hydro facility is 2 MW. Presently it is supplying the community of Atlin BC with electricity. The facility is owned and operated by the Taku River Tlingit First Nation (TRTFN) as an IPP with a contract with BC Hydro. The peak electrical demand on the local Atlin grid is about 1 MW and the average load is about 0.5 MW. There are three options under consideration for a connection to the Yukon grid:

1. 1.5 MW option, using surplus hydro from existing TRTFN Pine Creek hydro plant, annual energy sale potential 10 GWh/yr.

2. 3.5 MW option, using surplus hydro from existing station with 2 MW expansion (penstock has been sized for this expansion), annual energy sale potential of 23 GWh/yr.

3. 8.0 MW option, using expanded existing hydro plant plus new 4 MW downstream plant on Pine Creek, annual energy sale potential of 52 GWh/yr. This two plant option was evaluated by Yukon Energy in the mid-1990's in response to a call for green power by BC Hydro.

The annual energy sale estimates assume a 75% capacity factor for the hydro plants. The powerline would be approximately 100 km long along Highway 7, running from Jakes Corner, Yukon to Atlin BC. It would be constructed at a voltage between 25 and 69 kV depending on the load transfer capability required, operability and economics. It is assumed a power sale agreement would be negotiated with the TRTFN, who have indicated their willingness to discuss this. None of these options has been assessed or permitted thus the earliest possible in-service date would be in the 2016-2020 time frame.

(e)

AH1 and AH2 refer to the units at the Aishihik Generating Station.

TOPIC: **Board Directive No. 3 Energy Conservation Office**

REFERENCE: **Application, page 6-7**

Yukon Energy has opened an Energy Conservation office and dedicated two full time employees to the management of research, pilot programs and policy/plan development. Through the Energy Conservation office Yukon Energy acts as Chair of the DSM working group and manages all contractors working on behalf of the partners.

QUESTION:

a) Please confirm that YEC has opened a new office, separate from YEC's current office, for energy conservation matters. If YEC has opened a separate office, why is it necessary to have a separate office?

b) Has YEC consulted its customers on whether there is a need or desire for the Energy Conservation office and whether customers are willing to pay for this service? If YEC, please provide details of the consultations.

c) Please describe any objectives or deliverables expected from the Energy Conservation office. What metrics are in place to ensure that the Energy Conservation office meets its intended purpose(s)?

d) If the Energy Conservation office completes work on behalf of all the partners, should YECL and YDC bear a portion of the costs required to open and run the Energy Conservation office? How does YEC propose to recuperate costs from other partners and how will the recuperation of costs be reflected in rate base?

ANSWER:

(a)

It was necessary to open a separate Energy Conservation office due to space limitations at YEC's Corporate Offices. Since the Main Street office opened it has become evident that there are also benefits due to proximity of this office to other organizations conducting similar business. This has provided for better working relationships within the community.

(b)

Public consultation on energy supply options generally, and DSM in particular, has indicated that the public does want the utilities to invest in DSM initiatives. To do this YEC was required to hire staff and open an office. The public was not consulted on the opening of new office space. This was an internal decision related to the spatial capacity limitations of the Yukon Energy corporate offices.

(c)

The Conservation Department is obligated to develop a DSM Plan and implement a DSM Plan that achieves targets as set out in the DSM Plan.

All Energy Conservation employee hours are attributed to DSM projects and subject to the rigour of cost effectiveness tests as part of the administrative costs of each program.

Other ongoing programs and deliverables are as follows:

- The Energy Conservation department has committed to residential and commercial end use studies (REEUS, CEEUS) on a bi-annual basis. The REEUS and CEEUS will provide qualitative data that will be used to analyze, verify, and adjust programs.

- The modeling conducted during the CPR process provides a quantitative baseline against which all DSM programs will be monitored. The CPR modeling will be conducted every five years to analyze, verify, and adjust programs to meet the targets set out by the working group and the YEC resource plan.

- Future communications and education programming will be subject to qualitative metrics such as impressions, clicks, or student hours. The DSM plan includes a section to define and assign timelines to EM&V.

(d)

The administrative costs of DSM projects are shared with partners on a per project/program basis. In the development of the DSM plan, all programs have been developed to include administration. The programs are all analyzed using the industry

best practice of four cost-effectiveness tests (Total Resource Cost, Participant Cost, Rate Impact Measure, and Utility Cost/program Administrator Cost). Only programs which have a positive cost/benefit ratio (including both incentive and program costs) have been added to the DSM plan for implementation by the utilities.

TOPIC: **Wind Generation Capacity/Capacity Factor**

REFERENCE: **Application, Appendix 6.1 page 6.1-7**

The only performance indicator determined for the wind turbines is Capacity Factor. The two wind turbines combined to produce a net Capacity Factor of 3.36% in 2009; 1.19% in 2010 and 5.6% in 2011.

QUESTION:

a) What are the nameplate capacities of the two wind turbines?

b) What capacity factors are experienced by wind turbines in other jurisdictions? Are the capacity factors of the two wind turbines comparable to those in other jurisdictions?

c) Does YEC expect the capacity factors for these wind turbines to change, and if so, how?

ANSWER:

(a)

The nameplate information for the wind turbines is as follows:

- WW1 – Bonus, 30/150kw, 480V; and
- WW2- V47,660 KW,690 volts, Turbine #11503.

(b)

The Capacity Factor in other jurisdictions is typically in the area of greater than 20%. The primary reason why YEC's Capacity Factor is considerably lower relates to site access. The location is typically inaccessible in the winter months and the units are prone to Rime icing which means they are out of service for most of the winter months.

(c)

The Capacity factor will not increase for these units. Please see response to YCS-YEC-1-10 with regard to specific plans and maintenance.

TOPIC: Transmission Infrastructure/Interruptions

REFERENCE: Application, Appendix 6.1, page 6.1-10

Typically YEC customers experience fewer customer hour interruptions than the CEA average. Much of this is attributable to having diesel back-up in communities which is readily available when an outage occurs that impacts the transmission infrastructure.

QUESTION:

a) What are the causes of the more frequent, but shorter, outages in the system?

b) Does Yukon Energy have a plan to reduce the frequency of its outages? Please explain your response.

ANSWER:

(a)

Shorter outages are typically driven by adverse weather, lightning and/or snow conditions. These have been the highest causes of outages for two of the last three years (2009 and 2010), with scheduled or planned outages being the highest in 2011. These causes are of a more critical nature and impact an isolated electrical grid more than the infinite bus grids found down south.

(b)

To address the majority of adverse weather related outages would require large capital expenditures (tens of millions of dollars) to rebuild affected infrastructure to a higher standard of construction and loading (i.e., older transmission lines). Consequently, there are at this time no plans to address these types of outages.

YEC plans to reduce frequency and duration of outages by maintaining and/or replacing assets – budgeting funds for this work will be based on review and analysis of all outages to determine the equipment trends.

TOPIC: Cost of Conversion to IFRS

REFERENCE: Application, Appendix 6.2, page 6.2-4

Additional costs are, and will continue to be incurred with respect to the conversion to IFRS due to increased internal and external consulting time, IT system costs and additional audit and other compliance costs. Costs for this extensive conversion process are expected to total $667,076 by the end of 2012 and are addressed in greater detail in Tab 5 and Appendix 5.5 (Deferred Projects Between $100,000 and $1 million).

QUESTION:

a) What are the incremental costs associated with the deferral of the adoption of IFRS? In your response, please provide a breakdown of the incremental costs by category.

ANSWER:

(a)

YEC does not anticipate any incremental costs associated specifically with the deferral of IFRS adoption. Management expects the costs to be the same as if the deferral had not occurred, only spread over a longer time frame.

TOPIC: **IFRS/Advisor**

REFERENCE: Application, Appendix 6.2, page 6.2-4

Yukon Energy hired an advisor experienced with IFRS to assist in developing and executing its conversion to IFRS…

QUESTION:

a) Is the IFRS advisor a FTE or a contractor?

b) When did the advisor begin collaborating with YEC in order to execute IFRS?

c) Initially, when was the advisor's mandate expected to end?

d) How has delaying IFRS affected the advisor's expected end date?

e) To date, how much of the advisor's initial mandate has been completed?

ANSWER:

(a)

The IFRS advisor is a contractor.

(b)

The advisor started collaborating with YEC in order to execute IFRS in about March 2009.

(c)

The advisor's mandate was initially expected to end within a few months of conversion, originally planned for January 1, 2011.

(d)

The advisor will continue to work with YEC through conversion, probably into the first quarter of 2013.

(e)

The mandate of the International Financial Reporting Standards ('IFRS') conversion project and the oversight role of the external advisor was split into several phases.

- **Phase 1 – Initial overview and planning phase** - This included a diagnostic report from the external consultant that outlined the major accounting gaps between the Canadian Generally Accepted Accounting Policies ('GAAP') and IFRS. This initial phase also included a project mapping exercise to outline the major steps along the conversion path and the issues for consideration that Yukon Energy Corporation ('YEC') will need to consider. This phase has been completed.

- **Phase 2 – Detailed accounting assess phase** - This used the diagnostic phase to drive into a detailed comparison by the external consultant between YEC's current accounting practice under Canadian GAAP and the issues, interpretations and choices available under IFRS. The outputs from the detailed phase are accounting papers under IFRS that outline the significant changes in policy, quantification and disclosure under IFRS.

  The Canadian Accounting Standards Board initially approved an optional one year deferral of the mandatory date for first time adoption of IFRS by entities with rate regulated activities. In March 2012, the Canadian Accounting Standards Board announced that they would be extending the option to defer adoption of IFRS by another year, for years beginning on or after January 1, 2013. YEC has decided to elect this option to defer its transition from Canadian GAAP to IFRS by one more year, and therefore, will commence reporting under IFRS for the year beginning April 1, 2013. As such the accounting papers previously prepared will need to be updated for any changes to the accounting standards under IFRS for this adoption period. Furthermore, there are accounting areas that need to be finalized for YEC's chosen policy adoption in areas such as regulatory balances

under IFRS (which continues to be monitored at the standard setting body (the IASB)), decommissioning obligations and areas of property, plant and equipment.

- **Phase 3 – Design phase** - This phase focused on building the tools required for conversion based on management's decisions around accounting options and the related disclosures. This included but was not limited to a production of the financial reporting required under IFRS for the annual financial statements. This mock set of IFRS financial statements has been undertaken and included a review of accounting disclosures in the financial statements and the build-up of the supporting information required from the financial reporting systems. Most steps in this phase have been completed but the mock-up IFRS financial statements as drafted will need to be updated following the decision to defer adoption of IFRS for periods on or after April 1, 2013.

- **Phase 4 – Implementation** - This phase focused on implementing the changes identified in the detailed accounting and design phases and ensuring that YEC has the ability to report under IFRS as 'business as usual'. The required stages of this phase have not been completed as it will depend on the production of real-time IFRS financial information in the year beginning April 1, 2013.

Included in the phases noted above is the requirement for sign-off from the external auditors on policies adopted, financial statement production and disclosures. This has not been finalized. Also, while baseline accounting training on IFRS impacts has been undertaken by YEC the education and issues for the full Board and senior management will need to be completed nearer the date of external reporting under IFRS for the first time.

TOPIC: **Financial Statements**

REFERENCE: **Application, Tab 9, 2010 Audited Financial Statements**

QUESTION:

a) The 2010 financial statements were released May 10, 2011. Please provide the 2011 financial statements.

ANSWER:

(a)

Please see Attachment 1 to this response.

Yukon Energy Corporation

2011 Annual Report



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Message from the President

Yukon Energy's 2011 annual report was prepared under our Board's direction and represents a balanced and accurate summary of the Corporation's economic, environmental and social performance for the calendar year ending December 31, 2011.

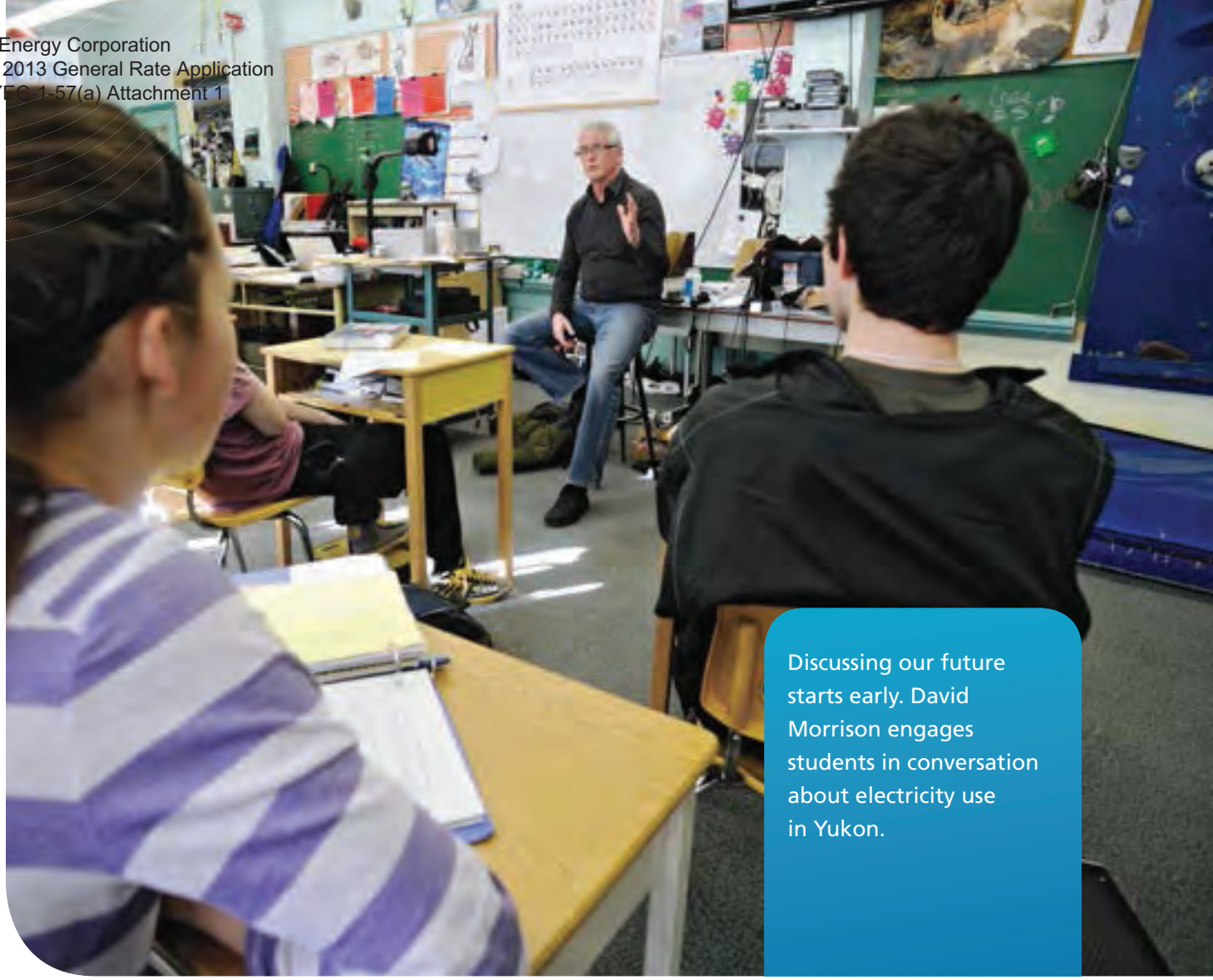
I must start by saying that 2011 was probably one of Yukon Energy's busiest on record, and the monumental feats that we were able to achieve are in large part because of our dedicated and highly skilled employees. I would like to thank all our staff for their extraordinary effort over the last 12 months.

Yukon Energy's primary focus in 2011 was two-fold: to complete some major projects started in previous years, and to engage Yukoners in a meaningful and wide-ranging discussion about the territory's energy future—what it should look like and how to get there.

All our major projects and initiatives are outlined in detail in this report. Briefly, key projects include:

- Mayo B, which involved building a 3.7 kilometre penstock and new powerhouse downstream from the existing plant. It more than doubled the amount of hydro power that could be generated at our Mayo facilities.
- Carmacks-Stewart Transmission Project – Stage 2, which saw our transmission system extended from Pelly Crossing to Stewart Crossing and allowed us to connect our two major hydro grids, thus providing more flexibility and reliability of service.
- Aishihik 3, which saw the installation of a seven megawatt hydro generator in our existing Aishihik hydro plant.
- Research into other clean energy options, including waste-to-energy, biomass and biogas, wind, geothermal, hydro enhancements and new hydro.
- Research into using liquefied natural gas as a transitional fuel to eliminate our reliance on diesel as a back-up fuel source.
- Establishment of an energy conservation department at Yukon Energy, and carrying out several energy conservation-related pilot projects and initiatives.
- A major energy-planning charrette that brought together a variety of Yukoners to help plan for a clean energy future for the territory.
- A Yukon-wide community tour to gather input for the development of a Yukon-wide energy conservation plan, and to share energy conservation tips and tools.
- Co-hosting a First Nations energy forum to explore business opportunities in clean energy and concluding protocol agreements with a number of Yukon First Nations.

I would be remiss if I did not make note of Yukon Energy's excellent safety record. Our staff have now gone nearly five years without a lost time incident, ranking us among the best small utilities in the country in terms of number of days lost.



Discussing our future starts early. David Morrison engages students in conversation about electricity use in Yukon.

Photo: Mike Thomas

As always, our ultimate goal is to achieve operational excellence. We measure our success by our ability to deliver safe, reliable and sustainable power to our customers, our ability to attract and retain a skilled and engaged workforce, our respect for the environment and for the communities and people we serve, and our recognition that Yukoners' needs power what we do.

Our focus in 2011 was two-fold: complete existing major projects and engage Yukoners in a meaningful way.

David Morrison
President and CEO



Keynote speaker, Dr. Mark Jaccard, leads a conversation about clean energy systems during the energy charrette in March.

Photo: archbould.com

Corporate Profile

Established in 1987, Yukon Energy is a publicly-owned electrical utility that operates as a business, at arm's length from the Yukon government.

We are the main generator and transmitter of electrical energy in Yukon. We work with our parent company Yukon Development Corporation to provide Yukoners with a secure supply of clean, electrical energy by focusing on renewable sources of power and energy solutions that complement our legacy hydro assets.

There are almost 15,000 electricity consumers in the territory. Yukon Energy directly serves about 1,800 of these customers, most of whom live in and around Dawson City, Mayo and Faro. Indirectly, we provide power to many other Yukon communities, including Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and Teslin, through distribution to the Yukon Electrical Company Limited. Yukon Electric buys wholesale power from Yukon Energy and sells it to retail customers in the territory.

Yukon Energy has the capacity to generate 129 megawatts of power. Ninety two megawatts of that are provided by our hydro facilities in Whitehorse, Mayo and Aishihik Lake (40 megawatts at Whitehorse, 37 megawatts at Aishihik and 15 megawatts at Mayo), 36 megawatts by diesel generators (which we currently only use as backup) and 0.8 megawatts by two wind turbines located on Haeckel Hill near Whitehorse.

Yukon Energy is incorporated under and regulated by the *Business Corporations Act*, the *Public Utilities Act* and the *Yukon Waters Act*.

Our headquarters are located near the Whitehorse Rapids hydro plant in Whitehorse, with community offices in Mayo, Faro and Dawson City.

Guiding Principles and Values

We strive to:

- make safety a priority in all that we do;
- recognize and encourage integrity, learning, growth and development;
- foster an attitude of teamwork;
- operate with respect for one another;
- be accountable to our customers and shareholders;
- act sustainably at all times (social, environmental and economic bottom-line);
- be innovative when seeking energy solutions;
- take a proactive approach to meeting electrical needs;
- develop partnerships in working to meet electricity needs; and
- optimize the use of our existing assets for the benefit of ratepayers.

Strategic Priorities

Optimize system reliability and system efficiency

One of Yukon Energy's highest priorities is to continually improve system reliability and efficiencies. A significant portion of our capital budget is dedicated to upgrading and modernizing the system.

Efficiency projects like improving the performance of hydro generating equipment and transmission lines are ongoing. Other major reliability initiatives in 2011 included:

- Completion of Stage 2 of the Carmacks-Stewart transmission line. This allowed us to join the Whitehorse-Aishihik-Faro and the Mayo-Dawson transmission lines so we could manage our assets as one integrated system.
- Commissioning of a third turbine at Aishihik and our Mayo B hydro plant. Both projects have not only given us additional hydro capacity, but have allowed us to use the available water more efficiently.
- Working with Yukon Electrical Company Limited to improve distribution efficiencies. Changes meant that outages could be kept to a smaller geographic area; for the very first time, Yukon Energy did not have any grid-wide outages in 2011.
- First phase of construction of a new sub-station in Mayo.

Develop clean energy solutions to meet forecast demand

Yukon Energy's 20-Year Resource Plan, developed in 2005, was assessed, and a great deal of work was done in 2011 to update it. The updated version will be ready for review by the public and the Yukon Utilities Board in 2012. This has provided another opportunity to work with Yukoners to develop options for meeting expected near-term and mid-term energy needs.

In 2011, new renewable energy projects included the addition of our Aishihik third turbine and Mayo B.

Implement an energy conservation/ efficiency program

A huge amount of time and effort was spent this year working towards the development of a Yukon-wide energy conservation plan/program. Projects included:

- Creation of a new energy conservation department within Yukon Energy.
- Information gathered from the public and Yukon stakeholders about what they want to see in a territory-wide energy conservation plan. The input was received through a Conservation Potential Review process, community consultation, surveys and workshops.
- Pilot Projects: LED streetlight project in Dawson City, Energy Conservation Kids Ed-Ventures program, and work on a solar pilot project at the Whitehorse Rapids Fishladder.
- Audits of the Alexco mine and Yukon Energy's Whitehorse and Dawson facilities. More audits are planned for 2012.
- Public outreach and education: clothesline public awareness campaign, new online energy calculator, One Change community tour, energy management workshops and Earth Hour activities.



Face-to-face conversations are one of many ways to share information about reducing electricity usage.

Photo: archbould.com

Secure project capital financing

The demand for electricity is growing year by year, and Yukon Energy does not have the capacity to develop new sources of energy all on our own. In 2011, Yukon Energy worked to find both public and private partners. Specific initiatives included:

- Completing the Mayo B project and Stage 2 of the Carmacks-Stewart transmission line through partnerships with the federal and Yukon governments and the First Nation of Na-Cho Nyak Dun.
- Working with the Yukon Indian Development Corporation and the Council of Yukon First Nations to host a First Nations Energy Forum to explore business opportunities in clean energy.
- Negotiating protocol agreements with the Champagne and Aishihik First Nations and the Kaska Dena Council.

Yukon Energy will continue to seek out partnerships where collaborative energy solutions can be found that both support the existing customers and support the growth of the economy.



Photo: archbould.com | Energy Audit of Yukon Energy buildings

Alignment with Shareholders' Letter of Expectation

Under both the *Yukon Development Corporation Act* and the *Corporate Governance Act*, the Minister Responsible for Yukon Energy is to work with our parent, Yukon Development Corporation (YDC), to negotiate a protocol on an annual or bi-annual basis.

The protocol outlines what is expected each year of both Yukon Energy and YDC. In addition, it has been the practice of the Yukon government to provide the Corporations with additional guidance in the form of a Shareholders' Letter of Expectation.

The most recent letter—which covers the period from April 1, 2010 to March 31, 2012—states that the Corporations will:

- Work with the Yukon government and other stakeholders on the implementation of the *Energy Strategy for Yukon* and the *Yukon Government Climate Change Action Plan*, and in particular, by participating in the development of an independent power producer policy, a net metering policy and a demand side management program.
- Complete the financial arrangement transfer payment agreement with the Yukon government regarding YDC's financial assistance.
- Work with Yukon Energy to ensure both Corporations carry out their obligations under the Yukon Energy/First Nation of Na-Cho Nyak Dun project agreement.
- Work with the Yukon government and Yukon Energy in preparing and implementing a work plan for demand side management initiatives.
- Work with First Nation development corporations on economic development opportunities.
- Ensure that Yukon Energy completes construction of Carmacks-Stewart transmission line Stage 2, thereby connecting the territory's two existing grids.
- Ensure that Yukon Energy completes the Mayo B project prior to March 31, 2012.
- Ensure that Yukon Energy continues work in preparation for the installation of the third turbine at the Aishihik hydro facility in anticipation of a winter 2011–2012 in-service date.
- Work with Yukon Energy to increase energy capacity by enhancing existing infrastructure, including improved efficiencies at the Whitehorse hydro plant, assessing ways to reduce line losses and the continued evaluation of the Atlin River, Marsh Lake and Gladstone Lake storage concepts.

Our Employees

Yukon Energy employs approximately 90 highly skilled and dedicated people in Whitehorse, Faro, Mayo and Dawson City. We are committed to being the employer of choice in Yukon.

We value our employees and ensure that we provide a respectful work environment. We offer competitive salaries, excellent benefits, generous paid vacations, vacation travel allowance and comprehensive training.

In Yukon Energy's overall human resources strategy, a strong, competent and professional workforce is deemed essential to the realization of the corporate vision. To maintain and enhance the skills needed to achieve our business objectives, the Corporation undertakes to:

- attract, recruit and retain a competent workforce that shares our values and is motivated to help sustain and improve the Corporation's assets;
- offer our employees opportunities for professional development to ensure a high level of skill, expertise and leadership; and
- ensure succession planning and the transfer of critical knowledge.

Photo: archbould.com | Energy Audit of Yukon Energy buildings



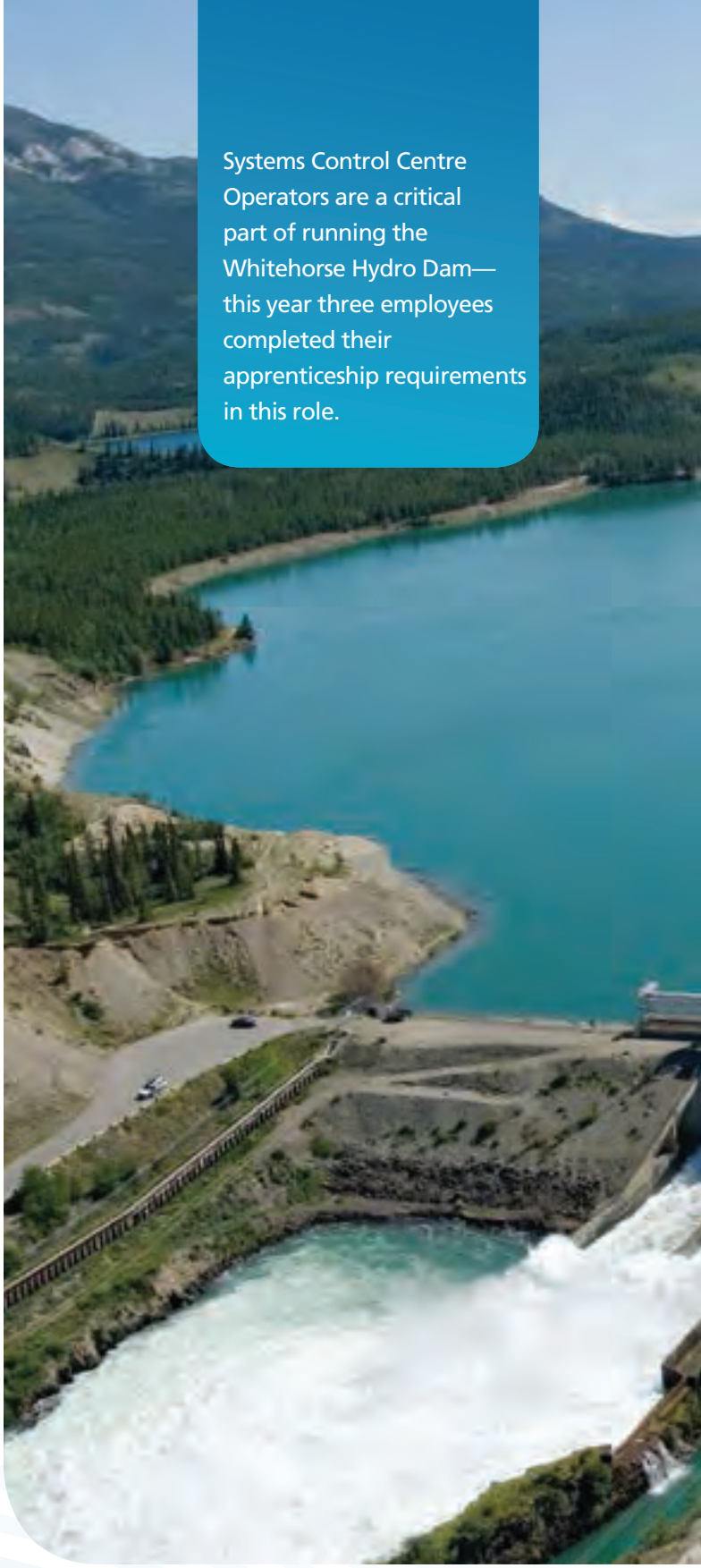
Long Service Awards

We are proud of our workforce and we have adopted several initiatives to recognize our employees' efforts. These include an annual celebration to recognize employees achieving milestones, annual employee and children's Christmas parties, summer barbecues, golf tournaments and other ad-hoc get-togethers. We would like to congratulate our 2011 Long Service Award recipients:

- **Ed Chaplin** – 40 years
- **Ken Sawyer** – 25 years
- **Darrell Johnson** – 20 years
- **Attila Janits** – 15 years
- **Shelley Dixon** – 10 years
- **Steve Milner** – 10 years
- **Ed Mollard** – 10 years
- **Jim Petelski** – 10 years
- **Austin Osborne** – 5 years
- **Maureen Thompson** – 5 years

New Department

Yukon Energy established an energy conservation department in 2011 to work with stakeholders on Yukon-wide energy conservation and efficiency programs. This department will also help the Corporation find ways of reducing our own energy use. Energy conservation is a critical element in helping us meet Yukon's growing energy needs.



Systems Control Centre Operators are a critical part of running the Whitehorse Hydro Dam—this year three employees completed their apprenticeship requirements in this role.

Apprenticeship Program

Yukon Energy's apprenticeship program is an important part of our human resource strategy in meeting some of our labour needs for both the present and future. It is rewarding to see how far the program has progressed since it was implemented in 2006. Since that time, about 16 Yukoners have gone through our apprenticeship program in the areas of power systems electrician, power line technician, systems control centre operator and heavy duty equipment technician. Almost all of them continue to work for us now that they have their journey tickets.

Congratulations to the following employees for successfully completing their apprenticeship requirements in 2011:

- **Al Porter** – Power Systems Electrician
- **Steve Blysak** – Systems Control Centre Operator
- **Mike Hannah** – Systems Control Centre Operator
- **Myles O'Brien** – Systems Control Centre Operator

Summary of Utility Operations

		2011	2010	2009	2008	2007	2006
Generating Capacity (in MW)							
Hydro		92[1]	75	75	75	75	75
Diesel		36	36	36	36	36	36
Wind		1	1	1	1	1	1
Total		**129**	**112**	**112**	**112**	**112**	**112**
Peak Demand (in MW)							
WAF System	Connected	67	65	64	59	61	
Mayo	Grid	7	5	5	5	5	
Total		**77[2]**	**74**	**70**	**69**	**64**	**66**
Generation (in GWh)							
Whitehorse Rapids		232	234	224	206	206	217
Aishihik		132	112	119	107	98	81
Mayo		21	32	29	28	27	27
Wind		-	-	-	-	-	1
WAF Diesel		8	3	2	1	-	1
Other Diesel		8[3]	2	1	-	1	-
		401	**383**	**375**	**342**	**332**	**327**
Electric Sales (in $000)							
Residential		1,800	1,524	1,535	1,523	1,509	1,456
General Service		3,342	3,315	3,007	2,804	2,731	2,645
Industrial		4,599	3,311	3,191	329	-	-
Wholesale		24,170	23,301	22,291	22,999	22,459	22,127
Secondary Sales		46	644	1,442	777	1,000	917
Other		90	83	81	86	377	383
		34,047	**32,178**	**1,547**	**28,518**	**28,077**	**27,528**
Electric Sales (MWh)							
Residential		12,834	11,398	11,596	11,359	10,908	10,665
General Service		21,538	22,570	20,042	18,523	17,507	17,037
Industrial		43,259[4]	30,255	29,355	3,200	-	-
Wholesale		290,541[5]	276,345	267,229	263,820	254,914	251,861
Secondary Sales		552	10,489	17,384	18,753	24,225	22,185
		368,724	**351,056**	**345,607**	**315,655**	**307,554**	**301,748**
Cents Per kWh							
Residential		14.03	13.37	13.24	13.41	13.84	13.66
General Service		15.52	14.69	15.00	15.14	15.60	15.52
Industrial		10.63	10.94	10.87	10.27	-	-
Wholesale		8.32	8.43	8.34	8.72	8.81	8.79
Secondary Sales		8.30	6.14	8.30	4.14	4.13	4.13

[1] Hydro capacity was increased by the addition of the Mayo B and AH3 projects commissioned late in 2011.

[2] The Peak Demand for 2011 was achieved after the grids were connected. This reduces the relevance of system peak demands for the WAF and MD grids as reported in prior years.

[3] Diesel generation of 16 GWh equates to 4% of Total Generation. Two thirds of this was required to meet system peaks and one third was required for capital projects.

[4] 2011 is the first year that both the Minto and Alexco mines are on the system for the full 12 months.

[5] Year to year growth in Wholesales sales of 14 GWh (5%) reflects an increasing preference towards electric heat as the primary heat source for new residential and general service construction in Whitehorse.

Photo: archbould.com

Ensuring Reliability of Service

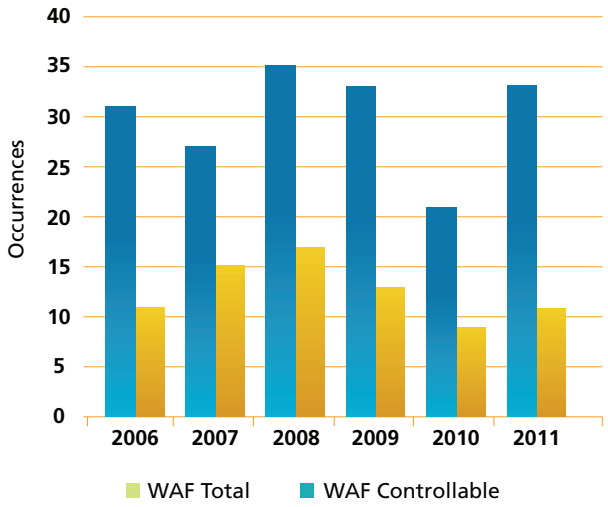
We take our responsibility to provide reliable power very seriously.

Three years ago, Yukon Energy embarked on an aggressive capital maintenance schedule that saw approximately two-thirds of our core capital budget go towards projects related to reliability. In 2011, we continued to work our way through a list of maintenance capital projects. While we had slightly more controllable outages on our Whitehorse-Aishihik-Faro transmission system in 2011 than in the previous year (11 in 2011 compared to nine in 2010) our trend over the longer term is improving. (We had 12 controllable outages in 2009 and 19 in 2008.) The good news for 2011 is that of the 11 controllable outages, none of them resulted in a grid-wide blackout. This shows the success of the modifications we have been making to our protection system. As the number of customers affected by an outage decreases, so does the amount of time required to restore power.

On our Mayo-Dawson grid we experienced eight controllable outages, compared with nine the previous year. We did have an unfortunate number of uncontrollable outages on our northern grid, mostly as a result of heavy snow and lightning strikes. However, even those numbers were down from 2010 (13 uncontrollable outages in 2011 compared with 19 the previous year). While there is little we can do about weather-related outages, we will continue to work hard to decrease controllable outages throughout the territory.

One initiative that will help address reliability is our Computerized Maintenance Management System that we are phasing in starting in 2012. This tool will improve our ability to plan for, budget, and schedule equipment maintenance on a daily to multi-year basis.

WAF Outage Data



MD Outage Data

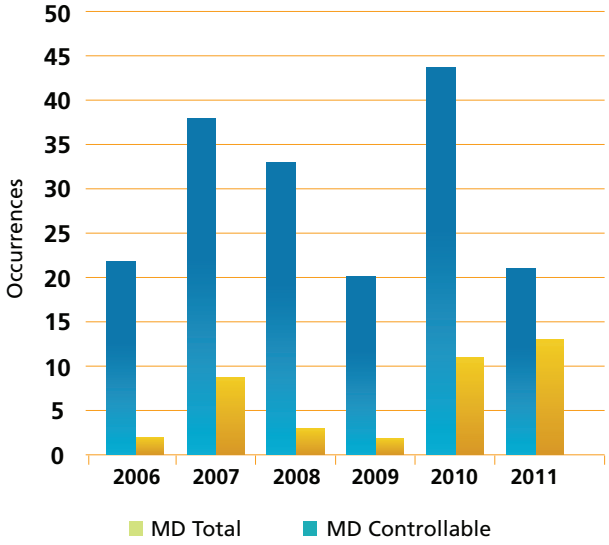




Photo: archbould.com | Mayo B powerhouse

Meeting Demand

Yukon Energy is planning for the future in ways that will ensure a secure and continuous supply of energy that is sustainable, affordable and clean.

Our goal is to meet the growing demand for electricity with renewable energy that complements our existing hydro system. To that end, we pursued a number of initiatives in 2011 that will enhance our current infrastructure.

Mayo B

The Mayo B hydro project involved building a new powerhouse 3.7 kilometres downstream from the existing hydro plant. Construction of Mayo B began in June 2010. In December 2011 it was tied into the territory's transmission grid and is now providing clean and renewable electricity to Yukoners. Mayo B increases our capacity to generate clean power at the existing site from five megawatts to 15 megawatts, without the need for a new dam or reservoir. It offsets several million dollars worth of diesel each year and reduces greenhouse gas emissions by about 25,000 tonnes annually.

Mayo B created more than 60 direct jobs for Yukoners and provided spin-off benefits to approximately 120 Yukon businesses. Close to $12 million was spent in Yukon as a result of this project including labour, materials and supplies. Of that amount, close to $2 million was spent in the Village of Mayo.

The Mayo B project was completed on time and within budget ($120 million). Contributions came from the federal government's Green Infrastructure Fund ($53.35 million), the Yukon Development Corporation, the Yukon government and through an investment by the First Nation of Na-Cho Nyak Dun (combined total of $30.14 million), and from electrical customers ($36.5 million). The cost to ratepayers will be spread over the lifetime of the project (50+ years).

Mayo Substation

Our existing substation in Mayo is at the end of its life and needs upgrading. That's particularly important with our new Mayo B hydro facility now in service. The substation must be able to handle all the power coming from both Mayo A and Mayo B, and re-route it to any and all communities connected to the Yukon grid.

This year the civil and foundation work was done for the new substation; the project will be completed in 2012.

Carmacks-Stewart Transmission Project, Stage 2

In June 2011, Stage 2 of the Carmacks to Stewart Crossing transmission line was completed. It involved building a new 138 kv transmission line from Carmacks to Stewart Crossing in Central Yukon (approximately 172 kilometres long), with a spur line to the Minto mine. Completing Stage 2 has allowed us to connect our northern and southern grids. Having one integrated transmission system has given us the ability to better manage our power.

Stage 1 of the project, from Carmacks to Pelly Crossing and a spur to the Minto mine, was completed and energized in November 2008. This allowed us to provide the mine and the community of Pelly Crossing with surplus hydro power. (Previously, both were on diesel.) It has led to reductions in greenhouse gas emissions of between 25,000 and 30,000 tonnes per year.

The cost of Stage 2 was approximately $40 million, with $17.65 million of that coming from the federal government's Green Infrastructure Fund and the rest from the Yukon Development Corporation.

The transmission line project resulted in substantial economic benefits for Yukon. It's estimated that approximately 200 Yukoners worked on Stage 1 of the project in one way or another, with a similar number involved in Stage 2 of the project directly or indirectly.

Aishihik 3

This is another of our hydro enhancement projects completed in 2011. Adding a seven megawatt hydro generator to the Aishihik hydro facility (which until December 2011 had two 15 megawatt hydro generators) has allowed us to use our plant more efficiently, since it has given us the ability to produce more power using less water. This new unit will save Yukoners $1 million or more per year in diesel costs and reduce greenhouse gas emissions by an estimated 3,800 tonnes annually.

Geothermal

Because Yukon is located in an area of the Pacific known as the Ring of Fire, the potential is good for finding significant geothermal resources that could be used to produce electricity.

In 2011, we planned to do further drilling at Jarvis Creek near Haines Junction, following good results from some early research. However, we were unable to secure a drilling rig due to the mineral exploration boom underway, so instead we focused on assessing potential sites in the Stewart Crossing/Mayo and Whitehorse regions. Early results show there is good geothermal potential in these areas, although much more work is needed before a decision could be made as to whether one or more geothermal plants would be feasible.

In 2012 we will collect additional temperature data in the Whitehorse area.

Photo: archbould.com | Aishihik 3



Wind

We continue to look for ways of using wind as a part of our clean energy complement. Yukon Energy has completed an assessment of the wind regime on Tehcho (formerly Ferry Hill) near Stewart Crossing. The results are positive enough that we are now seriously looking at the feasibility of building up to a 20 megawatt wind farm on the site. In 2011, wind monitoring equipment was installed at Tehcho. We will use this equipment over the next one to two years to collect data that will help us determine if a wind farm is viable in the Tehcho area.

In 2011, we also did some wind mapping in the Haines Junction area, and we completed an assessment of the wind regime at Mt. Sumanik, another site we are considering for a wind farm. The data showed Mt. Sumanik wind regimes are similar to those at Tehcho.

Enhanced Storage Projects

Yukon Energy is committed to optimizing our existing hydro infrastructure before developing new hydro projects. To this end, there are a number of enhancement concepts we are examining that could increase production at our Whitehorse, Mayo and Aishihik hydro facilities. These include increased storage ranges in the Southern Lakes (Marsh, Tagish and Bennett) and Mayo Lake, which together could increase the winter output of our Whitehorse and Mayo hydro facilities by 11 gigawatt hours per year on average. This is the energy equivalent of displacing approximately $2.5–$3 million of diesel generated electricity annually. Diverting water from Gladstone Creek into Aishihik Lake would allow more power to be produced at our Aishihik plant; up to 30 gigawatt hours per year increase in renewable energy production could result.

In 2011, Yukon Energy continued engaging with local stakeholders, First Nation governments and the general public on these potential projects. In particular, we held workshops and public meetings with residents of Mayo, Marsh Lake and Tagish to share results from our field studies and to determine information gaps where more research is needed. Our focus for the Gladstone Diversion Concept in 2011 was mainly to work with the Kluane and, Champagne and Aishihik First Nations to begin heritage and traditional use studies. We also collected additional water flows and lake elevation data.

There's an ongoing emphasis on workshops and public meetings as projects move forward.

New Hydro

Yukon Energy is exploring the next generation of new hydro development projects (2012 to 2020 time frame). This includes possible sites on the upper reaches of the Pelly River (between 10 and 80 megawatts and up to 500 gigawatt hours a year) and in the area of Moon Lake and Tutshi/Windy Arm in the Southern Lakes region (up to 12 megawatts and up to 70 gigawatt hours a year).

In 2011, we looked at potential sites on the Upper Pelly River to gather hydrological data. We also investigated the potential to develop small hydro sites at Moon Lake and Tutshi/Windy Arm. We will follow up in 2012 by collecting water flow information on the Upper Pelly, Moon and Tutshi Lakes.

Waste-to-Energy

In 2011, Yukon Energy continued the work started in 2010 looking at the possibility of using municipal waste to produce electricity and district heat. We believe this process could allow production of up to two megawatts of electricity year-round, using waste from Whitehorse area landfills and possibly supplemented with mill waste or other surplus wood material.

There are a number of issues that still must be addressed, including how to maintain continued emphasis on recycling and waste diversion, ensuring all harmful emissions will be removed to air emission/control standards, and finding local uses for the valuable steam and waste heat available from a waste-to-energy facility.

In October 2011, we hosted a workshop that allowed Yukoners to learn more about this idea. The feedback from the public will be invaluable to us as we continue to explore this potential energy option.

Biogas

Yukon Energy began a study in 2011 on the potential of using organic matter (food, brewery spent grains, waste cooking oil, slaughterhouse waste and sewage sludge) to produce a methane-rich gas known as biogas. This process would complement the waste-to-energy process and could produce in the range of 1,600 megawatt hours of electricity a year. The organic waste would be taken from the City of Whitehorse's compost collection program.

Biomass

Another concept Yukon Energy is assessing for a possible energy source is to use fire kill and beetle kill wood, along with waste from sawmills, to produce electricity and district heat. In June 2011, Yukon Energy had a biomass preliminary energy evaluation done. The report identified biomass resources within a 250 kilometre radius of Whitehorse that could potentially provide the feedstock required to maintain a 25 megawatt electrical generating facility for 20 years.

Subsequent to that report, however, stakeholders and members of the public attending a Yukon Energy-sponsored workshop on this issue asked us to look at smaller scale biomass options instead. In partnership with the Alsek Renewable Resource Council, the Village of Haines Junction, and the Champagne and Aishihik First Nations, we are now assessing the viability of a smaller plant in the Haines Junction area.

Liquefied Natural Gas

In 2011, Yukon Energy began assessing the feasibility of using liquefied natural gas (LNG) as a transition source of energy for power and district heat. LNG is less expensive than diesel and produces fewer greenhouse gas emissions. The idea would be to use LNG in the short term until new, clean, and preferably renewable, sources of energy can be developed. We will continue to investigate this potential option in 2012.

District Heat

The benefits of any thermal project in Yukon, whether it is waste-to-energy, biomass, biogas or liquefied natural gas, can only be fully realized if use can be made of the waste heat that is produced as a by-product of this form of generation. In 2011, Yukon Energy—in partnership with the City of Whitehorse and the Yukon government—began work on a feasibility study assessing the potential of a district heat system in Whitehorse. The work is



Photo: archbould.com | Energy Charrette

examining areas of potential load and energy sources to supply the system with heat. The study will be completed in 2012.

Energy Conservation and Efficiencies

Energy conservation is a crucial element in helping us meet Yukon's growing electricity needs. In August 2011, Yukon Energy created an energy conservation department to work with Yukon Electrical Company Limited, the Yukon government, and other stakeholders to develop a territory-wide energy conservation and efficiency plan. The new department is also helping Yukon Energy find ways of reducing our own energy use.

The energy conservation plan is expected to be ready for implementation in 2013.

Yukon Energy chairs an energy conservation working group, made up of representatives from Yukon Electrical Company Limited and the Yukon government's Energy Solutions Centre along with two of our own staff. We also participate in a demand side management steering committee, made up of senior officials from the two utilities and the Yukon government. Both groups meet regularly to ensure planning is done collaboratively and that programs are executed in a transparent, cooperative manner that avoids duplication.

Conservation Potential Review

Yukon Energy has been working to find out more about how people use electricity in the territory and where the greatest gains might be in terms of energy conservation and efficiencies. In 2011, we partnered with the Yukon Electrical Company Limited and the Yukon government's Department of Energy, Mines and Resources to collect this information.

We hired ICF Marbek to do a conservation potential review. Through its research, the company sought answers to the following questions:

- How do Yukoners currently use energy? (i.e. What percentage of energy consumption goes towards heat, hot water, lighting, plug loads, etc.?)
- How much power would Yukon need in future years if there weren't any energy conservation/efficiency initiatives put in place?
- How much potential is there in Yukon for energy savings through conservation/efficiency initiatives?
- Where are the greatest gains to be made in terms of conservation of electricity?

The consultants gathered the information using customer billing data, stakeholder consultation and customer surveys. They processed all the collected data and returned to Yukon in November to share their initial findings. Through stakeholder workshops they asked participants to talk about how much of the electricity savings identified in the draft report can realistically be achieved within Yukon's residential, commercial and renewable sectors.

ICF Marbek is using the feedback it received during these workshops to further refine its report. The final report will be available in early 2012.

One Change Community Tour

In the summer of 2011, Yukon Energy took our conservation message on the road. Together with Yukon Electrical Company Limited and the non-profit group One Change, we visited almost every community in the territory. We set up tents with interactive displays in highly visible areas, gave away energy efficient products, and talked to hundreds of Yukoners about what they think a territory-wide electricity conservation plan should look like. The input will assist us in our work to develop conservation programs for Yukon.

LED Streetlight Pilot Project

In 2011, we did research on light-emitting diode (LED) streetlights in Dawson City, with positive results. The research shows that the annual energy used by the traditional high pressure sodium streetlights is 416 kilowatt hours per light, compared with only 150 kilowatt hours per LED streetlight, a savings of 64 percent.

However, LED technology is changing rapidly and we would like to test some options that weren't available to us when we started the pilot project. In 2012, we will experiment with several different types of LED streetlights to determine which will be the best for our northern needs.

Alexco Mine Audit

In the summer of 2011, we partnered with Alexco Resource Corporation to do an audit of their mine site near Keno. We'll continue working with Alexco in 2012 to implement some of the suggested energy saving measures. We will conduct similar initiatives with other Yukon mines and we will work with the City of Whitehorse to audit their facilities. Audits are a great way to identify opportunities for savings and start to plan for a conservation based future.

Internal Audit

Yukon Energy is looking at our own operations as well with an eye to conserving energy. In 2011, we completed an audit of our Whitehorse and Dawson City offices and plant buildings, and we are prioritizing actions that will increase the efficiency of our facilities. Yukoners will be able to follow our progress on our website **yukonenergy.ca**.

Fridge and Freezer Retirement Program

In 2011, Yukon Energy partnered with the Yukon government's Energy Solutions Centre to help members of the public replace their old refrigerators and freezers with new more energy-efficient models. The used appliances must be at least five years old and in working condition. Not only will Yukoners receive $50 for each fridge or freezer they have replaced (up to two appliances), but the Energy Solutions Centre will remove the old model, take it to the landfill, and pay the landfill tipping fee. Yukon Energy will continue to support this program into 2012.

Online Energy Calculator

With assistance from Maritime Electric, we developed an online energy calculator in 2011. It allows Yukoners to determine how much electricity each of their household appliances and other electronic equipment requires to operate. The tool gives members of the public the ability to better manage their electricity usage and lower their power bills.



Photo: Mike Thomas | Stuart Hickox from One Change talks about energy conservation with high-school students.

Celebrating the Clothesline

In the spring of 2011, Yukon Energy ran a public awareness campaign that promoted the use of clotheslines. Employees set up a booth at an annual trade show in Whitehorse and gave away hundreds of packages of clothespins, along with several drying racks and clotheslines. We also provided tip sheets that included other energy saving information.

We're listening. Collecting data on electricity use helps us understand conservation potential.

Dollars to Sense Workshops

Yukon Energy, working with Yukon Electrical Company Limited, and Natural Resources Canada, hosted a series of energy management workshops in 2011 for Yukon businesses and First Nation and municipal governments. Sessions were offered both in the spring and fall. We will offer them again in future years if there is demand.

Energy Conservation Kids Ed-Venture Program

Yukon Energy and the Yukon Conservation Society partnered in 2011 to provide an afternoon of learning and fun for pre-schoolers, focused on energy conservation and electricity. The aim was to teach the children about using electricity safely and wisely. This was done through music and dance, storytelling, hands-on science and crafts. We plan to expand this program to other locations in 2012.

Earth Hour

Yukon Energy worked with the Yukon Conservation Society and the Yukon government's Energy Solutions Centre this year to promote Earth Hour. It's an annual event that encourages people to reduce their energy consumption as much as possible for one hour, and think of ways that they could continue to conserve throughout the year. This year Yukoners reduced their energy consumption by about one megawatt. That's up from 2010, at which time Yukoners cut their consumption by 0.8 of a megawatt during Earth Hour.

Independent Power Producers/Net Metering

Yukon Energy is working with Yukon Electrical Company Limited and the Yukon government on independent power producers (IPPs) and net metering policies. Work will continue in 2012 on these initiatives. When implemented, a net metering policy will allow customers to generate their own clean electricity and reduce the amount of power they buy from a utility. An IPP policy will enable Yukon Energy to buy power from private sources and support the development of Yukon's renewable economy.



Marc-Andre Lavigne talks about net metering at the Whitehorse Rapids Fishladder. Watch it at **www.youtube.com/yukonsenergyfuture**

Net Metering Solar Project

Yukon Energy began work in 2011 on a net metering solar pilot project. We selected a site for the demonstration project (the Whitehorse Rapids Fishladder) and ordered the solar panels and related equipment. The system will be installed at the fishladder during the summer of 2012. It will serve two purposes: to help power the ladder's visitor reception building, and to allow us to test run the steps other Yukoners will need to take if they wish to generate renewable power and send a portion of it back to Yukon Energy's grid. We will also monitor the amount of solar generation produced.

Secondary Sales

There was good news in 2011 for 13 Yukon businesses and government departments. A surplus of available water for electrical generation allowed us to once again offer our secondary sales program for several weeks between late August and early October.

The secondary sales program gives eligible Yukon businesses the option of using hydro power to heat their facilities instead of diesel fuel or propane, both of which are more expensive and generate greenhouse gas emissions. They pay two-thirds of the cost of heating with diesel fuel, in exchange for the service being limited and fully interruptible. They are required to maintain a backup heating system for use when secondary sales are not available.

In September 2010, low water at the Aishihik and Mayo hydro facilities forced us to indefinitely suspend the secondary sales program. However, this summer, with all our reservoirs essentially full, we could offer the program for a limited time.

Minto Debt

In February 2011, the Minto mine repaid a Yukon Energy loan in full, some four years ahead of schedule.

As part of the Power Purchase Agreement with the mine, Yukon Energy agreed to provide an $18 million loan, repayable at 6.5 percent over seven years (to November 2015). The money was used to cover the cost of the spur line into the mine property, plus a $7.2 million contribution to the main Carmacks-Stewart transmission line.

The reason for the loan was to allow the Minto mine to go into operation, so it could provide jobs for Yukoners and give Yukon Energy a new customer that would help reduce rates for other customers. Rates to residential customers decreased by 2.47 percent as a result of Minto coming on line. Ratepayers also benefitted from the $3.7 million in interest that we earned on the loan.

Meeting Our Regulatory Obligations

Phase II Hearing

In the fall of 2010, Yukon Energy and the Yukon Electrical Company Limited appeared before our regulator, the Yukon Utilities Board, for a Phase II hearing. The purpose of the hearing was to provide the Utilities Board with the information it needed to make decisions regarding three topics:

1) What percentage of the total amount of money the utilities need to operate should be paid by each class of customer (residential, small business, government and industry);

2) How the rates within each class should be designed; and

3) Whether there should be any changes in the terms under which the utilities provide service to customers.

The Yukon Utilities Board made its ruling in January 2011. In summary, the board said the following:

1) The Board recognized that as a result of Yukon government Orders-in-Council, no changes can be made before 2013 to the overall revenues charged to each rate class. The Board also observed that the revenues from the residential rate class are considerably below the costs to serve this class—residential customers pay less than 80 percent of the true cost of their power, while business and industry pay more than 100 percent and government general service customers pay over 140 percent of what it costs to provide them with power. In its Order, the Board said that once the government's Orders-in-Council expire at the end of 2012, "the Board expects that both utilities will jointly come before this Board with a new Phase II Application to correct the current imbalances."

2) In terms of how the rates within each class should be designed, both Yukon Energy and Yukon Electrical Company Limited had argued that there should be price signals set to encourage people to conserve electricity. The utilities suggested that a new rate block be established and that the more power used, the higher the rate charged for that power. Yukon Energy had also proposed that there be a substantial increase in the cost of any power consumed by residential customers above 2,500 kilowatt hours per month, and there be a decrease in power bills for those residential customers who keep their usage under 1,000 kilowatt hours per month. (The average monthly residential usage is about 800 kilowatt hours per month.)

The Utilities Board did create three blocks instead of the current two for residential and small business customers, each block being at a higher rate.

The Board rejected Yukon Energy's idea for a decrease for non-government residential customers in the First Block (up to 1,000 kilowatt hours per month), making the observation that a reduction in these first-energy block rates is not warranted because the revenues paid by these residential customers are below the cost of their power and that this issue should be corrected when Order-in-Council 2008/149 expires (see Point 1). The Second Block, between 1,001 and 2,500 kilowatt hours per month, would see a slight reduction of up to 0.2 percent, and the Third Block, also known as the runoff rate, (anything over 2,500 kilowatt hours per month) would see an increase of between 0.2 percent (at 2,600 kilowatt hours per month) and 4.4 percent (at 5,000 kilowatt hours per month).

The Utilities Board approved the utilities' proposal for four blocks for non-government small business and municipal

government rates, with the Fourth Block being an initial step toward the transition to a new large business rate class that the Board directed the utilities to put forth in their next General Rate Applications. The First Block (up to 2,000 kilowatt hours per month, would see reductions of between 0.8 and 2 percent. The Second Block (from 2,001 to 15,000 kilowatt hours per month) would see reductions of between 0.1 to 1.5 percent. The Third Block (15,001 to 20,000 kilowatt hours per month) would see increases of up to 4.8 percent. And the Fourth Block (over 20,000 kilowatt hours per month) would see increases of between 0.7 and 3.8 percent.

For the government residential and general service rate class, the Board agreed to the same rate blocks as for non-government customers with inclining block rates for the first three rate blocks. Compared to the equivalent non-government rate classes, the Board suggested higher runoff rates for the government rate classes and also adjusted the utilities' proposals to ensure that rates increase as monthly use increases.

Rate Schedule 39

Rate Schedule 39 is the rate charged to our industrial customers. (Current customers include the mines at Minto and Keno.) This rate was set by the Yukon government for the period from 2007 to 2012 in an Order-in-Council (2007/94) and was later approved by the Yukon Utilities Board. The rate provides for increases for inflation each year starting in 2010. For that initial year (2010) there was no increase, as inflation was negative. However in 2011, Yukon Energy requested an increase of 2.8 percent to reflect the rise in inflation. The YUB approved the request in April 2011.

Video is playing an increasing role in public engagement. How to safely use the boat lock at the Lewes dam is one of many Yukon Energy videos now online.



Health and Safety

Safety Record

Yukon Energy's excellent safety record continued in 2011. Yukon Energy employees have worked nearly five years without a lost time incident. This safety record is a testament to our employees' high standard of safe work practices.

The final phase of the implementation of the Certificate of Recognition (COR) requirement for contractors will take effect July 1, 2012. After that date, any contractor bidding on construction work for us will need to provide proof of COR as a tendering or bidding requirement.

Also in 2012, Yukon Energy will be required to undergo an independent external maintenance audit. This audit is a requirement of the COR program. The COR is issued to employers who develop and implement health and safety programs that meet established standards set out by the Northern Safety Network and the Yukon Workers' Compensation Health and Safety Board.

Construction projects were the main focus of our safety field work in 2011. There were no serious injuries on the Mayo B project, Yukon Energy's largest capital project this year.

Wellness Program

Yukon Energy recognizes the benefits of a healthy workforce and we promote a healthy and active lifestyle for our employees. In 2011, more than 52 percent of the employees used the company's wellness subsidy program. That's a 20 percent increase from 2010.

Safety Video

Every year in Canada there are more than 1,000 contacts with energized high voltage power lines (with vehicles, heavy equipment, trees, etc.). Incidents of break-ins at electrical substations are also fairly common. In both cases, first responders such as the RCMP, fire department, or ambulance attendants are called. If these first responders are not aware of the dangers of energized power lines, they could be seriously injured or killed.

This is why Yukon Energy, along with a number of other electrical utilities, partnered with the Canadian Electricity Association in 2011 to produce a safety DVD called *Electricity: the Invisible Killer*. Yukon Energy distributed the DVD to first responders throughout the territory.

Public Safety Campaigns

Yukon Energy's Whitehorse Rapids hydro dam is located within city limits and in the heart of a popular recreational area used by runners, hikers, kayakers and dog walkers. Because of this, public safety is a priority for us. As in previous years, we ran an annual media campaign in 2011 that warned people of the dangers of being near a hydro dam. In addition, we continued to distribute a safety booklet aimed at elementary school children. The booklet focuses on the importance of taking care when playing or recreating near or on water that is close to our hydro facilities.

The boat lock at Yukon Energy's Lewes dam is frequently used by travellers on the Yukon River. In 2011 we produced a short video on how to safely and correctly use the lock. The video is accessible through our website and our newly established YouTube channel. We also gave an evening workshop so members of the public could receive personal instruction on using the boat lock.



Balancing Yukon's energy needs with a commitment to environmental stewardship.

Photo: archbould.com | Shannon Mallory taking water samples.

Protecting Our Environment

Yukon Energy is proud of our commitment to environmental stewardship and biodiversity. We are a member of the Canadian Electricity Association (CEA) and as such we actively participate in the CEA's Sustainable Electricity Program.

Yukon Energy recognizes that in providing services and products to Yukoners, there will always be environmental impacts. Our goal is to balance the need for safe, reliable, and affordable energy with that of meeting Yukoners' energy requirements without significant adverse effects to the environment or the people and animals that depend on that environment.

Fish and Fish Habitat Protection

In cooperation with our partner the Yukon Fish and Game Association, we maintain one of the world's

longest fishladders. It not only provides passage for migrating Chinook salmon beyond the Whitehorse dam, but offers opportunities for scientific and cultural information gathering and sharing. Last year, 1,534 salmon passed through the ladder, compared to 672 in 2010.

Yukon Energy, in partnership with the Yukon government, operates an important fish hatchery on the Yukon River in Whitehorse. For the third year in a row, the hatchery was able to support a Ta'an Kwäch'än First Nation initiative to re-introduce Chinook salmon to Fox Creek by providing salmon eggs for the program.

In 2012, Yukon Energy will evaluate the potential to participate in salmon habitat enhancement activities with the Carcross/Tagish First Nation.

Yukon Energy, in cooperation with the First Nation of Na-Cho Nyak Dun, has two fish and fish habitat enhancement studies underway that will continue in 2012 on the Mayo River.

As part of the Mayo B project, a salmon rearing channel will be constructed on the Mayo River in 2012. The nearly 1,000 metre long channel will provide high quality rearing habitat for juvenile Chinook salmon as well as resident fish species throughout the year.

Climate Change

During the summer of 2011, Yukon Energy hired scientists from the Northern Climate Exchange at Yukon College to gather information on the expected impacts of climate change on the glaciers that feed our hydro systems. We also asked them to make recommendations about what we should do to better prepare for any changes in flow from glaciers.

The scientists gathered information through satellite and aerial photographs and verified it through work on the ground. They then compared it with historical data. They will submit their report to us in 2012.

Some of our staff also received training this year that will help them better understand climate change science, and provide them with tools that can be used when doing current and future resource planning.

In 2012, we will begin a three-year study that looks in more detail at the effects of climate change on the Southern Lakes area. Partners for this project include Yukon College's Northern Climate Exchange, the University of Alberta and the Yukon Geological Survey.

GHG Emission Reductions

Yukon Energy is committed to managing greenhouse gas (GHG) emissions to mitigate the impact of our operations on climate change, while adapting to its effects.

Some of our 2011 initiatives aimed at minimizing greenhouse gas emissions included:

- Completion of Stage 2 of the Carmacks-Stewart transmission line project;
- Completion of the Aishihik third turbine project;
- Completion of a pilot energy efficiency program with light-emitting diode (LED) streetlights in Dawson City; and
- Continuing to research renewable alternative energy supplies with low carbon footprints to offset diesel generation (e.g., geothermal, wind, hydro-enhancements).

Engaging Yukoners

As part of our priority to engage Yukoners, we are changing the way we involve First Nations and other local governments, stakeholders and the Yukon public in our project-specific and longer term resource planning.

Previously, public involvement began once a decision was made to move forward on a specific project or a resource plan was finalized and ready for filing with the Yukon Utilities Board.

It is now corporate practice to engage Yukoners at the concept stage of a project so that we can all work together to identify issues, research priorities and opportunities for project collaboration.

Energy Charrette

One of the first concrete examples of this approach was a three-day charrette we hosted in March 2011. Close to 100 Yukoners, along with national and international energy experts, came together to talk about how to meet the territory's future energy needs. The purpose of the charrette was to educate the participants, help inform Yukon Energy's updated 20-Year Resource Plan, develop guiding principles for energy decision making and to find out how Yukoners want to be involved in planning Yukon's energy future. We also held discussions in three rural Yukon communities, and input from those meetings was included as part of the charrette process.

That event was followed up by a series of one-day workshops that focused on individual energy options identified at the March charrette as having the most potential for the territory. There were two such workshops in 2011: one on waste-to-energy and the other on biomass, with more planned for 2012.

20-Year Resource Plan Update

As was mentioned in the previous section, Yukon Energy is in the midst of revising our 20-Year Resource Plan, last updated in 2006. We are using the early engagement approach in developing this document. The energy charrette and subsequent workshops have provided a great deal of fodder in helping us with this plan. A draft is expected to be ready for public review and input in the first half of 2012. Once it is finalized it will be filed with the Yukon Utilities Board for review.

Public Opinion Surveys

As part of Yukon Energy's ongoing public education work, we completed another set of public and stakeholder opinion surveys in 2011. (The first survey was done in June 2010.) The initial surveys were designed to find out what Yukoners knew and believed about the Corporation. The findings helped us design a public awareness campaign to give people a better understanding about Yukon Energy, what we are trying to achieve, and why.

Following the campaign, a second round of phone and internet surveys was done to gauge whether the public's knowledge about Yukon Energy had changed. The results indicated an increased awareness about energy issues, specifically about Yukon Energy's operations. However, there was a slight decline in the level of confidence that Yukon Energy could effectively plan and develop



Photo: archbould.com

clean energy sources for future needs. In response, we developed a public information campaign to provide concrete information about the work we are doing to find new clean energy sources. That campaign will continue into 2012, and when it concludes more public surveys will be done to measure the impact.

Project-specific Public Information

To help keep the public up to date on specific projects and concepts that Yukon Energy is undertaking, the Corporation held several public meetings and/or open houses in 2011 in the communities of Marsh Lake, Tagish, Mayo and Whitehorse. This is in addition to a Yukon-wide community tour we undertook with the Yukon Electrical Company Limited and the Ottawa-based organization One Change to talk about developing energy conservation programming for the territory.

Yukoners were provided with regular updates on all our major projects via several newsletters that were distributed to households and posted on our website, as well as a series of videos we produced and posted on YouTube, our website, and our social media sites. Frequent project updates were also provided on our blog, Twitter, and Facebook.

At spring meetings held in the Southern Lakes communities, Yukon Energy took the opportunity to update the public on what we expected peak summer water levels would be. The information is useful to residents because it assists them in preparing their properties for possible flooding in high water years. *Note that 2011 was not a high water year.*

> Public awareness, consultation, and engaging stakeholders in planning is key to our electricity future.

In addition to the public meetings, Yukon Energy provided regular summer water level updates to Tagish and Marsh Lake residents via email, posters, and our website and blog.



Photo: archbould.com | Energy Charrette

Here is what some of the charrette participants said about the process:

"In my opinion, the Yukon Energy Charrette has been a huge success and is a fantastic starting point in terms of facing our present and future energy challenges."
– **Katie Peters**, Grade 11 student

"Yukon Energy is the new benchmark in effective public consultation. Energy is the number one issue facing Yukon and Yukon Energy engaged the public in a meaningful way to communicate the challenges and options. They demonstrated that they were listening and have earned lots of trust by acting on that input and continuing to maintain that relationship."
– **Sandy Babcock**, Yukon Chamber of Commerce president

"The Yukon Energy Charrette was a good learning opportunity for many Yukoners. Participants have gone out into the community with their new-found knowledge and shared information about complex (energy) issues. I feel there is a greater understanding and appreciation for the process that Yukon Energy has to undertake when juggling the competing priorities and the struggle to come to the best decisions."
– **Sally Wright**, Kluane Lake, Yukon



Photo: Justin Kennedy | Taking the energy conservation message to Old Crow

Building Partnerships with First Nations

Yukon Energy believes in building enduring business partnerships with local First Nations for energy projects. We devoted considerable time in 2011 to develop a comprehensive plan to engage Yukon First Nations on renewable energy projects within their traditional territories.

First Nations Energy Forum

Partnering with the Yukon Indian Development Corporation and the Council of Yukon First Nations, we held a two-day First Nations energy forum, which brought together representatives from First Nation governments and development corporations, along with other interested parties, to explore business opportunities in clean energy.

There was great discussion and a general agreement that this forum was a good first step. There was a request for continued dialogue and sharing of information on the topic of energy in the territory, and an overall sense that First Nation governments and development corporations are interested in exploring potential energy-related projects that would be a good investment for them.

Protocol Agreements

In 2010, we began a process aimed at reaching protocol agreements with a number of local First Nation governments and their development corporations. The purpose of the agreements is to provide a framework for us to work on energy development in a collaborative and respectful manner. In 2011, we signed agreements with several First Nations, including members of the Kaska Dena Nation and the Champagne and Aishihik First Nations.

Yukon Energy will continue to pursue this in 2012.

Supporting Our Communities

While Yukon Energy's primary job is to ensure a secure and sustainable energy future, we also feel a responsibility to help Yukon communities be as strong and healthy as possible.

That's why each year we give some of our profits to local organizations. In 2011, we donated approximately $75,000 to more than 30 community groups. The list covered everything from sports and recreation, the arts, education, and health and social services. Here are just a few examples of the types of organizations that we help.

Whitehorse Food Bank

Yukon Energy is a fervent supporter of the Whitehorse Food Bank, a facility that assists hundreds of needy Yukoners. 2011 was the fourth year in a row that Yukon Energy contributed financially to the organization.

Mae Bachur Animal Shelter

Yukon Energy has supported the Mae Bachur Animal Shelter for several years. However, in 2011 we tried something a little different. We invited members of the public to "like" our Facebook page. For every new "like" we promised to donate a dollar to the shelter. Our list of Facebook friends grew from fewer than 100 to more than 1,500, and in the process we were able to provide some much needed assistance to the animal shelter.

Skills Competition

Trades and technologies are crucial to our business. That's why we are happy to support Skills Canada Yukon's skills competitions. The territorial competitions are held every two years. This year's event took place in April in Whitehorse.

Available Light Film Festival

This winter film festival is a popular event; thousands of people turn out each year to view quality movies from all over the world. For the past three years Yukon Energy has been the co-presenter of the festival along with the Yukon Film Society.

Yukon Energy Klondike Heat Battle

Once again in 2011, Yukon Energy was the presenting sponsor for this annual event organized and hosted by Breakdancing Yukon. This dance competition drew some of the best b-boys and b-girls from Yukon and across Canada. The weekend included demonstrations, competitions (battles), and dance challenges. It was pure fun and entertainment for both the participants and audience members.

Scholarships

Again this year, Yukon Energy offered several scholarships for pre-apprenticeship as well as post-secondary programs. In total, scholarships were given to 11 deserving post-secondary students in 2011.

Photo: archbould.com | Mae Bachur Animal Shelter



School/Public Tours

Yukon Energy believes in the importance of educating tomorrow's generation about electrical production, energy conservation and electrical safety. To this end we offered numerous school tours in 2011 of our Whitehorse hydro plant, wind energy production site, and fishladder.

Yukon Sustainable Community Award

Five years ago, Yukon Energy entered into a partnership with the Association of Yukon Communities to recognize leadership in sustainable community development. Each year we present an award to an individual or group for a project that demonstrates environmental sustainability. In 2011, the award went to the City of Whitehorse, for broadening its purchasing practices to incorporate sustainability considerations.

Swan Cam/Fish Cam

One of the first signs of spring in Yukon is the return of the swans and other waterfowl, as they head to their nesting grounds further north. The birds gather by the hundreds at M'Clintock Bay on Marsh Lake in the southern Yukon. The bay is the first open water in the region and offers the birds easy access to food.

Each spring Yukon Energy sets up a webcam so that people can view the waterfowl in real time via their computers. The public response has been very favourable, with people from all over the world going online to see the swans.

Later in the season the web cam is moved to our Whitehorse Rapids Fishladder so that people can view the migrating Chinook salmon as well as the various species of freshwater fish that travel up and down the ladder.



Photo: Justin Kennedy | Whitehorse Rapids Fishladder

Research has shown that Yukoners are passionate about engaging in conversation about energy conservation.

Board of Directors and Corporate Governance

The Board of Directors at Yukon Energy oversees the conduct of business and supervises the President and Chief Executive Officer, who is in turn responsible for the day-to-day operations at Yukon Energy along with the Senior Management team.

The Board models its approach to corporate governance on best practices in Canada and abroad, as reflected in the advice and recommendations of bodies such as the Conference Board of Canada.

Board of Directors' Appointments

Section 3(1) of the *Yukon Development Corporation Act Regulations* (OIC 1993/108) sets out the process for being appointed to the Yukon Energy board. The Board of the Yukon Development Corporation (YDC) is appointed by the Yukon government, and in turn, the YDC board appoints the board of Yukon Energy.

One new person joined Yukon Energy's Board in 2011. We welcome Jason Bilsky, who joined the board in January. Our other board members include Chair Piers McDonald, Paul Birckel, Justin Ferbey, Judy Gingell, Pat Irvin, Luke Johnson and Diane Lister.

Remuneration

Remuneration for Yukon Energy board members has been benchmarked against two Conference Board of Canada reports entitled *Compensation of Boards of Directors 2003* and *Compensation of Board of Directors 2005*. Yukon Energy's board remuneration has also been benchmarked against the Conference Board's report *Board Practices in Crown Corporations 2008*.

The Board Chair is paid $400 per half day meeting (four hours or less) and $800 for a full day meeting (more than four hours). In addition, he is paid for a full day ($800) to prepare for each board meeting.

Board members receive $200 per half day meeting, and $400 per full day meeting, plus they receive a full day's remuneration ($400) for meeting prep time.

There are three committees that fall under Yukon Energy's board: the Audit, Governance, and the Human Resources committees. Committee Chairs are paid $300 per half day meeting and $600 per full day meeting, with one day ($600) of prep time per committee meeting.

Committee Members receive $200 per half day meeting and $400 per full day meeting. They do not receive remuneration for prep time.

Code of Conduct

Yukon Energy has a Code of Conduct to which all Board members are expected to adhere. A copy of the policy can be found on our web site at **yukonenergy.ca/about/profile/board/**.

ATIPP Legislation

Yukon Energy is now subject to the Yukon government's *Access to Information and Protection of Privacy Act.* The legislation is intended to protect the privacy of individuals who provide information to government. It also offers the public a formal method for requesting information if they are denied access to it by an organization and as such is a method used once other informal avenues have been exhausted.

Openness and transparency are important to Yukon Energy, and as a result, we already provide a great deal of information on our website. More information about the Corporation can be found on the Yukon Utilities Board, Yukon Environmental and Socio-economic Assessment Board and the Yukon Water Board websites.



Photo: archbould.com | Energy Charrette

Senior Management

David Morrison
President and C.E.O.

Hector Campbell
Director, Resource Planning & Regulatory Affairs

Linda Greer
Director, Human Resources & Information Management

Lawrence Joudry
Director, Engineering Services & Operations

Ed Mollard
Chief Financial Officer

Shelley Dixon
Corporate Secretary



Photo: archbould.com | First Nations energy forum

Management Discussion and Analysis

The Management Discussion and Analysis (MD&A) reports on the financial results of the corporation for the year ended December 31, 2011. It should be read in conjunction with the audited financial statements and notes that accompany this report.

As a territorial-owned corporation, Yukon Energy's mandate is to provide a continuous supply of electricity to meet the energy needs of consumers in Yukon. Yukon grids are not connected to other jurisdictions and Yukon Energy is the prime generator and transmitter of electrical energy in the territory.

Financial Overview

Net income from all sources in 2011 was $4.9 million (2010 – $4.8 million) which translates to a return on equity of 6.6 percent (2010 – 7.5 percent). Analysis of these results by income statement category follows.

Revenue

Revenue from electricity sales totaled $34 million (2010 – $32.2 million) which was over four percent higher than budgeted volumes. Wholesale sales, representing about 79 percent of sales volumes, were about $24.2 million of the total, a 4.9 percent increase over 2010.

During 2011, Secondary Sales were unavailable due to a lack of surplus hydro generation (with the exception of a few weeks in fall).

In the Industrial customer class, 2011 was the first full year of industrial operations for the Alexco resources operation in Keno, Yukon. This allowed sales in this category to exceed 40 GWh for the year.

Other retail sales were fairly flat in terms of growth for the year with total sales volumes about 34.3 GWh for the year (2010 – 34.0).

Expenses

Despite continued upward pressure on costs, Yukon energy successfully managed operating expenses to within four percent of budget. This result was achieved despite material diesel generation costs in early 2011 brought on by colder than average weather.



Photo: archbould.com | Carmacks-Stewart transmission line

Capital

The 2011 capital program saw the completion of three very significant projects: Mayo B hydro enhancement, Stage 2 of Carmacks to Stewart Crossing Transmission Project and the installation of a third turbine at the Aishihik facility. These projects, at a gross capital cost over $170 million, will improve reliability of supply and provide the utility with greater flexibility to manage our supply resources. Due to significant contributions from the federal and territorial governments, these projects will only affect the regulated rate base by about $40 million.

The utility also continued a number of resource option studies aimed at finding the next generation of supply projects. These projects are crucial to ensuring an adequate inventory of cost effective, sustainable, clean and reliable electrical energy.

Outlook

In 2012, management will continue to pursue new clean energy supply options while ensuring operations are run as cost-effectively as reasonably possible. Despite this, the utility expects to file a general rate application seeking rate increases in 2012 and 2013 to help defray cost increases. This will be the first increase to base rates from Yukon Energy since 1999.

International Financial Reporting Standards

In early 2008, the Accounting Standards Board (AcSB) announced that publicly accountable entities will be required to prepare financial statements in accordance with International Financial Reporting Standards (IFRS) for annual periods in fiscal years beginning on or after January 1, 2011. Since that time, the AcSB has granted two extensions to this deadline, most recently in May 2012. This deferral is offered to qualifying rate-regulated entities as a result by the International Accounting Standards Board to consider adding rate regulation to its agenda in 2012. As this could have a material impact on Yukon Energy's accounting structure, the utility has chosen to accept this deferral.

Financial Statements

December 31, 2011

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Management's Responsibility for Financial Reporting

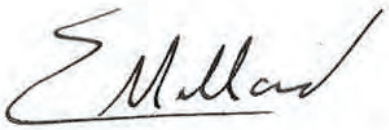
Management is responsible for the preparation of the financial statements and all other financial information relating to the Corporation contained in this annual report. The financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate 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

May 9, 2012

Auditor General of Canada
Vérificateur général du Canada

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of Yukon Energy Corporation

Report on the Financial Statements

I have audited the accompanying financial statements of Yukon Energy Corporation, which comprise the balance sheet as at 31 December 2011, and the statement of operations, comprehensive income and retained earnings and statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of Yukon Energy Corporation as at 31 December 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Auditor General of Canada
Vérificateur général du Canada

Report on Other Legal and Regulatory Requirements

In my opinion, the transactions of Yukon Energy 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 by-laws of the Yukon Energy Corporation.

Terrance DeJong, CA
Assistant Auditor General
for the Auditor General of Canada

9 May 2012
Edmonton, Canada

Yukon Energy Corporation
Balance Sheet
(in thousands of dollars)

As at December 31,	2011	2010
Assets		
Current		
Cash (note 4)	$ 7,235	$ 25,847
Accounts receivable (Note 5)	25,577	29,242
Materials and supplies	2,830	2,648
Prepaid expenses	614	368
	36,256	58,105
Customer contribution financing (Note 6)	**-**	17,424
Deferred uninsured losses (Note 7)	**576**	432
Diesel contingency fund (Note 8)	**902**	891
Property, plant and equipment (Note 9)	**374,591**	287,350
Deferred charges and intangible assets (Note 10)	**24,240**	18,963
	$ 436,565	$ 383,165
Liabilities		
Current		
Bank indebtedness (Note 11)	$ 5,540	-
Accounts payable and accrued liabilities (Note 12)	28,031	16,859
Construction financing (Note 13)	13,905	47,500
Current portion of long-term debt (Note 16)	4,974	3,864
	52,450	68,223
Faro mine dewatering deferral revenue (Note 14)	**397**	397
Long-term pension liability (Note 22)	**1,137**	1,035
Contributions in aid of construction (Note 15)	**173,566**	140,686
Regulatory provision for future removal and site restoration costs	**4,711**	4,764
Diesel contingency fund (Note 8)	**902**	891
Long-term debt (Note 16)	**120,190**	101,449
	353,353	317,445
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
Contributed surplus (Note 17)	**14,600**	-
Retained earnings	**29,612**	26,720
	83,212	65,720
	$ 436,565	$ 383,165

Commitments and Contingencies (Notes 23 and 24)
The accompanying notes are an integral part of the financial statements.
Approved by the Board

_____, Chair _____, Director

Yukon Energy Corporation

Statement of Operations, Comprehensive Income and Retained Earnings
(in thousands of dollars)

For the year ended December 31,	2011	2010
Revenue		
Sales of power (Note 18)	$ 34,047	$ 32,178
Other	496	476
	34,543	32,654
Operating expenses		
Operations and maintenance (Note 19)	10,288	7,899
Administration (Note 20)	8,872	7,938
Amortization of property, plant and equipment	6,013	5,657
Amortization of deferred charges	905	860
Amortization of intangible assets	528	548
	26,606	22,902
Income from operations	**7,937**	9,752
Other income		
Allowance for funds used during construction	555	514
Amortization of capital assistance	546	378
Interest income	309	1,238
	1,410	2,130
Other expenses		
Interest on borrowings	4,302	7,005
Provision for uninsured losses (Note 7)	100	100
	4,402	7,105
Net income	**4,945**	4,777
Other comprehensive income	**-**	-
Comprehensive income	**4,945**	4,777
Retained earnings, beginning of year	**26,720**	21,943
Dividend	**(2,053)**	-
Retained earnings, end of year	**$ 29,612**	$ 26,720

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,	2011	2010
Operating activities		
Cash receipts from customers	$ 34,511	$ 32,679
Cash paid to employees and suppliers	(17,208)	(5,923)
Interest paid	(3,558)	(7,005)
Interest received	309	1,616
Cash provided by operating activities	**14,054**	21,367
Financing activities		
Receipt of construction financing	20,000	47,500
Repayment of short-term financing	-	(25,000)
Repayment of long-term debt	(21,197)	(4,139)
Contributions in aid of construction	38,358	61,813
Cash provided by financing activities	**37,161**	80,174
Investing activities		
Additions to property, plant and equipment	(86,334)	(79,505)
Additions to deferred charges and intangible assets	(6,457)	(6,920)
Repayment of long-term receivable	17,424	-
Cash used in investment activities	**(75,367)**	(86,425)
Net increase (decrease) in cash	**(24,152)**	15,116
Cash, beginning of year	**25,847**	10,731
Cash end of year	**$ 1,695**	$ 25,847
Cash includes:		
Cash (Note 4)	7,235	25,847
Bank indebtedness	(5,540)	-
Total	1,695	25,847

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, 2011

1. NATURE OF OPERATIONS

Yukon Energy Corporation (the "Utility") is incorporated under the Yukon *Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation (YDC), a corporation owned by the Government of Yukon (YG). 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
The 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. As 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 principles 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 reviewed and 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 borrowing costs related to borrowing that portion of the rate base which is financed with debt plus the costs to provide a reasonable rate of return on that portion of the rate base which is financed with equity).

The YUB assesses the prudency of costs added to rate base, which includes an allowance for funds used during construction (AFUDC) charged to capital projects. The YUB also reviews the appropriateness of asset depreciation rates, which are periodically updated by the Utility through depreciation studies.

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 Utility's overall 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 (Note 28).

Yukon Energy Corporation

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

December 31, 2011

1. NATURE OF OPERATIONS - continued

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 capital structure of 60% debt and 40% equity at year end. Annual dividends are declared to the parent and typically loaned back in order to maintain this ratio during normal on-going operations. When large assets are purchased or constructed, the parent may be required to make an equity contribution.

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 differ from the accounting policies prescribed by using GAAP. In particular, the timing of the Utility's recognition of certain assets, liabilities, revenues and expenses as a result of regulation differ from that of a non-regulated enterprise. The impact on the financial statements of accounting for rate regulated operations are further described in Note 3. The significant accounting policies have been classified accordingly in the notes below:

Rate regulated accounting policies

Allowance for funds used during construction
The cost of the Utility's property, plant and equipment and deferred charges includes an allowance for funds used during construction (AFUDC) as allowed by the regulator. In prior years, the AFUDC rate estimate was based on the Utility's weighted average cost of capital (which included a cost of debt component and a return on equity component). In 2011 management revised its AFUDC rate estimate to remove the return on equity component and calculated the estimate based on the Utility's weighted average cost of debt. This change in estimate was applied prospectively effective January 1, 2011. The AFUDC rate estimate was 4.483% for 2011 (2010 - 7.09%).

Property, plant and equipment
The gain or loss on the disposal or retirement of property, plant and equipment, with the exception of land and vehicles, is deferred and amortized over the remaining expected useful lives of the assets.

Faro mine dewatering deferral revenue
Faro mine dewatering deferral revenue represents amounts ordered by the YUB to be held by the Utility on behalf of ratepayers. The YUB has sole discretion to direct disposition of these funds, typically through refunds to customers or applied to ratepayer deficits.

Deferred uninsured losses
The Utility maintains a regulatory account for recording 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.

Yukon Energy Corporation

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

December 31, 2011

2. SIGNIFICANT ACCOUNTING POLICIES - continued

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 charges
Deferred charges are recorded at cost and include an AFUDC component as allowed by the regulator.

All deferred charges are amortized to earnings on a straight-line basis over terms approved by the YUB.

Cost of feasibility studies and infrastructure planning which did not result in a capital project are amortized over terms ranging between five and ten years.

IFRS costs are associated with the accounting conversion from Canadian Generally Accepted Accounting Principles to International Financial Reporting Standards.

Deferred customer service costs are amortized over twelve years.

The deferred hearing cost account is used to record the deferral of costs associated with preparation and defense of applications to the YUB. The periods of amortization range from 10 to 45 years.

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

Diesel contingency fund
The Utility maintains an asset and an offsetting liability on behalf of ratepayers. The fund is used to reimburse 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
Materials and supplies
Diesel fuel, materials and supplies are recorded at the lesser of average cost and net realizable value. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined. Major spare parts are recorded in the Utility's books as property, plant and equipment.

2. **SIGNIFICANT ACCOUNTING POLICIES - continued**

Property, plant and equipment

Property, plant and equipment is stated at cost and includes an AFUDC component which is recorded under rate regulated accounting. Cost includes materials, direct labour, applicable actual directly attributable administration overhead, and, if applicable, direct finance charges capitalized during construction, less accumulated amortization. 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 50 years
Distribution	30 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 or Government. These contributions are deferred upon receipt and 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 operations against amortization expense while amortization of capital assistance from the parent or Government is disclosed separately under Other income.

Deferred licensing costs

Costs related to obtaining license renewals for hydro and diesel generation facilities 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 separate licenses, with terms ranging from 17 to 25 years. Diesel generation air emission permits have a term of three years. These costs are treated as intangible assets and are measured at initial cost and amortized over the life of the license.

Environmental liabilities

Environmental liabilities consist of the estimated costs related to the remediation of environmentally contaminated sites. The Utility will accrue a liability and record an expense, related to present or past activities of the Utility, when there is a legal obligation to remediate the contamination and the costs can be reasonably estimated. If the likelihood of the Utility's obligation to incur these costs is either not determinable or the costs cannot be reasonably estimated, the contingency is disclosed in the notes to the financial statements. The Utility reviews its estimates of future environmental liabilities on an ongoing basis as described in Note 24.

2. SIGNIFICANT ACCOUNTING POLICIES - continued

Employee pension plan

The Utility sponsors an employee defined benefit pension plan which provides benefits based on the length of service and average salaries for the five highest-paid consecutive years of service. Employees joining the Utility after January 1, 2002 are not eligible to participate in the defined pension plan. Effective January 1, 2011, the Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan. The Utility contributes amounts to the pension plans as recommended by an independent actuary.

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. Pension costs include the adjustments resulting from the plan enhancements, actuarial gains and losses, and changes in assumptions which are amortized over the expected average remaining service period of active employees. The excess of the net unrecognized actuarial gains and losses over 10% of the greater of the accrued benefit obligation and the fair value of the plan assets is amortized on a straight-line basis over the expected average remaining service period of active employees, which is currently 9 years for the employee plan (2010 - 9 years) and 5 years for the executive plan. The transitional asset (liability) arising when these policies are first applied is amortized over the average remaining service period of active employees when the amendment is recognized, which is 18 years for the employee plan and 5 years for the executive plan. The expected return on plan assets is based on the fair value of these assets.

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.

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, employee pension obligations and regulated assets and liabilities. Actual results could differ by a significant amount from these estimates.

Management's estimates and assumptions, especially those affecting the reported amounts of regulated 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.

ACCOUNTING CHANGES

Future Accounting Changes

Publically accountable enterprises are required to move from Canadian Generally Accepted Accounting Principles to International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board (IASB) and adopted by the Canadian Institute of Chartered Accountants, for years beginning on or after January 1, 2011. IFRS uses a conceptual framework similar to Canadian GAAP, but there are significant differences in recognition, measurement and disclosures.

On October 1, 2010, the Canadian Accounting Standards Board (AcSB) issued guidance to allow, but not require, entities with rate regulated activities to defer the transition. The Utility had elected to take this deferral option. In March 2012, the AcSB announced a further one year deferral for qualifying rate regulated entities to January 1, 2013. This further extension is offered in recognition that the IASB may choose to include rate-regulated activities on its future agenda. The Utility has chosen to adopt this deferral and continues to monitor the situation.

Yukon Energy Corporation

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

December 31, 2011

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 on the statement of operations as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in income in the period that the YUB renders a subsequent decision.

Regulatory assets represent future costs associated with certain revenues, 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.

In the absence of rate regulation the Utility's net income would have decreased by $4,923,000 in 2011 (2010 - decreased by $6,893,000). The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event:

	2011	2010	Expected remaining recovery/ settlement (years)	For 2011: In the absence of Rate Regulation the Utility's Net Income would have increased (decreased) by:
Regulatory assets:				
Deferred charges (Note 10), net book value				
Feasibility studies and infrastructure planning	$ 14,884	$ 11,463	5 to 10	$ (3,421)
Deferred customer service costs	571	635	10	64
Hearing costs	2,376	1,635	10 to 45	(741)
Dam safety review	95	119	5	24
IFRS planning	566	434	Indeterminate	(132)
Deferred uninsured losses (Note 7)	576	432	Indeterminate	(144)
Diesel contingency fund (Note 8)	902	891	Indeterminate	(11)
	19,970	15,609		(4,361)
Regulatory liabilities:				
Faro mine dewatering deferral revenue (Note 14)	397	397	Indeterminate	-
Deferred insurance proceeds (Note 15)	6,546	6,816	25	(270)
Regulatory provision for future removal and site restoration costs	4,711	4,764	Indeterminate	(53)
Diesel contingency fund (Note 8)	902	891	Indeterminate	11
	12,556	12,868		$ (312)
Net impact of assets and liabilities	$ 7,414	$ 2,741		$ (4,673)
Impact of other items through Income statement				
Fuel Price Adjustment				(250)
Total effect				$ (4,923)

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION - continued

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 and infrastructure planning
The Utility undertakes certain projects whose objective is to determine the feasibility of a range of solutions. While in progress, the costs of these feasibility projects are included in these accounts. As well, if the feasibility project determines there is not a viable solution, these projects are closed out and amortized to income over a prescribed number of years. These values are also included in the feasibility accounts. The cost of feasibility projects that result in a capital project are transferred to the cost of the resultant project. In the absence of rate regulation, expenses in 2011 would have been $3,421,000 higher (2010 - $5,263,000 higher expenses).

Deferred customer service costs
The costs associated with negotiating terms of service with a new industrial customer. In the absence of rate regulation, expenses in 2011 would have been $64,000 lower (2010 - $65,000 lower expenses).

Hearing costs
These costs are associated with the YUB regulatory proceedings. The costs consist primarily of various rate and project review proceedings. The Utility is directed to defer and amortize the costs over terms at the discretion of the YUB. In the absence of rate regulation, expenses in 2011 would have been $741,000 higher (2010 - $561,000 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 and YUB Order 2009-8. In the absence of rate regulation, expenses in 2011 would have been $24,000 lower (2010 - $119,000 higher expenses).

IFRS planning
These costs are associated with the accounting conversion from Canadian Generally Accepted Accounting Principles to International Financial Reporting Standards. In the absence of rate regulation, expenses in 2011 would have been $132,000 higher (2010 - $179,000 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 an asset and a liability. The DCF attracts interest based upon short-term bond rates. Any negative balance attracts interest at the lowest short-term borrowing rate available to the Utility through its line of credit.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION - continued

(b) Diesel contingency fund - continued
Pursuant to YUB order 1996-6, the Utility from time to time is required to transfer amounts to or from the fund 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 income and expenses in 2011 would have been higher by $11,000 from interest earned on the DCF (2010 - $4,000 higher income and expenses).

(c) Deferred uninsured losses
The YUB has approved the use of a deferral account for uninsured damages and injuries as a means of self-insurance. The account is maintained through an annual provision approved by the YUB. In order to eliminate the deficit rate payers owed as a result of uninsured losses, the Utility was directed by YUB Order 2009-8 to record an annual provision of $100,000 in 2010 and each subsequent year. In the absence of rate regulation, GAAP would require costs to be expensed as incurred and, therefore, expenses in 2011 would have been higher by $144,000 (2010 - $321,000 higher expenses). The period over which the provision will be recovered is dependent on the magnitude of future actual losses incurred and cannot be estimated.

Regulatory liabilities

(d) 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 revenue account.

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.

(e) Deferred insurance proceeds
The deferred insurance proceeds relates to a fire at the Whitehorse Rapids Generating Station in 1997 which, pursuant to YUB 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 net income in 2011 would have been lower by the amount of the amortization of $270,000 (2010 - $270,000 lower).

(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 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. YUB Order 2005-12 also directs the Utility to notify interveners and interested parties when the balance of the provision reaches $2,000,000.

Yukon Energy Corporation

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

December 31, 2011

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION - continued

(f) Regulatory provision for future removal and site restoration costs - continued
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 2011 expense would have been higher by the amount of actual removal and site restoration costs incurred in the year of $53,000 (2010 expenses - $244,000 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.

(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 2011, fuel expenses were recovered and consequently higher by $250,000 (2010 fuel expense lower by $111,000).

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"). For the year 2010 AFUDC was based on the Utility's weighted average cost of capital. AFUDC is also included in the cost of property, plant and equipment for financial reporting purposes, and is amortized over future periods as part of the total cost of the related asset, based on the expectation that amortization expense, including the AFUDC component, will be approved for inclusion in future customer rates. Because the AFUDC rate for 2010 included a cost of equity component, the amount capitalized in that year exceeds what would otherwise be allowed in the absence of rate regulation. In the absence of rate regulation, revenue for 2010 would be $112,000 lower. The impact on revenue for 2011 is nil.

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 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.

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, 2011

4. CASH

The cash balance includes an amount of $7,235,404 (2010 - $2,691,308) that is restricted for the payment of a contractor holdback.

5. ACCOUNTS RECEIVABLE

	2011	2010
Green Infrastructure Funding (Note 15)	$ 19,724	$ 22,757
Wholesale energy sales	2,663	3,015
Retail energy sales	1,528	1,774
Other	1,662	1,696
	$ 25,577	$ 29,242

6. CUSTOMER CONTRIBUTION FINANCING

Under the terms of a Power Purchase Agreement with an industrial customer, the Utility agreed to finance the cost of transmission assets built to serve the customer. YDC also loaned the Utility cash in an amount equal to this receivable at substantially the same terms which was recorded as long term debt (see Note 16). During 2011, this financing was paid in full by the industrial customer, and on the same day, the loan owing to YDC was paid in full.

7. DEFERRED UNINSURED LOSSES

	2011	2010
Opening balance	$ 432	$ 111
Provision	(100)	(100)
Losses incurred		
Asset replacements	244	421
Closing balance	**$ 576**	$ 432

YUB Order 2009-8 directed the Utility to charge $100,000 to this provision starting in 2010.

8. DIESEL CONTINGENCY FUND

	2011	2010
Opening balance	$ 891	$ 887
Interest	11	4
Closing balance	**$ 902**	$ 891

The annual return on investments for 2011 was 1.21% (2010 - 0.50%). The fair market value of these investments is equal to their carrying amount due to the short term maturity of the investments.

Yukon Energy Corporation

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

December 31, 2011

9. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2011 Net book Value	2010 Net book Value
Generation	$ 276,335	$ 60,374	$ 215,961	$ 91,263
Transmission	134,495	18,524	115,971	68,986
Distribution	28,265	9,599	18,666	19,119
Buildings and other equipment	20,327	8,456	11,871	12,071
Transportation	4,578	1,624	2,954	2,946
Land and land rights	1,112	-	1,112	1,114
Construction-in-progress	8,056	-	8,056	91,851
	$ 473,168	**$ 98,577**	**$ 374,591**	$ 287,350

10. DEFERRED CHARGES AND INTANGIBLE ASSETS

	Cost	Accumulated Amortization	2011 Net book Value	2010 Net book Value
Intangible assets:				
Deferred licensing costs	$ 10,796	$ 5,049	$ 5,747	$ 4,677
Deferred charges:				
Feasibility studies and infrastructure planning	18,046	3,161	14,885	11,463
IFRS planning	566	-	566	434
Hearing costs	4,633	2,257	2,376	1,635
Deferred customer service costs	769	198	571	635
Dam safety review	332	237	95	119
	$ 35,142	**$ 10,902**	**$ 24,240**	$ 18,963

11. BANK INDEBTEDNESS

The Utility has access to a $10 million line of credit. The account accrues interest on withdrawals at prime rate minus 0.25% per annum. At December 31, 2011, the balance of this line of credit was $4,782,352 (2010 - $0).

12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2011	2010
Trade payables	$ 27,367	$ 16,263
Employee compensation	219	428
Other	445	168
	$ 28,031	$ 16,859

Yukon Energy Corporation

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

December 31, 2011

13. CONSTRUCTION FINANCING

	2011	2010
Construction financing	$ 13,905	$ 47,500
	$ 13,905	$ 47,500

Construction financing balances are monies advanced from the parent to assist in the development of Utility infrastructure, primarily the Mayo B Hydro Electric Project and Stage 2 of the Carmacks to Stewart Crossing Transmission Project. Interest on this funding is based on the Bankers Acceptance rate on the date of the cash draws plus 50 basis points. Interest is payable annually at December 31 and at the maturity date.

The Utility received an additional $20,000,000 in construction financing during the year. The Utility also entered into agreements with YDC, effective December 31, 2011, to roll-over $38,995,000 of the construction financing into long-term debt - $17,095,000 term note and $21,900,000 flexible term note (Note 16). In addition, YDC agreed to convert $14,600,000 of the construction financing into equity in order to maintain the Utility's capital structure of 60% debt and 40% equity which has been approved by the YUB. The $14,600,000 equity contribution has been recorded as contributed surplus on the Utility's balance sheet (Note 17).

14. FARO MINE DEWATERING DEFERRAL REVENUE

	2011	2010
Faro mine dewatering deferral revenue account:		
Opening balance	$ 397	$ 397
Closing balance	**$ 397**	$ 397

15. CONTRIBUTIONS IN AID OF CONSTRUCTION

			2011	2010
	Gross	Accumulated Amortization	Net	Net
Contributions from Canada (Note 5)	$ 67,277	$ 148	$ 67,129	$ 32,747
Capital assistance from parent since 1998	68,312	3,022	65,290	65,836
Contributions from customers since 1998	38,893	4,913	33,980	34,623
Pre-1998 contributions	1,739	1,118	621	664
Deferred insurance proceeds	11,602	5,056	6,546	6,816
	$ 187,823	**$ 14,257**	**$ 173,566**	$ 140,686

The Utility has entered into a contribution agreement with the Government of Canada for Green Infrastructure Funding for Stage 2 of the Carmacks to Stewart Crossing Transmission Line and the Mayo B Hydro Enhancement projects. The Utility is entitled to reimbursement of 50% of eligible costs to a maximum of $71 million during the period May 2009 to March 2012.

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, 2011

16. LONG-TERM DEBT

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

	2011	2010
Yukon Development Corporation		
$81,890,873 term note bearing interest at 4.25% repayable in annual installments of $3,000,000 principal, plus accrued interest with the balance of $68,890,873 due December 31, 2015	$ 78,891	$ -
$17,095,000 term note bearing interest at 3.69% repayable in annual installments of $683,800 principal, plus accrued interest, due December 31, 2036	17,095	-
$21,900,000 flexible term note bearing interest at 5.46% repayable in annual installments of $336,923 principal, plus accrued interest with the balance of $8,423,078 due December 31, 2051	21,900	-
$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	-	24,111
$27,313,661 unsecured term note bearing interest at 5.88%, repayable monthly and semi-annual principal payments commencing June 30, 2007 and ending December 31, 2023	-	20,887
$18,000,000 flexible unsecured 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	-	14,707
$18,000,000 term note related to the Transmission Line Construction Financing, bearing interest at 6.50%, repayable in variable monthly installments due December 2017	-	17,424
Unsecured advance bearing interest at 3.97%, due one year after demand	2,053	-
Unsecured advance bearing interest at 5.28%, due one year after demand	-	8,214
Unsecured advance bearing interest at 4.65%, due one year after demand	-	3,901
Unsecured advance bearing interest at 6.03%, due one year after demand	-	3,649
Unsecured advance bearing interest at 5.34%, due one year after demand	-	3,583
Unsecured advance bearing interest at 5.40%, due one year after demand	-	2,839
Carried forward to next page	**$ 119,939**	$ 99,315

Yukon Energy Corporation

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

December 31, 2011

16. LONG-TERM DEBT - continued

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

	2011	2010
Carried forward from previous page	$ 119,939	$ 99,315
TD Bank		
$12,400,000 term note bearing interest at 4.02% (2010 - 7.81%) payable in monthly installments of $94,406 (2010 - $102,000) interest and principal, with the balance due September 30, 2016.The note is guaranteed by the Yukon Government. The terms of the note were renewed October 3, 2011	4,891	5,724
Carmacks Stewart First Nation Liability		
Long-term liability payable to several First Nations related to the building of the Carmacks Stewart Transmission Line. These are non interest bearing, repayable in varying installments, due in 2028	334	274
	125,164	105,313
Less current portion	4,974	3,864
	$ 120,190	$ 101,449

$81,890,873 Term note
On January 1, 2011, the Utility entered into an agreement with YDC to renegotiate terms of all outstanding debt, excluding the term note related to the transmission line construction financing, between the two companies in the amount of $81,890,873.

$17,095,000 Term note
On December 31, 2011, the Utility entered into an agreement with YDC to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon.

$21,900,000 Flexible Term Note
The terms of the flexible term note provide for a maximum amount of interest payable within a calendar year, calculated based on the grid generation and purchased power on the electrical grid system connected with the Mayo Hydro Enhancement Project. The amount of interest payable as a result of the interest rate exceeding the maximum interest payable will abate forever.

Unsecured Advance
The Utility declared a dividend to YDC in the amount of $2,053,000 (2010 - $0) and this was loaned back to the Utility at an interest rate of 3.97% 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:

2012	4,974
2013	5,051
2014	5,091
2015	72,024
2016	1,893
Thereafter	36,131
	$ 125,164

Yukon Energy Corporation

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

December 31, 2011

16. LONG-TERM DEBT - continued

Fair value
Fair value at December 31, 2011 of $135 million (2010 - $124 million) for all long-term debt including current portions was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

17. CONTRIBUTED SURPLUS

Due to the amount of capital additions during the year, the Utility received an equity contribution of $14.6 million from YDC in order to maintain its capital structure at 60% debt and 40% equity. The funding for this contribution was sourced from the existing YDC construction financing (Note 13).

18. SALES OF POWER

	2011	2010
Wholesale	$ 24,170	$ 23,301
Industrial	4,599	3,311
General service	3,342	3,315
Residential	1,800	1,524
Sentinal and street lights	90	83
Secondary sales	46	644
	$ 34,047	$ 32,178

19. OPERATIONS AND MAINTENANCE EXPENSES

	2011	2010
Wages and benefits	$ 4,005	$ 3,923
Maintenance		
- hydro, diesel and wind	1,297	1,031
- building and vehicle	1,205	1,011
- lines and substations	898	587
Fuel	2,727	1,189
Water level measurement	156	158
	$ 10,288	$ 7,899

Yukon Energy Corporation

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

December 31, 2011

20. ADMINISTRATION EXPENSES

	2011	2010
Wages and benefits	$ 4,339	$ 3,811
General office	1,281	994
Insurance and taxes	1,071	1,078
Information systems	583	733
Training, recruitment and development	459	546
Environmental	325	298
Board of Directors	289	87
Intercompany services	251	252
Regulatory loss	248	58
Material management and contracting	26	81
	$ 8,872	$ 7,938

21. RELATED PARTY TRANSACTIONS

The Utility is related in terms of common ownership to all Government of Yukon (YG) departments, agencies and Crown Corporations. Transactions are entered into in the normal course of operations with these entities. All transactions are recorded at the rates set out by the YUB.

Revenue from related parties is included in other revenue on the statement of operations. Interim Electrical Rebate program revenues are received from YDC in accordance with terms established by YG which established the program to protect certain ratepayers by minimizing the impact of rate increases. These revenues are included in the sales of power on the statement of operations.

The following table summarizes the Utility's related party transactions for the year:

	2011	2010
Revenue		
Sales of service to YDC	$ 231	$ 236
Program cost reimbursement from YG	100	109
Rate subsidy received from YDC	262	246
Operating expenses		
Payment of interest on borrowings from YDC	$ 3,961	$ 6,472
Other receipts		
Project contribution from YDC	$ 1,300	$ -
Capital contributions from YDC	-	53,417
Construction financing from YDC	-	47,500
Other payments		
Repayment of principal on borrowings from YDC	$ 20,424	$ 3,057
Repayment of short-term financing to YG	-	25,000

21. RELATED PARTY TRANSACTIONS - continued

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

	2011	2010
YDC		
Accounts receivable	$ 499	$ 233
Accounts payable	$ 836	$ 110
Construction financing	$ 13,905	$ 47,500
Current portion of long-term debt	$ 4,021	$ 3,056
Long-term debt	$ 115,918	$ 96,258
YG		
Accounts receivable	$ 420	$ 152

These balances are non-interest bearing and payable on demand except for construction financing and long-term debt.

The Utility also entered into agreements with YDC, effective December 31, 2011, to roll-over $38,995,000 of construction financing into long-term debt - $17,095,000 term note and $21,900,000 flexible term note (Note 16). In addition, YDC agreed to convert $14,600,000 of the construction financing into equity in order to maintain the Utility's capital structure of 60% debt and 40% equity which has been approved by the YUB. The $14,600,000 equity contribution has been recorded as contributed surplus on the Utility's balance sheet (Note 17).

In addition, the Utility declared a dividend to YDC in the amount of $2,053,000 (2010 - nil) and this was loaned back to the Utility at an interest rate of 3.97% in order to maintain the capital structure. This advance is unsecured and due one year after demand.

22. PENSION COSTS AND OBLIGATIONS

An actuarial valuation for funding purposes of the employee defined benefit plan was performed as of January 1, 2010. The next valuation for funding purposes will be conducted as of January 1, 2012. An actuarial valuation for funding purposes of the executive defined benefit plan and supplemental executive retirement plan was performed as of January 1, 2011. The pension costs and obligations are based on the data used in these funding valuations and have been projected to December 31, 2011 in accordance with generally accepted actuarial standards.

The fair value of the plan assets is based on market values as reported by the plans' custodians as at December 31, 2011. The distribution of assets by major asset class is as follows:

	December 31, 2011	December 31, 2010
Equities	45.9%	53.1%
Fixed income securities	43.5%	37.9%
Real estate	10.6%	9.0%

22. PENSION COSTS AND OBLIGATIONS - continued

Information about the Utility's defined benefit plans as at December 31, in aggregate, is as follows:

		2011		2010
Accrued benefit obligation determined by actuarial valuation	$	13,568	$	11,100
Fair value of plan assets		9,665		8,902
Funded status - plan deficit	$	3,903	$	2,198
Unrecognised amounts:				
- Transitional asset (liability)		(192)		119
- Net accumulated actuarial losses		(2,573)		(1,143)
Accrued benefit liability	$	1,137	$	1,174
Current portion of accrued benefit liability	$	-	$	139
Long-term portion of accrued benefit liability		1,137		1,035
Accrued benefit liability	$	1,137	$	1,174
Pension costs	$	561	$	510
Employer contributions	$	596	$	508
Employee contributions	$	111	$	121
Benefits paid	$	137	$	132
Significant assumptions for employee defined benefit plan:				
Discount rate - accrued benefit obligation		5.25%		5.75%
Discount rate - pension costs		5.75%		6.25%
Expected long-term rate of return on plan assets		6.50%		6.50%
Assumed rate of salary escalation		3.00%		3.00%
Significant assumptions for executive pension plans:				
Discount rate - accrued benefit obligation		4.50%		-
Discount rate - pension costs		5.75%		-
Expected long-term rate of return on plan assets		5.50%		-
Assumed rate of salary escalation		3.50%		-

The accrued benefit liability has been recorded by the Utility and its current portion of $0 (2010 - $139,000) is included in accounts payable and accrued liabilities on the balance sheet.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the employee 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 employee 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 2011, these were $306,000 (2010 - $289,000).

Total cash payments for employee future benefits for 2011, consisting of cash contributed by the Utility to its funded defined benefit pension plans and cash contributed directly to the RRSP were $902,000 (2010 - $681,000).

Yukon Energy Corporation

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

December 31, 2011

23. COMMITMENTS

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) Heritage Mitigation Plan. The Utility did not incur expenditures in 2011 on heritage projects and the amount to be expended in the future has not yet been determined; 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.

Contractual obligations
The Utility has entered into contracts to purchase products or services for which the liability has not been incurred as at December 31 2011 as the product or service had not been provided. The total commitments at year end are $4,356,000 (2010 - $89,963,000).

24. CONTINGENCIES
Carmacks to Stewart Crossing Transmission Project
The Utility completed the construction of the Mayo to Dawson City Transmission Line project during 2011. In April 2011, the line construction contractor notified the Utility of a potential claim under the contract alleging increased costs of $1,800,000 due to scheduling delays and change in scope caused by the Utility. The outcome of the potential claim is not determinable at this time and no amount has been recognized in the financial statements.

25. 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.

The Utility has conducted environmental site assessments at all its diesel plant sites. At sites where environmental contamination was found and a legal obligation to remediate the site existed, the Utility has conducted a full remediation. As at December 31, 2011 no new environmental liabilities, for which a legal obligation exists to remediate, have been identified by the Utility. The Utility will continue to use its Environmental Management System to monitor and assess previous and potential existing environmental liabilities on an ongoing basis.

26. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2011, the Utility's financial instruments included cash, accounts receivable, bank indebtedness, accounts payable and accrued liabilities, construction financing and long term debt. The fair value of cash, accounts receivable, bank indebtedness, accounts payable and accrued liabilities and construction financing approximate their carrying value due to the immediate or short-term maturity of these financial instruments.

The long-term debt is accounted for at amortized cost using the effective interest rate method. The fair value of the long-term debt is estimated by discounting the future cash flows using current rates for debt instruments subject to similar risks and maturities as disclosed in Note 16.

Interest rate risk
Interest rate risk is the risk that future cash flows or fair value of a financial instrument will fluctuate due to changes in market interest rates. The Utility is not exposed to significant interest rate risk due to its long-term debt having fixed interest rates.

Credit risk
Credit risk is the risk of failure of a debtor or counterparty to honour its contractual obligations resulting in financial loss to the Utility. The Utility's credit risk is minimal in that its primary customer is a regulated utility.

Liquidity risk
Liquidity risk is the risk that the Utility will not be able to meet its financial obligations as they fall due. The Utility's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Utility's reputation.

The Utility does not engage in hedging transactions.

27. CAPITAL MANAGEMENT

The Utility's capital is its shareholder's equity which is comprised of share capital, contributed surplus and accumulated funds in the form of retained earnings. The Utility manages its equity by managing revenues, expenses, assets and liabilities to ensure the Utility effectively achieves its objectives while remaining a going concern.

The Utility monitors its capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, which is comprised of long-term debt, including the portion of long-term debt due within one year. Short term debt related to assets under construction at the balance sheet date is excluded from the cost of debt calculation, as the assets are similarly excluded from the determination of rate base. Total capitalization is calculated as total debt plus total shareholder's equity as shown on the balance sheet. The Utility maintains a balance in retained earnings as an indicator of the Utility's equity position.

The Utility has a policy which defines it's capital structure at a ratio of 60% debt and 40% equity. This policy has been reviewed and accepted by the YUB.

Yukon Energy Corporation

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

December 31, 2011

27. CAPITAL MANAGEMENT - continued

The table below summarizes the Utility's total debt to total capitalization position:

(thousands of dollars)		2011		2010
Long-term debt due within one year	$	4,974	$	3,864
Long-term debt		120,190		101,449
Total debt		125,164		105,313
Less debt related to the Transmission Line Construction Financing (Note 16)		-		17,424
Total debt to include in the calculation	$	125,164	$	87,889
Share capital	$	39,000	$	39,000
Contributed surplus (Note 17)		14,600		-
Retained earnings		29,612		26,720
Total equity		83,212		65,720
Total capitalization	$	208,376	$	153,609
Total debt to total capitalization		60 %		57 %

There were no changes in the Utility's approach to capital management during the period.

28. SUBSEQUENT EVENTS

a) Subsequent to the year end, the Utility received a $10 million short term loan from YDC. The monies were used to finance working capital requirements while the Utility was claiming for cost reimbursement under Federal funding programming for the Mayo B and for Stage 2 of the Carmacks to Stewart Crossing Transmission Line projects.

b) On April 27, 2012 the Utility filed a General Rate Application with the YUB for test years 2012 and 2013.

c) Aishihik Third Turbine Project. This project was commissioned into service in December 2011. On March 2, 2012, the general contractor filed a claim with the Supreme Court of Yukon for $4,000,000 plus interest and costs alleging the Utility has not paid for work performed. The Utility has informed the contractor of claims for incomplete contract scope, uncorrected deficiencies and other claims. The outcome of the claim is not determinable at this time and no amount has been recognized in the financial statements.

29. COMPARATIVE FIGURES

Certain 2010 figures have been reclassified to conform with the current year's presentation.

Yukon Energy Transmission and Generation Facilities



YEC SYSTEM	(in MW)
Hydro Facilities	
Whitehorse (WAF)*	40.0
Aishihik	37.0
Mayo	15.4
Total	**92.4**
Wind Facilities	
Haeckel Hill	0.8
Diesel Facilities	
Whitehorse (WAF)	25.0
Faro (WAF)	10.4
Dawson	4.3
Mayo	2.0
Total	**41.7**
TOTAL YEC SYSTEM	**134.9**

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	**149.9**

*WAF Whitehorse–Aishihik–Faro grid

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Cover: Learning about renewable energy fosters good energy conservation habits.

Photo: archbould.com



TOPIC: **Depreciation study**

REFERENCE: **Application, Tab 10, Depreciation Study**

QUESTION:

a) Please provide a copy of the terms of reference and any correspondence, e.g. meeting minutes, etc., between YEC and KPMG regarding the depreciation study.

b) Page 10-7 lists several methods of life estimation. Please provide which life estimation methods were used for each of the asset classes (for generation, transmission and distribution).

c) Please explain why other northern utilities (NWT, Nunavut) or other utilities from B.C. or Alberta with similar climate and terrain were not used as comparators.

d) Please explain why specific details of the depreciation study were not provided, e.g. specific Iowa curves used, etc.

e) Please provide the amount YEC paid KPMG for the depreciation study.

ANSWER:

(a)

Please see Attachment 1 to this response. No formal meeting minutes or notes were prepared.

(b)

With reference to page 10-7, where quantitative methods were used KPMG employed an actuarial methodology referred to as the retirement-rate method. Please see YECL-YEC-1-55(a) Attachment 1 page 12, and YECL-YEC-1-60(b) for a list of those sub accounts that were analyzed using a quantitative approach.

(c)

KPMG used comparable utilities where public and up-to-date information was readily available. At the time of the KPMG study, Northwest Territories Power Corporation was in the middle of preparing their own depreciation study update the results of which were not yet available. Nunavut Power does not have hydro or transmission assets. BC Hydro was one of the key comparable utilities.

(d)

The document provided as Tab 10 of the 2012/2013 General Rate Application was a Preliminary Summary of Results provided in early 2012 to ensure that updated information on depreciation rates and asset lives could be incorporated into the 2012/2013 General Rate Application. KMPG's scope of work included completing a more detailed report providing the analysis, assumptions and methods supporting the conclusions and recommendations provided in Tab 10. Specifically, at page 10-2 of Tab 10 KMPG notes, "While this preliminary document sets forth our conclusions, please note that it is not intended to be considered a complete narrative report. This document will be supplemented by a complete narrative report fully outlining our assumptions and methodologies which will be delivered at a future date."

Since filing the General Rate Application, KMPG has completed its narrative report which is provided as Attachment 1 to YECL-YEC-1-55(a).

(e)

The cost of the depreciation study performed by KPMG was $84,500.



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Mr. Ed Mollard
Chief Financial Officer
Yukon Energy Corporation
PO Box 5920
Whitehorse, Yukon Y1A 5L6

December 2, 2011

Dear Ed,

RE: DEPRECIATION STUDY PROJECT

The purpose of this letter is to outline the terms of our engagement to provide professional services to assist management of Yukon Energy Corporation ('YEC', 'Yukon Energy', or the 'Entity') with its Depreciation Study Project.

The attached terms and conditions form an integral part of the terms of this engagement letter and are incorporated herein by reference.

BACKGROUND

Management of YEC has decided to initiate a project to assess and recommend appropriate depreciation rates consistent with depreciation accounting policies used under International Financial Reporting Standards ('IFRS') ("Depreciation Study Project").

The Depreciation Study Project produced by KPMG may be utilized by YEC in proceedings before the Yukon Utility Board and for other business purposes.

OBJECTIVES AND APPROACH

Our Depreciation Study Project Methodology adopts an approach which includes key project phases:

Part 1(A) Data Analysis and Detailed Assessment Phase

Part 1(B) Design, Development and Delivery Phase

Part 2 Support Phase

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

We have tailored our approach based on our understanding of your progress to date and your immediate needs.

Below we have summarized the key components of each project phase:

Phase 1 (A): Data Analysis and Detailed Assessment Phase

This first phase to the Depreciation Study Project focuses on:

- Understanding which assets are material to YEC and therefore in the project's scope;
- Analysis of historical data, including;
    - Review of previous depreciation study results and other information available for in-scope assets to understand the nature of the assets, historical acquisition or construction dates, current depreciation rates, planned usage requirements and risk factors affecting useful lives and salvage values;
    - Assess current componentization level of property, plant and equipment for in-scope assets and assess if amendments are required thereto;
- Interview engineers and other interested parties
- Perform a site visit of significant in-scope assets, where deemed necessary;
- Discuss with management the alternative methods for depreciating components (e.g. straight line, declining balance or sinking fund)
- Assess which available depreciation rate assessment models are appropriate from a quantitative and qualitative perspective for the size of YEC.

Deliverables

The deliverables for this Data Analysis and Detailed Assessment phase will include:

- Regular (weekly) updates summarizing progress on for example; assets within the scope of the study, components, and key findings, alternative depreciation rate analysis approaches and related recommendations thereon.

Phase 1 (B): Design, Development and Delivery Phase

In this phase the Depreciation Study Project focuses on:

- Adapting KPMG's depreciation rate assessment models for the data collected from the findings in Phase 1;
- Obtain necessary model inputs and assess outputs for reasonableness;

- Calculate and recommend the appropriate depreciation rate for each in-scope asset giving consideration to the expectancy of each property group to live a full cycle, or have a fixed retirement age or date;
- Review preliminary modeling and modeling results with management and amend modeling, as required.
- Provide recommendations as to the expected average life, and mortality dispersion for each in-scope asset, as well as the expected service lives for each in-scope asset, as well as the expected service lives and retirement dates of in-scope asset. Our recommendations will take into account the asset-lives of similar assets in other jurisdictions.
- Determine the average remaining life of property of in-scope assets in each class;
- Calculate the depreciation requirement for each depreciable in-scope asset and test the adequacy of the accumulated depreciation per book.
- Review at a qualitative, high-level, those asset categories out of scope for the detailed depreciation rate modeling.
- Finalizing the depreciation report, incorporating management's comments and suggestions;

Deliverables

The deliverables for this Second Phase will include:

- Draft model(s) and summary of significant findings for management review and comments.
- Final Depreciation Project Study Report.

Phase 2: Support Phase

This phase includes supporting YEC management in its expected upcoming GRA Application, including assisting in drafting presentation materials, attending meetings and presenting our report's findings, as needed.

Deliverables

The deliverables for this Phase will include:

- Communicating to YEC management, Board and other stakeholders, as directed by YEC
- Reviewing and responding to questions directed from YEC to KPMG
- Supporting YEC in its GRA Application process including attending as a witness before the YUB;

ENGAGEMENT TEAM

Peter Greenwood will be responsible for the overall quality of service YEC receives during the conduct of this engagement.

Vimal Patel will lead the service delivery for YEC during the course of this engagement.

As part of your engagement, KPMG ensures a level of quality control over the deliverables we provide to you. Our quality control starts with a designated KPMG partner who performs the Engagement Quality Review on significant documents and key deliverables to YEC. This role will be performed by Jonathan Erling.

We will also assign professionals with the necessary skills and experience to assist with on-site fieldwork as appropriate.

TIMING AND PROFESSIONAL FEES

We are prepared to begin our work upon receipt of a signed copy of this engagement letter and at a time mutually determined by YEC and KPMG. We anticipate that Phases 1A and B will take place over the months of December 2011 to February 2012. Phase 2 will likely take place in 2012.

As described in this letter the work will be undertaken in certain phases. The fees for Phases 1(A) and (B) will be $72,500.

Phase 2 will be undertaken on a time and materials basis. Our professional fees are based upon the specified skill level of the professionals providing the services and the amount of time and materials required to complete the engagement. The following table represents the hourly rates that will be applied on the Phase that is a time and material basis.

Level	Net Hourly Rate
Associate Partners and Partners (Patel, Erling, Greenwood)	$495
Senior Managers	$395
Managers	$260
Senior Accountants	$180
Advisory Staff	$155
Staff Accountants	$95

Our fees will be billed on a monthly basis based on the hourly rate of each professional working on this engagement and our invoices are due upon receipt. Administrative charges will not included in fees for Phases 1 A and B of the project. However on the Phase 2 Support Phase an administrative charge will be calculated based on a percentage of our fees (5%) and includes such expenses as photocopies, fax charges, printing of statements and reports, postage and delivery and administrative and report department assistance. Out of pocket expenses such as travel and accommodation will be charged as incurred.

Our professional fees are exclusive of Provincial HST. Accordingly, the appropriate amount of tax will be computed and shown separately on our invoices, together with our firm's HST registration number, so that you will have the information required to claim an input tax credit.

TERMS AND CONDITIONS

In addition to our Advisory Terms and Conditions set out in Appendix A, the following responsibilities and conditions are understood:

- KPMG will provide our services in accordance with the terms and conditions of this letter. Such services are not intended to be an audit, examination, attestation, special report, or agreed-upon procedures engagement as those services are defined in the CICA Handbook applicable to such engagements conducted by independent auditors. Accordingly, these services will not result in the issuance of a written communication to third parties by KPMG directly reporting on financial data or internal control or expressing a conclusion or any other form of assurance.



- This engagement contemplates providing general advice on the application of depreciation rates as well as advice on the application of depreciation issues to a specific transaction. This engagement does not contemplate providing advice on the application of accounting principles to specific transactions and facts and circumstances of YEC where you have previously sought guidance from your external auditor, and accordingly, this engagement is outside the scope of *CICA Handbook*, Section 7600, and Reports on the Application of Accounting Principles. If you have previously sought guidance from your external auditor and request our advice on the application of IFRS or other accounting principles to specific transactions previously discussed with them, such advice would be provided pursuant to a separate engagement letter and governed by the requirements of our professional standards as outlined in CICA 7600.
- KPMG will not provide advice on hypothetical transactions. KPMG's only role with respect to proposed or completed transactions will be to provide advice to specific facts and circumstances.
- KPMG will act as a contractor in providing these services as set out in this letter and does not undertake to perform obligations of YEC or its management, whether regulatory or contractual.
- The deliverables presented as part of this engagement (apart from the Depreciation Project Study Report) are for the use of YEC management, the Audit Committee, and Board of Directors and will be solely used for business purposes . We disclaim any responsibility or liability for losses, damages, or costs incurred by anyone as a result of the unauthorized circulation, publication, reproduction, or use of our deliverables contrary to the provisions of this letter. Our deliverables will reflect our observations as of the date we conduct our work. We disclaim any intention or obligation to update or revise the observations whether as a result of new information, future events or otherwise. Should additional documentation or other information become available which impacts upon the observations reached in our deliverables, we reserve the right to amend our observations and summary documents accordingly.
- There is no guarantee that all accounting and disclosure differences will be identified during the course of an assessment engagement. Certain accounting and disclosure differences can be identified only by detailed review of transaction contracts and other underlying documentation.
- Actions and decisions taken by YEC based on recommendations and analysis provided by KPMG during the course of this engagement remain the responsibility of YEC's management.
- GAAP and IFRS pronouncements and applied interpretations are subject to revision by the respective Canadian and International authoritative accounting bodies. Any accounting advice provided by KPMG will be based on our understanding of current pronouncements and interpretations at the the time we provide the advice, and such advice may therefore change materially in response to subsequent changes or revisions to



the pronouncements or interpretations. KPMG assumes no responsibility to update advice previously provided unless specifically requested by YEC.

- Management of YEC are responsible for their regulatory filings, including financial statements and the appropriate application of GAAP, including all records, judgments, estimates and assumptions necessary to ensure such statements comply with the relevant filing requirements. With regard to KPMG's services, management of the Entity is responsible for:
- Determining the objectives, scope, and extent of KPMG services.
- The accuracy and completeness of the facts, circumstances and supporting documentation provided to KPMG for purposes of formulating our analyses.
- Reviewing and approving the outputs of our work before they are used in your final preparation and regulatory filings.
- YEC will designate a Project Manager at management level to oversee the conduct of this project, including coordination of the Entity's required resources and review of draft deliverables. Entity personnel assigned to the project will review draft deliverables on a timely basis.
- KPMG will require the support of Entity personnel in order to achieve timely completion of the project. Support includes, but is not limited to, the collection of all relevant documents (paper or electronic) and the scheduling of interviews and coordination of meetings.
- Management will be responsible for satisfying the information requests of its external auditors and for providing to the external auditors the necessary information and representations they will require in connection with their audit activities.

* * * * *

If the terms of this engagement letter as set forth above are acceptable to you, please indicate your acceptance and authorization for KPMG to proceed with the related work by signing both copies of this letter in the appropriate space and returning one of the originals to us.

Yours Sincerely,

Peter Greenwood

Peter Greenwood
KPMG LLP
Partner

604 691 3187

agm/

Enclosures:

The arrangements and terms set out are as agreed:

Yukon Energy Corporation

By: [signature] Chief Financial Officer
(Name, Position)

Date: Dec 4/11

1. TERMS AND CONDITIONS.

a. The Terms and Conditions are an integral part of the accompanying Proposal or Engagement Letter from KPMG that identifies the engagement to which they relate.

b. In the event of conflict between the Proposal or Engagement Letter and the Terms and Conditions, the Terms and Conditions shall prevail unless specific reference to a provision is made in the Proposal or Engagement Letter. Other capitalized words in the Terms and Conditions shall have the meanings given to them in the Proposal or Engagement Letter.

2. SERVICES.

KPMG will use reasonable efforts to complete the performance of the services within any agreed-upon time-frame. It is understood and agreed that KPMG's services may include advice and recommendations; but all decisions in connection with the implementation of such advice and recommendations shall be the responsibility of, and made by, Client. KPMG will not perform management functions or make management decisions for Client. Nothing in the Terms and Conditions shall be construed as precluding or limiting in any way the right of KPMG to provide services of any kind or nature whatsoever to any person or entity as KPMG in its sole discretion deems appropriate.

3. CLIENT RESPONSIBILITIES.

a. Client agrees to cooperate with KPMG in the performance of the services under the Engagement Letter and shall provide or arrange to provide KPMG with timely access to and use of the personnel, facilities, equipment, data and information to the extent necessary for KPMG to perform the services under the Engagement Letter. To the extent that KPMG employees are on Client premises, Client will take all reasonable precautions for the safety of KPMG partners and employees at Client premises. Client shall be responsible for the performance of its employees and agents and for the accuracy and completeness of all data and information provided to KPMG for purposes of the performance by KPMG of its services hereunder. The Proposal or Engagement Letter may set forth additional responsibilities of Client in connection with the engagement. Client acknowledges that Client's failure to perform these obligations could adversely impact KPMG's ability to perform its services.

b. Client agrees that Client, and not KPMG, shall perform the following functions: (i) make all management decisions and perform all management functions; (ii) designate an individual who possesses suitable skill, knowledge and experience, preferably within senior management, to oversee the performance of the services under the Engagement Letter, and to evaluate the adequacy and results of such services; (iii) accept responsibility for the results of such services; and (iv) establish and maintain internal controls over the processes with which such services are concerned, including, without limitation, monitoring ongoing activities.

c. Client acknowledges and agrees that KPMG will, in performing the services, base its conclusions on the facts and assumptions that Client furnishes and that KPMG may use data, material, and other information furnished by or at the request or direction of Client without any independent investigation or verification and that KPMG shall be entitled to rely upon the accuracy and completeness of such data, material and other information. Inaccuracy or incompleteness of such data, material and other information furnished to KPMG could have a material effect on KPMG's conclusions.

d. Client acknowledges that information made available by it, or by others on Client's behalf, or otherwise known to partners or staff of KPMG who are not engaged in the provisions of the services shall not be deemed to have been made available to the individuals within KPMG who are engaged in the provision of the services hereunder. Client undertakes that, if anything occurs after information is provided by Client to KPMG to render such information untrue, unfair or misleading, Client shall promptly notify KPMG.

4. REPORTING.

a. During the performance of the services, KPMG may supply oral, draft or interim advice, reports or presentations but in such circumstances KPMG's written advice or final written report shall take precedence. No reliance should be placed by Client on any oral, draft or interim advice, reports or presentations. Where Client wishes to rely on oral advice or oral presentation, Client shall inform KPMG and KPMG will provide documentary confirmation of the advice concerned.

b. Subsequent to the completion of the engagement, KPMG will not update its advice, recommendations or work product for changes or modification to the law and regulations, or to the judicial and administrative interpretations thereof, or for subsequent events or transactions, unless Client separately engages KPMG to do so in writing after such changes or modifications, interpretations, events or transactions.

5. WORKING PAPERS AND USE OF REPORTS.

KPMG retains all rights in all methodologies, know-how, knowledge, applications and software developed by KPMG either prior to or during the engagement. KPMG also retains all rights (including copyright) in all reports, written advice and other working papers and materials developed by KPMG during the engagement. Unless contemplated by the Engagement Letter, all reports and written advice are intended solely for Client's internal use and, where applicable, government taxation authorities, and may not be edited, distributed, published, made available or relied upon by any other person without KPMG's express written permission. If such permission is given, Client shall not publish any extract or excerpt of KPMG's written advice or report or refer to KPMG without providing the entire advice or report at the same time. Subject to the restrictions of Section 6, KPMG is entitled to use or develop the knowledge, experience and skills of general application gained through performing the engagement.

6. CONFIDENTIALITY.

a. Except as described in section 5 above, Client will treat in confidence any KPMG methodologies, know-how, knowledge, application or software identified by KPMG as confidential information of KPMG, and will not use or disclose such confidential information of KPMG to others.

b. KPMG will treat as confidential all proprietary information and personal information obtained from Client in the course of the engagement. **c.** The above restrictions shall not apply to any information that: (i) is required by law or professional standards applicable to KPMG to be disclosed; (ii) that is in or hereafter enters the public domain; (iii) that is or hereafter becomes known to Client or KPMG, as the case may be, without breach of any confidentiality obligation; or (iv) that is independently developed by Client or KPMG, as the case may be.

d. KPMG shall be entitled to include a description of the services rendered in the course of the engagement in marketing and research materials and disclose such information to third parties, provided that all such information will be rendered anonymous and not subject to association with Client.

e. KPMG shall be entitled to share all information with all other member firms of KPMG International Cooperative ("KPMG International"). KPMG may also use such information to offer services that may be of interest to Client. KPMG may retain and may disclose to other member firms of KPMG International, subject to terms of this section, such information required for compliance with applicable professional standards or internal policies or quality reviews or share best practices.

f. Professional standards require KPMG personnel performing any audit or assurance services for clients to discuss or have available to them all information and materials that may affect the audit or assurance engagement. Client authorizes, if Client is or becomes an assurance Client, KPMG personnel performing services under the engagement to make available to the KPMG assurance engagement team and other KPMG personnel, the findings, observations and recommendations from the engagement and agrees that KPMG may use all such findings, observations and recommendations in KPMG's assurance engagement.

7. PERSONAL INFORMATION CONSENTS AND NOTICES.

Any collection, use or disclosure of personal information is subject to KPMG's Privacy Policy available at www.kpmg.ca. KPMG may be required to collect, use and disclose personal information about individuals during the course of this engagement. Client represents and warrants that: (i) it will obtain from individuals all consents required by law to permit KPMG to collect, use and disclose all personal information reasonably required in the course of the engagement, and (ii) it has provided notice of KPMG's potential processing of information outside of Canada (as described in paragraph 8 below) to all individuals whose personal information is disclosed to KPMG. Client consents to KPMG sending to Client, its officers, directors and employees, as applicable, electronic

messages including emails) relating to KPMG products and services and other matters of interest to Client.

8. INFORMATION PROCESSING OUTSIDE OF CANADA.

Personal and/or confidential information collected by KPMG during the course of this engagement (e.g. entries into KPMG's time and billing system and into KPMG's conflicts database) may be processed and stored outside of Canada by KPMG, KPMG International member firms providing services hereunder or third party processors. Such personal and/or confidential information may be subject to disclosure in accordance with the laws applicable in the jurisdiction in which the information is processed or stored, which laws may not provide the same level of protection for such information as will Canadian laws. KPMG's Privacy Officer noted in KPMG's Privacy Policy is able to answer any individual's questions about the collection of personal information required for KPMG to deliver services hereunder.

9. TAXES/BILLING/EXPENSES/FEES.

a. All fees and other charges do not include any applicable federal, provincial, or other goods and services or sales taxes, or any other taxes or duties whether presently in force or imposed in the future. Any such taxes or duties shall be assumed and paid by Client without deduction from the fees and charges hereunder.

b. Bills, including, without limitation, a charge on account of all reasonable expenses, including travel, meals, accommodations, long distance, telecommunications, photocopying, delivery, postage, clerical assistance and database research will be rendered on a regular basis as the engagement progresses. Accounts are due when rendered. Interest on overdue accounts is calculated at the rate noted on the invoice commencing 30 days following the date of the invoice.

c. Without limiting its rights or remedies, KPMG shall have the right to halt or terminate entirely its services until payment is received on past due invoices.

d. In the event that the engagement is terminated and Client proceeds to complete the transaction or financing within 18 months from the termination date, then the full amount of any Completion Fee shall be payable on closing of the transaction or the completion of financing, regardless of whether KPMG provided further service.

10. LIMITATION ON WARRANTIES.

THIS IS A SERVICES ENGAGEMENT. KPMG WARRANTS THAT IT WILL PERFORM SERVICES HEREUNDER IN GOOD FAITH WITH QUALIFIED PERSONNEL IN A COMPETENT AND WORKMANLIKE MANNER IN ACCORDANCE WITH APPLICABLE INDUSTRY STANDARDS. KPMG DISCLAIMS ALL OTHER WARRANTIES, REPRESENTATIONS OR CONDITIONS, EITHER EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, WARRANTIES, REPRESENTATIONS OR CONDITIONS OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

11. LIMITATION ON LIABILITY.

a. Client agrees that KPMG shall not be liable to Client for any actions, damages, claims, liabilities, costs, expenses, or losses in any way arising out of or relating to the services performed hereunder for an aggregate amount in excess of the fees paid by Client to KPMG under the engagement. On a multi-phase engagement, KPMG's liability shall be based on the amount actually paid to KPMG for the particular phase that gives rise to the liability.

b. In the event of a claim by any third party against KPMG that arises out of or relates to the services performed hereunder, Client will indemnify KPMG from all such claims, liabilities, damages, costs and expenses, including, without limitation, reasonable legal fees, except to the extent finally determined to have resulted from the intentional, deliberate or fraudulent misconduct of KPMG.

c. In no event shall KPMG be liable for consequential, special, indirect, incidental, punitive or exemplary damages, costs, expenses, or losses (including, without limitation, lost profits and opportunity costs). In any action, claim, loss or damages arising out of the engagement, Client agrees that KPMG's liability will be several and not joint and several. Client may only claim payment from KPMG of KPMG's proportionate share of the total liability based on degree of fault.

d. For purposes of this section, the term KPMG shall include its associated and affiliated entities and their respective partners, directors, officers and employees. The provisions of this section shall apply regardless of the form of action, damage, claim, liability, cost, expense, or loss, whether in contract, statute, tort (including, without limitation, negligence) or otherwise.

12. LEGAL PROCEEDINGS.

a. Client agrees to notify KPMG promptly of any request received by Client from any court or applicable regulatory authority with respect to the services hereunder, KPMG's advice or report or any related document.

b. If KPMG is required by law, pursuant to government regulation, subpoena or other legal process or requested by Client to produce documents or personnel as witnesses arising out of the engagement and KPMG is not a party to such proceedings, Client shall reimburse KPMG at standard billing rates for professional time and expenses, including, without limitation, reasonable legal fees, incurred in responding to such requests.

c. Client acknowledges that KPMG may from time to time receive requests or orders from professional, securities or other regulatory, judicial or governmental authorities (both in Canada and abroad) to provide them with information and copies of documents in KPMG's files including working papers and other work-product relating to Client. Except where prohibited by law, KPMG will advise Client of the request or order. Client hereby acknowledges that KPMG will provide these documents and information without further reference to, or authority from Client.

When such an authority requests access to KPMG's working papers and other work-product relating to Client's affairs, KPMG will, on a reasonable efforts basis, refuse access to any document over which Client has expressly informed KPMG at the time of delivery that the Client asserts privilege, except where disclosure of documents is required by law. Client must mark any document over which it asserts privilege as "privileged". If and only if the authority requires such access to privileged documents pursuant to the laws of a jurisdiction in which express consent is required for such disclosure, then Client hereby provides its consent.

Where privileged Client documents are disclosed, KPMG is directed to advise the authority that Client is permitting disclosure only to the extent required by law and for the limited purpose of the authority exercise of statutory authority. KPMG is directed to advise the authority that Client does not intend to waive privilege for any other purpose and that Client expects its documents to be held by the authority as privileged and confidential material (held securely, limited distribution, etc.). For greater certainty, Client and KPMG hereby agree that this acknowledgement (and, if required, consent) does not negate or constitute a waiver of privilege for any purpose and Client expressly relies upon the privilege protections afforded under statute and otherwise under law.

13. LIMITATION PERIOD.

No action, regardless of form, arising under or relating to the engagement, may be brought by either party more than one year after the cause of action has accrued or in any event not more than five years after completion of the engagement in the case of an advisory services engagement and not more than eight years after completion of the engagement in the case of a tax services engagement, except that an

action for non-payment may be brought by a party not later than one year following the date of the last payment due to such party hereunder. For purposes of this section, the term KPMG shall include its associated and affiliated entities and their respective partners, directors, officers and employees.

14. TERMINATION.

Unless terminated sooner in accordance with its terms, the engagement shall terminate on the completion of KPMG's services hereunder, which completion shall be evidenced by the delivery by KPMG to Client of the final invoice in respect of the services performed hereunder. Should Client not fulfill its obligations set out herein or in the Engagement Letter and in the absence of rectification by Client within 10 days, KPMG may, upon written notice, terminate its performance and will not be responsible for any loss, cost or expense resulting. The engagement may be terminated by either party at any time by giving written notice to the other party not less than 30 calendar days before the effective date of termination. Upon early termination of the engagement, Client shall be responsible for the payment to KPMG for KPMG's time and expenses incurred up to the termination date, as well as reasonable time and expenses to bring the engagement to a close in a prompt and orderly manner.

15. E-MAIL COMMUNICATION.

Client recognizes and accepts the risks associated with communicating by Internet e-mail, including (but without limitation) the lack of security, unreliability of delivery and possible loss of confidentiality and privilege. Unless Client requests in writing that KPMG does not communicate by Internet e-mail, Client assumes all responsibility or liability in respect of risk associated with its use.

16. POTENTIAL CONFLICTS OF INTEREST.

Except as otherwise set out herein, Client should be aware that it is not uncommon for KPMG to be auditors and/or advisors of more than one of the parties involved in a transaction. In such situations, KPMG takes appropriate measures to ensure that strict confidentiality is maintained in all respects. If these circumstances are identified, KPMG will advise Client of that fact, subject to confidentiality requirements, and will consider with Client what further measures, if any, are appropriate. Client further acknowledges that at some point KPMG may act contrary to Client's interest on unrelated matters.

17. FORCE MAJEURE.

Neither Client nor KPMG shall be liable for any delays resulting from circumstances or causes beyond its reasonable control, including, without limitation, fire or other casualty, act of God, strike or labour dispute, war or other violence, or any law, order or requirement of any governmental agency or authority.

18. INDEPENDENT CONTRACTOR.

It is understood and agreed that each of the parties hereto is an independent contractor and that neither party is, nor shall be considered to be, an agent, distributor or representative of the other. Neither party shall act or represent itself, directly or by implication, as an agent of the other or in any manner assume or create any obligation on behalf of, or in the name of, the other.

19. SURVIVAL.

Sections 1 to 16 and 19, 20, 24, 25 and 29 hereof shall survive the expiration or termination of the engagement.

20. SUCCESSORS AND ASSIGNS.

The Terms and Conditions and the accompanying Proposal or Engagement Letter shall be binding upon the parties hereto and their respective associated and affiliated entities and their respective partners, directors, officers and employees and successors and permitted assigns. Except as provided below, neither party may assign, transfer or delegate any of the rights or obligations hereunder without the prior written consent of the other party. KPMG may assign its rights and obligations hereunder to any affiliate or successor in interest to all or substantially all of the assets or business of the relevant KPMG practice, without the consent of Client. In addition, KPMG may engage independent contractors and member firms of KPMG International to assist KPMG in performing the services hereunder.

21. SEVERABILITY.

The provisions of the Terms and Conditions and the accompanying Proposal or Engagement Letter shall only apply to the extent that they are not prohibited by a mandatory provision of applicable law. If any of these provisions shall be held to be invalid, void or unenforceable, then the remainder of the Terms and Conditions and the attached Proposal or Engagement Letter, as the case may be, shall not be affected, impaired or invalidated, and each such provision shall be valid and enforceable to the fullest extent permitted by law.

22. ENTIRE AGREEMENT.

The Terms and Conditions and the accompanying Proposal or Engagement Letter including, without limitation, Exhibits, constitute the entire agreement between KPMG and Client with respect to the engagement and supersede all other oral and written representation, understandings or agreements relating to the engagement.

23. GOVERNING LAW.

The Terms and Conditions and the accompanying Proposal or Engagement Letter shall be subject to and governed by the laws of the province in which KPMG's principal office performing the engagement is located (without regard to such province's rules on conflicts of law) and all disputes arising hereunder or related thereto shall be subject to the exclusive jurisdiction of the courts of such province.

24. PUBLICITY.

Upon the closing of a transaction, KPMG will have the right (but shall not be obliged), at its expense, to publicize its association with the transaction by way of public announcement in "tombstone" or similar format, subject to prior review of the wording for any such announcement with Client.

25. KPMG INTERNATIONAL MEMBER FIRMS.

In the case of multi-firm engagements, all member firms of KPMG International performing services hereunder shall be entitled to the benefits of the Terms and Conditions. Client agrees that any claims that may arise out of the engagement will be brought solely against KPMG, the contracting party, and not against any other KPMG International member firms.

26. *SARBANES-OXLEY ACT.*

Except as set forth in the Engagement Letter, Client acknowledges that completion of the engagement or acceptance of KPMG's reports, advice, recommendations and other deliverables resulting from the engagement will not constitute a basis for Client's assessment of internal control over financial reporting or Client's evaluation of disclosure controls and procedures, or its compliance with its principal officer certification requirements under Section 302 of the *Sarbanes-Oxley Act of 2002* (the "Act"). The engagement shall not be construed to support Client's responsibilities under Section 404 of the Act requiring each annual report filed under Section 13(a) or 15(d) of the *Securities Exchange Act of 1934* to contain an internal control report from management.

27. NATIONAL INSTRUMENT 52-109.

Except as set forth in the Engagement Letter, Client acknowledges that completion of the engagement or acceptance of KPMG's reports, advice, recommendations and other deliverables resulting from the engagement will not constitute a basis for Client's evaluation of disclosure controls and procedures, or its compliance with its CEO/CFO certification requirements under *National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings*, including those related to the design of internal control over financial reporting.

28. SPECIFIC ACCOUNTING AND OTHER ADVICE.

Except as set forth in the Engagement Letter, the engagement does not contemplate the provision of specific accounting advice or opinions or the issuance of a written report on the application of accounting standards to specific transactions and facts and circumstances of Client. Such services, if requested, would be provided pursuant to a separate engagement.
Client should consult with and/or engage legal counsel for the purpose of advising on legal aspects of matters on which KPMG provides its advice and drafting any legal documents and/or agreements that may be required. To the extent legal counsel or other professional service providers are required, Client is exclusively responsible for engaging and paying such service providers.



29. TAX SERVICES.

a. If tax work is specifically requested by Client, KPMG will perform the procedures in accordance with this section. KPMG will base its findings exclusively on the facts and assumptions provided to KPMG by Client and Client's personnel and advisors. KPMG will consider the applicable provisions of the relevant taxing statutes, the regulations thereunder, applicable tax treaties and judicial and administrative interpretations thereof. KPMG will also take into account all specific proposals to amend such statutes, regulations and treaties publicly announced prior to the date of KPMG's reports, based on the assumption that these amendments will be enacted substantially as proposed. These authorities are subject to change, retroactively and/or prospectively, and any such changes could affect the validity of KPMG's findings and may result in incremental taxes, interest or penalties. KPMG's findings will not otherwise take into account or anticipate any changes in law or practice, by way of judicial, governmental or legislative action or interpretation. Unless Client specifically requests otherwise, KPMG will not update tax work to take any such changes into account.

b. KPMG will use professional judgment in providing advice, and will, unless Client instructs otherwise, take the position most favourable to Client whenever reasonable. All returns are subject to examination by tax authorities, and KPMG's advice may be audited and challenged by a tax authority. Client understands that KPMG's conclusions are not binding on tax authorities or the courts and should not be construed as a representation, warranty or guarantee that the tax authorities or courts will agree with KPMG's conclusion.

c. Client is also responsible for ensuring that KPMG's advice is implemented strictly in accordance with KPMG's recommendations. KPMG is not responsible for any penalties or interest assessed against Client as a result of a failure by Client to provide KPMG with accurate and complete information.

d. Unless expressly provided for, KPMG's services do not include representing Client in the event of a challenge by the CRA or other tax or revenue authorities.

30. LLP.

KPMG LLP is a registered limited liability partnership ("LLP") established under the laws of the Province of Ontario and, where applicable, has been registered extra-provincially under provincial LLP legislation. KPMG is a partnership, but its partners have a degree of limited liability. A partner is not personally liable for any debts, obligations or liabilities of the LLP that arise from a negligent act or omission by another partner or any person under that other partner's direct supervision or control. The legislation relating to limited liability partnerships does not, however, reduce or limit the liability of the firm. The firm's insurance exceeds the mandatory professional indemnity insurance requirements established by the various Institutes/Ordre of Chartered Accountants. Subject to the other provisions hereof, all partners of the LLP remain personally liable for their own actions and/or actions of those they directly supervise or control.

TOPIC: **Energy Reliability**

REFERENCE: **Application, pages 5-1 and 5-2**

Coordinated with these initiatives, Yukon Energy has also completed projects to enhance safety and reliability at the existing Mayo, Aishihik and Whitehorse hydro facilities.

-and-

Yukon Energy's level of "normal" or ongoing spending on capital works, outside of such major projects, over the period 2009 (actual) to 2013 (forecast) varies from a low of approximately $5.4 million (2012) to a high of $10.5 million (2010) averaging $7.26 million per year.

PREAMBLE:

The Board wishes to understand how forecast capital and maintenance expenses relate to reliability.

QUESTION:

a) From January 2009 to July 2011, there were 185 unplanned outages. Of those, 53 were due to human error, animal interactions with equipment and loss of generation. What steps is the company taking to reduce unplanned outages?

b) Please provide a copy in electronic format of the most recent system diagram (switch book/system map).

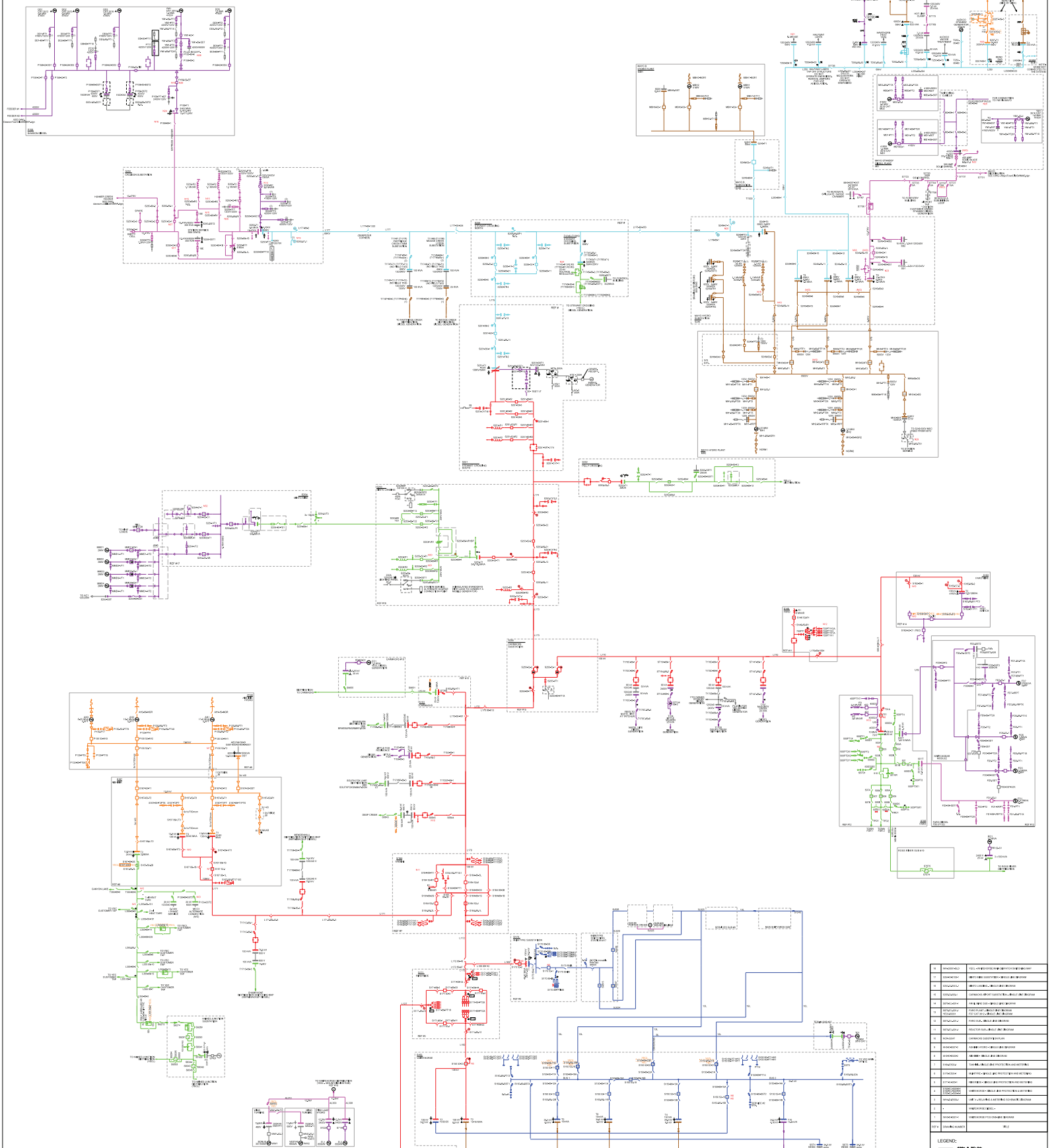
ANSWER:

(a)

Please see response to YUB-YEC-1-54(b).

(b)

Please see Attachment 1 to this response the most recent system diagram.


NOTES:
SYSTEM INTERLOCKS
S150
N1 S150 S4-1 BEFORE S150 S4-4
N2 S150 S4-12 BEFORE S150 S4-2
N3 S150 S4-3 BEFORE S150 S4-4
N4 S150 S4-4 BEFORE S150 S4-6
N5 S150 S4-5 BEFORE S150 S4-1 OR S4-2
N6 IF S150 S4-5 IS OPEN S150 S4-4 MUST BE CLOSED (EMITTER POWER TYPE)
S167
N7 S167 S4-1 BEFORE P130 S4-2
S725
N8 BKR 701 BEFORE BKR 503
S172
N9 S172 S4-1 BEFORE S172 S4-4
DEEP CREEK
N10 S5844 CLOSED FIRST
S5844 CLOSED SECOND
N11 - SWITCH ONLY WHEN S1643-S4-1 IS OPEN.
N12 - SWITCH ONLY WHEN S150 S4-11 IS CLOSED
N13 - SWITCH ONLY WHEN S150 S4-11 IS CLOSED
NOTES
N14 - SYNCHRONOUS CONDENSER. WHEN TAKEN OFF LINE SUBMERGE TOP 2 ROW OF DIVERTER.
N15 - S5844 S4-1 CLOSED ONLY WHEN S5844 S4-2 IS OPEN
N16 - OPERATE SWITCH ONLY WHEN THE BUS IS DE-ENERGIZED
N17 - SWITCH ONLY WHEN THE BUS IS DE-ENERGIZED
N18 - STANDBY SYNCHRONIZED LOCALLY BY OPERATOR. WHEN SYNCHRONIZED AND CLOSED UNITS TAKE THE DEMAND IS CLOSED
N19 - BREAKER CANNOT BE CLOSED UNTIL PROTECTIVE RELAYS ARE RESET ON BOTH FEEDOUT AND S5844
N20 - MECHANICAL INTERLOCK BETWEEN L170/44 AND S5844 PREVENTS BOTH BEING CLOSED CONCURRENTLY.
N21 - PHASE ROTATION TO BE CHECKED BEFORE FIRST PARALLEL. PHASE ROTATION TO MATCH SYSTEM AND L170/44.
N22 - CLOSE MEANS OF CONNECT BEFORE CLOSING GENERATOR.
N23 - S1 S2 S3 ZEROED AND TURNED OFF BEFORE S1 S2 S3 ARE CLOSED
N24 - 115KV/7.199/4.16KV TERTIARY NOT BROUGHT OUT
N25 - S2S-T1 CONNECTED SINGLE PHASE LINE TO LINE
N26 - SYNCHRONIZE SYNCHROSCOPE FUNCTION DONE BY SEQUENCER COMPUTER.
NOTES
N27 - NO DIVAL CHECK, CLOSE ONLY WHEN S2S04-S4 OR S2S04-S5 OPEN.
N28 - DISTRIBUTION SYSTEM CLOSE ONLY WHEN MS425-2 IS OPEN
N29 - OPERATE DISCONNECTS IN PANEL AC-4 BEFORE OPERATING BREAKERS
N30 - SWITCH ONLY WHEN S2S-S4-S1 IS OPEN
N31 - SWITCH ONLY WHEN S2S-S4-S2 IS OPEN
N32 - CLOSE ONLY WHEN S2S-S4-S1 IS OPEN/RACKED OPEN
N33 - GROUND TRIP BLOCK BEFORE OPERATION
N34 - 115KV CT/PD P1 SEALED AND TURN OFF BEFORE OPERATING S1 S2 S3 DISCONNECTS
N35 - SWITCH ONLY WHEN S2S-S4-S1 IS OPEN
N36 - OPERATE P1S-S4-S2 ONLY ONLY WHEN P1S-S4-S1 OPEN AND THEY BOTH CLOSE
LEGEND:
600V & BELOW
4160v & 2400V
5.5kV
12.5kV
25kV
34kV
69kV
138kV
INTERFACE POINT
N/O NORMALLY OPEN
UNDERGROUND OR TRAY
YUKON ENERGY CORPORATION
YUKON POWER SYSTEM
ONE LINE DIAGRAM

TOPIC: **Order-in-Council (OIC) 2012/68**

REFERENCE: **Application, page 1**

Pursuant to the OIC 2012/68 direction, the Board must ensure until the end of 2013 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and, subject in 2012 to the 3.4% already approved effective January 1, 2012, to the class of major industrial customers. Consequently, for both 2012 and 2013, all proposed rate adjustments for retail customers and industrial customers apply equally, as percentages.

PREAMBLE:

The Board wishes to understand YEC's interpretation of OIC 2012/68.

QUESTION:

a) With reference to the above quote, please explain your interpretation of the direction in OIC 2012/68.

ANSWER:

(a)

Yukon Energy's interpretation of the above noted direction in light of other Yukon rate policy direction provided by OIC 2007/94 and OIC 1995/90 is provided in Tab 4, Section 4.4 and Section 4.5.

For Retail Rates:

Firm retail non-industrial rates within each non-government retail customer class (i.e., rates for residential, general service and lighting customer classes) are required by OIC 1995/90 to be equal throughout Yukon for both Yukon Energy and Yukon Electrical customers, subject to allowed variation for run-off rates to reflect incremental costs that differ for different rate zones.

On October 3, 2008, the Yukon Government enacted OIC 2008/149 amending OIC 1995/90 to add the following immediately after Section 2 the following direction to be in effect until December 31, 2012:

> 2.1(1) the Board must ensure that rate adjustments for all retail customers apply equally, when measured as percentages, to all classes of retail customers.

OIC 2012/68 replaced section 2.1 provided in OIC 2008/149. Insofar as it affects all classes of retail customers, this new direction in effect extends the earlier section 2.1(1) direction until December 31, 2013, and ensures that the same percentage rate adjustments will also apply to the class of major industrial customers (subject to the new section 6(3) as set out in OIC 2012/68 which has replaced section 6(3) provided in OIC 2007/94).

In order to comply with this latest OIC direction provided by OIC 2012/68, the GRA Application proposes that the Yukon Energy revenue shortfall for 2012 and 2013 as shown in Table 4.1 be recovered through Revenue Shortfall Riders applied across the board to all firm retail and industrial rates in 2012 and in 2013 as follows:

- **2012:** An across the board Rider J of 6.40% applied on an ongoing basis to all firm retail customer rates and 2.90% applied on an ongoing basis to all firm major industrial customer rates (i.e., excludes customers served under Rate Schedule 32 and Rate Schedule 35).The calculation of the 2012 revenue shortfall and the required 6.4% increase in firm retail rates and 2.90% increase in firm industrial rates are set out in Table 4.2 in Tab 4 of the Application.

- **2013:** An across the board Rider R of 6.50% applied, on an ongoing basis, to all firm retail and industrial customer rates, including Rider J, starting January 1, 2013 (i.e., excludes customers served under Rate Schedule 32 and Rate Schedule 35). The calculation of the 2013 revenue shortfall and the required 6.50% increase in firm retail and industrial rates is set out in Table 4.2 of the Application.

For Industrial Rates:

In June 4, 2007, the Yukon Government enacted OIC 2007/94 amending OIC 1995/90 to add subsection 6(3) immediately after subsection 6(2). Subsection 6(3) at that time provided that "despite subsection (1), the Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary" attached as Schedule A to the OIC[1].

OIC 2012/68 has replaced section 6(3) provided in OIC 2007/94. This in effect requires that Rate Schedule 39, as approved in Board Order 2011-14, continue until December 31, 2013, except as follows:

1. If rates charged to retail customers for all or any part of 2012 are to be increased, then for that same period the greater of that increase and the percentage increase approved in Board Order 2011-14 [i.e., 3.4%] is to apply to the class of major industrial customers; and

2. The Board must otherwise ensure until December 31, 2013 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers.

In order to comply with this latest OIC direction provided by OIC 2012/68, the GRA Application provides that Rider J and Rider R will apply to major industrial customers as follows:

- Rider J (2012 Yukon Energy Revenue Shortfall Rider, with an interim rate to start July 1, 2012) provides for a rate increase of 6.4% for all retail customer classes and a rate increase of 2.90% for major industrial class customers (when combined with the 3.4% increase in Board Order 2011-14, the cumulative 2012 increase of 6.4% is equal to the rate increase charged to retail customers). The Rider J increase applies to all major industrial rates then in effect pursuant to Order 2011-14, including the fixed Rider F charge of 0.211 cents/kW.h.

[1] On August 25, 2008, Yukon Energy applied to have this firm Rate Schedule 39 per OIC 2007/94 approved by the Board. Subsequently, as provided for in OIC 2007/94, Board Order 2011-04 approved a 2.8% increase in Rate Schedule 39 demand and energy rates effective January 1, 2011 and Board Order 2011-14 approved a further 3.4% increase in Rate Schedule 39 demand and energy rates effective January 1, 2012.

- Rider R (2013 Yukon Energy Revenue Shortfall Rider) provides for a rate increase of 6.5% effective January 1, 2013 for all retail customer classes and for major industrial class customers. The Rider R increase applies to all major industrial rate then in effect, including Rider J and the fixed Rider F charge.