

YUKON ENERGY CORPORATION

2012/2013 GENERAL RATE APPLICATION
ROUND 2 - INTERROGATORY RESPONSES FILED

September 13, 2012

City of Whitehorse
(CW)

TOPIC: **Industrial Rate 39**

REFERENCE: **CW-YEC-1-7**

PREAMBLE:

YEC was asked:

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?

The City does not consider that YEC was sufficiently responsive and will further clarify the information requested.

QUESTION:

a) Does YEC consider that peak shaving is a conservation measure and, if employed by industrial customers, would contribute to diesel displacement? If yes, how has YEC incorporated peak shaving into its DSM initiatives? If YEC has not incorporated peak shaving into its DSM initiatives, what plans, if any, does YEC have to do so?

b) YEC's response to CW-YEC-1-7 states: "YEC cannot amend the provision. The Rate Schedule 39, which sets out this provision, is fixed by OIC until the end of 2013." Is YEC referring to OIC 2009-74, as discussed at pages 11-7 to 11-12 of the Application? If not, please specify which OIC(s) constrain YEC's actions with respect to Rate 39?

c) Does the OIC or OICs discussed in response to (b) above constrain the rate or Terms and Conditions of Service under Rate 39 or both? If yes, please specify how the rate or what Terms and Conditions of Service in the Electric Service Regulations or elsewhere are constrained by the OIC(s)?

d) What changes to the Terms and Conditions of Service could YEC implement immediately in order to make Rate 39 more attractive to customers?

e) Has YEC made, or does YEC intend to make, any recommendations to the Yukon government concerning Rate 39 prior to its expiry in 2013? If yes, please specify the recommendations made or intended to be made.

f) If YEC is granted an increase in revenue for the test years, what will be the directional and quantitative change in the Peak Shaving Credit available under Rate 39?

ANSWER:

(a)

Yes - Peak shaving of the type discussed here is considered a conservation measure.

If employed by any customer, this form of peak shaving contributes to displacement of required new generation "*capacity*" (e.g., new diesel generation MWs required to supply reliably the winter peak). However, it does not contribute, in a meaningful way, to displacement of diesel "*energy*" generation (MW.h) required during the winter.

As evidenced by the current Industrial rate, which resulted from the PPA that YEC negotiated with the Minto mine, Yukon Energy has worked with industrial customers and the YUB to provide the opportunity for conservation through the approved peak shaving rate incentive.

Yukon Energy also continues to work with potential new industrial customers such as Victoria Gold to examine opportunities for such customers to plan operations so as to reduce energy requirements during winter months and thereby displace YEC's required winter diesel energy generation.

Current DSM planning that YEC is doing with YECL is considering options for peak capacity reduction as well as overall diesel energy reduction, and these plan assessments will be discussed when the overall DSM plan proposals are concluded.

(b) through **(d)**

The response to CW-YEC-1-7 is referring to OIC 2012/68.

As noted in Tab 4, page 4-6 of the Application Section 6(3) provided in OIC 2007/94 was replaced in April 2012 with a new OIC direction (OIC 2012/68) which in effect requires that Rate Schedule 39 as approved in Board Order 2011-14[1] to continue until December 31, 2013 with certain exceptions as noted in Tab 4 of the Application:

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.

The Terms and Conditions of Service approved by the Yukon Utilities Board form part of the rate schedule. Tab 5 of the 2009 Phase II Rate Application (pages 5-8 to 5-11) outlines the basic elements of this policy that have been a component of the terms of service since YEC was first before the YUB for rate regulation. These elements or basic principles were crystallized in the Phase II Rate Application, but not modified.

Yukon Energy is not aware of any changes to the Terms and Conditions of Service that could be implemented at this time in relation to Rate Schedule 39 to make Rate 39 more attractive to customers.

[1] The new OIC retains Schedule A from OIC 2007/94, which set out Rate Schedule 39, Industrial Primary. The rate schedule approved in Board Order 2011-14 conformed to Schedule A of OIC 2007/94.

(e)

OIC 2012/68 does not expire until December 31, 2013. Yukon Energy has not at this time made or developed any proposals for future changes to Rate Schedule 39 following the expiry of OIC 2012/68 at the end of 2013.

(f)

Any increase in revenue approved for the test years will be recovered through Rider J and Rider R, which will apply equally to all firm rates and rate components, including the Rate Schedule 39 Demand Charge.

Accordingly, any increase in Rider J and Rider R will increase the related Peak Shaving Credit set at 50% of the Demand Charge (and applied to the Peak Shaved Load). On this basis, there will be an increase in the credit equal to the percentage increase approved for Rider J and Rider R.

TOPIC: **Diesel Contingency Fund**

REFERENCE: **CW-YEC-1-24(a)**

PREAMBLE:

YEC was asked:

> 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.

YEC's response states that "The Diesel Contingency Fund (DCF) operation is affected by the variability in, and not by the variability of water flow." The response directs the City to YUB-YEC-1-30 (b) for the required information.

The response to which the City was directed does not provide the requested information with respect to hydro variability nor does it provide information in the requested format.

QUESTION:

a) 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 existing grid hydro generation.
   ii. 10% lower than existing grid hydro generation.
   iii. Existing grid hydro generation.
   iv. 10% higher than existing grid hydro generation.
   v. 20% higher than existing grid hydro generation.

ANSWER:

(a)

The question does not quote YEC's response correctly, which stated as follows (the bolded part highlights the words omitted): "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 attached spreadsheet. In preparing the spreadsheet, the percentage changes were calculated based off the forecast hydro generation for the GRA for 2013 as the “existing grid hydro generation” value as detailed below.

Please note the following:

- For all of the scenarios, the grid load was retained at the GRA level of 430.357 GW.h.

- Secondary has been retained at 0 GW.h as per GRA forecasts. It is likely that in the higher flow cases some secondary sales would be made, but it is very difficult to forecast a precise value.

- The GRA forecast hydro for 2013 is 419.405 GW.h of hydro generation (101.8% of long-term average hydro generation of 411.95 GW.h) and 10.714 GW.h of diesel generation (59% of expected diesel generation of 18.1 GW.h based on long-term average hydro generation).

- For each of the cases, the following hydro generation values were used:
    - GRA forecast less 20% equals 335.524 GW.h of hydro generation. At the GRA load levels, this condition would be expected to be very rare, with droughts this bad or worse only occurring in approximately 4% of the conditions studied (typically corresponding to 1999 water conditions).
    - GRA forecast less 10% equals 377.464 GW.h of hydro generation. This condition would be expected to be quite rare, with droughts this bad or worse only occurring in approximately 12% of the conditions studied.

- GRA forecast plus 10% would equal 461.345 GW.h, however there is only 430.357 GW.h of load and generation cannot exceed load. As a result, this scenarios assumes no material diesel generation and all generation (other than a small amount of wind) to come from hydro.
- GRA forecast plus 20% ends up with the same result as GRA plus 10%.

The DCF balance begins with $0.946 million in a credit position which is an approximate 2013 starting balance (the precise value will depend on the transactions and interest for 2012). For calculation purposes, the interest is calculated at 2.5%; in practice this rate will be based on market rates in 2013.

Diesel Contingency Fund Scenario Analysis for Different Level of Hydro Generation (2013)

Case descriptions for 2013 scenarios (all scenarios assume wind generation at GRA forecast):

Case #1: Hydro Generation at GRA Forecast
Case #2: Hydro Generation 20% Lower than GRA Forecast
Case #3: Hydro Generation 10% Lower than GRA Forecast
Case #4: Hydro Generation 10% Higher than GRA Forecast
Case #5: Hydro Generation 20% Higher than GRA Forecast

		Cases				
		Case #1	**Case #2**	**Case #3**	**Case #4**	**Case #5**
	Hydro (MW.h)	419,405	335,524	377,464	430,119	430,119
	Diesel (MW.h)	10,714	94,595	52,655	0	0
	Wind (MW.h)	238	238	238	238	238
L1	Total YEC Supply (MW.h)	430,357	430,357	430,357	430,357	430,357
L2=L1-238	Actual Grid Load (Load less GRA Wind Generation) (MW.h)	430,119	430,119	430,119	430,119	430,119
L3	Grid Load Benchmark (MW.h) (Table 3.2-2)	430,000	430,000	430,000	430,000	430,000
L4	Diesel as % of Increased Load (MW.h)	56%	56%	56%	56%	56%
L5	Expected Base Diesel Generation (MW.h)	18,100	18,100	18,100	18,100	18,100
L6=(L2-L3)xL4	Expected Incremental Diesel Generation (MW.h)	67	67	67	67	67
L7=L5+L6	Total Expected Diesel Generation (MW.h)	18,167	18,167	18,167	18,167	18,167
L8=L7x59%	Expected Diesel Generation in Rates (MW.h)	10,714	10,714	10,714	10,714	10,714
L9	Actual Diesel Generation (MW.h)	10,714	94,595	52,655	0	0
L10=L9-L8	Diesel Generation to be Included in DCF (MW.h)	0	83,881	41,941	- 10,714	- 10,714
L11=L10x$0.3168	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)	$ 0	$ 26,574	$ 13,287	-$ 3,394	-$ 3,394
	DCF Opening Balance ($000s)	($ 946)	($ 946)	($ 946)	($ 946)	($ 946)
	Additions/Withdrawals	$ 0	$ 26,574	$ 13,287	($ 3,394)	($ 3,394)
	Secondary Sales Credit (note 1)	$ 0	$ 0	$ 0	$ 0	$ 0
	Closing Balance Before Interest	($ 946)	$ 25,628	$ 12,341	($ 4,340)	($ 4,340)
	Interest Earned (Charged) - estimated at 2.5%	($ 24)	$ 641	$ 309	($ 109)	($ 109)
	Closing Balance ($000s)	($ 970)	$ 26,269	$ 12,650	($ 4,449)	($ 4,449)

Notes:
1. YEC does not forecast secondary sales for the 2013 test year. Any actual secondary sales will be credited to DCF account.

TOPIC: **Forecast Cost of Debt**

REFERENCE: **Response to CW-YEC-1-38(e)**

PREAMBLE:

YEC was asked:

> "What is the timing of the forecast new loans from YDC and how have YEC and YDC forecast the cost of these new issues? (underlining added)."

YEC's response to this information request appears to have omitted a response to the second half of the question (underlined).

QUESTION:

a) Please provide a detailed description of the process employed by YDC and YEC to determine its forecast cost of debt for the test years. Please provide all the forecasts employed, historical spreads observed and all other numerical and judgmental factors employed in determining YEC's forecast cost of debt.

ANSWER:

(a)

Forecast cost of debt is based on estimates of the amount of debt which is prescribed by YEC's authorized capital structure (60% long-term debt and 40% equity) and a forecast interest rate.

Forecast debt amounts for each test year reflect the outcome of forecast rate base at year end, and the assumption that 60% of this rate base will be financed by long-term debt. The Application describes in detail the process carried out to arrive at forecast rate base requirements.

New YEC debt required at the end of each fiscal year has typically been provided by YDC. Since the early 1990s, interest rates on such new YDC debt have been set each

year based on a proxy for market conditions (i.e., long-term Canada bond rates plus 120 basis points to reflect the estimated spread for YEC debt guaranteed by the Yukon Government).

In 2010, YDC went to market for new long-term debt ($100 million bond with a 30 year term) and secured an interest rate of 5%. When preparing the current GRA forecasts in late 2011, YEC used this 5% most recent market-based long-term interest rate for the new long-term debt forecast for the test years. No other forecasts or analysis were employed.

Leading Edge
(LE)

TOPIC: **Tab 1 Introduction**

REFERENCE: **LE-YEC-1-1(g)**

PREAMBLE:

QUESTION:

a) In 1999 was there not a cost for diesel fuel (based on a unit cost of about $0.30 per litre) included in “base” rates?

b) In 2011 did base rates not include a cost for diesel fuel (based on a unit cost of about $0.96 per litre) in the new “base” rates?

ANSWER:

(a) and **(b)**

"Base rates" for firm service to retail customers are rates as approved by the YUB during revenue requirement reviews, and include specific rate schedules for each customer class and general rate riders (e.g., Rider J as approved in the past for YEC) applicable to all firm retail rates. "Base rates" as so defined do not include Rider F.

Diesel fuel was included in the YUB-approved revenue requirement that resulted in approved "base rates" in 1997 (which rates, subject to a new general rate rider resulting from the Faro mine closure, continued to apply in 1999) and 2009 (which rates continued to apply in 2011), and the approved forecast cost per litre for diesel fuel included in these "base rates" increased from 1997 to 2009 approximately as set out in the question. Notwithstanding the increased cost per litre for diesel fuel over this period, "base rates" for firm retail service as required to recover YEC's approved revenue requirement did not increase after 1999 until the current 2012/13 GRA.

In 2009 and 2011, customers also were affected by the then prevailing Rider F which is not part of the revenue requirement review process and not part of the base rates approved by the YUB based on revenue requirement reviews.

TOPIC: **Tab 1 Introduction**

REFERENCE: **LE-YEC-1-5(c)**

PREAMBLE:

QUESTION:

a) YEC says that it is important that the DCF "continue" to be built up which implies that the DCF is now building up. Please provide the relevant details for 2012 and 2013.

b) Does YEC have information that 2013 will be wetter than average or does YEC plan to use water stored in reservoirs to generate more than the actual proposed amount of hydro generation (which is 101.8% of long term average) in order to replenish the DCF?

ANSWER:

(a) and **(b)**

YEC's response to LE-YEC-1-5(c) referenced information that indicates a likelihood that the DCF will be built up to some degree during 2012 and 2013 test years. In addition to referencing current favorable water supplies (which tend to increase hydro generation above long term average in at least 2012), it was noted for 2013 that diesel generation at 59% or more of long term average (about 10.7 GW.h/yr or more) occurs only approximately 54% of the years at the forecast 2013 grid load. In short, due to the forecast loads, the assumed diesel generation in rates in 2013 is equal to about what can be expected to occur in roughly half of the years.

Based on favorable water conditions in 2012, it can be expected that favorable water storage at Aishihik and Mayo Lake will carry over into 2013. YEC, however, has no basis to predict whether 2013 will be wetter than average. The assumed amount of 2013 hydro generation in the GRA (at 101.8% of long term average) simply reflects the proposed 59% of long-term average diesel generation to be included in rates, rather than any YEC forecast of actual hydro generation in 2013.

TOPIC: **Tab 3 Revenue Requirement**

REFERENCE: **Page 3-3 re: Fuel Purchase Costs**

PREAMBLE:

QUESTION:

a) Does YEC include in its forecast revenue requirement to be recovered from the proposed rate riders, the cost of diesel fuel at the 2012-2013 GRA forecast cost per litre?

b) If the answer to (a) is yes, how will this affect Rider F calculations which captures fuel price variances for both YEC and YECL?

ANSWER:

(a)

Yes.

(b)

There will be no problem - Rider F calculations have always allowed for differences between YEC and YECL as regards GRA timing as it affects revisions to approved diesel fuel prices.

TOPIC: **Tab 3 Revenue Requirement**

REFERENCE: **LE-YEC-1-14(b)**

PREAMBLE:

QUESTION:

a) The response states in part: "Overall, the precipitation was below average for the year 2011" yet Table 2 indicates that precipitation was 10.5mm above the 1970 to 2000 average (the table erroneously states the variance as -10.5mm). Please clarify.

ANSWER:

(a)

The response to LE-YEC-1-14(b) should have read:

> Overall, the precipitation in the last months of 2010 was higher than average; however precipitation during the months leading up to the 2011 summer period fell drastically and was below average. This contributed to an average snowpack which resulted in an average water year within the southern lakes system. The above average rainfalls recorded during the summer months were not sufficient to increase water levels at Marsh Lake such that secondary sales could be resumed.

TOPIC: **Capital Projects**

REFERENCE: **Page 5-5/6 Mayo B Project**

PREAMBLE:

QUESTION:

a) What flow rate (in CMS) into Mayo A is required for it to run at full capacity, and what is that maximum capacity?

b) What flow rate (in CMS) into Mayo B is required for it to run at its full capacity, and is its capacity exactly 10MW? If not please provide its actual capacity.

ANSWER:

(a)

The Mayo A plant has never had performance testing completed since the installation of new runners approximately a decade ago, but the plant design flow is approximately 17 cms. The nameplate capacity of the Mayo A station is 5.31 MW (nameplate).

(b)

The Mayo B plant is designed to operate at 10 MW at 19 cms of flow. The detailed performance testing related to commissioning of the new plant is not yet completed.

TOPIC: **Other Matters**

REFERENCE: **Yukon Energy 20-year Resource Plan update and response to YECL-YEC-1-18(a)**

PREAMBLE:

QUESTION:

a) In a public meeting reviewing the draft updated 20-year Resource Plan Yukon Energy representatives indicated that they are soliciting input from the public this fall for the purpose of finalizing the Resource Plan update. Information circulating in the days following the meeting indicated that the end of September is the deadline for public comments for incorporation into the final plan update. Is this correct, and if not please provide the deadline date for receipt of public comments for consideration in finalizing the Plan.

b) When does Yukon Energy expect the final updated Resource Plan to be completed and made available to the public?

c) Does Yukon Energy expect the final plan to be reviewed by the Yukon Utilities Board in a proceeding, whether in writing or in hearing format?

d) If the answer is “yes” please provide the relevant details.

e) If the answer to the above is “no”, how does Yukon Energy propose to ensure that its Resource Plan update and all therein has been tested, and endorsed by the YUB / Yukon government / public so that it can be “translated” into supportable action plans as necessary? Please explain.

ANSWER:

(a)

The draft updated Resource Plan has been provided for review and comment by the public and participants in the current GRA proceeding. Accordingly, Yukon Energy will

be able to consider comments received until mid to late November, when the GRA hearing process has concluded.

Copies of the draft Resource Plan documents are available on YEC's web site (see below).

http://www.yukonenergy.ca/about/business/resourceplans/

(b) through **(e)**

The following was noted at Page 3 of the July 2012 Overview of 20-Year Resource Plan: 2011-2030 (which was provided in response to YECL-YEC-1-18(a)):

> "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."

The public review has been carried out since the release of the Overview in late July, and Yukon Energy will be able to consider comments received until mid to late November, when the current GRA hearing process has concluded. Yukon Energy will then provide to the public as soon as feasible thereafter the results of this review.

The Board and parties will have the opportunity in the current GRA proceeding to examine and ask questions about the Overview and draft 2011 Resource Plan that have been made public. Apart from this YEC GRA proceeding, Yukon Energy is not aware of any process for review by the Board of the 2011 Resource Plan other than processes initiated by ministerial direction pursuant to the *Public Utilities Act*, e.g., Part 3 proceedings to review designated energy projects.

As noted in the July 2012 Overview of 20-Year Resource Plan: 2011-2030, Yukon Energy recognizes that the 2011 Resource Plan, as with its predecessor, is a living document that continues to evolve. The Overview also noted that 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.

Utilities Consumers' Group
(UCG)

TOPIC:

REFERENCE: **Application Tables 3.1, 3.2, 3.3, 3.5, 3.6, 3.7, 3.8, 3.9, 3.10, 3.11, 3.12, 3.13, 3.15, Schedule 9 from CW-YEC-1-37(a) Attachment 1, Table 1 from UCG-YEC-1-21(b), Table 1 from UCG-YEC-1-22(b)**

PREAMBLE:

QUESTION:

a) Please provide a single schedule that outlines forecast versus actual results for all components of revenue requirement and all sources of revenue (including all customer classes) for years included in the last GRA (2008 and 2009) as well as years since the last GRA (2010 and 2011). Please provide the level of detail outlined in the referenced tables. Please provide the data in Excel spreadsheet format.

ANSWER:

(a)

Attachment 1 provides the components of the revenue requirement and sources of revenue in a single schedule.

This request does not seek any clarification of any first round interrogatory. All of the information requested is already on the record of this proceeding (either in the GRA Application or in IRs). The request is to provide for a re-packaging of this extensive information in one schedule - the format requested is unclear, and to provide all of the information requested in the detail requested could result in a large table that would not be easy to format or present in any coherent or useful manner. If single schedule formats other than the attached are desired, these can be prepared by UCG or any other intervenor in this proceeding based on the information already available.

Yukon Energy Corporation
Revenues and Expenses
($000s)

Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011
Utility expenses					
Non-Fuel Operating and Maintenance					
Production	Table 3.5	2,977	3,759	4,179	4,472
Labour		*2,179*	*2,796*	*2,943*	*2,994*
Diesel		*194*	*333*	*297*	*615*
Hydro		*560*	*602*	*895*	*852*
Wind		*8*	*6*	*6*	*5*
Operation Supervision		*36*	*22*	*38*	*6*
Transmission	Table 3.6	1,094	1,208	795	1,110
Labour		*482*	*453*	*319*	*396*
Brushing		*377*	*387*	*268*	*434*
Other Non-Labour		*235*	*369*	*208*	*280*
Distribution	Table 3.7	699	660	588	657
Labour		*521*	*546*	*477*	*473*
Brushing		*46*	*17*	*16*	*68*
Other Non-Labour		*132*	*97*	*96*	*116*
General Operating and Maintenance	Table 3.8	952	1,145	1,194	1,336
Labour		*94*	*143*	*184*	*142*
Transportation		*394*	*401*	*419*	*449*
Maintenance of Company Owned Properties		*384*	*471*	*489*	*650*
SCADA Communication		*80*	*130*	*102*	*96*
Administration	Table 3.9	6,148	6,453	6,418	7,197
Labour		*3,605*	*3,725*	*3,797*	*4,338*
Resource Planning		*17*	*18*	*24*	*128*
Communications		*105*	*98*	*119*	*98*
Customer Accounting		*206*	*182*	*185*	*194*
Environmental Mgmt		*52*	*50*	*82*	*152*
General		*734*	*886*	*611*	*804*
Information Systems		*425*	*595*	*548*	*388*
Fish Hatchery		*136*	*159*	*176*	*140*
Fish Ladder[1]		*26*			
Safety		*162*	*187*	*201*	*177*
Training		*211*	*205*	*150*	*184*
Recruitment		*169*	*138*	*192*	*83*
Board of Directors		*148*	*113*	*100*	*289*
Union		*26*	*9*	*72*	*25*
Regulatory Affairs		*57*	*27*	*77*	*156*
Material Management		*43*	*(6)*	*64*	*18*
Contracting		*11*	*60*	*17*	*8*
Professional Development		*15*	*9*	*2*	*15*
Insurance and Reserve for Injuries & Damages	Table 3.10	1,052	887	887	874
Insurance		*952*	*787*	*787*	*774*
Reserve Appropriation (RFID)		*100*	*100*	*100*	*100*
Property Taxes	Table 3.12	256	288	291	297
Total Non-Fuel Operating and Maintenance	Table 3.3	13,178	14,400	14,353	15,943

Yukon Energy Corporation
Revenues and Expenses
($000s)

Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011
Fuel and Purchased Power	Table 3.2	497	658	1,183	2,746
Fuel		*443*	*622*	*1,145*	*2,708*
Purchased Power		*54*	*36*	*38*	*38*
Depreciation and Amortization	Table 3.13	6,869	6,555	6,656	6,901
Fixed Asset Depreciation		*6,522*	*7,210*	*7,365*	*7,898*
Less: Customer contribution		*(1,091)*	*(1,896)*	*(1,846)*	*(2,175)*
Less: Amortization of fire insurance recoveries		*(270)*	*(270)*	*(270)*	*(270)*
Plus: Amortization of deferred charges		*1,707*	*1,511*	*1,407*	*1,447*
Total utility expenses		20,543	21,613	22,192	25,590
Return on Rate Base	Table 3.1	10,488	10,095	10,184	8,704
Average Rate of return on rate base	*Table 3.15*	*7.09%*	*6.90%*	*6.82%*	*4.84%*
Total	**Table 3.1**	**31,031**	**31,708**	**32,376**	**34,294**
Revenues					
Residential					
Sales (MW.h)	Table 2.1, UCG-YEC-1-21 (a) and (b)	11,183	11,676	11,386	12,710
Revenues ($000)	Schedule 9	1,335	1,386	1,359	1,694
General Service					
Sales (MW.h)	Table 2.1, UCG-YEC-1-22 (a) and (b)	19,543	19,672	22,719	21,305
Revenues ($000)	Schedule 9	2,637	2,696	2,942	3,218
Industrial					
Sales (MW.h)	Table 2.1	29,023	29,355	30,255	43,259
Revenues ($000)	Schedule 9	3,203	3,190	3,311	4,599
Lighting					
Sales (MW.h)	Table 2.1	293	523	297	297
Revenues ($000)	Schedule 9	74	63	77	85
Wholesale sales					
Sales (MW.h)	Table 2.1	267,747	267,229	276,345	290,541
Revenues ($000)	Schedule 9	18,314	18,279	18,902	21,940
Secondary					
Sales (MW.h)	Table 2.1	7,584	17,384	10,489	552
Revenues ($000)	Schedule 9	470	1,066	644	46
Rider J	Schedule 9	4,518	4,493	4,944	2,466
Post-GRA Reconciliation	Schedule 9	355	355		
Other Revenues	Schedule 9	125	181	198	247
Total Revenues		31,031	31,708	32,376	34,294

Note:
1. Fish Ladder cost for 2009-2011 actuals included in Production Function.

TOPIC:

REFERENCE: YEC Backgrounder to Application and response to YUB-YEC-1-2. When explaining the need for this Application and increased rates.

PREAMBLE:

YEC states:

- Demand from all sectors: the need for power by Yukon's mining industry is only part of the story. Increased residential, business and government consumption has also strained the power grid.

- Maintaining existing assets: the cost of keeping our aging infrastructure efficient and up-to-date has increased faster than energy rates. Yukon Energy's assets need substantial.

- Thirteen years of inflation: the costs of salaries, materials and services keep climbing.

- Funding tomorrow's energy: finding sufficient clean, affordable and reliable energy requires years of public and stakeholder consultation, research, engineering and project approval.

QUESTION:

a) Please confirm that increased load growth has provided greater revenues to YEC. Please provide details of the additional revenues related to load growth for 2009 through 2012 to date.

b) Please confirm that all load growth in 2009 through 2012 to date resulted in revenues that exceeded all incremental costs (not just generation-related costs). Please provide details offload growth and related revenues and costs.

c) If revenues related to load growth did not exceed incremental costs, please explain why a utility would spend millions of dollars to provide increased power generation for new customers when the expenses will exceed the revenues?

d) Please confirm whether the industrial rate covers all costs to serve industrial customers in 2012 and 2013. Please provide details of related costs and revenues.

ANSWER:

(a) and **(b)**

Confirmed, industrial load growth since 2009 has brought revenues that exceed incremental costs. For calculations, please see YUB-YEC-1-2.

(c)

As noted in YUB-YEC-1-2 (provided as Attachment 1 to this response) incremental revenues for industrial customers will exceed incremental costs in the test years. On a hypothetical basis, if revenues did not exceed incremental costs YEC still continues to have an obligation to provide power to customers within its service area, regardless as to class. When any customer class load grows, and there is not offsetting reductions in other classes, then the system must invest in expansion. This is the case whether the customer is a residential, commercial or an industrial customer, and regardless as to whether the cost of expansion power is above or below the rates being charged (which are typically more linked to average embedded cost than to incremental costs).

(d)

This is a cost of service question beyond the scope of the current hearing.

Based on the last cost of service study reviewed by the Board (2009), the industrial class was paying revenues well in excess of allocated cost of service.

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

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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:

REFERENCE: Application Page 1-10, YUB-YEC-1-8(a) Revised Attachment 1 and YUB-YEC-1-14

PREAMBLE:

YEC states:

- Forecast labour expense requirements by the end of the test period are approximately $2.5 million higher than that approved in 2009. This overall increase reflects a forecast 12.26 FTE increase in positions in 2013, down slightly from the approximately 13.05 FTE increase noted in 2011 compared to 2009 approved. Key areas of increase are President (2 FTE increase), Resource Planning and Environment (6 FTE increase), Finance, Customer Accounting & Purchasing (4.19 FTE increase), Operations (1.15 FTE increase) and Engineering (1 FTE increase).

- Over the period from 2009 approved to 2013 forecast there is also a similar $2.7 million overall increase in non fuel & non labour O&M cost requirements (about $1.3 million of this growth is expected in 2011 preliminary actuals). The largest areas of increase are in administration ($1.341 million increase in 2013 forecast over 2009 approved) and production ($0.639 million increase in 2013 forecast over 2009 approved).

QUESTION:

a) Please provide a chart summarizing all administrative labour costs and union staff labour costs for 2009 through 2012 to date.

b) Please provide a breakdown of positions, salaries, wages and benefits for all administrative and union staff positions for 2009 through 2012 actual to date and forecast (i.e., each individual administrative position compensation and each designated union personnel compensation and number in each department).

c) Please provide details of all positions of all FTEs added in 2009 through 2012 referencing whether they are administrative or union.

d) Please provide a chart with the annual costs of all FTEs added in 2009 through 2012.

e) Please provide details of actual consultant costs incurred (i.e., a breakdown of the summary provided), contracts and services provided for 2009, 2010 and 2011 as well as forecast for 2012 and 2013.

f) Please explain whether and how the additional FTEs have resulted in savings on consultant costs.

ANSWER:

(a)

YEC does not track staff costs in the manner requested. Given the volume of IRs and prescribed deadlines, the manual process to accumulate this information cannot be completed at this time. In lieu of this, the table appended below is assembled from summary tax information that is indicative of annual costs but will not reconcile precisely to figures in the Application.

For the purposes of this question, YEC is assuming "administrative" refers to non-union staff.

Please see Table 1 below for union and non-union wages and benefits.

Table 1 – Union and Non-Union Wages and Benefits

	2009	2010	2011	2012 YTD
UNION	$ 5,501,886	$ 5,906,284	$ 6,331,298	$ 3,967,342
NON UNION	$ 3,652,246	$ 3,655,329	$ 4,138,711	$ 2,734,362
Totals	**$ 9,154,132**	**$ 9,561,614**	**$ 10,470,009**	**$ 6,701,703**

(b)

YEC is now subject to ATIPP legislation since 2009, and as a result YEC believes such information cannot, as requested, be disclosed.

(c)

Please see Table 2 below which provides FTEs added 2009 through 2012 and provides whether position is administrative or union.

Table 2 – FTEs added 2009 through 2012 (administrative vs union)

Position Added	Union Member	Year Added	Count
SQL/Sharepoint Administrator	Yes	2010	1
Communications, Protection & Control Technologist	Yes	2010	1
Apprentice Millwright-moved in 2011 to Apprentice Powerline Tech.	Yes	2010	1
Electrical Engineer	No	2010	0
Capital Maintenance Electrician	Yes	2010	1
Capital Maintenance Mechanic	Yes	2010	1
Director, Major Projects	No	2010	1
Plant Operator-Faro	Yes	2010	0.75
Environmental Coordinator	Yes	2011	1
Resource Planning Engineer	No	2011	1
Backfill Controller	No	2011	1
Manager, Energy Conservation	No	2011	1
Energy Conservation Administrator	Yes	2011	1
SCC Operator	Yes	2011	1
Financial Analysis	Yes	2012	1
TOTAL			**13.75**

Note: Table 2 only includes FTE additions for permanent and term positions and does not include adjustments to casual positions or reductions in complement. With this considered the total FTE increase between 2009 and 2012 would be 12.26 FTEs as noted in Table 3.4 of the Application.

(d)

YEC does not track staff costs in the manner requested. Given the volume of IRs and prescribed deadlines, the manual process to accumulate this information cannot be completed at this time. In lieu of this, the table appended below is assembled from summary tax information that is indicative of annual costs but will not reconcile precisely to figures in the Application.

Annual costs for all FTEs added in 2009 through 2012 are as noted below.

Table 3 – Total Annual Cost of Cumulative Additional FTEs

Year	Cumulative FTEs	Total Annual Cost
2009	0	$ -
2010	6.75	$594,814
2011	12.75	$1,195,934
2012	13.75	$1,688,429

(e)

YUB-YEC-1-8 provides a breakdown of all consultant costs for the years referenced and a description of the services provided/forecast to be provided. The question is not clear what additional "details" are required.

(f)

Depending on the circumstances, added positions may result in consulting cost savings; however:

- Yukon Energy has been undergoing material growth in demand and systems which requires additional staff. For example, the capital electrician and mechanic are needed to deal with large capital programs, at the same time as maintenance trades are required to deal with increased assets under their responsibility.

- Staff are also hired to manage new programs or functions. For example, the DSM program is a new and material initiative for Yukon Energy that required staff to oversee.

As far as savings from displaced consultants, YEC will hire staff where there is a long term requirement for a given specialty in-house and in each of these cases the work being done in-house results in consultants or contractor savings to the full extent of the staffing costs.

TOPIC:

REFERENCE: Response to CW-YEC-1-31

PREAMBLE:

Yukon Energy has included a "placeholder" expense related to estimated costs for the current GRA (Phase I) Application.

QUESTION:

a) Please provide details of the estimated costs related to the $1.1 million placeholder amount including a breakdown of all forecasted consultant costs (including name of each consultant and work to be completed) as well as a breakdown of all forecasted internal costs and work details.

ANSWER:

(a)

A breakdown of these forecast costs cannot be provided at this time. As noted the $1.1 million amount provided is a placeholder amount (meaning that the amount was not based on detailed estimates).

GRA hearing costs when finalized after a hearing are broken down by consultant (including legal and payments for YUB and intervenor costs) or by internal costs and work details. Due to the nature of oral hearings, where costs will be affected by the issues and levels of detail pursued and time periods for the hearing process, YEC does not attempt to forecast such costs on any detailed basis when preparing a GRA. For budgetary purposes, YEC estimated the cost of the project as follows:

Consultants and other costs (includes legal and payments to YUB and interveners)	$1.0
Contingency	0.1
	$1.1

These estimates were based roughly on the cost of the last YEC GRA proceeding (08/09); total incurred costs were as follows:

YEC Internal costs (including legal and consulting)	$0.701
Intervenor and Board costs	0.219
	$0.920

For the current process, until the first round of IRs was filed it was difficult to predict how intensive the work requirements for YEC or its consultants would be. The first round of IRs included 906 questions and to respond within the time period required was a labour intensive process that required considerable additional resources. Based on the last GRA, YEC also could not predict a second round of IRs in this process. This has added approximately 130 further questions (bringing the total number of IRs in this proceeding to an unprecedented 1036 IRs). The volume of interrogatories and detailed nature of some of the questions is indicative of a process with a larger number of issues and greater complexity than past GRAs, as well as a process extending over a longer time period than the last GRA.

The requested detailed information will all be available at the time of the cost award review process (after the Board has issued its final Order and the oral hearing is complete). As in recent reviews, this process will include exhaustive and specific detail including breakdown of actual invoiced costs by consultant and internal YEC costs.

TOPIC: **DSM**

REFERENCE: **Response to YUB-YEC-1-46, Application Appendix 5.2, Application page 2-5 and Application Tables 5.5 – 5.7**

PREAMBLE:

YEC is looking to recover DSM-related costs of pilot projects despite the fact that audit recommendations have not been implemented and no peak-shaving benefits will be realized in the test years. There is limited explanation provided regarding the activities listed in Attachment 1 of YUB-YEC-1-46(d) and it is impossible to guess what might be included under "YEC – Owner Costs", "DSM Reallocations" and "Phone & Cell" or even what these areas are about.

QUESTION:

a) Please provide a cost-benefit analysis and full description of all DSM-related activities undertaken in 2010, 2011 and forecast for the test years.

b) Please explain why customers receiving energy audits are not paying for the cost of the audit since they will receive the benefits.

c) Please identify the energy efficiency and conservation efforts that have already been undertaken by industrial customers.

ANSWER:

(a)

Cost benefit analyses are provided for specific programs when these programs are developed after a Conservation Potential Review is undertaken.

The Conservation Potential Review was undertaken in 2011 and 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 such, the DSM work is in Phases 2 and 3 of planning, i.e., preparing the business cases for specific program activities. In this respect as DSM

programming for the test years is still being developed, cost/benefit analyses are not available at this time.

With regard to DSM-related activities undertaken to the end of 2011, the response to YUB-YEC-1-46 describes all DSM-related activities that account for total spending of approximately $1.037 million to the end of 2011. Over 90% of these expenditures are related to DSM planning for which program cost benefit assessments are not applicable, including the DSM Conservation Potential Review, pilot programs, community engagement, end use surveys, working groups, energy audit and management plan, and public education/communication. The DSM/LED Streetlight Project (on which $0.061 million was spent to the end of 2011) is a specific DSM program for which cost benefit analysis is being used to shape the program design.

The DSM program is on YEC's website at link below.

http://www.yukonenergy.ca/downloads/db/1121_Dawson%20LED%20Streetlight%20Pilot%202011%20Report.pdf

(b)

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.

Further, 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 recommendation 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.

(c)

Implementation of specific DSM measures is the responsibility of the industrial customer. Yukon Energy does not at this time have specific information regarding specific conservation measures implemented at each industrial customer site.

TOPIC: **Internal DSM**

REFERENCE: **Response to CW-YEC-1-21(b)**

PREAMBLE:

YEC indicates that the regulatory cost forecasts for 2012 and 2013 include $1.074 million in 2012 and $1.635 million in 2013 for DSM and that a material portion of DSM costs incurred to date, and expected to be incurred in the test years, relate to internal DSM within YEC.

QUESTION:

a) For each of the projects related to "internal DSM within YEC", please provide a detailed breakdown and explanation of each project, a cost-benefit analysis of each project, the targeted savings for each project, and details of feasibility analysis showing how these targeted savings will be achieved.

ANSWER:

(a)

An audit of YEC's key facilities has been completed. YEC is currently evaluating the recommendations and completing cost/benefit analysis of the potential projects.

To date, no specific projects have been identified for execution.

TOPIC: **Transmission and Distribution**

REFERENCE: **Response to CW-YEC-1-18 and CW-YEC-1-19**

PREAMBLE:

QUESTION:

a) Please provide a detailed explanation on why any of the transmission and distribution costs shown on the charts in these IR responses increase above the annual inflation rate between 2011 and 2012 and between 2012 and 2013.

ANSWER:

(a)

YUB-YEC-1-17 provides an analysis of transmission brushing costs. YECL-YEC-1-28 provides an analysis of distribution brushing costs. Copies of each response are provided as Attachment 1 to this IR for reference.

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: **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:

REFERENCE: Application Tab 7, Schedule 11, Page 7

PREAMBLE:

New YDC Loans are identified for 2011 ($19.148 million), 2012 ($41.421 million) and 2013 ($50.111 million).

QUESTION:

a) Please provide a detailed explanation of what each of these loans has / will be used for, the terms of these loans, and the costs to ratepayers of these loans in each of the test years.

ANSWER:

(a)

To clarify, the New YDC Loan amounts in the preamble are cumulative in 2012 and 2013, e.g., the 2012 amount of $41.421 million includes $22.911 new debt at year end plus the remaining $18.510 amount of the 2011 new debt of $19.148 million.

Forecast new loans are assumed to be issued in the respective forecast years (2011-2013) to maintain 60% debt and 40% equity ratio based on year-end ratebase. Financing cost of the new loans in these years is forecast at 5% annual interest rate assuming the new-long term debt is secured at the end of the forecast year. Although titled as “New YDC Loans”, YDC finances YEC’s new long-term debt only when such funds are available from YDC. Future loans may be provided by external financing.

Schedule 11 in Tab 7 shows forecast interest costs on these loans, i.e., interest of $0.960 million in 2012 (based on $19.148 million new loan at end of 2011) and interest of $2.071 million in 2013 (based on the $22.911 million new loan at the end of 2012 as well as the new loan at the end of 2011). The New YDC Loans contribute about 21% of the 2012 Total Cost of Interest (Mid-Year Cost of Debt of 3.38%) and about 37% of the 2013 Total Cost of Interest (Mid-Year Cost of Debt of 3.90%). The Mid-Year Cost of

Debt is applied in Schedules 4B and 4C to determine the forecast Return on Rate Base for each test year.

TOPIC:

REFERENCE: Application Tab 5

PREAMBLE:

QUESTION:

a) Please provide details of the YUB's direction from regulatory reviews of any major capital project costing $1 million or more.

b) Please provide any correspondence or letters of concern from Champagne Aishihik FN or any interested party on the Gladstone Diversion project.

c) Please provide any correspondence or letters of concern from Taku River Tlingit FN, Protect Atlin Lake Society or any interested party on the Atlin Lake Storage project.

d) Please provide any correspondence or letters of concern from Marsh Lake Community or any interested party on the Marsh Lake Storage project.

e) Please provide correspondence or letters of concern from Nacho Nyak Dun FN or any interested party on the Mayo Lake Enhanced Storage project.

ANSWER:

(a)

It is unclear what is being referred to in terms of "YUB direction".

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 before they are constructed:

1. **Approach #1: Directions from Government under Section 17 or 18 of the PUA** – This approach has been used in the past for the 1992 YEC/YECL Resource Plan review and the 2006 20-Year Resource Plan review. In each case the Board was given direction to provide a report and recommendations to the government.

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 obtain a review by the YUB of a capital project or projects before they are constructed is through a General Rate Application. Yukon Energy continues to bring before the Board for review in this GRA, and in previous GRAs, information on its ongoing major capital projects.

[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.

(b) through **(e)**

The request to "provide any correspondence or letters of concern" from various specific parties "or any interested party" on the four named projects is an overly broad request and is not even seeking to clarify anything specific from the first round of IRs. The projects noted have been ongoing for many years and numerous individuals within YEC and numerous consultants and stakeholders have been involved in each project. Even to properly respond to a more reasonable request would require significant time and cost to gather together all the information. In addition, such overly broad requests invariably raise concerns regarding confidentiality, privacy concerns and privilege that must be carefully reviewed before any information is produced.

Given the nature of this proceeding, the fact that it is an overly broad request, and because of the above noted concerns, YEC is not in a position to provide the information requested.

TOPIC:

REFERENCE: Rate Schedule 39 Escalation Clause

PREAMBLE:

QUESTION:

a) Please confirm that the annual escalation clause for demand and energy charges of the Firm Mine Rate (Rate 39) remains intact under OIC 2012/068 and any rate adjustments allowed as part of this current proceeding.

b) Please confirm that any additional revenues from adjustments to industrial rates will benefit non-industrial ratepayers and explain how this will be accommodated.

ANSWER:

(a)

As noted in Tab 4 of the Application, 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.

(b)

Not confirmed, other than for added revenues as approved by the YUB in this GRA.

With regard to added revenues approved by the YUB in this GRA, the requirement to increase industrial rates by more than occurred as of January 1, 2012 results in a lower rate rider requirement overall to secure the same revenue requirement, and thus a lower rate increase for classes of retail customers.

In each test year, Yukon Energy is seeking the same percentage increase to both retail and industrial rates.

TOPIC: **Reserve for Injuries and Damages**

REFERENCE: **Application page 3-17 and Response to YUB-YEC-1-6**

PREAMBLE:

The Reserve for Injuries and Damages account is maintained to address uninsured and uninsurable losses as well as the deductible portion of insured losses. The only alternative considered by YEC to applying the remaining balance in the Faro Dewatering Account against the outstanding balance of the Reserve for Injuries and Damages account was to include the RFID in rate base.

QUESTION:

a) Please provide details of the costs currently included in the RFID account and how these costs were incurred.

b) Please identify the cost of purchasing additional insurance to cover some or all of the costs identified in the RFID account.

ANSWER:

(a)

Please see the response to YECL-YEC-1-51(b) and (c) provided as Attachment 1 to this response.

(b)

The RFID account is maintained to address uninsured and uninsurable losses as well as the deductible portion of insured losses. No cost can be identified for purchasing additional insurance to cover some or all of the costs identified in the RFID account.

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:

REFERENCE: Reference: Application Tab 7, Schedule 5 and Schedule 10

PREAMBLE:

According to its web site, YEC's "philosophy is to help make a difference in the communities where we live and work, and we take our responsibility seriously to be an active and good corporate citizen. As a public utility we annually give a portion of our net earnings back to Yukoners through donations and sponsorship to non-profit groups. Yukon Energy's Donations and Sponsorship Program is a significant source of assistance for many Yukon groups and is clearly improving the quality of community life. The program is also good business. It is part of the ongoing process of being open, accessible and recognized by Yukon ratepayers. Yukon Energy's Donations & Sponsorship Program provides financial support to registered non-profit groups in the following areas: Arts, culture, tourism / Sports and recreation / Health, social services and education.

QUESTION:

a) Please confirm that the $85,000 proposed to be recovered from ratepayers in both 2012 and 2013 and that none of YEC's donations are recovered from other sources.

b) Please confirm that tax benefits associated with these donations are reflected in the application's revenue requirement.

c) Please provide details of where these donations will be made in 2012 and 2013.

d) Please provide details of other jurisdictions where publicly-owned utilities are allowed to recover charitable donations from ratepayers as involuntary contributions to charity rather than having these costs borne by the shareholders.

ANSWER:

(a)

Not confirmed. Donations are not part of the determination of utility income in the GRA revenue requirement.

(b)

As a crown-owned company, YEC is not subject to income tax regulation. Therefore, there is no tax benefit.

(c)

Donations are made based on a review of requests received during the year. Recipients are not specifically budgeted for.

(d)

YEC is not privy to this information.

TOPIC:

REFERENCE: Application – Rate Riders

PREAMBLE:

QUESTION:

a) Does YEC intend to conduct a rate design review with YECL in order to determine what base rates would be without riders?

ANSWER:

(a)

No, not as part of the current GRA. To determine base rates would require a joint Phase II review with YECL, including an updated joint cost of service analysis, and this is beyond the scope of the current proceeding.

In Reasons for Decision, Board Order 2012-18 states with respect to YEC's current GRA that "questions directed at the rate class level for costs are outside the scope of the application and they are more appropriately addressed in a Phase II proceeding." In correspondence to all parties dated August 30, 2012 the Board also noted, “at this time, the Board considers that no benefit will accrue to customers in the filing of a Phase II application. To be effective, such applications should be filed jointly by YEC and YECL when there are no Orders-in-Council in force providing rate direction for all rate adjustments for retail customers and major industrial customers”.

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 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 a Phase II Rate Application (including cost of service and rate design changes) 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: **Rider J**

REFERENCE: **Application – Rate Riders, CW-YEC-1-37(a) Attachment 1**

PREAMBLE:

QUESTION:

a) Please provide details of the revenue recoveries through Rider J by customer class since it was originally approved in Order 1998-5 as well as details of the costs that have been directed recovered through Rider J.

ANSWER:

(a)

The 2009 Phase II Rate Application addressed the need to adjust base rates to reflect current costs and revenue requirements and eliminated the Rider J[1] and Rider R[2] (approved at that time) from customer bills.

The Rider J and Rider R included in the Yukon Energy 2012/2013 GRA are separate Riders that bear no relation to these earlier Riders.

[1] Subsequent to the 1996/97 GRA, the Faro mine (which comprised 40% of the load on the system) closed permanently in early 1998. After a limited scope proceeding in 1998, involving Yukon Energy as sole applicant, Rider J was established for all retail rates of both Companies to recover specific identifiable and major adverse net rate revenue impacts on Yukon Energy from the Faro mine closing. The Rider J rate was originally approved in Order 1998-5 on an interim basis at 15.28%. In Order 1999-5 the rider was finalized at 18.74% effective December 1, 1999, and in Order 2003-02 the rider was reduced to 14.93% effective January 1, 2003.

[2] This Rider R was set to collect the approved 2009 YECL revenue requirement over a full year based on approved 2009 forecast loads. Rider R of 10.526% of 2009 firm retail sales revenues at base rates, effective January 1, 2010 (Order 2009-5).

TOPIC:

REFERENCE: Application – Across-the-Board Rate Adjustment

PREAMBLE:

QUESTION:

a) Please explain how the share of cost of service borne by non-industrial classes of customers will change as a result of rate adjustments applied in equal percentages across each class.

ANSWER:

(a)

The Board in Order 2012-8 noted "In general, as this General Rate Application is to test the prudency of the requested revenue requirements for YEC for the years 2012 and 2013, questions directed at the rate class level for costs are outside the scope of the application and they are more appropriately addressed in a Phase II proceeding." In correspondence to all parties dated August 30, 2012 the Board also noted, "at this time, the Board considers that no benefit will accrue to customers in the filing of a Phase II application. To be effective, such applications should be filed jointly by YEC and YECL when there are no Orders-in-Council in force providing rate direction for all rate adjustments for retail customers and major industrial customers".

The above question is requesting cost of service information previously ruled outside the scope of the current process.

TOPIC:

REFERENCE: Response to UCG-YEC-1-17

PREAMBLE:

YEC states that it has not assessed measures that the Yukon Government might adopt to bring in legislation or policy related to performance-based regulation.

QUESTION:

a) Please explain why YEC has not initiated anything in response to the YUB's recommendation in its January 2007 report on the 20-Year Resource Plan.

ANSWER:

(a)

The Board did not specifically recommend adoption of performance based regulation in the January 2007 report on the 20-Year Resource Plan. The Board only *suggested* that YEC and YECL consider a performance-based regulation mechanism[1] as part of a broader Phase I and Phase II Review process (which was undertaken in 2008/2009 by both utilities).

As noted in response in various prior IR responses since the 2005 Required Revenues and Related Matters proceeding (as detailed in UCG-YEC-1-17(d)) implementing performance based regulation would require a multi-year performance-based regulatory framework that 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

[1] Page 50 of January 2007 Report on the 20-Year Resource Plan notes as follows, "Now is an appropriate time for YEC and YECL to have a complete review of all GRA Phase I and Phase II matters. The Board recommends that YEC and YECL file a full GRA application before October 31, 2007. The application should include a full cost of service, rate design and an update of the Electric Service Regulations. The Board also suggests that YEC and YECL consider a performance-based regulation mechanism. As well, the Board recommends that evidence be provided as to what other utilities provide for Maximum Company Investment and model theirs accordingly."

Government might adopt to bring in legislation or policy related to performance-based regulation.

Yukon Conservation Society
(YCS)

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please resubmit your response to YCS's first set of Information Requests in the format requested by the YUB (including not only the reference to answers contained in other IR Responses, but also copies of the responses themselves). Thank you.

ANSWER:

(a)

In a letter to all parties in the YEC 2012 GRA proceeding, dated August 30, 2012, the Board confirmed its direction that "YEC is to provide all references when submitting its responses to the second round of IRs and those IRs from the first round to which the Board directed YEC provide better and adequate answers. All references within the information response should be provided either by copying and pasting the referenced information response or via hyperlink".

Yukon Energy noted in the cover letter to the July 27, 2012 IR filing that it "provided cross references in a number of responses – as in past proceedings, in order to assist in review of cross referenced IR responses, Yukon Energy will provide the Board with an electronic consolidation of all interrogatory responses with hyperlinks embedded where there are cross references to other IRs. An electronic consolidation should be available to be provided early the week of July 30, 2012. As in the past, it is expected the Board can make this document publically available on its website to assist interested parties in review of the material".

In an email to all parties dated August 1, 2012, YEC provided the following link to the consolidation of all IRs. This consolidation includes hyperlinks where there are references to other IRs.

http://www.youryukon.com/yec/

Due to the large file size the consolidation cannot be emailed. However, a CD with the consolidation can also be provided upon request to Yukon Energy.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) In June of 2010, Yukon Energy Corporation President David Morrison went to market to sell a $100 million bond with an interest rate of 5%. How was this money used to finance Mayo B, the Carmacks-Stewart Transmission Line, and studies into potential future projects?

ANSWER:

(a)

The $100 million bond was a bond issued for YDC, not for YEC.

- YDC provided $52.5 million as a no cost contribution for Mayo B and CSTP Stage 2;

- YDC provided $36.5 million as debt and equity financing for Mayo B; and

- The remaining $11 million was provided as financing for other projects.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) How will the ability to pay the 5% interest rate on this $100 million debt be affected by the refinancing of YEC's debt to a lower interest rate of 4.25%?

ANSWER:

(a)

The $100 million debt is a YDC debt, not a YEC debt.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) The Yukon News reported that Yukon Energy Corporation planned to set up a "sinking fund" to accrue value until it matures in 30 years. Please describe the status and progress of this fund.

ANSWER:

(a)

There is no sinking fund set up in Yukon Energy's books.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Why was the 20-Year Resource Plan included in the GRA late in the process?

ANSWER:

(a)

Specifically, the Overview to the 2011 20-Year Resource Plan: 2011-2030 was provided in response to specific interrogatories. Further, this document was only finalized and made public in late July 2012, shortly before the IR responses were finalized.

The current regulatory process is to review Yukon Energy's 2012 and 2013 revenue requirement, and is not specifically to review the 20-Year Resource Plan. As such, the Resource Plan documents made public to date are not "included" for approval in the GRA per se, but are available to be reviewed and queried by the Board and interested parties as part of that proceeding.

It is expected that at the oral hearing the Board and intervenors will have an opportunity to ask specific questions about the Overview and the 2011 Resource Plan previously made public.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Why are some YEC representatives saying the Resource Plan submitted to the YUB is a draft, and that public comments would be incorporated once consultations were complete, but other YEC representatives are saying the version submitted to the YUB is the final version? Which is correct?

ANSWER:

(a)

It is correct to say that this is a draft document available for public comment.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Why are the summary, overview and overall documents of the 20 Year Resource Plan different from each other (and not simply in terms of each is shorter than the latter, but in content – as in, some last minute additions were made to the summary that didn't make it into the overview, and some last minute additions that did make it into the overview did not make it into the long form documents.) Please describe, because there is such a discrepancy in the literature, which version we are to take as the plan, and why they are not congruent?

ANSWER:

(a)

The draft 2011 Resource Plan: 2011-2030, as with its predecessor, is a living document that continues to evolve. Differences between the two documents referenced in the question reflect information available at the time each document was prepared.

In this respect, it is noted that the draft 20-Year Resource Plan: 2011-2030 is dated December 2011 while the Overview to the 20-Year Resource Plan: 2011-2030 is dated July 2012. The December 2011 document reflects a summary of information and analysis based on best available information at that time. The Overview includes certain updates based on information available at time of preparation and filing of that document in July 2012, as well as a Section 8 that includes Yukon Energy's Recommended Plans.

Yukon Energy has been in a public engagement process since the release of the Overview in late July. Yukon Energy will consider comments received until mid to late November, when the current GRA hearing process has concluded. Yukon Energy will then provide to the public as soon as feasible thereafter the results of this review.

As noted in the Overview, 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.

TOPIC: **Resource Plan**

REFERENCE: **YECL-YEC-1-18**

PREAMBLE:

QUESTION:

a) Please explain why the 20 Year Resource Plan includes Waste-To-Energy when YEC has no plan to pursue this option?

ANSWER:

(a)

Yukon Energy only recently determined that Waste-To-Energy will not be pursued further at this time. As reviewed below, this option was in fact examined by YEC as part of the 2011 Resource Plan process.

As indicated in the Overview provided as Attachment 1 to YECL-YEC-1-18, the 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 first activity Yukon Energy undertook preparing its 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 charrette held in March 2011. The charrette identified a number of near term options that were subsequently assessed as part of the 2011 Resource Plan (this included Waste to Energy). As such the resource plan includes a summary of relevant information regarding waste to energy as a potential resource option, and provides an assessment of this option using the

planning criteria adopted at the Charrette (i.e., reliability, flexibility, affordability and environmental responsibility). A workshop was also held specifically held on Waste to Energy in October 2011.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please explain why YEC wrote and released its draft (or final?) 20-Year Resource Plan to the public and the YUB before conducting a wind mini-charrette?

ANSWER:

(a)

Yukon Energy has been very clear that the draft 2011 Resource Plan: 2011-2030, as with its predecessor, is a living document that continues to evolve, i.e., the 2011 20-Year Resource Plan; 2011-2020 reflects information and analysis as of December 2011 and the Overview to the draft 20-Year Resource Plan; 2011-2020 reflects updates as of July 2012.

The resource planning process is expected to continue to evolve to reflect new information and changing circumstances.

Workshops have been held (and will continue to be held) on various specific topics as part of the resource planning process. Workshops to date were held independent of (and generally after) preparation of the materials contained in the draft report dated December 2011. A wind workshop is planned for later in 2012 or early in 2013.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please describe in detail the assumptions that were factored into the calculations used to determine the cost per kilowatt hour of each of the short-term options and how they are compared with each other.

ANSWER:

(a)

Costs per kilowatt hour were estimated in the Resource Plan for each of the short term options using the same load forecasts, long-term average grid hydro generation models, general economic assumptions and range of assessment factors.

A central focus in this cost assessment was each option's comparative ability, over its economic life, to displace diesel energy generation.

Costs for each option were stated in terms of kilowatt hours of diesel expected to be displaced - not in terms of kilowatt hours of production expected to be generated. This approach facilitated assessment of each option on a common basis, relative to "default" diesel generation - and reflected Yukon-specific conditions where an isolated grid removes any effective market for generation 'surplus' to loads served directly on the grid.

Costs per kilowatt hour of diesel displaced were also assessed for each option under a range of grid load conditions - looking at both near-term costs per kW.h (2015-2019) and present value costs per kW.h over the economic life of each option (lifecycle costs of energy or "LCOE"), and examining scenarios with and without potential DSM/SSE. This approach checked the extent to which cost-based ranking of the options was sensitive to the assumed loads and the scale of potential diesel displacement.

Section 8 of the Overview of 20-Year Resource Plan: 2011-2030 presents the following summary conclusions of this analysis (page 47):

> "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."

Section 8 of the Overview goes on to review how Tables 8-1 and 8-2 in that section 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. The following summary conclusions are provided at pages 47-48 of the Overview:

- "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."

As requested, the assumptions that were factored into the calculations used to determine the referenced costs per kilowatt hour of each of the short term options are described in detail in Appendix A to this response.

Appendix A: Detailed Review of Assumptions

Table 8-2 of the 20-Year Resource Plan: 2011-2030 Overview provides the list of short term options reviewed in the Overview, as well as a summary of key assumptions factored into the cost analysis of each option, e.g., option scale, capital cost, reliable peak winter capacity contribution, annual energy supply capability and forecast 2015-2019 average diesel energy displacement (GW.h/year) under Scenario A and B loads with DSM/SSE. This table summarizes how the options are compared with each other.

For ease of reference, Table 8-2 is provided below.

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.

Table 8-2 provides two separate types of cost/ kWh of diesel displaced for each option (for diesel, only fuel and O&M costs are included – for all other options, capital costs as well as any fuel and O&M cost estimates are included):

- **2015-2019 Annual Costs (cents/ kWh diesel displaced)** – Shows for each option, over the 2015-2019 period, the range of annual cost per kW.h of diesel displaced for Scenario A and B loads; option annual costs reflect normal utility revenue requirement financing based on assumed capital and operating costs, assumed economic life, and assumed 6.56% blended average cost of debt and equity.

- **Lifecycle Cost of Energy (2010 cents/kW.h diesel displaced)** – LCOE cents/kWh (present value cost in 2010$ over economic life of option) of diesel displaced under various load scenarios, e.g., Scenario A and B loads with DSM/SSE, Scenario A 2019 load extended to 2030, and full utilization of all energy each year to displace diesel.

The LCOE and present value cost assume a discount rate (average blended cost of capital for debt and equity) 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 option economic 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.

In each non-diesel option and load case, the "cents/kWh" reports the estimated annual costs divided by the relevant forecast diesel displacement by the option for the specified load forecast. In this way, the capability of each option to displace diesel is recognized and a comparison can be provided to the cost of diesel, i.e., to provide value, an option must displace diesel generation that would otherwise be required and one goal is to achieve such displacement at a lower cost than diesel. This assessment reflects assumed continuation of Yukon's isolated grid, with the generation and transmission facilities and permitting as currently approved and in place (plus Mayo Lake enhanced storage).

The following additional assumptions underlying the costs and load forecast are detailed in the 2011 20-Year Resource Plan Overview.

- The Capital Costs [2010$] for each near term option are listed in Table 8-2[1].

[1] See Overview, notes to Figure 6-1 at page 29. Also Overview, footnotes 15 to 19 at page 26.

- Diesel is assumed to be able to provide all of the firm capacity required (up to 37 MW) at a capital cost of $1.5 million/MW; the requirement takes into consideration load growth and need to replace all existing YEC diesel generation over the 20 year forecast period.
- LNG is assumed to be located in Whitehorse at YEC's current facilities at a capital cost of $1.8 million/MW for combined cycle units, and to provide firm capacity to the grid. Scale of LNG assumed LNG development reflects assumed load scenarios (22 MW for Scenario A and 30 MW for Scenario B) and estimated development that would be appropriate for the forecast grid load. It is assumed that BC based LNG supply is not limited.
- Wood biomass assumed at 15 MW of firm capacity (scale estimated to be relevant to the load forecasts) located close to the grid in Minto burn area (location reflects estimated least cost feedstock location for this scale of plant) at cost of $5.7 million per MW; in contrast, a larger plant (e.g., 25 MW) would need to be located in Whitehorse to secure least cost wood biomass required for this scale of operation. It was determined that any plant larger than 15 MW would be more costly under forecast grid loads. The smaller 2-3 MW wood biomass pilot plant is being examined as potential pilot project being considered in the Haines Junction area as explained below – in this location, no firm capacity would be provided to the grid under N-1 capacity planning criteria.
- Waste-to-Energy (WTE) assumed at 2.2 MW of firm capacity located at Whitehorse (capital cost of $17.7 million/MW). The 2.2 MW scale was assessed to be the 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.
- 21 MW wind option assumed to be located at Ferry Hill. Wind generation; this wind option does not provide any reliable capacity, and the overall option therefore includes 5 MW DRUPS (diesel rotary uninterruptible power) to enhance reliability (adds 5 MW to reliable grid capacity)[2]. This wind option capital cost is assumed at $3.6 million/MW for 26 MW (21

[2] In assessing the Ferry Hill or Mount Sumanik 20 or 21 MW wind farms, it is assumed that approximately 5 MW of spinning reserve is currently available and that (regardless of wind resource use) about 10 MW of existing non-base loaded hydro units would be converted to synchronous condenser peaking units. A 21 MW wind farm is then assumed to require a further 5 MW DRUPS be added to the grid to provide adequate reliability. (See Yukon Energy 20-Year Resource Plan: 2011-2030, December 2011; footnote 112 at page 63).

MW wind and 5 MW DRUPS), including transmission to the grid ($10 million for DRUPS, $83.4 million for wind farm at Ferry Hill with transmission connection to Stewart Crossing substation). As noted in Table 8-2, a smaller 10.5 MW wind option was examined but was slightly less cost-effective at forecast loads than the 21 MW option[3].

- Marsh Lake hydro storage adds about 1 MW reliable capacity (assumes this occurs at the existing Whitehorse hydro plant without any changes at this plant). Gladstone Diversion was also examined as a potential near-term hydro enhancement, but was determined to not be potentially available for in-service prior to late 2017[4].

- The forecast average diesel displacement for each option [2015-19] is provided in Table 8-2 for Scenarios A and B with DSM/SSE (this time period is selected to show comparative costs in the initial years of operation, and assuming adequate mine loads to secure effective utilization of near term options examined – after 2021, mine loads are assumed to be shut down in these scenarios and such shut downs severely affect the costs per kW.h of diesel displacement for non-flexible resource options).

- All costs assume long-term average annual hydro generation each year during the period.

[3] The 10.5 MW option was assumed to be connected only to the Stewart Crossing north substation, and that no added DRUPS would be required for reliability so long as the wind resource is limited to this scale on the grid. Capital cost (2010$) of $49.552 million. (See Yukon Energy 20-Year Resource Plan: 2011-2030, December 2011; pages 63 and 94).

[4] Gladstone Diversion hydro adds minimal or no reliable capacity (due to Aishihik Transmission line vulnerability); estimated capital cost of $40 million; through enhanced use of the existing Aishihik hydro facility, Gladstone Diversion could add maximum annual energy capability of 36.6 GW.h/year if fully utilized (see Overview, Table 8-1).

- The fuel and O&M costs are detailed in the 2011 20-Year Resource Plan Overview, and are as follows for relevant near-term resource options (unless otherwise noted, inflation assumed at 2%/year):
    - **Diesel O&M**[5] – 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$) are assumed at 28c/kW.h (escalated at general inflation assumed at 2%/year), reflecting YEC's approved 2009 GRA fuel prices (e.g., 96 cents per litre at Whitehorse) and a 50/50 average of estimated costs for existing and new units (range of unit efficiencies and O&M cost). Diesel fuel prices in 2011 were generally higher than the approved 2009 fuel prices; however, based on October 2011 NYMEX futures, future diesel prices would be slightly lower than assumed in the Resource Plan (NYMEX futures based prices about 3% lower in 2012, 5% lower by 2015 and 6% lower by 2018).
    - **LNG O&M**[6] – Forecast LNG costs assume 22 MW [Scenario A with DSM/SSE – adjusted to 30 MW for Scenario B] combined cycle generation units at Whitehorse (50% energy efficiency [6.562 Mcf/MW.h] and 44% average annual plant capacity factor] with LNG supplied by truck from Kitimat at a cost of 2.7 cents/kWh (2010$) for all LNG supply costs other than LNG fuel. Cost of LNG fuel is at assumed natural gas price in BC plus $3/MMBtu (2010$) to reflect conversion cost 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 ($11.07/MMBtu after inflation). Although combined cycle provides opportunities for waste heat sales in Whitehorse, no waste heat revenue offsets assumed with LNG option in this analysis. Non-fuel O&M costs (2010$) of $15/MW.h assumed for power generation.
    - **2.2 MW Waste to Energy**[7] – 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 $3.3 million per year (2010$).

[5] See Overview, footnote 11 at page 16.
[6] See Overview, footnote 25 at page 30.
[7] See Overview, footnote 26, page 30.

- **Wood Biomass O&M (15 MW)**[8] – This assumes wood biomass plant 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/ ODT. This assumes 2%/year inflation of costs. The Wood Biomass option is typically assumed to operate year round – however, it is also assumed to be flexible enough to shut down under scenarios where 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 after 2020 under the LCOE assessments with Scenario A and B with DSM/SSE).
- **Wood Biomass O&M (3 MW Haines Junction)**[9] – This assumes wood biomass plant to be located at Haines Junction with wood biomass requirement of 0.87 ODT/MW.h at an average cost (2012$) of $108/ODT. This assumes 2%/year inflation of costs. This Wood Biomass option is typically assumed to operate year round – however, it is assumed to be flexible enough to shut down under scenarios where grid annual load drops to very low levels after 2020 (as a result, the material O&M cost of $121/ MW.h (2011$) is saved after 2020 under the LCOE assessments with Scenario A and B with DSM/SSE).
- **Wind O&M (21 MW)**[10] – Annual operating cost (2010$) of $38/MW.h for 55.6 GW.h of assumed annual average generation.
- **Marsh Lake Storage**[11] – Annual operating cost (2010$) of $8/MW.h for 6.4 GW.h of assumed annual average generation for Scenario A with DSM/SSE.

[8] See Overview, footnote 27, page 30.
[9] See Overview, footnote 40, page 46. Yukon Energy is 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. Cost estimate assumptions adopted in Table 8-2 reflect cost assumption prepared to date for this potential project.
[10] See Yukon Energy 20-Year Resource Plan: 2011-2030, December 2011; page 94.
[11] See Yukon Energy 20-Year Resource Plan: 2011-2030, December 2011; page 91.

TOPIC:

REFERENCE:

PREAMBLE:

QUESTION:

a) Please describe the assumed costs of natural gas, now and into the future, that were factored in the assumptions of the affordability of LNG as a near-term option.

ANSWER:

(a)

The BC gas price (2010$) was assumed in the draft 2011 Resource Plan 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). See Overview, footnote 25 at page 30. Current BC natural gas prices in the field are below $3.00/MMBTU.

Yukon Electrical Company Limited
(YECL)

TOPIC: **DCF & ERA**

REFERENCE: **YUB-YEC-1-30(b)**

PREAMBLE:

In response to YUB-YEC-1-30(b), YEC provided scenarios, relative to the GRA Forecast, to show the related impacts on the DCF and the ERA. YECL wishes to gain a better understanding of the impacts on the DCF and ERA based on additional scenarios.

QUESTION:

a) In addition to the 4 scenarios provided in response to YUB-YEC-1-30(b), please provide calculations (in excel format) to show the impacts on the DCF and ERA based on increases(+)/decreases(-) of Wholesale and Retail & Industrial loads relative to the GRA Forecast as follows:

   i. Wholesale load, +5 GW.h, Retail & Industrial Load, -4 GW.h.
   ii. Wholesale load, +5 GW.h, Retail & Industrial Load, -6 GW.h.
   iii. Wholesale load, -5 GW.h, Retail & Industrial Load, +4 GW.h.
   iv. Wholesale load, -5 GW.h, Retail & Industrial Load, +6 GW.h.

ANSWER:

(a)

Please see the attached schedule and Excel file. For clarity, in dealing with these specific scenarios, Yukon Energy notes the following:

- In order to run the full scenario, it is necessary to specify a quantity of diesel assumed to be consumed. The attached tables insert sample values (14 GW.h for the load growth cases, and 12 GW.h for the load decline cases). The ERA calculations are not sensitive to the value selected, but the DCF values are sensitive to this.

- The DCF calculations remain as set out in YUB-YEC-1-30(b).

- The ERA scenarios set out in YUB-YEC-1-30(b) remain valid. However, to deal with the particular unique scenarios set out in this request, the formula for calculating "Incremental Diesel Generation Subject to the ERA Charge (MW.h)" has been amended (row 59 of the "Proposed ERA" tab in the Excel file). To re-iterate, the principles underlying this formula are as follows:
    - When there is load growth on the system (actual annual loads > YEC GRA level), and:
        1) That load growth is not caused by YECL load growth (actual wholesale sales for the year is less than or equal to the levels used in YEC's GRA), then no ERA is applied; or
        2) That load growth is caused in whole or in part by YECL (wholesale sales > YEC GRA levels), then a calculation will be performed to determine the appropriate YECL share of the load growth, and the ERA charge will be applied to that growth.
    - When the system loads decline (actual annual loads < YEC GRA level), and:
        1) That load reduction is not caused by YECL load reductions (actual wholesale sales for the year is greater than or equal to the levels used in YEC's GRA), then no ERA credit is applied; or
        2) That load reduction is caused in whole or in part by YECL (wholesale sales < YEC GRA levels), then a calculation will be performed to determine the appropriate YECL share of the load reduction, and the ERA credit will be applied to that reduction, up to 10% of the GRA forecast wholesale load.
    - Where the YECL load changes are driven by underlying changes in YEC delivery areas (e.g., if the reason YECL's load grows is because of growth in YECL's sales to YEC at a downstream delivery location, such as Johnson's Crossing, where YEC repurchases back from YECL power than was originally generated by YEC), then this will not be considered to be YECL load growth or load reductions for the purpose of ERA determinations.

Case descriptions for 2013 scenarios (all scenarios assume wind generation at GRA forecast):

Case #1: Wholesale +5 GW.h GRA Forecast; Retail -4 GW.h GRA Forecast; Actual Diesel Generation Above Expected
Case #2: Wholesale +5 GW.h GRA Forecast; Retail -6 GW.h GRA Forecast; Actual Diesel Generation Above Expected
Case #3: Wholesale -5 GW.h GRA Forecast; Retail +4 GW.h GRA Forecast; Actual Diesel Generation Above Expected
Case #4: Wholesale -5 GW.h GRA Forecast; Retail +6 GW.h GRA Forecast; Actual Diesel Generation Above Expected

		Cases (possible actual loads and diesel generation)			
	GRA	**Case #1**	**Case #2**	**Case #3**	**Case #4**
Retail and Industrial (MW.h)	97,685	93,685	91,685	101,685	103,685
Wholesale (MW.h)	298,228	303,228	303,228	293,228	293,228
Total Sales (MW.h)	395,913	396,913	394,913	394,913	396,913
Losses (MW.h)	34,444	34,531	34,357	34,357	34,531
Total Generation (MW.h)	430,357	431,444	429,270	429,270	431,444
Hydro (MW.h)	419,405	417,206	417,032	417,032	417,206
Diesel (MW.h)	10,714	14,000	12,000	12,000	14,000
Wind (MW.h)	238	238	238	238	238
Total Generation (MW.h)	430,357	431,444	429,270	429,270	431,444
Diesel MW.h	10,714	14,000	12,000	12,000	14,000
Proposed ERA Determination & related DCF determinations					
In Base Rates Excluding ERA MW.h (YEC's Income Statement)	10,714	10,714	10,260	10,714	11,073
Charged/credited via ERA (MW.h)	0	359	0	-454	0
Total in Rates (Expected Diesel)	10,714	11,073	10,260	10,260	11,073
Charged/credited via DCF (MW.h)	0	2,927	1,740	1,740	2,927
Total Diesel	10,714	14,000	12,000	12,000	14,000

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	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

Case #1 - Actual Load at GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected

Assumptions

	Hydro	417,206		
	Diesel	14,000		
	Wind	238		
L10	Total Actual YEC Supply	431,444	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	431,206	MW.h	Assumed (431 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 1,206 MW.h	675	MW.h	56% of Grid Load between 430 GW.h and 435 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	18,775	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	11,073	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	2,927	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)	$927		

Case #2 - Actual Load Above GRA Forecast; Wind at Forecast; Actual Diesel Generation Above Expected

Assumptions

	Hydro	417,032		
	Diesel	12,000		
	Wind	238		
L10	Total Actual YEC Supply	429,270	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	429,032	MW.h	Assumed (429 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 4,032 MW.h	2,097	MW.h	52% of Load between 425 GW.h and 430 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	17,397	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	10,260	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	1,740	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)	$551		

Case #3 - Actual Load Below GRA Forecast; Wind below forecast; Actual Diesel Generation Above Expected

Assumtpions	Hydro	417,032		
	Diesel	12,000		
	Wind	238		
L10	Total Actual YEC Supply	429,270	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	429,032	MW.h	Assumed (429 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 762 MW.h	2,097	MW.h	52% of Load between 425 GW.h and 430 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	17,397	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	10,260	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	1,740	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)	$551		

Case #4 - Actual Load Below GRA Forecast, Wind Generation at forecast; Actual Diesel Generation Below Expected

Assumtpions	Hydro	417,206		
	Diesel	14,000		
	Wind	238		
L10	Total Actual YEC Supply	431,444	MW.h	
L11=L10-238	Actual Grid Load (Load less GRA Wind Generation)	431,206	MW.h	Assumed (431 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 1,206 MW.h	675	MW.h	56% of Grid Load between 430 GW.h and 435 GW.h is diesel
L14=L12+L13	Total Expected Diesel Generation	18,775	MW.h	
L15=L14x59%	Expected Diesel Generation in Rates	11,073	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	2,927	MW.h	
L18=L3xL17	Incremental Diesel Generation Cost to Charge (Refund) DCF ($000s)	$927		

Note:
The numbers are rounded to the nearest integer.

Case descriptions:

Case #1: Wholesale +5 GW.h GRA Forecast; Retail -4 GW.h GRA Forecast; Actual Diesel Generation Above Expected
Case #2: Wholesale +5 GW.h GRA Forecast; Retail -6 GW.h GRA Forecast; Actual Diesel Generation Above Expected
Case #3: Wholesale -5 GW.h GRA Forecast; Retail +4 GW.h GRA Forecast; Actual Diesel Generation Above Expected
Case #4: Wholesale -5 GW.h GRA Forecast; Retail +6 GW.h GRA Forecast; Actual Diesel Generation Above Expected

Inputs

	Cases				
	GRA	**Case #1**	**Case #2**	**Case #3**	**Case #4**
Retail and Industrial (MW.h)	97,685	93,685	91,685	101,685	103,685
Wholesale (MW.h)	298,228	303,228	303,228	293,228	293,228
Total Sales (MW.h)	395,913	396,913	394,913	394,913	396,913
Losses (MW.h)	34,444	34,531	34,357	34,357	34,531
Total Generation (MW.h)	430,357	431,444	429,270	429,270	431,444
Change from GRA Forecast					
Retail and Industrial (MW.h)		-4,000	-6,000	4,000	6,000
Wholesale (MW.h)		5,000	5,000	-5,000	-5,000
Total Sales (MW.h)		1,000	-1,000	-1,000	1,000
Losses (MW.h)		87	-87	-87	87
Total Generation (MW.h)		1,087	-1,087	-1,087	1,087
Hydro (MW.h)	419,405	417,206	417,032	417,032	417,206
Diesel (MW.h)	10,714	14,000	12,000	12,000	14,000
Wind (MW.h)	238	238	238	238	238
Total Generation (MW.h)	430,357	431,444	429,270	429,270	431,444
Diesel MW.h	10,714	14,000	12,000	12,000	14,000
less: DCF	0	2,927	1,740	1,740	2,927
Total in Rates (Expected Diesel)	10,714	11,073	10,260	10,260	11,073
Incremental Diesel in Base Rates (MW.h)		359	-454	-454	359
Incremental Diesel in Base Rates (% of Total Gen'n Change)		33%	42%	42%	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	5,000	-5,000	-5,000	
Incremental Wholesale Related Generation (MW.h)	0	5,435	5,435	-5,435	-5,435	at 8.7% losses (Table 2.2 of GRA)
Incremental Diesel Generation Subject to ERA Charge (MW.h)	0	359	0	-454	0	
Incremental Wholesale Sales Subject to ERA Credit (MW.h)	0	330	0	-418	0	sales equivalent of diesel gen.
Amount paid under normal ongoing billing ($000s)	$ 24,747	$ 25,162	$ 25,162	$ 24,332	$ 24,332	
ERA Adjustment to be Paid (Refunded) ($000s)	$ -	$ 79	$ -	($100)	$ -	
Total Amount Paid after ERA ($000s)	$ 24,747	$ 25,241	$ 25,162	$ 24,232	$ 24,332	

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: **YECL Load Forecast**

REFERENCE: **UCG-YEC-1-19**

PREAMBLE:

UCG-YEC-1-19:

> "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."

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	-	-

CW-YEC-1-6 (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."

YECL is interested in YEC's source for the load forecast.

QUESTION:

a) Please provide documentation provided by YECL in 2011 that supports YECL's load forecast for 2012 and 2013.

ANSWER:

(a)

Attachment 1 provides dated versions of the spreadsheets provided by YECL to YEC. In summary:

- YEC requested forecast information from YECL September 9, 2011.
- The information YECL provided to YEC on September 9, 2011 is provided in Attachment 1 (PP-YECL to YEC – 20110909).
- The forecast for 2012 was revised by YECL on September 13, 2011 whereby it increased from 286 GWh to 289 GWh. (PP-YECL to YEC-20110913).
- Further forecasts for 2013 were provided September 14 and September 15. The September 15 version was the last version sent from YECL to YEC. YEC was advised that the YECL forecast used a 2% growth factor (compared to 2.26% used by YEC in the 2012/13 GRA). This forecast also corrected an error regarding provision for line loss and assumed Fish Lake was back in production in August of 2012. (PP-YEC to YECL-2011092014 and PP-YECL to YEC-2011092015).
- Further discussion occurred in December where YECL told YEC that Fish Lake had been delayed until the end of 2012.

PP - YECL to YEC - 20110909

Yukon Electrical - 2012 BP - Preliminary
Purchased Power Forecast

Yukon Electrical - 2012 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2012 TOTAL	2013 TOTAL	
Primary - WAF	33,905,220	25,249,708	27,291,965	21,550,193	20,822,313	20,252,061	18,553,006	18,763,824	20,296,119	21,873,359	26,529,310	30,386,749	285,473,826	288,870,662	1.190%
Secondary - WAF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	33,905,220	25,249,708	27,291,965	21,550,193	20,822,313	20,252,061	18,553,006	18,763,824	20,296,119	21,873,359	26,529,310	30,386,749	285,473,826	288,870,662	
Keno	34,354	29,069	32,114	28,589	26,426	14,649	15,872	19,479	23,808	25,972	33,427	37,515	321,273	321,595	
Pelly															
Stewart	66,681	61,809	61,934	43,442	40,877	27,224	23,122	29,885	37,137	45,357	58,143	66,288	561,899	562,461	
	101,035	90,878	94,048	72,031	67,303	41,874	38,994	49,364	60,945	71,328	91,570	103,803	883,172	884,055	
	34,006,255	25,340,586	27,386,013	21,622,224	20,889,617	20,293,934	18,592,000	18,813,188	20,357,063	21,944,687	26,620,880	30,490,553	286,356,998	289,754,717	
$$$															
YEC Shortfall - Rider 'J'	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Primary POP	34,006,255	25,340,586	27,386,013	21,622,224	20,889,617	20,293,934	18,592,000	18,813,188	20,357,063	21,944,687	26,620,880	30,490,553	286,356,998	289,754,717	1.187%

-

PP - YECL to YEC - 20110913

Yukon Electrical - 2012 BP - Preliminary
Purchased Power Forecast

Yukon Electrical - 2012 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2012 TOTAL	2013 TOTAL	
Primary - WAF	33,904,777	25,702,964	27,291,965	21,550,193	21,468,108	19,138,580	19,937,626	18,763,824	21,597,652	21,873,359	26,529,310	30,386,749	288,145,108	288,870,662	0.252%
Secondary - WAF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	33,904,777	25,702,964	27,291,965	21,550,193	21,468,108	19,138,580	19,937,626	18,763,824	21,597,652	21,873,359	26,529,310	30,386,749	288,145,108	288,870,662	
Keno	34,354	29,069	32,114	28,589	26,426	21,622	22,823	26,907	23,808	25,972	33,427	37,515	342,625	342,967	
Pelly															
Stewart	66,681	61,809	61,934	43,442	40,877	32,721	27,887	33,153	37,137	45,357	58,143	66,288	575,428	576,004	
	101,035	90,878	94,048	72,031	67,303	54,342	50,710	60,060	60,945	71,328	91,570	103,803	918,053	918,971	
	34,005,811	25,793,842	27,386,013	21,622,224	21,535,412	19,192,922	19,988,336	18,823,884	21,658,597	21,944,687	26,620,880	30,490,553	289,063,161	289,789,633	
$$$															
YEC Shortfall - Rider 'J'	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Primary POP	34,005,811	25,793,842	27,386,013	21,622,224	21,535,412	19,192,922	19,988,336	18,823,884	21,658,597	21,944,687	26,620,880	30,490,553	289,063,161	289,789,633	0.251%
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	

PP - YEC to YECL - 20110914

Yukon Electrical - 2012 BP - Preliminary
Purchased Power Forecast

Yukon Electrical - 2012 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2012 TOTAL	2013 TOTAL	
Primary - WAF	33,904,777	25,702,964	27,291,965	21,550,193	21,468,108	19,138,580	19,937,626	18,763,824	21,597,652	21,873,359	26,529,310	30,386,749	288,145,108	288,870,662	0.252%
Secondary - WAF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	33,904,777	25,702,964	27,291,965	21,550,193	21,468,108	19,138,580	19,937,626	18,763,824	21,597,652	21,873,359	26,529,310	30,386,749	288,145,108	288,870,662	
Keno	34,354	29,069	32,114	28,589	26,426	21,622	22,823	26,907	23,808	25,972	33,427	37,515	342,625	342,967	
Pelly															
Stewart	66,681	61,809	61,934	43,442	40,877	32,721	27,887	33,153	37,137	45,357	58,143	66,288	575,428	576,004	
	101,035	90,878	94,048	72,031	67,303	54,342	50,710	60,060	60,945	71,328	91,570	103,803	918,053	918,971	
	34,005,811	25,793,842	27,386,013	21,622,224	21,535,412	19,192,922	19,988,336	18,823,884	21,658,597	21,944,687	26,620,880	30,490,553	289,063,161	289,789,633	
										Increased ESO from FL#1			(2,747,000)		
										Base sales			286,316,161		
										2013 Fcst with growth by 2%			**292,042,484**		
Total Primary POP	34,005,811	25,793,842	27,386,013	21,622,224	21,535,412	19,192,922	19,988,336	18,823,884	21,658,597	21,944,687	26,620,880	30,490,553	289,063,161	289,789,633	0.251%

PP - YECL to YEC - 20110915

Yukon Electrical - 2012 BP - Preliminary
Purchased Power Forecast

Yukon Electrical - 2012 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's) for fiscal 2012

2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2012 TOTAL	2013 TOTAL	
Primary - WAF	33,904,777	25,702,964	27,291,965	21,550,193	21,468,108	19,138,580	19,937,626	18,763,824	21,597,652	21,873,359	26,529,310	30,386,749	288,145,108	291,568,129	1.188%
Secondary - WAF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	33,904,777	25,702,964	27,291,965	21,550,193	21,468,108	19,138,580	19,937,626	18,763,824	21,597,652	21,873,359	26,529,310	30,386,749	288,145,108	291,568,129	
Keno	34,354	29,069	32,114	28,589	26,426	21,622	22,823	26,907	23,808	25,972	33,427	37,515	342,625	342,967	
Pelly															
Stewart	66,681	61,809	61,934	43,442	40,877	32,721	27,887	33,153	37,137	45,357	58,143	66,288	575,428	576,004	
	101,035	90,878	94,048	72,031	67,303	54,342	50,710	60,060	60,945	71,328	91,570	103,803	918,053	918,971	
	34,005,811	25,793,842	27,386,013	21,622,224	21,535,412	19,192,922	19,988,336	18,823,884	21,658,597	21,944,687	26,620,880	30,490,553	289,063,161	292,487,101	
$$$															
YEC Shortfall - Rider 'J'	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Primary POP	34,005,811	25,793,842	27,386,013	21,622,224	21,535,412	19,192,922	19,988,336	18,823,884	21,658,597	21,944,687	26,620,880	30,490,553	289,063,161	292,487,101	1.184%

Yukon Electrical - 2012 Business Plan Preliminary Forecast of Wholesale Purchases. (kW.h's) for fiscal 2013

2013	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2013 TOTAL
Primary - WAF	34,128,465	25,670,118	27,348,370	21,495,822	21,412,168	19,552,372	20,335,623	19,169,800	22,003,013	22,337,434	27,089,018	31,025,928	291,568,129
Secondary - WAF	0	0	0	0	0	0	0	0	0	0	0	0	0
	34,128,465	25,670,118	27,348,370	21,495,822	21,412,168	19,552,372	20,335,623	19,169,800	22,003,013	22,337,434	27,089,018	31,025,928	291,568,129
Keno	34,389	29,098	32,146	28,617	26,453	21,643	22,846	26,934	23,831	25,998	33,460	37,552	342,967
Pelly													
Stewart	66,747	61,871	61,996	43,486	40,918	32,753	27,915	33,186	37,174	45,402	58,201	66,355	576,004
	101,136	90,969	94,142	72,103	67,371	54,397	50,760	60,120	61,006	71,400	91,661	103,907	918,971
	34,229,601	25,761,087	27,442,512	21,567,925	21,479,538	19,606,769	20,386,383	19,229,920	22,064,018	22,408,834	27,180,679	31,129,835	292,487,101
$$$													
YEC Shortfall - Rider 'J'	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Primary POP	34,229,601	25,761,087	27,442,512	21,567,925	21,479,538	19,606,769	20,386,383	19,229,920	22,064,018	22,408,834	27,180,679	31,129,835	292,487,101

TOPIC: **Capital Projects**

REFERENCE: **YECL-YEC-1-27**

PREAMBLE:

YECL is interested in understanding how YECL's costs are factored in YEC's capital projects.

QUESTION:

a) Please provide, in table format, a list of all planned capital projects included in this application which will cause extended outages – longer than four hours – to YECL and its customers.

b) Please provide timelines for when YEC plans outages for YECL for each of the capital projects listed in part (a) above.

c) Please explain if there are any budgeted amounts for YECL's costs in each of the capital projects listed in part (a) above. If so, please provide the budgeted costs.

ANSWER:

(a) and **(b)**

Yukon Energy meets with YECL on a regular basis to discuss upcoming capital plan projects that will require outages well in advance of the projects going forward. Please see Table 1 below for planned 2012 and 2013 projects with planned extended outages.

Table 1 – Capital Projects with Planned Extended Outages

2012	2013
L250 Transmission maintenance September 2012 Affects YECL customers at Keno	L250 Transmission maintenance Not currently scheduled Affects YECL customers at Keno
Mayo S249 Substation project Scheduled for late October/early November Affects YECL customers at Keno.	L355 Line maintenance Not currently scheduled Affects YECL customers at Haines Junction
CSTP Breaker repairs Scheduled for October Affects Pelly and Stewart Crossing customers	

(c)

No provision exists in the project budgets for YECL costs. Each utility may be impacted by activities undertaken by the other utility that cause outages and requirements for diesel generation. Each utility must address its own costs and determine when it is necessary to return to the regulator to seek an adjustment to its revenue requirement.

Yukon Utilities Board
(YUB)

TOPIC: **Forecast Accuracy**

REFERENCE: **YUB-YEC-1-1**

PREAMBLE:

For example, the 2011 Resource Plan Update forecast non-industrial load for 2011 was at 339.3 GW.h, while the 2011 actual non-industrial load was 357.7 GW.h (including 8.7% losses), which is 18.4 GW.h higher than the 2011 Resource Plan forecast.

QUESTION:

a) When was the 2011 Resource Plan Update forecast completed?

b) Does YEC consider an 18.4 GW.h or 5.5% error rate in its update forecast acceptable?

ANSWER:

(a)

The 2011 Resource Plan forecast was prepared prior to mid-year 2011 based on information available at that time. Work commenced January 2011 and was largely completed in February 2011. Summary forecasts available in April 2011 for Base Case, Scenario A and Scenario B are the same as those provided in the December 2011 document.

The 2011 Resource Plan load forecast was updated in the 2012/13 GRA Application for updated industrial forecasts for existing mines (information provided late in 2011) and for actual 2011 non-industrial sales.

Subject to the above updates, the Application reflects 2011 resource planning forecasts for non-industrial loads, i.e., the same growth rate was applied after 2011, with no DSM/SSE impacts assumed during the test years.

(b)

The 18.4 GWh variance provided in response to YUB-YEC-1-1 is overstated, and should be 13.8 GW.h. The correction relates to the 2011 actual non-industrial load as per Table 2.1 of the Application, which was 324.8 GW.h (excluding secondary sales), and after adding assumed losses of 8.7% becomes 353.1 GW.h (not 357.7 GW.h as shown in the response to YUB-YEC-1-1).

The 13.8 GW.h variance noted for 2011 is not considered an "error" as it compares two different forecasts prepared for two different purposes - and with different available information.

- The Resource Plan load forecast is a long-term (20-Year) forecast based on an assessment of 9-year average growth trends (based on actual non-industrial sales from 2001 to 2010)[1]. It utilized 2010 actual non-industrial loads as the basis for projecting non-industrial loads over 20 years using one overall average annual long-term growth rate, combined with mine-specific load forecasts based on information as then provided by or for each mine. In this respect the Resource Plan load forecast was not intended to accurately forecast (and should not on its own be used for the purposes of forecasting) sales and generation for any specific set of years, and was not relevant on its own to forecast sales and generation in any specific set of GRA test years.

- In contrast, the GRA used actual 2011 non-industrial load information (as well as updated mine load information) and considered new YECL information affecting YEC non-industrial wholesale loads for individual test years.

[1] 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 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 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).

The higher actual non-industrial growth in 2011 as compared to the 2011 Resource Plan reflects wholesales, i.e., YEC retail sales were basically unchanged in 2011 as compared with 2010

With regard to 2011, footnote 8, page 2-4 of the GRA Application specifically notes that 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 due to the following:

- Unavailability of hydro generation from Unit 1 of Fish Lake hydro generation plant (added 4.35 GW.h to the 2011 sales)[2]; and

- 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).

For the **2011 Resource Plan,** a forecast growth rate of 2.26% was applied to 2010 actual firm non-industrial sales (310.8 GW.h) plus Fish Lake generation (3.4 GW.h), in order to reflect native YECL wholesale loads. Final YEC IS forecast firm sales for each year were then determined net of an assumed Fish Lake annual average generation of 8.73 GW.h (based on YUB 2008/2009 GRA determinations). At the time the 2011 Resource Plan forecasts were developed it was noted that for 2011 the forecast Fish Lake generation continued to be reduced (approximately 3.3 GW.h) to reflect shut down of one unit; however, this was not used to modify 2011 forecast loads (as the focus was not on 2011 loads as such). Accordingly, the 2011 load forecast in the 2011 Resource Plan of approximately 312.4 GW.h reflected a 2010 load of 314.1 GW.h increased by 2.26% (forecast total 321.1 GW.h), less assumed Fish Lake generation at 8.73 GW.h. With an assumed 8.6% losses (per the 2011 Resource Plan), the forecast 2011 load as shown was 339.3 GW.h. Adjusting for actual 2011 Fish Lake generation as well as higher assumed losses at 8.7% per the GRA, the equivalent 2011 forecast based on the 2011 Resource Plan forecast would be 344.3 GW.h, i.e. a variance of 8.8 GW.h (or 2.6%) from actual of 353.1 GWH. Some of this variance reflected colder than normal

[2] Unit #1 failed in March 2010. The 2010 actual results in the 2011 Resource Plan reflected Fish Lake generation reduced to only 3.4 GW.h for that year. Per discussions with Yukon Electrical management in fall 2011, this unit was expected to be back in service in January 2013.

weather in 2011; the balance reflected YECL sales growth that year in excess of the 2.26% long-term average assumed for the grid.

TOPIC: **Cost of Service**

REFERENCE: **YUB-YEC-1-2**

PREAMBLE:

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.

And

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).

QUESTION:

a) Would YEC characterize its 2012 costs as materially different from those in the mid-1990s?

b) Did YEC collaborate with YECL in the development of its load forecast?

c) If the answer to (b) is no, how did YEC arrive at its load forecast?

ANSWER:

(a)

The above-noted excerpts included in the preamble (from response to YUB-YEC-1-2) relate specifically to cost of service in relation to rates. In that context, YUB-YEC-1-2 (as quoted above) notes that for residential customers the cost of service study approved in the 1996/97 GRA and the cost of service study reviewed in the 2009 Phase II Rate Application both indicate that existing rates do not recover even 85% of the average costs to serve residential customers.

This statement does not mean that utility costs, or the structure of costs, have not materially changed from the mid 1990's to present, but instead indicates specifically that when these cost are translated into a cost of service analysis which assigns the revenue requirement to each customer classes in order to reflect the distinctive consumption characteristics of each class that contribute to cost causation on the overall system (i.e., classification of customer costs for each function, i.e., generation, transmission, distribution), the results for the residential customer class do not materially change.

(b) and **(c)**

YEC and YECL discuss on an ongoing basis how best to forecast the Primary and Secondary energy sales between companies. 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.

In 2011, YECL provided its 2012 load forecast in September and during refinement discussion 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 wholesale purchases. The 2011 Actual wholesales to YECL were adjusted to address unavailability of hydro generation from Unit 1 of Fish Lake hydro generation plant and colder than normal weather in that year prior to application of the 2.26% average annual growth rate.

As part of the preparation of the Resource Plan load forecast in early 2011, YECL was provided with an early working draft of the appendix supporting the methodology and approach for developing an update to the long term, non-industrial load forecast for Yukon and noting a slightly higher growth rate (2.34%). This analysis, with some adjustments supported the 2.26% non-industrial growth rate used in the 2011 Resource Plan.

TOPIC: **Mayo A & B**

REFERENCE: **YUB-YEC-1-4, LE-YEC1-19**

PREAMBLE:

QUESTION:

a) Does the inclusion of Mayo B effectively de-rate or reduce the possible generation output of Mayo A?

b) Is there any scenario where both Mayo A & B are simultaneously used at full rated capacity?

ANSWER:

(a)

No. Possible generation output of Mayo A is still 5.4 MW.

(b)

Yes, but it would be a very limited set of circumstances where this may apply, i.e., seasonally (summer), for periods of brief duration when there is sufficient water and load on the system. No economic value was assigned to this operating possibility in the analysis leading to the decision to construct Mayo B.

TOPIC: **Aishihik Third Turbine**

REFERENCE: **YUB-YEC-1-5**

PREAMBLE:

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.

QUESTION:

a) Please provide all scope changes from the time the project was first proposed (20-Year Resource Plan) and 2010 and the reasons for the changes.

ANSWER:

(a)

There was no material change in scope from the time the project was proposed in the 2006 Resource Plan, outside of that which was identified in the Application (i.e., as noted on page 5-9 of the Application, after the turbine and construction related contracts were in place project scope changes had to be done to address additional design considerations identified by AECOM [i.e., add cooling facilities to the generator hall]).

The scope of the project as developed was to install a smaller and more efficient third turbine in order to provide the following system benefits:

(1) To provide for efficiencies in water usage achieved at lower generation loads by only running one small unit or by running only one small and one large unit.

(2) To better utilize the available water for peaking generation by having additional capacity at the Aishihik Hydro facility.

In this regard, since the 2006 Resource Plan, the project concept was a horizontal Francis turbine with an installed capacity of 7 MW, with associated controls and equipment and an upstream turbine inlet valve and piping in the bypass tunnel of the Aishihik Generating station, with a scope that included the following major items:

- Engineering and project management of the overall project;
- Removal of rock and replacement of the downstream plug;
- Purchase, delivery and commission of a turbine generator system including hydraulics, lubrication, turbine inlet valve and controls;
- Purchase and installation of a governor system;
- Purchase and installation of the major piping to and from the turbine;
- Purchase and installation of all of the interconnecting piping and wiring for the turbine generator system;
- Commissioning personnel from Engineering firm; and
- Owners costs for project monitoring and commissioning.

TOPIC: **Faro Dewatering Account Funds**

REFERENCE: **YUB-YEC-1-6(b)**

PREAMBLE:

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.

QUESTION:

a) Please provide the calculations in support of the above-mentioned statements.

b) Please confirm that other than what was provided in the (b) response to the referenced question, that YEC did not consider other alternatives to the use of the funds in the Faro Dewatering Account. If not confirmed, please discuss the other alternatives.

ANSWER:

(a) and **(b)**

YEC did not consider other alternatives to the use of the funds in the Faro Dewatering Account, and no calculations were made to support what has become past practice.

As noted in the above-referenced response, the funds available in the Faro Dewatering Account have in proceedings since the 2005 Required Revenues and Related Matters proceeding been applied against outstanding balances in the RFID Account (as in the 2008/2009 GRA) or to address revenue deficiencies (for example following Order 2009-8[1]). In both cases, absent application of these funds (set aside in a deferral account to

[1] For example in the 2008/2009 GRA Compliance Filing the required true up adjustment for 2009 to recover $0.355 million from ratepayers related to over-refunds occurring in 2009, absent application of funds available from the Faro Dewatering Account Yukon Energy would have been required to apply for an across the Board time-limited rider charge to collect the revenue shortfall that occurred over the 11 months period from January 1, 2009 to November 30, 2009, applied over 6 months (collection rider of 1.67% from December 1, 2009 to May 31, 2010).

be used in future for ratepayer benefit subject to Board direction), the revenue requirement would increase.

For the 2012/13 GRA, absent application of the remaining funds in the Faro Dewatering Account against the outstanding balance in the RFID, this amount ($0.398 million) would be treated on the same basis as the balance of funds in the RFID, i.e., instead of including costs of approximately $0.036 million per year to amortize a remaining balance of $0.180 million over 5 years, the GRA would include costs of approximately $0.116 million per year to amortize a remaining balance of $0.578 million. In effect, an additional $0.080 million in annual amortization costs would be added to the revenue requirement.

TOPIC: **Atlin Storage**

REFERENCE: **YUB-YEC-1-8(b)**

PREAMBLE:

QUESTION:

a) Were any amounts in relation to this project expensed after a Park Designation was granted to the area by the Government of British Columbia? If yes, please detail the amounts.

b) Was a cancellation clause included in the agreement with the consultant for the Atlin project? If not, why not?

ANSWER:

(a)

Yukon Energy was notified on July 15, 2011 of the park designation. Consultants were directed in writing to stop work immediately the same day and a project wind up meeting was held August 4, 2011 to decide how to effectively wind down the project. Approximately $5,100 was further costs were incurred after July 15, 2011 for consultant time and YEC labor to close out the project files. Any other items expensed after July 15, 2011 related only to recording of costs incurred prior to that date.

(b)

Yes, there was a cancellation clause and the consultants' work was stopped the same day Yukon Energy was made aware of the park designation.

TOPIC: **Marsh Lake Storage**

REFERENCE: **YUB-YEC-1-25**

PREAMBLE:

The 2006 20-Year Resource Plan estimated an increase in long-term average hydro energy from this facility by 7.7 GW.h/year at a capital cost of no more than $1.0 Million. The 2012 GRA is forecasting a total cost in the area of $10,500,000.

QUESTION:

a) Please reconcile and fully explain the difference in the two cost estimates.

b) At what dollar level does YEC view this project as uneconomical?

ANSWER:

(a)

The cost estimate from the 2006 Resource Plan hearing ($1 million capital cost) was based on the following:

- Project related costs would relate primarily to planning activities (i.e., consultation and licensing) as required to seek an amendment to the Whitehorse Rapids water licence to enable modified operation of Marsh Lake within its current lake levels to enhance fall/winter storage.

- No new physical works would be required for this project.

- Licensing and other pre-decision activities were assumed to require a year such that the project could potentially come into service in 2007.

The early estimate provided in 2006 was based on a relatively simple concept and approach to the project. This estimate pre-dated and did not consider the more complex and rigourous regulatory processes that exist today under YESAA which require more

detailed scientific baseline work. Further, this was also a pre-feasibility estimate and as such was not informed by any detailed or rigourous scientific study of the conditions on the lake as required to determine project feasibility in order to make any commitment to proceed (i.e., prepare environmental assessment, engage in regulatory review processes prior to commitment to construct).

After further work and consultation was undertaken prior to the YUB hearing on the 2006 Resource Plan, 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 licensing process. As a result, YEC withdrew the project from its near-term options proposed for review by the YUB at that time.

Subsequently, in its Report and Recommendations to the Minister of Justice regarding the 2006 20-Year Resource Plan, the YUB noted that "[it] sees some viability to this project in terms of either displacing diesel generation or delaying future capacity additions" and recommended the project be retained in the Resource Plan but removed as a near-term project (i.e., at that time "near-term" referred to commitments by 2009 to meet loads out to 2012). Yukon Energy continued to consult with the residents of Marsh Lake to develop a further understanding of the natural causes of high water on Marsh Lake and by the 2008/2009 GRA work on the project had proceeded again. A third party consultant was hired in 2009 to provide project management services as well as integrated engineering and environmental/socio-economic services necessary to provide the baseline information required to determine project feasibility.

The overall concept for the project remains the same, however, the regulatory process, including the need to undertake significant scientific baseline studies, consultation requirements and related mitigation costs to secure approvals is materially more complex than originally contemplated. There are also added costs expected for physical works to accommodate the project.

The current cost estimate of $10.5 million included in the 2012/13 GRA Application (Tab 5) is based on the following:

- ***Planning and Feasibility*** – As noted, based on public concern extensive public consultation and planning work was undertaken compared to what was initially

contemplated in 2006. Planning and feasibility costs of $3.231 million to the end of 2011 primarily relate to the following activities:

- **Public Consultation** – Due to the significant public concern Yukon Energy engaged extensively with the local residents of Marsh Lake and the local First Nation in order to keep them informed on issues of concern and on progress with the project. This included meetings with individuals, public meetings and two separate workshops to review in detail issues of concern raised by local residents. Yukon Energy also brought in knowledge experts to explain the effects of the project on lake levels.
- **Extensive work on shoreline erosion and groundwater issues** – Due to identified public concern a significant amount of environmental studies have been undertaken to understand the effects of shoreline erosion and groundwater issues. This included extensive mapping of most of the shoreline of Marsh Lake and Tagish Lake, installation of piezometers around the lake and comprehensive work to define areas susceptible to erosion.
- **Hydraulic modeling** – Hydraulic monitoring of southern lakes was undertaken in order to understand the relationships between the lakes and the water flows between the lakes.

- ***Mitigation design (shoreline erosion and surface water)*** – Mitigation design likely to be required by regulators to address shoreline erosion and surface water concerns are estimated to comprise approximately half of the total $10.5 million project cost. However, at this time the actual costs for mitigation cannot be known with any certainty.

- ***Potential construction costs*** are now expected to be incurred to revise the control structure at Lewes Bridge and to cover mitigation costs (to address shoreline erosion and higher groundwater levels anticipated due to higher water levels during fall months).

(b)

A decision regarding whether or not a project should proceed is based on an assessment of various cost and risk factors specific to the project being reviewed, the options then available, and the grid load that is forecast to be supplied. Accordingly, it is

not appropriate to specify a specific dollar level at which YEC would view a project as uneconomical. Any such determination in future would be based on projected value of diesel displaced (which reflects grid load forecasts after DSM/SSE as well as forecast diesel fuel prices), the cost of competing resource options to displace forecast diesel generation, consideration of resource option reliability and flexibility to accommodate load shifts, and any relevant environmental responsibility considerations.

With regard to Marsh Lake, as noted in Tab 5, the project has an LCOE (2010$) estimated at 8.5 cents/kWh assuming a capital cost (2010$) 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 also assumed to provide 1 MW of added reliable winter peak capacity at the Whitehorse hydro plant. Subject to securing regulatory approvals, this option tends to be highly rated due to its small scale and ability to focus energy supplied in winter months, its contribution to added reliable winter capacity, and its long term ability to enhance existing hydro generation.

With a full utilization LCOE of 8.5 cents/kWh this remains an attractive near term project that enhances the existing system without material construction requirements or development of a greenfield site. Further as indicated in Table 8-1 and Table 8-1 in the Overview to the 20-Year Resource Plan: 2011-2030, this project has a forecast LCOE under Scenario A loads with DSM/SSE of 11.4 cents/kWh and a 2015 to 2019 annual cost (c/kWh of diesel displaced) of 15-16 cents/kWh. This remains attractive at Scenario A loads (within the full range of DSM/SSE considered) compared to other near term and longer term options as reviewed in the Overview to the 20-Year Resource Plan: 2011-2030 and is very attractive compared to the default diesel requirement of 28 cents/kWh (fuel and O&M only) assumed in the Resource Plan.

Marsh Lake Storage remains attractive at Base Case loads forecast in the 2011 Resource Plan. i.e., the forecast LCOE (2010$) under Base Case loads with DSM/SSE is 12.1 cents/kW.h (see 20-Year Resource Plan: 2011-2030, page 98).

Please also see response to YUB-YEC-2-16(f).

TOPIC: **Gladstone Diversion**

REFERENCE: **YUB-YEC-1-25**

PREAMBLE:

QUESTION:

a) Is the Gladstone diversion project supported by the Department of Fisheries and Oceans, and the Champagne and Aishihik First Nations?

b) If the answer to part (a) is affirmative, please explain the basis for your answer.

c) If the answer to part (a) is not affirmative, please discuss the prudency of continued expenditures on this project.

ANSWER:

(a) through **(c)**

YEC has been working with Department of Fisheries and Oceans (DFO) and the Champagne and Aishihik and Kluane First Nations with regard to the Gladstone Diversion project and, as reviewed below, the prudency of continued expenditures on this project is being guided by these discussions.

In sum, due to the very positive economic benefits of the project and overall system benefits, Yukon Energy is continuing with work necessary to determine project feasibility as required for a commitment to proceed with preparation of environmental assessment and other regulatory filings. As noted in Tab 5 of the Application, the project is forecast to provide up to an additional 36.6 GW.h (on average) of production from the Aishihik facility, focused in the winter months at a project cost estimated at $40 million (2010$) with an LCOE over the 65 year project life estimated at 5.7 c/kW.h (assuming full utilization of added energy generation and YEC blended capital cost averaging 6.56%/year). This hydro enhancement opportunity continues to offer higher potential long-term diesel displacement at the lowest project LCOE compared to any other

identified current near term supply options being reviewed, including hydro enhancement options.

Yukon Energy has undertaken fieldwork to react to concerns raised by regulators and stakeholders. The baseline studies and field work undertaken indicate no basis for concern that there will be potential significant environmental effects related to the project that cannot be mitigated. Decision making in a risk management context will consider (1) whether scientific baseline studies continue to indicate positive results; (2) whether there is received support from Champagne and Aishihik and Kluane First Nations; and (3) any ongoing pressures driven by system requirements to displace baseline diesel generation as the system grows. Even if the project does not proceed in the near term, the overall potential benefits indicate that the project should be at least retained as a potential longer term option.

DFO

DFO regulates projects to ensure they comply with the Fisheries Act and the terms and conditions of any Authorization provided pursuant to the Fisheries Act and does not "support" any particular project.

As part of its internal assessment process to determine whether there is sufficient baseline information to undertaken an environmental assessment, YEC provided DFO with a conceptual proposal in 2010. DFO subsequently indicated that it had a concern that the proposed Gladstone concept will result in significant impacts to fish and fish habitat in the Yukon and Alsek river systems, both of which support high value fisheries, due particularly to transfer of pathogens and parasites from one watershed to the other. DFO suggested that YEC revise its concept to eliminate the interbasin water transfer and reduce negative effects to fish habitat.

YEC advised DFO that the concept is still in the very early stages of study/planning, specifically the collection of baseline information and preliminary engineering development to gain an understanding of the feasibility of the concept. Specifically, YEC noted its intention as part of the baseline studies to gather sufficient information regarding the presence of pathogens and parasites, and the risk associated with potential transfer of any pathogens and parasites after all mitigation measures are considered - and, once this information is available and the preliminary assessment of

risk can be completed, its intention to share this with DFO staff for further discussion and analysis. The results of a full year of baseline studies provide no evidence to date to support a concern regarding interbasin pathogen transfer.

Prior to proceeding with further baseline studies needed for further discussion with DFO, YEC has focused on going to a next stage with Champagne and Aishihik and Kluane First Nations.

Champagne and Aishihik and Kluane First Nations

Yukon Energy has worked with the Champagne and Aishihik and Kluane First Nations since the project inception, at the political leadership level (Chief and Counsel) and at the First Nations membership level (community meetings). Yukon Energy has worked with these First Nations using a staged approach. YEC initially explained the project concept and at each stage of work informed the First Nations of work that Yukon Energy would like to proceed with and obtained agreement from the First Nations at each stage to proceed with the work described. Although the First Nations have not given an indication of support for the project they have agreed that YEC can continue to undertake studies and other work required to determine project feasibility.

With respect to Gladstone, Yukon Energy is committed to working with the First Nations until they make a decision by the First Nations as to whether or not they will support the project. It is hoped that a decision will be made in late 2012 or in early 2013.

Following a decision by the First Nations, it is expected that in 2013 Yukon Energy will make a decision as to whether to defer the project or proceed with field and engineering studies needed to prepare an environmental assessment application.

The above reflects a prudent risk management approach for the project, i.e., a decision on the next phase of material spending (related to engineering and field studies in preparation of a YESAB submission) will not be made until there is a decision from the local First Nations regarding support for the Project.

The 2012 spending ($0.200 million) relates to consultation activities and collection of baseline data (pathogen studies) that would be required in any event for the project to proceed and that can facilitate the project being shelf ready to proceed at a future date

(after 2013). Spending in 2013 will be adjusted depending on YEC's go forward decision at that time.

TOPIC: **Transmission Brushing Costs**

REFERENCE: **CW-YEC-1-18, City of Whitehorse (CW), 2012/2013 General Rate Application Interrogatory Responses Filed**

PREAMBLE:

"In 2010, labour drops $0.134 million from 2009; the primary cause of this is the loss of the 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. "

And

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

The Board would like to understand how the lost of the two power line technicians affected brushing and vegetation management.

QUESTION:

a) Please comment on how losing the two power line technicians affected the quantity and quality of YEC's brushing program in 2010.

b) Please comment on any consequences experienced by the reduction of the two power line technicians and any brushing activities in 2010.

c) Please comment on whether YEC can sustain brushing costs at levels similar to that experienced in 2010 levels without creating any problems or issues in the future.

ANSWER:

(a) and **(b)**

The loss of two power line technicians did not directly affect the quantity and quality of YEC's transmission line brushing program in 2010. The 2010 brushing program was effected by a significantly increased fire season in comparison to 2011. Based on the daily fire danger rating YEC policy is to suspend brushing (hydro axe) to mitigate potentially staring fires using mechanical equipment.

The power line technicians support the transmission line brushing program by providing on site safety orientations to the brushing contractor (Utility Arborist) and identification of danger/hazard trees observed through the line patrol process. Remaining staff performed these functions as required.

(c)

Overall there is a need for an expanded and more frequent level of brushing in the system due to longer transmission lines and changes in vegetation caused by wetter climate and more growth.

Maintaining brushing expenses at a level of spending as low as a 2010 would create problems in the future - the cyclic brushing plan and Integrated Vegetation Management Plans (created by ECI under its Transmission Vegetation Condition Assessment) have identified a need for a substantial increase of funds to the transmission brushing program in order to deal with a backlog of brushing that is urgently required.

Please see page 12.2-22 of Attachment 12.2 (page 21 of the Yukon Energy Corporation Transmission Vegetation Condition Assessment prepared by ECI) which notes as follows:

> Under YEC current maintenance strategy and practice (mowing and brushing crew), moving to a 10-year cyclic program may be cost prohibitive at $1,096,000[11] compared to the current expenditure of approximately $350,000 per year. Of the three ECI proposed maintenance cycles (7-year, 8-year and 10-year cycle), ECI recommends the 10-year cycle as the best fit for YEC. If YEC shifts to

an IVM maintenance strategy and modifies contracting methodology, the maximum YEC should expect to spend approximately $500,000 - $672,000 per year with the 10-year cycle option. A vegetation management program that utilizes IVM as a key maintenance strategy will realize significant cost savings in the future as well as reducing the risk of vegetation caused grow-in interruptions to the high voltage system.

TOPIC: **Distribution Brushing Costs**

REFERENCE: **CW-YEC-1-19, City of Whitehorse (CW), 2012/2013 General Rate Application Interrogatory Responses Filed**

PREAMBLE:

> Actual expenses were lower in 2009 and 2010 for several reasons: brushing – completed with internal labour as opposed to contractors;
>
> And
>
> Table 1: Distribution Costs per km of Transmission Line ($000)

The Board would like to better understand distribution brushing costs. Table 1: Distribution Costs per km of Transmission Line ('000) shows that the brushing costs per km of distribution lines in 2009 and 2010 was less than 40 per cent of the brushing costs for 2009 GRA compliance and FYF 2011.

QUESTION:

a) Please confirm that these savings are due to using internal labour instead of contractors.

b) Please comment on why YEC is not using internal labour for brushing despite the significant cost savings.

c) Please comment on whether YEC is currently using contractors to brush the transmission lines and whether the same cost savings could be expected if internal labour were used.

ANSWER:

(a)

The primary reason why the 2009 and 2010 brushing amounts in the "brushing" line on Table 1 were lower than anticipated in the compliance filing is because internal staff were used on some of the brushing activities that took place during those years. Internal staff can be used when they have time available and the type of brushing activity requires limited equipment and the terrain is easily accessible (e.g. to fell small danger trees located on or near ROWs). In 2009 and 2010 a considerable amount of the brushing activities were the type that could be undertaken by internal staff. It should be noted that in 2009 and 2010 the internal labor costs for undertaking that work is not included in the "brushing" line of Table 1 -- those internal labor costs are included in the "labor" line.

(b)

In 2011 and 2012 (and forecast for 2013) YEC's brushing requirements requires external contractors. This type of brushing involves more full scale brushing of the distribution lines, and is in many cases undertaken on more challenging terrain. Where possible -- if they have available time and the bushing requirements are more limited -- internal staff may be used. However, during the test years, given YEC's brushing requirements it is not anticipated that material brushing activities can be carried out by internal staff.

(c)

YEC is currently using contractors to brush transmission lines; the type of brushing activities required for transmission lines is not conducive to being performed by internal staff and in any event cost savings would not likely accrue because YEC does not own the specialized equipment nor have the trained operators required to efficiently brush transmission ROWs (i.e. hydro-axe or equivalent).

TOPIC: **Demand-side Management (DSM) Accounting Policy**

REFERENCE: **YUB-YEC-1-38, Yukon Utilities Board (YUB), 2012/2013 General Rate Application Interrogatory Responses Filed**

PREAMBLE:

> "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."

The Board would like to better understand YEC's DSM accounting policy.

QUESTION:

a) Please comment on whether it is common practice for a utility to include improvements in corporate end use in DSM.

b) Please comment on any other jurisdictions which have allowed similar improvements to be included in DSM.

ANSWER:

(a) and **(b)**

With respect to the treatment of utility improvement and corporate costs in DSM in other jurisdictions, YEC can provide the following information related to BC Hydro:

The term "demand-side measure" is broadly defined in the British Columbia *Clean Energy Act* to mean a rate, measure, action or program undertaken:

(a) To conserve energy or promote energy efficiency;

(b) To reduce the energy demand a public utility must serve; or

(c) To shift the use of energy to periods of lower demand.

but does not include:

(d) A rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia; or

(e) Any rate, measure, action or program prescribed.

With respect to part (e), to date no rate, measure, action or program has been excluded by the Minister under subsection 37(b) of the *Clean Energy Act*.

BC Hydro's DSM Implementation Plan includes the "Lead By Example" program which targets electricity savings at BC Hydro's facilities through energy efficiency capital projects and working to instill conservation policies, procedures and behaviours throughout BC Hydro's organization.[1] Pursuant to subsection 44.2 of the *Utilities BCUC Act,* BC Hydro included an updated DSM Plan and planned expenditures for 2012 and 2013 as part of its November 2011 amendment to its F12/14 Revenue Requirements Application. Spending on cross-category DSM (which includes both the Lead By Example and Sustainable Communities programs) was forecast at $14.5 million for the two-year 2012 and 2013 period (4.5 per cent of total forecast spending on DSM programs)[2]. BC Hydro applied to amortize DSM expenditures over a 15 year period.

The changes to the amortization period from 10 to 15 years and the DSM expenditures in the amended application were approved by the BCUC in the Order G-77-12A dated June 20, 2012 and available:
http://www.bcuc.com/Documents/Decisions/2012/DOC_30916_G-77-12A_BCH-F2012-F2014-RRA-Determination.pdf.

[1] Refer to page 9A-14 of Appendix 9A to the 2012 Integrated Resource Plan available: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix43.Par.0001.File.DRAFT_2012_IRP_APPX_9A.pdf.

[2] Refer to Page II-3-8 of the Amended Appendix II to the F12/F14 Revenue Requirement Application available: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/rev_req/amended_bch_f12_f14_rra_appendices.Par.0001.File.amended_bch_f12_14_rra_appendices.pdf.

TOPIC: **Vacancy Rates**

REFERENCE: **YECL-YEC-1-46, Yukon Electrical Company Limited (YECL), 2012/2013 General Rate Application Interrogatory Responses Filed**

PREAMBLE:

"Table 1: Annual Vacancy Rate by Department."

The Board would like to better understand YEC's vacancy forecast.

QUESTION:

a) Please confirm that the units in Table 1: Annual Vacancy Rate by Department re FTEs and not percentages.

b) Please describe how YEC came up with the forecast vacancy rates for the test period.

c) Please comment on why the same vacancy rate is expected in each department.

ANSWER:

(a)

Confirmed.

(b)

The forecast vacancy rate of 3 positions is based on an average of the past four years as follows in Table 1 below.

Table 1 – Average Vacancy Rate

Year	Vacancies
2008	4
2009	3
2010	1.94
2011	3.41
Total 2008 to 2011	12.35
# of years	4
Average	3.09
Rounded	3.00

(c)

On a forecast basis, Yukon Energy does not have expectations of different vacancy rates for each department. YEC is a small company and some departments within the company are only 1 or 2 staff. It would be extremely difficult to assess what vacancy rate should be applied to these scenarios and would not add significantly to our ability to manage this cost.

TOPIC: **Administration/ Communication Costs**

REFERENCE: **YUB-YEC-1-20, Yukon Utilities Board (YUB), 2012/2013 General Rate Application Interrogatory Responses Filed**

PREAMBLE:

> "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. "

The Board would like to better understand the information campaign.

QUESTION:

a) Please provide more information regarding YEC's public information campaign (e.g., type of material sent out / information disseminated) and a breakdown of each cost.

b) Has the information campaign been successful? How has YEC been tracking this success? What results can YEC show to justify this costs and continuing this program? Please quantify (e.g., How many questions has Janet received?).

c) How has the information campaign benefitted rate payers?

d) If the website upgrade costs $0.05 million, why does the communications budget not decrease by $0.05 million in 2013?

ANSWER:

(a)

Please see Attachment 1 to this response for 2010 and 2011 costs. A detailed breakdown is not available for 2012 as the year is not yet complete.

(b)

The campaign has resulted in a significant amount of people accessing Yukon Energy's public information and resources. Based on increased number of individuals accessing the website, the program has proven very successful.

Surveys

Yukon Energy has been measuring the *Knowledge, Awareness & Behaviour* (KAB) of Yukoners since 2010, using this data as a baseline measurement of communications strategy effectiveness. Key findings as they relate to the ongoing KAB survey work are available at the link below.

http://www.yukonenergy.ca/energy/public_engagement/surveys/

Communications Recall

As part of ongoing survey initiatives, respondents are asked to recall various communications tools used by Yukon Energy. The high level of recall indicates effectiveness of the messaging. The following are key findings:

- 46% recall recent household mailer;
- 48% recall recent Yukon Energy advertisements;
- 49% changed views of energy issues ("a little or a lot"); and
- 52% of respondents increased knowledge or awareness of energy issues ("a little or a lot").

Website Traffic (Oct 15 2009 to Dec 31st 2009 vs Oct 15 2011 to Dec 31 2011)

Traffic to the Yukon Energy website is a basic indicator of public interest in various facets of the Corporation. Traditionally employment focused pages have consistently ranked highest with respect to page views. However, throughout the information

campaigns the traffic to project-related energy future pages increased, making campaign-related content the second most used aspect of the site.

- 12.3% average increase in unique page views; and
- 21% average increase in duration on page.

Blog/ *Ask Jane*t Traffic Data (Oct 15 2009 to Dec 31st 2009 vs Oct 15 2011 to Dec 31 2011)

Ask Janet has allowed Yukoners to ask questions of Yukon Energy on their own time while giving Yukon Energy valuable insight into issues of interest to Yukoners. The blog has successfully acted as a resource and starting point for any energy-related discussion in Yukon.

- 61% average increase in blog traffic;
- 62% average increase in duration on page; and
- 50 Ask Janet questions covering a range of topics.

Yukon Energy YouTube Channel

In less than 12 months, Yukon Energy has created 2,896 total video views on our new YouTube channel, which features short video of our various projects and research work.

Facebook

Yukon Energy created a Facebook page as a natural platform to engage Yukoners in the energy future discussion. The page has grown to over 1,500 active members who engage Yukon Energy on a variety of energy-related topics.

Highly effective, this medium is both inexpensive and flexible, allowing Yukoners to communicate on their own time through an environment that is comfortable to them.

- On average, Yukon Energy interacts with 7.3 Yukoners a day on Facebook;

- Facebook audience has grown 24 times its size in 12 months or by over 2,000%;

- Daily friends of friends (i.e., potential reach) in excess of 159,000 users;

- Daily engaged users - 24.5; and

- Daily engaged friends of friends (i.e., actual reach) 3671 users.

(c)

The survey results and statistics related to the increasing number of people accessing YEC communication tools indicates clearly that ratepayers are receiving significant information related to the activities of the Corporation.

In order to meaningfully engage in the two-way communication of collaborative, transparent decision-making, ratepayers need to be aware of what Yukon Energy's goals, plans and challenges are, to see how all the pieces fit together in the big picture. In order to engage the public in consultation, information needs to be communicated widely and effectively so that it reaches a maximum public audience. To put it another way, it's hard to talk to someone, let alone make decisions with them, if they don't understand what's happening.

The public has multiple platforms for speaking to Yukon Energy directly, including community meetings, *Ask Janet*, the Yukon Energy blog and Facebook. Yukon Energy's investment in communications means Yukoners now have a voice in shaping the energy future of their territory, which not only affects ratepayers' bottom line, but the overall economic, environmental and social stability of the Yukon as a whole.

Apart from the public at large, a major audience for communications is Yukon Energy's stakeholders, which includes businesses and associations, community organizations, First Nations, governments, and other groups who have a vested interest in supporting a fiscally responsible, sustainable energy strategy for Yukon. By understanding Yukon's short and long term energy needs and supply strategy, stakeholders are more inclined to envision a positive investment future in Yukon, resulting in economically stronger communities.

Yukon Energy has invested in developing and maintaining a strong relationship with ratepayers - a group that includes Yukon Energy employees, board members, stakeholders, and the Yukon public at large. Surveys conducted at critical stages in communications development and delivery indicated from the outset that ratepayers are highly interested in our territory's energy issues.

In order to meet the energy needs of ratepayers, Yukon Energy has to be aware of what those needs are. The old model of corporate governance where Yukon Energy made decisions about the territory's energy management, then informed the public about those decisions, is no longer a viable approach to corporate responsibility. Yukon Energy's model of public engagement as part of the decision-making process required a major shift in the way that the Corporation communicates with the public. Instead of Yukon Energy making decisions *for* ratepayers - about the money they pay for electricity and how that electricity is supplied - the Corporation is making decisions *with* ratepayers.

(d)

Page 3-12 of the Application incorrectly states that $0.050 million was budgeted for upgrading YEC's website in 2012. This statement was incorrect. The $0.050 million for a website upgrade was part of the initial communications draft budget for 2012, but the expenditure was not approved and so was not in the final communications budget number submitted to the YUB.

YEC Public Information Campaign 2010

	COST
Build Research/Benchmarks/Measure/Evaluation	
Strategic Communication Planning/Project Research	$ 30,000.00
Creative strategy: 3 targets; writing, art, presentations	$ 12,100.00
> compile key information for 3/4 target groups	
Survey development: process, frequency plan	
• benchmark research from existing data	
• intercept/interview planning: stakeholders & allies	
• survey planning: stakeholders & allies	
• monitoring media: print, radio, blogs; track attendance	
at public meetings	$ 14,000.00
Evaluation and Reporting	$ 6,600.00
	$ 600.00
Total Development	**$ 63,300.00**
Key Stakeholders and Allies	
• survey/intercept/interviews of Allies (ongoing)	
Yukon Govt, Yukon Chamber of Commerce	
Whitehorse Chamber of Commerce, TIAY,	
First Nations, Association of Yukon Communities	
City of Whitehorse, Yukon Electrical Company, others	
• Ongoing measurement: teams conducting/collecting	
> **stakeholders and allies**	
	$ 4,800.00
Message Strategy: writing, PPT, one-sheet, support, displays	$ 6,600.00
Develop Vision Campaign PowerPoints and updates - 3 different	$ 5,280.00
Scheduling events: management and support	$ 4,400.00
Design, production of materials	$ 6,050.00
> misc. expenses and printing during year	$ 1,800.00
Total Campaign	**$ 28,930.00**
General Public	
Communication planning, creative development and managem	$ 4,866.34
• survey/intercept general audience (ongoing)	$ 5,280.00
Yukon Residents	
• Update public advertising formats with new key messages	
• website: micro site	$ 26,767.50
> Phase One Development	
> Phase Two Development	
> Facebook	
• household mailer	$ 3,897.72
• bill stuffer (very few customers)	
• newspaper advertising/inserts supporting campaigns	$ 69,997.18
• online advertising	$ 13,314.41
• Television	$ 1,058.83
• community signage	$ 7,591.39
• events/trade shows	$ 918.00
> pop-up display units as backdrop, other collateral	
• radio ads	$ 8,139.71
• signage:	
> digital signage	$ 10,329.40
> YE sites and vehicles	$ 4,485.53
Staff promotion item - mugs	$ 2,123.99
Total Campaign	**$ 158,770.00**
TOTAL	**$ 251,000.00**

YEC Public Information Campaign 2011

	Cost
Build Research/Benchmarks/Measure/Evaluation	
research - project support, stakeholder interviews	$ 6,820.00
public survey costs	$ 16,237.50
online support for web, survey monkey, research	$ 4,042.50
Sourcing / contracting survey staff	$ 302.50
Contracts with survey staff	$ 1,560.00
Stakeholder survey contact cards, develop, produce	$ 1,024.50
Production work for other projects: ppt, mugs, prepress	$ 3,190.00
Z-Card mailer (printing and mailing costs only)	$ 17,778.26
50% cost of mugs	$ 3,641.10
Total Development	**$ 54,596.36**
Key Stakeholders and Allies	
Communication Channels Coordination and Content	$ 5,900.00
> YE updates to channels / email invites	
• existing / expand contact lists; establish comm schedule	
• write, format, distribute updates	
Total Campaign	**$ 5,900.00**
General Public	
Communication planning, creative development and management	$ 68,207.50
> Print Ads	$ 14,769.00
• Yukon News	
• Whitehorse Star	
• What's Up Yukon	
> Household Mailers (2)	$ 3,963.38
• distribution (2)	
> Radio	$ 3,474.90
• CHON FM	
• CKRW AM	
• production and talent of 8 different ads	$ 2,500.00
> Transit	$ 3,500.00
• interior	
• exterior	
> Digital signage	$ 2,352.56
> Community signage - continue existing program	
• placement costs (annual)	$ 3,145.05
> Website - Phase 3 updates and additions	$ 9,550.00
> campaign videos (8)	$ 14,000.00
> online poll	$ 3,600.00
> online advertising	$ 6,675.62
• Whitehorse Star	
• CBC North	
• What's Up Yukon	
• Facebook	
> Facebook page	$ 1,750.00
> YouTube page	$ 487.50
Total Campaign	**$ 137,975.51**
TOTAL	**$ 198,471.87**

TOPIC: **Costs of converting to IFRS**

REFERENCE: **YUB-YEC-1-55 & YUB-YEC-1-56, Yukon Utilities Board (YUB), 2012/2013 General Rate Application Interrogatory Responses Filed**

PREAMBLE:

"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."

And

"The advisor started collaborating with YEC in order to execute IFRS in about March 2009."

And

"The advisor's mandate was initially expected to end within a few months of conversion, originally planned for January 1, 2011."

And

"The advisor will continue to work with YEC through conversion, probably into the first quarter of 2013."

The Board would like to better understand YEC's transition into IFRS.

QUESTION:

a) How is the advisor compensated (e.g., hourly, fixed salary)?

b) Given that the ASB did not grant the 2012 deferral option until October 2010, YEC should have been ready, or very close to being ready, for IFRS starting

January 2011. Please comment and provide a percentage to demonstrate how prepared YEC was for IFRS in October 2010.

c) Please describe in detail what work the advisor has completed since January 2011 and what work still needs to be completed for the 2013 transition.

d) Please provide the total amount (related to the IFRS adoption) that YEC would have added to the rate base if YEC had adopted IFRS in 2011.

e) Please provide the total amount (related to the IFRS adoption) that YEC is expecting to add to rate base following the adoption of IFRS in 2013.

f) Please confirm that no incremental costs are associated with the deferral of IFRS adoption.

ANSWER:

(a)

The advisor is compensated hourly.

(b)

When the AcSB issued the last deferral, YEC was working very hard to meet the January 2011 deadline. Conversion to a new basis of accounting is a very rare event, and therefore it is difficult to assign a percentage to the progress made as there is significant uncertainty around the level of effort required to complete documentation. At the time of the last deferral YEC had completed approximately 15 of 26 position papers.

(c)

Since January 2011 the advisor has been working with the YEC employee in charge of conversion. Topics that have been covered include advice on documentation of the componentization of assets, Asset Retirement Obligations documentation, Accounting Policy documentation and application under IFRS, monitoring and updating on status of rate regulated accounting.

The advisor has been instrumental in drafting of the accounting papers for the auditors. There has been an ongoing review of accounting papers throughout 2011. Fifteen accounting papers have been written. Four accounting papers have been sent to the auditor for final review. There are eleven more accounting papers completed in draft format which require final review and approval before being forwarded to the auditors. The advisor has not completed work since January 2012.

The estimated effect of IFRS or interpretations on YEC's accounting records is estimated at this time and subject to change through to the date of issuance of its year ended December 31, 2013 financial statements. IFRS and its interpretations will evolve up to December 31, 2013. As well, compliance is subject to review and sign off by external auditors which will not happen until Q2 2013 – there could be additional expenditure in order to defend positions and possibly amend documentation/implementation. These and other factors may impact IFRS reporting requirements and YEC's cost estimate for complete conversion. The time estimate at this point is as follows:

- Estimate of in house time 520 hours of various employees time = **$30,000;**
- Consultants time = **$65,000;**
- Contingency = **$10,000; and**
- Total = **$105,000.**

(d)

There is currently $580,000 charged to the IFRS project at the end of 2011. This amount would have increased by approximately $100,000 if IFRS was adopted in 2011.

(e)

There is currently $580,000 charged to the IFRS project at the end of 2011. It is expected that the amount to be added to ratebase following the adoption of IFRS to be approximately $685,000.

(f)

Confirmed.

TOPIC: **YEC Planning Cost Accounting Policy (PCAP)**

REFERENCE: **YUB-YEC-1-39**

PREAMBLE:

> …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 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.
> …
>
> …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.

QUESTION:

a) The PCAP refers to "planning and study costs which are pure research in nature. Please provide why YEC customers should be accountable for "planning and study costs which are pure research in nature." What test does YEC for determining prudency for such costs?

b) Please list previous planning and study costs which are pure research in nature or are related to ongoing operations.

c) Are "Planning costs incurred in relation to major projects that do not meet Reasonable Assurance [which YEC proposes to promptly close] out in annual stages, and [amortize] over 5 years"1 considered to be reviewed during a GRA process? If not how are such costs reviewed by the Board or intervenors?

d) Under 2.2 (a) of YEC's proposed PCAP, how long can future expenditures be held without meeting YEC's reasonable assurance test? Further, if these costs are then deferred, when do these costs come under regulatory review?

e) Please explain how the PCAP provides a clear decision-making framework which addresses transparency/accountability and intergenerational equity concerns.

f) With respect to the above quote taken from YUB-YEC-1-39(d), on what basis does YEC make the decision to proceed or not to proceed? Economics – i.e. dollars per KW? Additionally, in its response to YUB-YEC-1-39(d), is YEC stating that costs such as assessment, licensing, engineering and tendering costs are hard to forecast with any reasonable assurance. Please explain.

g) In its answer to YUB-YEC-1-39(e), is YEC submitting that these costs will not form part of the total project costs?

ANSWER:

(a)

The Planning Cost Policy addresses how costs will be accounted for in YEC's revenue requirement and does not address how the prudence of individual cost items will be assessed. In this regard, as noted in Section 2.1 of the Planning Cost Accounting Policy (Appendix 5.1 of the Application):

> "Planning and study costs which are pure research in nature, or are related to ongoing operations, shall be recorded as an expense of the period in which they are incurred, with the exception of planning and study costs related to ongoing operations that provide long-term or multi-year benefits to the system which will be deferred and amortized according to this policy. "

The above addresses only how each type of cost will be accounted for (i.e., expensed in the year incurred or deferred and amortized for a longer time period).

The prudence and value of each cost proposed to be included in rates, whether considered to be research, related to ongoing operations or for a project that provides

long term, multi-year benefits, must be assessed separately on its own merits during a General Rate Application process.

(b)

The concept of expensing costs that are considered pure research in nature or related to ongoing operations originated with the original planning cost accounting policy provided in the early 1990's. This original policy noted with regard to pure research that costs of this type, if any, are not expected to be significant. As such, Yukon Energy considers such costs to relate to negligible research or operations work that does not provide enduring or multi-year benefits. Yukon Energy cannot provide any recent examples of such costs. All research or studies related to ongoing operations in recent years has been considered to provide longer term benefits to the system and has been amortized over 5 years once the study is complete.

(c)

Yes - all costs proposed to be included in a utility revenue requirement, and rates, in a GRA Application are subject to review by the Board and intervenors.

The current GRA Application includes costs for projects that YEC concludes do not meet Reasonable Assurance (i.e., under the proposed Planning Cost Accounting Policy, costs are closed out at year end 2011 or year end 2012 with amortized amounts included in one or both of the proposed test year revenue requirements). In this respect the YUB will review the prudence of expenditures to date for each such project prior to including such costs in rates.

(d)

Future expenditures can only be held for 12 months - 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. Costs will not be carried/ deferred beyond periods of approximately 12 months – with the exception of the special transition policy applicable to certain projects for the test years, all costs incurred within the 12 month period will be closed out and amortized over 5 years.

Section 2.3(b) notes all projects will be scrutinized by YEC as part of the year-end financial review to ensure the requirement for annual milestones and closeouts is being met with tangible products or reports required within the deferral period to demonstrate a used or useful asset and balances written off to income in the year incurred where there is no demonstrable asset. Deferred and amortized costs that arise after the current GRA review and continue to be expensed in future test years will be subject to review by the YUB at the time of the next GRA prior to being included in future rates.

(e)

In summary, the policy is being implemented to enhance accountability and transparency by providing for decision making and public review of costs (to the extent that rates are affected) at earlier planning stages. A review of project costs at earlier stages will also provide for intergenerational equity and accountability. Costs will be subject to review prior to being included in rates at each GRA. Further detail is reviewed below.

In the above referenced IR response Yukon Energy noted as one of the principles applied in the development of the updated Planning Cost Accounting policy the need for the policy to "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 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). With this context in mind, the policy reflects the above principles as follows:

- ***Provides a clear decision making framework*** – The updated Planning Cost Accounting Policy provides a clear framework for decision making:
    - **Section 2.1 and 2.3(b)(ii)** indicate costs that are to be written off to income in the year incurred.
    - **Section 2.2** outlines the threshold for planning costs to meet (i.e., Reasonable Assurance) before such costs will be recognized as work in

progress assets and carried beyond each year end as a deferred cost without amortization.

- **Section 2.3** outlines the annual financial year end review process to be followed to determine: (1) whether there is reasonable assurance of a Corporation commitment to construction; and (2) for projects where there is not reasonable assurance, a review process to ensure requirement for annual milestones and closeouts has been met, with tangible products or reports required.

- ***Rate Stability*** – The updated Planning Cost Policy provides for rate stability as follows:
  - It provides for a PUB review of current balances and for inclusion of prudently incurred planning costs incurred to date in rates (reducing future rate impacts where continued deferred costs are included in rates.
  - The 5 year amortization period provides for 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 10 year amortization period for projects that have met the reasonable assurance test but are later abandoned is proposed to mitigate and smooth rate impacts which 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. This also reflects the reality that the further along in the planning stages a projects proceeds, the greater the likelihood that significant costs will be incurred related to assessment, licencing, engineering and tendering costs.
  - As noted in Section 4.1 of the Planning Cost Accounting Policy, the one-time special transition approach for costs presently in WIP to be implemented over the 2012 and 2013 test eyras is 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.

- ***Transparency/ Accountability*** – Planning costs incurred to date are subject to a full review by the YUB and intervenors at this time unless a Reasonable Assurance test is stated to have been met, and therefore such costs do not continue to be deferred (limiting the extent of timely review of such costs affecting rates) until a decision is made not to proceed with the project or the project is completed and in service (and is proposed to be included in rate base at a future GRA.

- ***Intergenerational Equity*** – Pushing significant deferred costs to the future shifts risks and cost burdens to future ratepayers, and the Planning Cost Accounting Policy provides a clear decision-making framework regarding the inter-generational treatment of any such costs that are not related to a project that YEC has concluded to be reasonably likely to proceed through permitting and other final development stages. In this respect, the policy seeks to ensure that (1) costs are expensed each year and not shifted to future ratepayers unless there is an accounting justification for treatment as deferred costs; (2) deferred costs projected in the current GRA to occur before 2014 are subject to five year amortization (except for costs related to specific transition project subject in this GRA to 10 year amortization) and a prudence review by the YUB at this time (i.e., this review is not shifted to some future date) unless the project is stated to have met the Reasonable Assurance test and is not projected to come into service during the test years; (3) deferred costs determined by the YUB to be prudent are included in rates at this time (if deferred and amortized in 2012 and/or 2013), with the requirement that any other future deferred costs (including such costs incurred after the test years) be reviewed by the YUB prior to being included in rates at a future date.

(f)

The referenced quote addresses accounting treatment, rather than the basis for YEC to make a decision to proceed or not to proceed with a specific project. Each such decision is made based on project specific circumstances, information and projected requirements and options. As noted below, such decisions take into account all relevant project circumstances and are not necessarily based only on cost or dollars per kW.

The referenced IR was addressing the reasons and rationale underlying the amortization period of 10 years for projects that have met reasonable assurance but are later abandoned. The response noted that the longer amortization period recognized the reality that even after Reasonable Assurance and a decision to proceeding with licencing of a project, up to the Decision to Construction a decision may be made to abandon the project. The longer amortization period addressed the reality that the further along in the planning stages a project proceeds, the higher the incurred costs are likely to be.

This discussion in that IR is focused entirely on accounting for costs incurred and measures undertaken to mitigate rate impacts in certain circumstances (and does not address the prudence of individual projects or project costs or the tests for determining whether it is prudent to proceed with a particular project at a particular point in time).

Reasonable assurance as discussed above (and as understood and applied in the Planning Cost Accounting Policy) is an accounting test (i.e., point at which costs can continue to be deferred as capital WIP without amortization). The above discussion (and response to YUB-YEC-1-39(d)) does not address project planning and risk assessment frameworks, and in the context provided is not stating that "costs such as assessment, licencing, engineering and tendering costs are hard to forecast with any reasonable assurance".

For the second part of the question, regarding whether YEC is stating costs such as assessment, licensing, engineering and tendering costs are hard to forecast with any reasonable assurance – the answer is no. As noted above, the decision to proceed or not to proceed with a project depends on the circumstances of the particular project under review and is based on relevant factors for project planning through the project decision phases.

For example, as noted in the Mayo B Part 3 Application, over 2007-2008 Yukon Energy initiated an update to the studies of hydro sites and enhancements previously identified as relatively promising that could provide up to 50 to 100 GWH/yr of new renewable energy within the 2010 to 2015 time period[1]. Mayo B was identified as the largest available enhancement opportunity to Yukon Energy's existing hydro generating facilities (in terms of energy benefits) among the eligible options potentially available to begin

[1] YEC at that time saw a potential need to serve up to at least three mine projects (Minto, Carmacks Copper, and Alexco).

operation in this time period; it was also considered the only enhancement opportunity that could feasibly be licensed and built to be in service within the 2011 and 2012 time period. Other options reviewed at the time had more attractive forecast LCOE's but did not proceed further at that time in project planning stages (towards preparation of environmental assessment and initiation of licencing and regulatory review processes) due in part to the fact that they could not reasonably be licenced and constructed within the required time period.

(g)

Yes. In the event that a project is subsequently developed, such costs will have been amortized separately starting prior to the project coming into service.

TOPIC: **Marsh Lake Storage**

REFERENCE: **YUB-YEC-1-42**

PREAMBLE:

> "An LCOE (2010$) is estimated at 8.5 cents per kW.h, assuming a capital cost (2010$) 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 Board requires further information.

QUESTION:

a) Please provide the 8.5 cents per kWh full utilization LCOE analysis (lines 9-12, page 5-33 of the Application) in an EXCEL spreadsheet with all formulae intact, including all underlying assumptions.

b) Table 1 of YUB-YEC-1-42, compares default diesel requirement with Marsh Lake storage on lines 1 and 2. Respecting the default diesel requirement please provide the rationale for comparing 6.4 GW.h/yr Marsh Lake storage to 292 GW.h/yr default diesel.

c) Please provide the underlying assumptions for all the columnar items in Table 1 of YUB-YEC-1-42, on a line-by-line basis.

d) Is the $10.5 million forecast cost to complete the project over and above the $4.83 million3 total projected deferred cost?

e) If the answer to (d) above is no, please explain why the total projected deferred costs are not included in Table 1, as part of the capital costs for the Marsh Lake project?

f) When reviewing projects, does YEC adhere to a $/MW.h benchmark to make a decision whether or not to proceed with a project. Please justify the criteria that may or may not signal the end to a project from YEC's perspective.

ANSWER:

(a)

The requested Excel format file was provided in consolidated package of Round 1 IR responses as Attachment 1 to YUB-YEC-1-42(f) and (h). For the convenience the Excel file has been re-attached. Please see Attachment 1 to this response.

(b)

Table 1 included in the response to YUB-YEC-1-42 is a summary of information included in table 8-1 of the Resource Plan Overview (provided as Attachment 1 to YECL-YEC-1-18). The 292 GWh for diesel noted in Table 1 is in effect the annual energy capability for 37 MW of diesel, i.e., this is how many GWh of energy can be generated by this supply option, assuming full use 91% of the annual hours. In contrast, Marsh Lake has an annual energy capability of 6.7 GWh. This comparison allows readers to assess energy capability for each option relative to capital costs required for each option and relative to forecast diesel generation under Scenario A loads with DSM/SSE.

(c)

Please see YCS-YEC-2-10(a) for the underlying assumptions for columnar items in Table 1 of YUB-YEC-1-42. O&M costs for the Marsh Lake project are assumed (2010$) to be at $8/MW.h (0.5% per year of total capital cost).

(d) and **(e)**

The $10.5 million cost to complete the project is not over and above the $4.83 million total projects cost forecast by end of 2013. Table 1 of YUB-YEC-1-42 indicates an estimated capital cost (2010$) of 10 million.

(f)

Yukon Energy does not consider a fixed $/MW.h benchmark in making a decision regarding whether or not to proceed with a project. Each project will be evaluated based on its own facts and circumstances, considering existing and projected system requirements and risks as well as options then available to meet projected requirements.

Studies and planning work are required in order to effectively evaluate a supply option and determine whether there is a viable project that should proceed to construction. The criteria used to assess resource supply options are noted in the Overview of 20-Year Resource Plan: 2011-2030, and include reliability, affordability, flexibility and environmental responsibility.

By way of example, in 2007-2008 YEC reviewed several potential new supply options and elected to proceed with Mayo B even though this option, among those then examined, did not have the lowest estimated cost of energy on a per kW.h basis. As noted in the Part 3 Application for Mayo B, Yukon Energy's decision at that time not to proceed then with certain other options reflected risks regarding timely regulatory approval as well as the projected magnitude of diesel displacement requirements within the near-term planning period.

Please also see response to YUB-YEC-2-7(b).

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, Waste to Energy/Biomass/Biogas**

REFERENCE: **YUB-YEC-1-47**

PREAMBLE:

> "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)."

The Board requires further information.

QUESTION:

a) Please provide Table 1 in an EXCEL spreadsheet with all formulae intact and please include all underlying assumptions.

b) Table 1 of YUB-YEC-1-47, compares default diesel requirement with waste to energy, 25 and 15 MW wood biomass, and 3 MW wood pilot scenarios. Respecting the default diesel requirement, please provide the rationale for comparing the different capacities, i.e. 2.2, 25, 15 and 3 MW for the scenarios vs 37 MW capacity for the default diesel requirement.

c) The default diesel requirement is made up of $56 million capital costs. Please provide all underlying costs that make up this total.

d) Do the capital costs for the waste to energy, wood biomass and wood pilot projects include the costs of feasibility costs to date and future related studies? If not, please explain why project-related costs shown in Table 1 of YUB-YEC-1-40 should not be capitalized with their respective projects.

ANSWER:

(a)

Please see Attachment 1 to this response for the Excel format of Table 1 to YUB-YEC-1-47(a) and please see YCS-YEC-2-10(a) for the underlying assumptions.

Please note that the numbers are hard entered as the analyses are prepared in separate files for each project. Also, there was a typographical error in Table 1 to YUB-YEC-1-47(a) regarding forecast LCOE for 3 MW Wood Pilot project (23.1 cents/kW.h). The corrected version is provided in Table 1 below.

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 [2]	42.8	16.6
15 MW Wood Biomass	86	15	120	72	33-35	40.1 [2]	28.8	15.8
3 MW Wood Pilot (Haines J.)	19	3	24	18	28-29	35.4 [2]	24.7	17

Notes:
1. Forecast LCOE = Levelized Cost of Energy (cents/ kW.h of forecast diesel displaced [2010$]) over project life at Scenario A load scenario.
2. Assumes no O&M cost after 2020 when mines are forecast to shut-down.

(b)

Table 1 is a summary of information provided in Table 8-1 and Table 8-2 included in the Overview to the 20-Year Resource Plan: 2011-2030. In this respect the capacity information provided for each of the noted projects: 25 MW Wood Biomass, 15 MW Wood Biomass and 3 MW Wood pilot (Haines Junction) describes the defined resource option as reviewed in the Resource Plan and provides the capability of each project based on assumed operation through the year.

(c)

The $56 million capital cost (2010$) for diesel is based on 37 MW (the forecast new diesel capacity required to meet grid capacity planning criteria by 2030 under all load forecast scenarios with DSM/SSE, taking into account planned retirements of existing diesel units). The assumed cost (2010$) for new diesel capacity at existing YEC facilities is $1.5 million per MW.

(d)

In general, the forecast capital costs for these projects do not include the costs of studies to date, but will include future related studies after such time as there is reasonable assurance that a Corporation commitment will be made to proceed with the project. Please see explanation below.

The new Planning Cost Accounting Policy included in 2012/13 GRA application (please see Appendix 5.1 of 2012/13 GRA) proposes 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. Therefore, the planning study costs for the projects that do not meet reasonable assurance will promptly be closed out in annual stages, and amortized over 5 years. If there is reasonable assurance that the construction will occur[1], than 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.

[1] 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 (i.e., the YEC "Commitment to Proceed" test).

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 [2]	42.8	16.6
15 MW Wood Biomass	86	15	120	72	33-35	40.1 [2]	28.8	15.8
3 MW Wood Pilot (Haines J.)	19	3	24	18	28-29	35.4 [2]	24.7	17

Notes:
1. Forecast LCOE = Levelized Cost of Energy (cents/ kW.h of forecast diesel displaced [2010$]) over project life at Scenario A load scenario.
2. Assumes no O&M cost after 2020 when mines are forecast to shut-down.

TOPIC: **Mayo Lake Enhancement Project**

REFERENCE: **YUB-YEC-1-46**

PREAMBLE:

> "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 Licensing 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."

The Board requires further information.

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 an EXCEL spreadsheet with all formulae intact and please include all underlying assumptions.

b) Are the above-noted expenses to be capitalized as Mayo Lake enhancement project expenses when the project has been completed? Please explain.

ANSWER:

(a)

The requested Excel format file was attached to the consolidated package of Round 1 IR responses as Attachment 1 to YUB-YEC-1-45(a). For convenience the Excel file has been re-attached. Please see Attachment 1 to this response.

(b)

The referenced expenses are to be capitalized as Mayo Lake enhancement project expenses when the project has been completed and comes into service. In the 2012/13 GRA, the project is forecast to come into service prior to 2013 and deferred costs related to Mayo Lake Hydro Enhancement Project are forecast to close-out in the end of 2012 and amortize over the remaining life of the current license (13 years) starting from 2013.

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, Gladstone ($4.4 million)**

REFERENCE: **YUB-YEC-1-43**

PREAMBLE:

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 an Excel spreadsheet with all formulae intact and please include all underlying assumptions.

ANSWER:

(a)

As noted in response to YUB-YEC-1-43(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 $40 million (2010$).

The requested Excel format file was attached to the consolidated package of Round 1 IR responses as Attachment 1 to YUB-YEC-1-43(a). For convenience the Excel file has been re-attached. Please see Attachment 1 to this response.

Gladstone project LCOE

Capital ($000)		2010	$40,000	
Capital ($000)		2018	$46,866	
O&M	(Fixed)	2010	$200.0	$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%
Preferred	0%	0.00%	0.00%
Equity	40%	8.49%	3.40%
Total	100%		6.56%

	2015$	2010$
PV Cost $000's	51,348	43,825
Project LCOE		$0.057

Gladstone project LCOE

Year	Rate Base	Depr	Return	O&M	Total $000	Annual Energy GW.h
2016			0		0	
2017	46866				0	
2018	46145	721	3053	234	4,008	36.60
2019	45424	721	3005	239	3,965	36.60
2020	44703	721	2958	244	3,923	36.60
2021	43982	721	2911	249	3,880	36.60
2022	43261	721	2863	254	3,838	36.60
2023	42540	721	2816	259	3,796	36.60
2024	41819	721	2769	264	3,754	36.60
2025	41098	721	2721	269	3,712	36.60
2026	40377	721	2674	275	3,670	36.60
2027	39656	721	2627	280	3,628	36.60
2028	38935	721	2579	286	3,586	36.60
2029	38214	721	2532	291	3,544	36.60
2030	37493	721	2485	297	3,503	36.60
2031	36772	721	2437	303	3,462	36.60
2032	36051	721	2390	309	3,420	36.60
2033	35330	721	2343	315	3,379	36.60
2034	34609	721	2295	322	3,338	36.60
2035	33888	721	2248	328	3,297	36.60
2036	33167	721	2201	335	3,256	36.60
2037	32446	721	2153	341	3,216	36.60
2038	31725	721	2106	348	3,175	36.60
2039	31004	721	2059	355	3,135	36.60
2040	30283	721	2011	362	3,095	36.60
2041	29562	721	1964	370	3,055	36.60
2042	28841	721	1917	377	3,015	36.60
2043	28120	721	1869	384	2,975	36.60
2044	27399	721	1822	392	2,935	36.60
2045	26678	721	1775	400	2,896	36.60
2046	25957	721	1727	408	2,856	36.60
2047	25236	721	1680	416	2,817	36.60
2048	24515	721	1633	424	2,778	36.60
2049	23794	721	1585	433	2,739	36.60
2050	23073	721	1538	442	2,701	36.60
2051	22352	721	1491	450	2,662	36.60
2052	21631	721	1443	459	2,624	36.60
2053	20910	721	1396	469	2,586	36.60
2054	20189	721	1349	478	2,548	36.60
2055	19468	721	1302	488	2,510	36.60
2056	18747	721	1254	497	2,473	36.60
2057	18026	721	1207	507	2,435	36.60
2058	17305	721	1160	517	2,398	36.60
2059	16583	721	1112	528	2,361	36.60
2060	15862	721	1065	538	2,324	36.60
2061	15141	721	1018	549	2,288	36.60
2062	14420	721	970	560	2,251	36.60
2063	13699	721	923	571	2,215	36.60
2064	12978	721	876	583	2,179	36.60
2065	12257	721	828	594	2,144	36.60
2066	11536	721	781	606	2,108	36.60
2067	10815	721	734	618	2,073	36.60
2068	10094	721	686	631	2,038	36.60
2069	9373	721	639	643	2,003	36.60
2070	8652	721	592	656	1,969	36.60
2071	7931	721	544	669	1,935	36.60
2072	7210	721	497	683	1,901	36.60
2073	6489	721	450	696	1,867	36.60
2074	5768	721	402	710	1,834	36.60
2075	5047	721	355	725	1,800	36.60
2076	4326	721	308	739	1,768	36.60
2077	3605	721	260	754	1,735	36.60
2078	2884	721	213	769	1,703	36.60
2079	2163	721	166	784	1,671	36.60
2080	1442	721	118	800	1,639	36.60
2081	721	721	71	816	1,608	36.60
2082	0	721	24	832	1,577	36.60
PV		10,808	35,703	4,836	51,348	