REFERENCE: Application, page 2-1

YEC directly serves about 1900 customers at the distribution (retail) level (about 11% of all electrical retail customers in Yukon), most of whom live in and around Dawson City, Mayo and Faro.

QUESTION:

a) Should the remaining 89% of retail customers or their representative be consulted on rate design issues?

ANSWER:

(a)

In Yukon, as a result of OIC 1995/90 (and predecessor OICs going back to the time before YEC's first rate application), all retail ratepayers of YEC and YECL have an equal and direct interest in the revenue requirements of each utility and in related retail rate design issues. The Board is required to establish equalized rates for each retail rate class that do not vary as between YEC and YECL, reflecting the combined revenue requirement of the two utilities and a common rate design for customers of both utilities.

It is unclear what type of consultation the question envisages. If the question refers to Board processes, today, as in the past, all ratepayers have the ability to take part in the process established by the Board to deal with YEC's Application. More specifically in this Application a large percentage of ratepayers are directly or indirectly represented by intervenors who are actively taking part in the Board's process.

REFERENCE: Application, page 2-5

Forecast industrial sales as provided in July 2008 by Minto Explorations Ltd. for the last three months of 2008 are 6,845 MW.h and forecast industrial sales for 2009 are 29,023 MW.h.

QUESTION:

a) What date did sales to Minto begin? What are the 2008 actual energy sales to Minto?

b) Please reconcile the 2009 forecast industrial sales to Minto versus the assumed load of 32.5 GW.h in the PPA application. What loads in the original assumptions did not materialize?

ANSWER:

(a)

Commencement of Delivery as defined in the PPA occurred on November 22, 2008. The mine was first energized on November 15, 2008. Between November 15, 2008 and November 22, 2008, crews worked on equipment settings and completed commissioning activities.

Actual energy sales to Minto in 2008 were 3,200,484 kWhs (see PWP/HML-YEC-1-16(a)).

(b)

Based on information provided by Minto, Yukon Energy is unable to provide any more detail than has been provided at Tab 2 of the Application (pages 2-5 and 2-6).

REFERENCE: Section 2.2.2.2 Update on Other Mines

The projected in-service date at this time is 2011, with an expected annual requirement averaging approximately 4 GW.h per month (48 GW.h per year) and a mine life of at least six years.

QUESTION:

a) If the projected in-service date is 2011, when would construction need to begin?

b) Would 2010 inventory and other working capital items be affected by this project?

c) If this mine goes ahead, does this accelerate the need for the second phase of the CSTP?

d) Are costs with respect to the Carmacks Copper PPA included in the forecast of regulatory costs during the test years?

ANSWER:

(a)

Yukon Energy does not have environmental regulatory approvals required to construct transmission to the site of the Carmacks Copper project. While any line may require up to 1 year for construction, environmental studies and reviews may necessitate up to one additional year (depending on the voltage and level of YESAB review).

(b)

Yukon Energy does not typically use inventory for the purposes of major capital projects. As a result, there would be no expected impact on inventory levels or other capital items for 2010.

(c)

If the Carmacks Copper mine proceeds in the near-term, it underlines the need for the second stage of the CSTP.

However, the Carmacks Copper project is only one potential basis for accelerating the second phase of CSTP. At the present time, it is also expected that near-term government infrastructure funding combined with connection of the Alexco mine in 2010 may serve as the impetus for proceeding quickly with this project.

(d)

No. Any costs for such PPA negotiation are part of the Western Copper grid connection (deferred planning and study costs). No costs are presently forecast for regulatory review for a Carmacks Copper PPA.

REFERENCE: Application, Page 3-2

Completion of Stage One CSTP, which contributes to these increased revenue requirements, is the key factor leading to an overall 2009 rate reduction.

QUESTION:

a) On what date did Minto become a customer of YEC?

b) When did the actual connection of the Minto mine to the grid occur?

c) When did Pelly Crossing connect to the grid?

ANSWER:

(a)

Commencement of Delivery as defined in the PPA occurred on November 22, 2008.

(b)

The mine was first energized on November 15, 2008. Between November 15, 2008 and November 22, 2008, crews worked on equipment settings and completed commissioning activities.

(c)

The community of Pelly Crossing was energized from the transmission line on November 19, 2008.

REFERENCE: **Insurance and Reserve for Injury and Damages (IRID)**

QUESTION:

a) Please provide a continuity table of IRID showing the appropriations going in and the charges against for the years 2005 to 2009 inclusive.

b) Please provide a detailed breakdown of the actual charges against IRID for the years 2005-2008 inclusive and the forecast charges for 2009.

ANSWER:

(a) and **(b)**

Please see table below which provides a continuity schedule for the Reserve for Injuries and Damages (RFID) for the years 2005 to 2008 inclusive. With respect to 2009, the GRA has been prepared on the assumption that charges would equal the 2009 appropriation, at $150,000.

Please see also response to YECL 29.

Continuity Schedule – YEC Reserve for Injuries and Damages

	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)
Opening Balance	**797**	**-33**	**500**	**463**
Additions				
Computer Stolen	4			
Third Party Vehicle Damage - Mayo	1			
Service Truck Fire Loss	1			
Dawson Hse H20 Damage	6			
Marsh Lake Dam Repair	2			
YUB Board Order 2005-12 transfer from Reg Liability	-743			
Takhini Substn Break-In		15		
Kulan Break In		32		
L171 Lightning Arr Failure		11		
L171 Insulator Failure		35		
Whitehorse Hydrant Leak		36		
Unit 63 Vehicle Theft		2		
WH1 Hub and Blade Repair		302		
Aishihik Cable Repair		200		
L174 Broken Pole			39	
Marsh Lake Water Damage			17	
Kulan Warehouse Water Damage			7	
L172 Insulator Failure				40
Rock Creek Crossing				11
Polaris Ranger & Trailer Replacement				9
Repair Outage Damage				25
Streetlight damage				1
Total	**-730**	**633**	**63**	**86**
Annual Provision	**-100**	**-100**	**-100**	**-50**
Closing Balance	**-33**	**500**	**463**	**500**

REFERENCE: **Application, Page 3-16**

QUESTION:

a) Does the balance in Regulated Liabilities accrue interest? If not, why not?

ANSWER:

(a)

No, the balance in Regulated Liabilities does not accrue interest. Regulatory Liabilities represent amounts held by the utility on behalf of ratepayers, and act as an offset to ratebase and as such do not accrue any interest (but rather serve effectively as a form of no-cost capital).

REFERENCE: **Application, Page 3-17**

QUESTION:

a) Please provide a continuity schedule of the balance in FRSR from 2005 to 2009 inclusive.

b) Since Order 2005-12, has YEC made any changes to its depreciation assumptions or undertaken any further studies on depreciation?

ANSWER:

(a)

Please see response to CW-YEC-1-25(a).

(b)

YEC has not made any changes to its depreciation assumptions or undertaken any further studies on depreciation since Order 2005-12.

REFERENCE: Application, Page 3-17

The largest component of this increase since 2005 ($0.547 million) relates to planning and study costs, which is primarily studies of the existing system and options for expanding the quantity of renewable generation, as well as studies related to the safety and reliability of the system, the Minto Mine PPA negotiations, and other small projects, offset by the termination of amortization since 2005 on old study amounts as they become fully amortized.

QUESTION:

a) What is the result of the studies on renewable generation?

b) Why are the Minto PPA negotiations accounted for in this manner?

c) Why are safety and reliability studies amortized and not directly expensed?

ANSWER:

(a)

Studies on renewable generation have concluded that there are near-term as well as long-term opportunities for Yukon Energy to expand the available complement of renewable generation, as well as transmission interconnections that facilitate optimum use of renewable generation in order to meet anticipated load increases.

The main focus of recent studies has been to identify and assess near term options (i.e., in-service as soon as 2010 and up to 2015) to serve potential new load that may be connected during this time.

At a high level, the conclusions indicate that the unit costs of enhancement to existing hydro generation (as well as timing requirements to develop) are below the costs (and development timing) that would need to be incurred for developing new “greenfield” hydro sites. Options studies for enhancements to existing generation identified Mayo B as the largest single addition to the system in terms of energy (in the range of 30-40 GW.h) and licencing timeframe. Smaller generation enhancements, such as a small scale Atlin winter storage project, the Marsh Lake Fall-Winter storage project, or a

Gladstone diversion, were also identified as near term options that can be developed at an attractive cost, but earliest feasible in-service dates present specific risks that depend on the timeframes necessary to plan and licence the projects. More information on these options is provided at Tab 5, page 5-20.

Other enhancements to existing facilities, such as re-runnering existing hydro units, are still being reviewed.

(b)

The Minto PPA negotiations are accounted for in this manner in order to amortize the costs of putting in place the PPA over the period of benefits derived from the agreement.

(c)

Finance Accounting Practice FX-005, filed as an Attachment to YUB-YEC-1-59.1 (filed during the Requirement Revenues and Related Matters hearing) provides (at page 13) guidelines for the amortization of study costs. The costs are amortized in part as they are only periodic requirements (such as the study that resulted in Yukon Energy adopting a new capacity planning criteria) or the benefits of the studies extend over a number of years.

REFERENCE: **Application, Page 3-19**

QUESTION:

a) Please provide the terms of the YDC loans and notes as listed in Schedule 13 of Tab 7.

ANSWER:

(a)

Please see Note 13 to the 2007 Financial Statements included in the Application at Tab 9, as well as the response to CW-YEC-1-26(a).

REFERENCE: **Application, Page 3-20**

QUESTION:

a) Why did YEC acquire this instrument and not obtain unsecured financing from YDC?

b) Does YEC plan on refinancing this note with YDC at a lower interest rate in 2011?

ANSWER:

(a)

YEC acquired this instrument in 1996 to replace a term note with Canada. At the time financing from YDC was not available.

(b)

There are no plans at this time to refinance this note with YDC at a lower interest rate because the pre-payment provisions of the TD loan are prohibitively expensive.

REFERENCE: Application, Page 3-21

In both the YEC 1998 proceeding and 2005 proceeding, efforts were made to permit a cost-effective and simple means to set the fair level of ROE. In particular, in the 2005 proceeding, the fair ROE for test year 2005 was proposed by YEC to be set by reference to the British Columbia Utilities Commission (BCUC) formulaic approach, based on YEC receiving a 52-basis-points premium due to its risk compared to low risk utility.

QUESTION:

a) In Order 2005-12 did the Board determine that the use of the BCUC automated adjustment mechanism for ROE did not impose a precedent in Yukon?

b) Is it YEC's view that that determination should serve/impose a precedent for Yukon?

c) Has anything changed that would lower the risk premium for YEC closer to that of FortisBC?

d) Has the BCUC determined the base ROE for 2009? If so, what is it?

ANSWER:

(a)

Yes. In Appendix A to Order 2005-12, the Board determined that an appropriate rate of return on common equity for Yukon Energy was 9.05%, based on the BCUC benchmark for a low risk utility with an added risk premium of 52% (less 0.50% per OIC 1998/32). The Board noted at that time that "using the BCUC automated adjustment mechanism as a proxy of rate of return on equity does not impose a precedent in the Yukon and is an expedient means of determining return for the current one-year period."

(b)

Not necessarily. In the 2005 Required Revenues and Related Matters Application, Yukon Energy used a simplified approach that relied upon the detailed, expert analysis undertaken by the BCUC to determine the return on equity for a benchmark low risk

utility. As noted in the Application (at Tab 8 pages 8-9 and 8-10, and in responses to information requests during the review of the Application), Yukon Energy proposed this simplified approach to setting the fair return on equity for 2005 in order to reduce costs related to preparing and reviewing expensive and contentious cost of capital evidence that would have to be borne by ratepayers.[1]

At that time Yukon Energy was clear to distinguish the difference between using the BCUC benchmarking approach for determining the revenue requirement for 2005 alone, and adopting fully the system of annual ROE adjustments implemented in BC, noting as follows:[2]

- The Application for review at the time only addressed revenue requirement and rates for that year (2005); under the orderly approach towards regulation adopted by Yukon Energy in bringing forward its application at that time further rate changes and revenue requirement reviews would be deferred until 2007 at the earliest.

- To establish an annual ROE adjustment mechanism in Yukon would require a more rigourous review of the merits of moving towards such an annualized approach; this would likely be undertaken via a generic ROE proceeding that that included both utilities. It was noted that the process utilized in British Columbia evolved over several years, applied to the entire jurisdiction, and although complex was understood by all utilities and intervenors in that jurisdiction.

- Any annualized adjustment process for determining ROE would require practical implementation issues to be investigated and some efficient review process determined that would allow for timely review and participation by interested parties.

[1] In its 2005 Required Revenues and Related Matters Application Yukon Energy noted at page 3-23, "In recent years, many jurisdictions in Canada have adopted approaches to setting the fair return on equity that eliminate the routine requirement in rate requirement hearings for specific rate of return evidence from independent experts. Preparation of such expert evidence is costly and time-consuming. Yukon Energy believes that it is appropriate to adopt approaches that can avoid the need for such expert evidence when setting the fair return on equity for regulated power utilities in Yukon."

[2] These concerns were discussed in the 2005 Required Revenues and Related Matters Application at Tab 8 and in response to YUB-YEC-1-22 provided during that proceeding.

In this regard, Yukon Energy acknowledged that the use of the BCUC benchmarking approach should not set a precedent with regard to setting an annual ROE.

However, it is noted that the precedent of relying upon a benchmarking mechanism for determining the return on equity for a single application extends beyond the 2005 proceeding. The YUB did use this approach to a limited extent in determining Yukon Energy's fair return for 1998 during the 1998 hearing where the 1998 ROE was set based on adjusting the approved 1997 ROE by an approach similar to the BCUC approach (except that 100% of the change in long Canada bonds was applied rather than the 80% sliding scale factor used by the BCUC).[3]

Yukon Energy's position regarding the use of the BCUC benchmarking methodology continues to be as follows:

- It does not set (and should not be viewed as setting) a precedent in this jurisdiction regarding the implementation of an ongoing annual ROE adjustment process (even in non-GRA years) as is used in British Columbia.

- Relying upon the BCUC low risk utility benchmark along with a reasonable risk premium of 52% as previously approved by the Board in Order 2005-12 is a fair and efficient means of determining a fair return on equity for the utility for the current test period, and is a simplified approach that reduces the overall cost to the ratepayer through eliminating the requirement for costly expert assessment and testimony.

(c)

No.

In the 2005 Required Revenues and Related Matters Application, YEC provided a table (Table 8.2 in that application) that compared certain operating and financial statistics for YEC and utilities regulated by the BCUC. At that time, YEC noted that Aquila Networks Inc (now FortisBC) had approximately 92,000 customers and approximately $440 million in ratebase. This compared to YEC's 2005 forecasts of 1,750 customers and $143

[3] This was discussed during the 2005 Required Revenues and Related Matters proceeding in response to MCMAHON-YEC-1-35 and MCMAHON-YEC-1-18(c).

million in ratebase. YEC's customer counts and ratebase were approximately 2 per cent and 22 per cent of Aquila's at the time.

YEC notes that FortisBC's 2009 Revenue Requirements Application[4] forecasts approximately $914 million in ratebase and 112,000 customers in 2009. This compares to YEC's forecasts of 1,889 customers (2 per cent of FortisBC's) and proposed mid-year rate base of $153 million (17 per cent of FortisBC's) for 2009.

In the 2005 Required Revenues and Related Matters Application, YEC provided another table (Table 8.3 in that application) that compared the nature of business for YEC and utilities regulated by the BCUC. YEC noted that it had a somewhat greater business risk than the relevant BC utilities based on its reliance on its own generation (far higher than for FortisBC), and its lack of any interconnection with external electricity markets. Since the 2005 application these material differences have not changed – and YEC's business risk has increased somewhat due to connection of a new industrial customer.

Based on this, in YEC's view there is no information available that would suggest YEC's business risk today is closer to FortisBC's than at the time of the 2005 Required Revenues and Related Matters Application.

(d)

BCUC Letter No. L-55-08 provides a 8.47% benchmark return on equity for a low risk utility. Considering the 0.52% risk premium for Yukon Energy approved in Board Order 2005-12 together with the 0.50% deduction directed by OIC 1998/32, the 2009 fair ROE for Yukon Energy is 8.49%.

[4] Preliminary 2009 Revenue Requirements Application dated September 2008.

REFERENCE: Application, Page 3-21

Absent implementation of the approvals and consequential rate reductions proposed in this application, YEC's forecast return on equity for the test years is 9.55% for 2008 and 11.03% for 2009.

QUESTION:

a) How does this statement reconcile with the requested ROEs?

ANSWER:

(a)

Absent a rate reduction, the ROEs that would arise are above the level for Yukon Energy requested in the Application. The requested ROEs provide a key factor in determining the actual rate reduction proposed in the Application.

Yukon Energy has brought forward for Board review and approval a revenue requirement application that implements overall rate reductions for the test years in order to reflect benefits secured from the timely completion of Stage One of the Carmacks-Stewart Transmission Project and connection of Minto mine to the grid through the approved Power Purchase Agreement with Minto. As noted, without Board approval of the proposed rate decreases as requested at pages 2 and 3 of the Application (and discussed in Tab 4, pages 4-14 to 4-16), Yukon Energy's forecast would indicate that but for YEC's Application YEC would be earning higher revenues and a higher return on equity than YEC is proposing in its Application.

To be clear, the present YEC Application process is designed to implement a rate reduction that will align the utility's earnings with a fair level of ROE as determined utilizing the method adopted in 2005 (2008 at 8.64% and 2009 at 8.49%). As explained in the Application, YEC's proposed rate reduction passes back to retail customers throughout Yukon (including YECL retail customers) the net benefits secured from connecting the new Minto mine load.

REFERENCE: Application, Page 4-5

Only one term for the secondary energy service (Rate Schedule 32) is proposed to be changed in this Application. In the 2005 proceeding, YEC received approval for a procedure related to determining the timing of scheduled secondary sales interruptions based on forecasting the quantity (hours) of diesel generation expected to be required over the coming seven day period in winter (i.e. interruptions were to be initiated if YEC forecast a requirement to dispatch diesel generation for more than 10% of the hours over the coming seven-day period).

QUESTION:

a) At the time of the 2005 proceeding, what source(s) was YEC using for the seven-day forecast?

b) Are there alternative sources YEC can use other than Environment Canada?

ANSWER:

(a)

Yukon Energy did not have a forecast for seven days. The proposal was made based on the assumption that a seven day forecast was ideal for planning secondary sales interruptions. However, once required to implement the proposal, Yukon Energy was made aware that no forecast readily fit the rate schedule as proposed. In order to implement the procedure, Yukon Energy was required to extrapolate the sixth and seventh days out of the Environment Canada data, which is not a preferred method for implementing the rate.

(b)

There are no practical alternative sources that have been identified.

REFERENCE: **Application, Page 4-6**

QUESTION:

a) In Order 2007-5, did the Board only approve Rate Schedule 35 on an interim basis?

b) Did the Board express concerns about a lack of cost of service (COS) associated with this new rate?

c) Did the Board direct YEC, with YECL, to provide electronic COS models for the next GRA?

ANSWER:

(a)

Confirmed.

The Board provided the following directives specific to Rate Schedule 35:

- **Directive 4:** Upon review of the negotiated rate, the Board observes that it is close to the level set for Rate 32. This does provide some comfort to the Board as Rate 32 does not appear discriminatory. The Board is prepared to approve, on an interim basis, the level of Rate 35 as applied for by YEC.

- **Directive 5:** Should Minto pursue Rate 35, proposed audit and control measures and reporting requirements must be established between YEC and Minto, and then YEC is to file these with the Board. YEC is not to implement Rate Schedule 35 until such approval has been granted.

- **Directive 6:** The Board directs YEC to amend the wording for Rate Schedule 35 when such an opportunity arises.

The Board reiterated that Rate Schedule 35 was only approved on an interim basis in Order 2008-13, noting that "the Board is of the view that all matters with respect to Rate Schedule 35 remain outstanding" and stating at page 2:

> YEC is to apply to the Board for approval of Rate Schedule 35 and any related matters at such time as when all outstanding directions with respect to Rate Schedule 35 have been fulfilled and when YEC is in a position to implement Rate Schedule 35.

Yukon Energy has not forecast any sales under Rate Schedule 35 for the test years and in the current application is not requesting final approval of Rate Schedule 35. Tab 4 (page 4-6) notes that Minto Explorations has not provided Yukon Energy with the further information regarding specific auditable reporting and control mechanisms required to be reviewed by the Board prior to final approval of the rate. The Application notes that "because the YUB prerequisites for this rate have not been met, and the forecast quantities of power available for such service are very limited, Yukon Energy forecasts do not include any Rate Schedule 35 sales in the test years."

(b) and **(c)**

Confirmed.

The Board in Order 2007-5 approved Rate Schedule 35 on an interim basis, and noted in its Reasons for Decision (Appendix A to the Order) that while it drew comfort from the fact the Rate Schedule 35 requested a rate be set at a similar level to Rate Schedule 32, it was concerned about rates being set in the absence of a cost of service study, noting that a complete COS study would enable testing of costs to serve all rate classes, including Rate 35.

The Board provided the following general directive that YEC and YECL were to provide a COS study and Rate Design with the next GRA, noting that it would enable testing of Rate Schedule 35:

- **Directive 3:** The Board reiterates its earlier direction that YEC and YECL to provide a complete COS study and rate design with their next GRA. The COS is to include updated studies on allocators and to look at the feasibility of direct assigning assets, where applicable to certain rate classes. Further, the Board

> expects to see justification on the allocation of transmission assets. The Board questions the rationale of defining the CSTP project as one of diesel displacement in light of YEC's comments that the project is a project to serve system requirements. For the next GRA (Phase II), the Board directs both YEC and YECL to provide their electronic COS models and to distinctly show costs as being related to generation, transmission and distribution. Further, generation costs are to be separated based on each generation type (i.e. hydro, diesel, wind etc).This will enable testing of costs to serve all rate classes, including Rate 35.

As noted in the 2005 Required Revenues and Related Matters hearing process, as well as in response to interrogatories filed during the PPA hearing process, secondary energy rates are not cost based rates and are not set based on a cost of service study. Secondary sales are interruptible and not firm and pursuant to Rate Schedule 32, the power must be "in excess of normal consumption and represents incremental electric usage displacing an alternative fuel source by an appliance primarily installed in order to provide space or process heating". As noted at page 4-5 of the Required Revenues and Related Matters Application:

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

The Required Revenues and Related Matters Application (at page 4-5) and the response to YUB-YEC-1-12 (12.1) (also provided during the Required Revenues and Related Matters hearing) describe the rate design process used to set the secondary sales rate (Rate Schedule 32) noting, "the rate design for this rate is based on a value for service basis. **It is not a cost-based rate"** (emphasis added).

This view was reiterated during the PPA Interrogatory process where it was noted in response to UCG-YEC-1-26(3) that "a cost of service is not required to determine a secondary energy rate, i.e., it was not used or suggested to be needed to determine the current rate Schedule 32."

As noted in Section 4.1.3 of the Power Purchase Agreement Application, the Low Grade Ore Processing Secondary Energy Rate (Rate Schedule 35) is an interruptible rate supplied from surplus hydro to Industrial Primary customers (who are supplied under Rate Schedule 39). As defined, this rate is to be limited to the processing of low grade copper ore. YEC proposes that unlike Rate Schedule 32 (Secondary Energy), where the rate is adjusted quarterly (based on changes in heating oil prices), Rate Schedule 35 will remain fixed. Finally, to underline how Rate Schedule 35 remains connected to Rate Schedule 32, any Rate Schedule 35 sales are subject to surplus hydro generation being available after service of Rate Schedule 32 customers.

More generally, in respect of the Board's expectation that YEC and YECL would file a COS study in the next GRA, see also YUB-YEC-1-20.

REFERENCE: Appendix A to YUB Board Order 2007-5

Therefore, the Board reiterates its earlier direction that YEC and YECL must provide a complete COS study and rate design with their next GRA.

QUESTION:

a) How does YEC interpret the above quoted direction?

ANSWER:

(a)

I. Overview

YEC interprets the above quoted sentence in the context of the circumstances at that time (including the cost of service related issues under the PPA reviewed in Order 2007-5 and the earlier Resource Plan recommendation to the Minister), and the Board's modified ratemaking mandate since Order 2007-5.

In the context of the issues being dealt with by the Board in Board 2007-5, and the Board's legislated mandate in place at that time, the Board's expectation is clear. The Board clearly expected at that time (as did YEC) that YEC and YECL would file a complete cost of service study and rate design in the next General Rate Application ("GRA"). However, the Board's ratemaking mandate has been materially revised since that time by OICs 2007/94 and 2008/149 obviating the need for a cost of service (COS) study in order to deal with YEC's current GRA. As outlined in more detail below, this is the primary reason why YEC did not file a cost of service study as part of its current GRA.

In order for the Board and all stakeholders to fully understand why a cost of service study was not filed in YEC's current GRA, YEC believes it would be helpful to review the history of this issue and the material changes in the Board's mandate which has occurred since Board 2007-5 was rendered.

II. First Reference to Joint YEC/YECL Filing Made in Context of Cost of Serving Minto Mine

To be precise, although the Board refers to "its earlier direction" in Order 2007-5 -- in fact the reference is not to a direction but a recommendation the Board made in its report to the Executive Commissioner on YEC's 20 Year Resource Plan ("Report"). At page 50 of the Report the Board's recommendation relating to COS was as follows:

> Now is an appropriate time for YEC and YECL to have a complete review of all GRA Phase 1 and Phase 2 matters. The Board ***recommends*** that YEC and YECL file a full GRA application before October 31, 2007. The application should include a full cost of service, rate design and an update of the electric service regulations. (Emphasis added)

This recommendation was made in the context of a discussion relating to Industrial Contribution policy and issues arising out of Minto Mine's potential capital contribution to the Carmacks-Stewart Transmission Line. The issue of the appropriate level of contribution and the cost of serving that customer would clearly be informed by a COS study. Although the recommendation was framed more generally -- YEC understood and appreciated the Board's interest in reviewing a full COS study when dealing with those issues.

III. Direction in Order 2007-5 Made in Context of Reviewing Proposed Minto Mine Rate

Board Order 2007-5 followed the Report. The Board's direction in that order relating to COS was made during its review of Yukon Energy's proposed Minto Mine Rate under the Power Purchase Agreement.

Immediately prior to reiterating its direction in regard of cost of service, and after quoting Section 6(1) of OIC 1995/90 direction to ensure that rates charged to major industrial customers are sufficient to recover cost of service to that class, the Board stated as follows (at page 5):

> The Yukon regulatory environment is one that prefers a direction of standardized utility practice in regards to rates. ***Such standardized utility practice includes providing a full COS calculation when***

> ***designing new rates*** . . . The Board understands that YEC has faced strict time constraints with respect to this CSTP.
>
> YEC acknowledges 'the Board alone has the power to set rates and determine COS methods used for rate setting purposes pursuant to its constituent legislation and regulations'. However, YEC recognizes the jurisdiction of the YUB, the timing YEC has requested presented challenges for the Board and Intervenors and establishing and participating in the proceeding. Recognizing the time constraints faced by YEC the Board has endeavoured the meet these timelines; ***however, as a result, YEC's evidence in some areas is not as complete as the Board*** would normally expect, in particular, with respect to COS. (Emphasis added)

Accordingly, the Board's direction was made in the context of the need for a COS study when reviewing the appropriateness of the rate being proposed for the Mine. Its concern in this regard led to the Board setting the Minto Mine rate on an interim basis until such time as a decision is rendered in the next GRA, which (in the context of the Board's other expectations) would allow that rate to be tested in the next GRA using a cost of service study before finalizing it.

IV. Intervening Events Since 2007-- Board's Ratemaking Mandate Materially Changed Since 2007 Direction

In both the Report and in Order 2007-5, the Board recognized the importance of a COS study given its general ratemaking jurisdiction in existence at that time under the *Public Utilities Act* and related OIC directions. However, for the purposes of the Board's review of YEC's GRA things have changed. The Board's ratemaking mandate has been materially changed by OIC 2007/94 and OIC 2008/149.

(i) OIC 2007/94 - Makes COS Irrelevant to Rate Schedule 39 Until 2012

Soon after Order 2007-5, OIC 2007/94 was passed. In that OIC, the YTG directed that Rate Schedule 39 be specifically fixed thereby making the cost of service issues discussed in the Report no longer relevant in relation to industrial rates until after 2012. OIC 2007/94 states as follows:

> The Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to the Rate Schedule 39, Industrial Primary, attached hereto as Schedule A.

(ii) YEC/YECL Worked Towards a Joint Cost of Service Filing Until OIC 2008/149

Following the Board's direction in Order 2007-5 and notwithstanding OIC 2007/94, YEC and YECL did undertake discussions relating to comprehensive GRA filings, including a joint COS and redefined filing targeted for late 2008. In correspondence filed with the Board Yukon Energy noted its expectation to efficiently address COS matters within GRA filings to occur in 2008. In a letter to the Board dated December 17, 2007, Yukon Energy informed the Board that its revenue requirement filing would be delayed until August/September, 2008 (see the letter as quoted in Order 2009-1). YEC's letter also outlined YEC's understanding that the then planned "Consolidated Phase 2 cost allocation and rate design filing" by YEC and YECL would be concurrent with Yukon Energy's revenue requirement.[1]

(iii) OIC 2008/149 - Makes COS Irrelevant to All Rates Until 2012

Before the filing of Yukon Energy's General Rate Application, Yukon Energy became aware of OIC 2008/149, setting out YTG's direction to ensure that there be no rate rebalancing between rate classes at this time. YEC's Application conforms with OIC 2008/149.

Like OIC 2007/94 did in relation to Rate Schedule 39, OIC 2008/149 obviated the need for producing a cost of service study for all other rates until at least 2012. It states:

> The Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers.

[1] YECL subsequently, without discussion with Yukon Energy, filed its own GRA with statements that differed from this understanding as set out by Yukon Energy in December, 2007.

The OIC notes that this provision expires on December 31, 2012.

Since OICs 2008/149 and 2007/94 do not expire until December 31, 2012, cost of service cannot be used for rate rebalancing at this time. A joint filing, as contemplated by the Board in Order 2007-5 and previously discussed by YEC and YECL, is not feasible or efficient at this time, and a full cost of service filing is not required for the Board's review of the current YEC Application. These realities and the material change in the Board's ratemaking mandate are the primary reasons why YEC filed its GRA without a cost of service study.

(iv) YEC GRA Dealing Simply with Meeting Rate Design Criteria in OIC 1995/90

In its Application YEC has attempted to address immediate concerns related to runout rates that presently do not meet the rate design criteria for the Yukon established by OIC 1995/90 by promoting "economy and efficiency". In this vein, YEC has not embarked upon any new rate redesign initiative at this time. As reviewed in more detail in response to YUB-YEC-1-21, YEC has merely sought to ensure that current runout rates are modestly adjusted, where feasible, to better meet the regulated requirements and past practices for the Yukon jurisdiction as regards runout rates applicable on a uniform basis to retail residential customers of both YEC and YECL. YEC believes that this concern can be effectively and efficiently addressed via review of Yukon Energy's current GRA Application.

REFERENCE: **Runoff (or "Second Block") Rates**

QUESTION:

a) Please describe the consultation process YEC utilized when developing its principles on runoff rates.

b) What is YEC's understanding of YECL's views on this new rate structure?

c) Given that YECL directly serves a significantly larger customer base than YEC, should YECL's views been considered?

d) How were the criteria for runoff rates developed?

ANSWER:

(a)

It is unclear what consultation process the question envisages. YEC did not "develop" some new set of principles on runoff rates for its Application – to the contrary, it began to re-apply principles, directions and precedents well established in Yukon through past joint YEC/YECL GRAs and related YUB decisions.

To be clear, in adjusting the runoff rates to better reflect the requirements of OIC 1995/90, Yukon Energy did not develop new rate design principles for runoff rates. It applied established Yukon rate design principles. Such principles are required to comply with OIC 1995/90, and have been consistently applied in Yukon GRAs and YUB Reports extending as far back as 1992, including extensive previous reviews by the Board and previous Board Orders.

The rate design principles related to runoff rates were subject to a full hearing process in 1992 where YEC and YECL provided a joint submission on Cost of Service and Rate Design which set out the utilities' joint positions on the subjects. The rate design principles examined during that proceeding were summarized in the Yukon Utilities Board report to the Minister in Executive Council pursuant to the 1992 review process.
The Rate Design and Cost of Service filing that was reviewed by the Board in 1992 was developed jointly by Yukon Energy and YECL, and the two utilities were full participants

in the proceeding. These principles were practically implemented in subsequent OIC directions to the YUB (including OIC 1995/90, which extended the relevant runoff rate setting principles to all rate zones) and in joint YEC/YECL rate applications (the 1993/94 GRA and the 1996/97 GRA filing).

(b)

As noted in (a) above, this rate design premise is not a "new" rate structure to Yukon or to YECL.

The rate design principles for runoff rates were fully reviewed and concurred with by YECL in 1992 (via a joint submission of YEC and YECL) and in the last joint GRA filing of YEC/YECL (1996/97 GRA) in accordance with the regulatory framework in the Yukon at that time with OIC 1995/90 (subsection 4(3)). During the 1992 Cost of Service and Rate Design Review process YEC and YECL jointly took the position that in order to make rational decisions regarding the use of electricity the consumer should be aware of the long run marginal cost of supply and noted that the runoff rate should at least reflect short-run incremental costs to promote efficiency (see page 38 of report attached as response to YUB-YEC-1-21(d)). In subsequent joint GRA filings in 1993/94 and 1996/97, the utilities applied for runoff rates adjusted to reflect short run incremental (i.e., diesel) costs, initially in diesel-served rate zones and then (in 1996/97) also in the hydro grid rate zone.

(c)

As noted, YECL's views regarding these rate design principles were fully considered during the 1992 process that reviewed rate design and cost of service in Yukon, and have subsequently been fully considered in past joint GRA filings where the rate design principles underlying the runoff rate were reviewed by the Board.

In Yukon, as a result of OIC 1995/90 (and predecessor OICs going back to the time before YEC's first rate application), all retail ratepayers of YEC and YECL have an equal and direct interest in the revenue requirements of each utility and in related retail rate design issues. The Board is required to establish equalized rates for each retail rate class that do not vary as between YEC and YECL, reflecting the combined revenue requirement of the two utilities and a common rate design for customers of both utilities.

After 1997 (when YEC's management agreement with YECL ended), efforts have been made by both utilities to resume discussion and joint planning on various matters. To be effective, a joint and sustained commitment is needed in this regard.

(d)

Please see Attachment 1 to this response which provides the YUB's report to the Minister in Executive Council provided June 1, 1992, and sets out the principles regarding rate design in Yukon. Rate design related to setting runoff rates that promote "economy and efficiency" are discussed at pages 37-40 of the attached report. As noted, this report followed a joint submission by both utilities as well as an oral hearing in 1992.

In sum, the Board made the following comments and recommendations related to runoff rates in its report:

- "The Board considers the efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decision regarding the future and current use of electricity."

- "The Board considers that runout rates should reflect short-run incremental costs in each of the rate zones as specified in the OIC and that fixed costs incurred by the Companies should be recovered by demand charges, fixed charges and energy charges in the first energy block. The Board recognizes that this will result in an increase in the hydro zone runout rate."

- The Board recommended that the runout rates for all zones should be adjusted to reflect short-run incremental costs.

In Decision 1993-8, regarding the 1993 General Rate Application, the Board reiterated its view that the cost of service methodology and proposed rates designed in accordance with OIC 1992/62 and the 1992 Cost of Service and Rate Design hearing remained appropriate.

Following the YUB's 1992 Report, the following rate design principles related to runoff rates for the Yukon were subsequently included in Rate Policy Directive in OIC 1995/90:

- **4(2)** The Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.

- **4(3)** The Board must fix runoff rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency, and separate runoff rates may be allowed in this regard for customers in different communities or rate zones, provided that such runoff rates for customers in each non-government retail customer class are fixed for each community or rate zone throughout Yukon in accordance with the same rate design principles.

The application of these rate design principles was last reviewed and approved by the YUB during the 1996/97 GRA. As noted at page 4-10 to 4-12 of the Application, the principles as approved in that GRA filing underlie the current filing.

REVIEW OF
COST OF SERVICE TO
AND
RATES CHARGED TO
ELECTRICITY CUSTOMERS IN YUKON

RECEIVED
JUN 0 8 1992

REPORT TO
COMMISSIONER IN EXECUTIVE COUNCIL
BY
YUKON UTILITIES BOARD

JUNE 1, 1992

TABLE OF CONTENTS

Page

EXECUTIVE SUMMARY

1. INTRODUCTION 1

2. PROCEDURES FOLLOWED BY THE BOARD 3

2.1 Community Meetings 5

2.2 Public Hearing 6

3. RATE DESIGN PRINCIPLES AND ISSUES 7

4. COST OF SERVICE PRINCIPLES 8

5. COST OF SERVICE STUDY PREPARED BY YEC/YECL 10

5.1 Functionalization 10

5.2 Classification 11

5.2.1 Classification of Plant 11
5.2.2 Classification of O&M Expenses 12

5.3 Allocation of Costs to Customer Classes 13

6. COST OF SERVICE - CANADIAN PRACTICE 14

7. COST OF SERVICE - CURRAGH 16

8. COST OF SERVICE - DISCUSSION OF MAJOR ISSUES 18

8.1 General 18

8.2 Classification of Generating Plant 19

8.2.1 Classification of Hydro Generating Plant - General (Excluding Whitehorse Unit #4) . . 19
8.2.2 Classification of Hydro Generating Plant - Whitehorse Unit #4 24
8.2.3 Classification of Diesel Generating Plant . . 25

Page

8.3 Allocation of Transmission Plant 26

8.4 Classification of Generation O&M Expenses 30

8.5 Marketing Expense 31

8.6 Classification and Allocation of Other Costs of Service 32

9. RATE DESIGN 32

9.1 Revenue to Cost Ratios 32

9.2 Phase-In of Rate Changes 36

9.3 Promotion of Economy and Efficiency in the Use of Electricity 37

9.3.1 Long-Run Marginal Costs 38
9.3.2 Other Rate Design Factors which Promote Economy and Efficiency in the Use of Electricity 41

9.4 How Can Rate Design Respond to Environmental or Other Costs Not Included in Cost of Service 45

9.5 Extent to Which Rate Design Responds to the Current Costs Required to Develop New Power Sources 47

9.6 How Should Demand-Side Management Activity be Reflected in Rate Design 47

10. CURRAGH CONTRACT 48

SUMMARY OF RECOMMENDATIONS

GLOSSARY OF TERMS

EXECUTIVE SUMMARY

Pursuant to Order-in-Council 1991/62, the Board conducted a cost of service and rate design review. As part of this review, the Board conducted community meetings in Haines Junction, Carmacks, Dawson City, Teslin, Watson Lake and Whitehorse.

The principal recommendations made to the Board at the community meetings were that rates for electricity in Yukon should be cost based, general service - government rates should not be applied to municipal governments, conservation of electricity should be encouraged, and the use of multiple increasing block rates should be considered. A written submission was received from the City of Dawson.

The technical aspects of the review were examined at a public hearing in the City of Whitehorse on May 4th to 7, 1992. Prior to the public hearing, YEC/YECL provided a written submission on their cost of service and rate design to all interested parties.

Curragh Resources Inc. also filed expert evidence, and submissions were received from the City of Whitehorse, the Association of Yukon Communities, the Yukon Conservation Society and Gary McRobb, Esq.

The Companies submitted that the primary criteria for rate design are the need for rates sufficient to meet the revenue requirement, the fair apportionment of costs to customer classes, and the promotion of economy and efficiency in the use of electricity.

The fair apportionment of costs to each of the customer classes requires a cost of service study. A cost of service study usually proceeds in three steps, functionalization, classification and allocation, in order to estimate the costs caused by each customer class.

The Companies' cost of service study followed Yukon's rate policy as set forth in the Order-in-Council in that, generally, the same rates would prevail for each customer class throughout Yukon.

The Companies examined cost of service practices of other Canadian hydro electric utilities, and concluded that they followed generally accepted Canadian practices.

The following three major cost of service issues were examined:

(1) Classification of hydro generating plant;

(2) Classification of Whitehorse Hydro Unit #4; and

(3) Allocation of the Whitehorse/Faro transmission line.

The Companies classified hydro generating plant 40% to demand and 60% to energy on the basis of cost causality and the practices of other Canadian hydro electric utilities.

Curragh advocated classifying all fixed costs to demand and all variable costs to energy and, thus, recommended classifying 100% of hydro generating assets to demand. Curragh recognized that not all of the hydro generating capacity can be used to meet system peak and, thus, suggested allocating 70% of the hydro generating plant costs on the basis of coincident peaks and 30% of the costs on the basis of energy.

The Board recommends hydro generating plant, excluding Whitehorse Unit #4, be classified 40% to demand and 60% to energy.

The Companies classified Whitehorse Unit #4 100% to energy on the basis that it had been constructed for the purpose of displacing diesel generation and that its construction had not resulted in any increase in the ability of the Companies to meet demand at the time of system peak.

Curragh submitted that Whitehorse Unit #4 should be classified 100% to demand.

The Board recommends that Whitehorse Unit #4 be classified 100% to energy and that the Companies be directed to perform a study of the impact of Whitehorse Unit #4 on the ability of the Aishihik dam to provide capacity at the time of system peak.

The Companies assigned 85% of the cost of the Whitehorse/Faro transmission line to Curragh. The remaining transmission costs were allocated to all customer classes, including Curragh.

Curragh submitted that either the transmission costs allocated to Curragh should be limited to 85% of the Whitehorse/Faro transmission line or Curragh should be allocated only its proportionate share of total transmission costs.

The Board recommends that the Companies' allocation of transmission costs is appropriate.

The Board recommends that a target range for revenue to cost ratios of 90% to 110% be established for all customer classes other than the industrial class, and that the Companies take the necessary steps to improve the quality of their cost of service study so that a target revenue to cost ratio of 95% to 105% will be attainable.

The Companies indicated that they intend to move the industrial rate class revenue to cost ratio close to 100% at the time of the next general rate application.

Curragh submitted that, while a cost of service study provides a guide for rate making, other considerations may require pricing a customer at rate levels less than those indicated by a cost of service study. Curragh advocated that its rates should be established through a negotiation process between Curragh and YEC.

The Board notes that revenue to cost ratios for large industrial customer classes typically are at or above 100%. The Board recommends that a target revenue to cost ratio of 100% be established for the industrial rate class, and that the rates to be charged to Curragh should be determined by the Board only after a public hearing.

The Board recommends that the changes to rates required to bring the revenue to cost ratios within the ranges established be phased-in over a reasonable period of time, and that the Board monitor the progression of revenue to cost ratios toward the acceptable range in future general rate applications.

The Board considers the efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decisions regarding the use of electricity.

The Companies submitted that, to make rational decisions, customers should be aware of the long-run marginal costs, and advocated that the runout rate should reflect such costs.

The Board recognizes that the Order-in-Council requires the runout rates to reflect short-run incremental costs. The Board recommends that the runout rates for all zones should be adjusted to reflect the short-run incremental costs, and that the Companies undertake a study for the purpose of identifying long-run marginal costs that should be included in the runout rates.

The Board makes several other recommendations with respect to the promotion of the efficient use of electricity.

The Board recommends that the Companies be encouraged to monitor ways in which rate design can be used to reflect environmental or other costs not included in cost of service.

The Board recommends that Demand-Side Management issues be addressed at the time of the Companies' upcoming capital hearing.

The Board concurs with the City of Whitehorse's recommendation that it is not appropriate to cast cost of service studies and rate design principles in stone. The Board recommends that it be provided with the flexibility to react to future changes in circumstances, and to determine the appropriate cost of service and rate design practices to be used in Yukon.

1. INTRODUCTION

This report is submitted to the Commissioner in Executive Council pursuant to Section 11 of Order-in-Council, 1991/62 ("OIC"). Section 11 of the OIC states:

> "(1) The Board shall conduct a full review of costs of service to and of rates charged to all classes of customers within the Yukon and shall recommend appropriate methods of determining costs of service and appropriate principles for establishing rates to be used for rate applications made after 1991.
>
> (2) When conducting its review and making its recommendations the Board shall observe the following guidelines:
>
> (a) cost of service for each customer class must be determined on a Yukon-wide basis that is consistent with Yukon's rate policy, having the same rate for the same class of customer throughout the Yukon, no rate differentiation between utilities, and provision for runoff rate variations in accordance with the principles set out in subsection 6(2);
>
> (b) customer classes examined must include each class currently used for rate making purposes;
>
> (c) costs must be determined on a prospective basis for a test period conforming to the period for which the Board approves rates as a result of Yukon Energy Corporation's and The Yukon Electrical Company Limited's 1991 general rate applications;
>
> (d) the review must investigate principles and methods currently applicable in Canada for similar hydro based and northern diesel service areas and must examine the implications of any options in this regard that may merit adoption in Yukon;
>
> (e) the review must investigate the extent to which regulated rates reflect cost of service for different customer classes in Yukon and in other Canadian jurisdictions;

(f) the review must examine implications of adjusting future rates in order to bring rates closer to costs for all customer classes in Yukon.

(3) The review must also investigate the extent to which rate design should respond to factors other than cost of service for each customer class such as:

(a) promotion of economy and efficiency in the generation, transmission, distribution, and use of power;

(b) environmental or other costs that are not currently included in cost of service for the utilities;

(c) current cost required to develop new power supplies; and

(d) demand-side management activities carried out in accordance with the principles set out in subsections 5(1) and (2).

(4) The Board must begin its review by soliciting submissions from Yukon Energy Corporation and The Yukon Electrical Company Limited as part of their 1991 general rate applications and shall direct the companies to prepare such submissions in accordance with the guidelines set forth in subsection 11(2).

(5) The Board shall deliver its report to the Executive Council Member on or before June 1, 1992."

The principles set out in subsection 5(2) referred to above are as follows:

"(2) Separate runoff rates must be allowed for non-government retail customers to reflect short-term incremental energy costs in communities supplied primarily by generation other than hydro, but

(a) for residential non-government retail customers, the runoff rate may be applied only to consumption in excess of 1,000 kWh per month, and

(b) for general service non-government retail customers, the runoff rate may be applied only to whichever of the following the Board approves:

(i) consumption in excess of 2,000 kWh per month, or

(ii) consumption in excess of a level which would, for an average customer of that class, be equivalent to 2,000 kWh per month for general service non-government retail power customers."

2. PROCEDURES FOLLOWED BY THE BOARD

The procedures followed by Yukon Utilities Board ("Board") in the conduct of its review pursuant to the OIC were as follows:

(1) The Board began its review by soliciting submissions from Yukon Energy Corporation ("YEC") and The Yukon Electrical Company Limited ("YECL") ("the Companies") as part of their 1991/92 general rate applications.

Inasmuch as the Board had determined that the matters to be investigated during the course of the review would be dealt with in a separate proceeding, these matters were not addressed in detail during the course of the 1991/92 general rate applications of the Companies.

(2) After the hearing of a Notice of Motion from Curragh Resources Inc. ("Curragh") dated February 19, 1992 the Board published a Notice of Public Hearing indicating that the review would take place in the City of Whitehorse commencing on May 4, 1992.

(3) On March 11, 1992 YEC/YECL distributed updated information respecting their cost of service and rate design to all Intervenors in the preceding general rate application, all Yukon communities, special interest groups and all First Nations.

It should be noted that the rate setting process is usually divided into two phases. The first phase is the determination of the revenue requirement. The second phase is the determination of rates; the subject of this review. The Companies' interest in the second phase is the establishment of "just and reasonable" rates, and they are generally neutral as to what rates are paid by each of the customer classes.

(4) All Intervenors were provided with the opportunity to make written interrogatories to the Companies respecting their methods and procedures to which the Companies provided written responses.

(5) All Intervenors were provided with the opportunity of filing evidence respecting the matters to be reviewed. The only party which filed expert evidence in the review proceedings was Curragh who called Dr. Malcolm Jackson, a consultant in the field of public utility regulation. Both YEC/YECL and the Board made written interrogatories to Curragh.

(6) The Board conducted community meetings at various locations in Yukon and a public hearing in the city of Whitehorse.

2.1 Community Meetings

The Board conducted community meetings in Haines Junction, Carmacks, Dawson City, Teslin, Watson Lake and Whitehorse over the period April 6th to May 4, 1992. The City of Dawson presented a written submission to the Board at the community meeting in Dawson City. The Board prepared a report on these community meetings which was filed as an exhibit in the public hearing. The principal recommendations made to the Board at the community meetings were as follows:

(1) Rates for electricity in Yukon should be cost based. Subsidies to specified groups of customers subject to very high rates should be dealt with as a direct subsidy.

(2) General service - government rates should not be applied to municipal governments.

(3) The conservation of electricity should be encouraged. Although the charging of an equalized rate for a basic block of energy was acceptable, the size of the basic block should gradually be reduced.

(4) The use of multiple increasing block rates should be considered.

The issues raised at the community meetings were examined at the public hearing and will be dealt with by the Board in this report.

2.2 Public Hearing

The technical aspects of the review were examined at a public hearing in the City of Whitehorse on May 4 to 7, 1992. Those participating in the hearing were YEC, YECL, Curragh, the City of Whitehorse, the Association for Yukon Communities, Peter Percival, Esq. and Gary McRobb, Esq.

The Board provided an opportunity to the public to make presentations to the Board at the end of each day of the scheduled sittings. One such presentation was made by Mr. Bob Van Dijken representing the Yukon Conservation Society. During the course of the proceedings a presentation was made by His Worship Mayor Peter Jenkins on behalf of the Association of Yukon Communities.

At the conclusion of the hearing, the Companies and Intervenors were provided with an opportunity to make final submissions to the Board.

3. RATE DESIGN PRINCIPLES AND ISSUES

As explained in the YEC/YECL evidence, rate design involves establishing the prices that each customer will pay for electricity. Rate design principles typically refer to a requirement for "just and reasonable" rates, recognizing that rate design involves a balancing of different objectives which may, from time to time, be in conflict.

The Companies outlined the primary criteria for rate design. These criteria include the need for rates which would provide sufficient revenue to meet the revenue requirement approved by the Board, as well as the requirement for revenue stability and predictability. The rates should fairly reflect the costs incurred by the utility to serve the various classes of customers.

A further objective is the promotion of economy and efficiency in the generation, transmission, distribution and use of electricity, and involves the structuring of rates so as to provide price signals to users of electricity which will encourage optimum use of the utilities' facilities.

The Companies also noted that rates should reflect the value of service provided to the customers, that rates should be stable and reasonably predictable allowing customers to make realistic cost projections, and that rates, generally, should be practical and not overly complicated.

Regulators of Canadian electric utility corporations typically consider the fair cost apportionment criteria to be of primary importance in determining rates and, accordingly, utilize cost of service studies as one of the major factors to be considered in the determination of rates.

4. COST OF SERVICE PRINCIPLES

The determination of the cost incurred by a utility to provide service to its customer classes is achieved through a cost of service study. Such a study usually proceeds in three steps as follows:

(1) Functionalization:

Functionalization refers to the segregation of capital assets and operating expenses into groupings which represent the specific functions carried on by a utility. These four functions are generally generation, transmission, distribution and general. They comprise the major tasks which a utility must perform to provide electric service.

(2) Classification:

Classification refers to the division of the costs associated with each of the functions into components which reflect the relationship between the services provided by the utility and the principal cause of the related costs. The principal causes of costs are the customers' demand requirements, their energy use and the number of customers served. The classification components most commonly used are demand, energy and customer.

(3) Allocation:

Allocation is required to distribute the demand, energy and customer costs associated with each function to the utilities' customer classes. Allocations are made on the basis of various demand, energy and customer allocation factors. The customer classes commonly used are residential, general service, industrial, wholesale and street light.

Through the processes described above, the utility obtains a measure of the costs incurred to serve each of the customer classes. This cost information typically becomes a starting point in the design of just and reasonable rates.

5. COST OF SERVICE STUDY PREPARED BY YEC/YECL

For the purpose of this proceeding, YEC/YECL prepared a detailed cost of service study. The Companies followed Yukon's rate policy as set forth in OIC Section 11, subsections (2)(a) to (2)(f) in that it was proposed that the same rate for each customer class would prevail throughout Yukon and customer classes examined were those currently used for rate making purposes. Also, costs contained in the cost of service study reflected forecast costs for the test year 1992 which had been allowed by the Board as a result of a recent general rate application by the Companies. During the review, the extent to which rates currently reflect cost of service for different customer classes in Yukon and the implications of adjusting future rates in order to bring them closer to costs were investigated.

5.1 Functionalization

The Companies functionalized their plant and operating expenses among the four basic functions of generation, transmission, distribution and general. The functionalization process carried out by the Companies did not raise any controversy at the hearing and appears to the Board to be in compliance with generally accepted practices. Therefore, this issue will not be discussed further in this report.

5.2 Classification

The second step in the cost of service study carried out by the Companies was the classification of plant and operating expenses.

5.2.1 Classification of Plant

The basic principle followed by the Companies was that plant should be classified on the basis of intended use. This is generally referred to as the cost causation principle. The Companies classified the cost of general hydro assets 40% to demand and 60% to energy based on their examination of classification practices by other hydro electric utilities in Canada.

Whitehorse Hydro Unit #4 was classified 100% to energy on the basis that the unit was constructed for the sole purpose of displacing diesel generation and did not in any way increase the Companies' capacity at the time of system peak.

The cost of diesel plant was classified 100% to demand on the basis that diesel plants are constructed to provide capacity and that in other jurisdictions in Canada they are generally classified 100% to demand.

Transmission plant was classified 100% to demand as transmission assets were sized to meet the expected coincident peak demand of the system.

Distribution assets, which account for approximately 20% of costs assigned to customer classes, were classified to customer and demand on the basis of what the Companies described as commonly accepted utility practice. Classification of distribution plant and operating expenses involved the exercise of considerable judgement in determining the appropriate classification bases.

5.2.2 Classification of Operating and Maintenance Expenses

The Companies stated that the classification of Operating and Maintenance ("O&M") expenses also followed the principle of cost causation. A major operating expense, fuel, was allocated 100% to energy following generally accepted practice. Other generating O&M expenses were allocated 50% to demand and 50% to energy on the basis of the experience of YECL's parent which operates in Alberta.

Transmission O&M was classified 100% demand consistent with the classification of transmission plant.

The classification of distribution O&M was performed on an account by account basis to reflect the Companies' view of the causation of the various components. Similarly, marketing O&M, customer accounting, general plant O&M, and administrative and general O&M were classified on a cost causation basis as determined by the Companies.

Depreciation expense was classified on the basis of corresponding gross plant while return and income taxes were classified on the basis of rate base less customer contributions. This base forms the foundation for calculation of total return and income tax. Municipal taxes and all-risk insurance were classified on the basis of gross assets.

9.3 Allocation of Costs to Customer Classes

The Companies allocated generation demand related costs on the basis of the coincident peak of the various customer classes. Energy related generating costs were allocated to customer classes on the basis of energy produced to serve the customer classes. Except for 85% of the cost of the Whitehorse/Faro transmission line which was assigned specifically to Curragh, transmission costs were allocated on the basis of the coincident peak of the various customer classes. Generation and transmission O&M were allocated on the same basis as generation and transmission plant.

The allocation of distribution plant and O&M expenses was performed on a number of bases. Demand related costs were allocated on the basis of non-coincident peak demands of the customer classes and customer related costs were generally allocated on the basis of the average number of customers in each customer class.

6. COST OF SERVICE - CANADIAN PRACTICE

The position taken by the Companies in the proceedings was that they followed generally accepted Canadian practice in the functionalization, classification and allocation of their costs. This position was not disputed by the Intervenors except with respect to two major items: the classification of hydraulic generating plant and the allocation of the Whitehorse/Faro transmission line. These differences will be discussed later in this report.

The Companies based their statement that they complied with generally accepted Canadian practice on their experience in the industry and on a review of practices of other electric generating utilities in Canada which had predominantly hydro based generation. The Companies examined the current practices of B.C. Hydro, Quebec Hydro, Manitoba Hydro and Ontario Hydro and concluded that these utilities classified from 56.5% to 71% of hydro generating costs as energy. The Companies concluded from this review that it would be appropriate for them to classify 60% of hydro generating costs (excluding Whitehorse Unit #4) to energy.

The Companies took the position that Whitehorse Unit #4 was unique in character in that it had been constructed for the purpose of displacing diesel generation and that its construction had not resulted in any increase in the ability of the Companies to meet demand at the time of system peak. Due to the unique nature of this generating unit, the companies did not submit any precedent from other jurisdictions to support its treatment. The Board has not been able to find any precedent.

The Companies submitted that the allocation of costs relating to the Whitehorse/Faro transmission line was in accordance with generally accepted practice in Canada. Under generally accepted practice in Canada, assets devoted to serve a specific customer class are assigned to that specific class. In determining the proportion of the Whitehorse/Faro transmission line to be specifically assigned to the industrial class, the Companies relied on the conclusions of the National Energy Board ("NEB") in its decision regarding Northern Canada Power Commission ("NCPC") dated June 1985. At Page 43 of that report the NEB determined that it was reasonable that 85% of the costs of the Whitehorse/Faro transmission line should be assigned to Cyprus Anvil Mining Corporation ("Cyprus Anvil"), and that this proportion took into consideration the fact that the Companies' remaining transmission costs would be allocated to all customer classes on the basis of their coincident peak demand.

7. COST OF SERVICE - CURRAGH

Curragh called Dr. Malcolm Jackson to present evidence on the appropriate methodology for the preparation of the cost of service study and the determination of rates. Dr. Jackson's evidence centered around two principal issues: the classification of the cost of hydro generating assets and the allocation of the cost of transmission facilities.

Dr. Jackson advocated the fixed variable method of classifying the cost of hydro generating plants. Dr. Jackson justified his choice of the fixed variable method on the use of this method by electric utilities in Alberta, Maritime Electric Company, Limited and Nova Scotia Power Corporation. Under the fixed variable method, all fixed costs are allocated to demand and all variable costs are allocated to energy. The result of Dr. Jackson's recommendation is to classify 100% of hydro generating assets, including Whitehorse Unit #4, to demand.

Dr. Jackson recognized that, due to natural changes in water flow, not all of the hydro generating capacity can be used to meet the demand at system peak. For this reason, Dr. Jackson allocated 70% of the costs to customer classes on the basis of their coincident peak demands and 30% of the costs to customer classes on the basis of energy.

Dr. Jackson's recommended treatment of the cost of transmission lines was to pool all transmission costs and allocate them to all customer classes on the basis of their coincident peak demands. Dr. Jackson's position was that, prior to the arrival of Curragh in Yukon, these costs were "sunk costs" and as such were required to be recovered from existing electric consumers in Yukon and the taxpayers of Canada. He considered that at the time of Curragh's arrival in Yukon any contribution by Curragh in excess of incremental costs associated with serving it would benefit other Yukon customers. He advocated that there should be no specific assignment of costs associated with the Whitehorse/Faro transmission line to Curragh.

As an alternative, Dr. Jackson recommended that 85% of the cost of the Whitehorse/Faro transmission line be assigned to Curragh but that Curragh not be held responsible for any portion of other transmission facilities and related costs.

In addition, Dr. Jackson recommended that the Companies' marketing expenses, which were ultimately allocated by the Companies 85% on the basis of energy and 15% on the basis of the number of customers, should be ultimately allocated 50% on the basis of each of these factors.

8. COST OF SERVICE - DISCUSSION OF MAJOR ISSUES

8.1 General

There was little controversy between the participants during the review on many of the cost of service study issues; the controversy having been restricted mainly to the classification of hydro generating plant, the allocation of transmission costs and the classification of marketing expenses. The Board will deal with each of these issues separately in this report.

The Board considers that the practices followed by the Companies with respect to all other issues relating to the cost of service study follow generally accepted practice in Canada and have, in the Board's opinion, been appropriately applied in Yukon.

The Board recognizes the position taken by the City of Whitehorse that it would not be prudent:

> "... to cast electric cost of service studies and rate design principles in stone. Recommendations to the Yukon government as a result of this review should recognize this constant state of change and provide for the ability of the Public Utilities Board to react to this change on a timely basis." [Tr.764]

Recommendation #1:
The Board recommends that it be provided with the flexibility to react to future changes in circumstances, and to determine the appropriate cost of service and rate design practices to be used in Yukon.

8.2 Classification of Generating Plant

8.2.1 Classification of Hydro Generating Plant - General (Excluding Whitehorse Unit #4)

In order to recognize that hydro generating plant was constructed for the dual purpose of providing capacity to meet the peak demands of its customers and the energy required by its customers over time, the Companies classified 40% of the cost of hydro generating plant to demand and 60% to energy. The basis of this classification was a review by the Companies of practices of other Canadian generating utilities with a high proportion of hydro facilities.

On cross-examination, Company witnesses acknowledged that there were a number of ways of determining the appropriate proportion of hydro generating plant costs to be allocated to energy. One such method is the plant factor method, wherein a portion of plants costs are allocated to energy on the basis of capacity required for average demand requirement and the cost associated with the remaining capacity are classified as demand. Company witnesses explained that in their experience the plant factor method has not been used for anything other than hydro facilities and that they have concerns with its use even for hydro facilities due to potential instability in the results it produces from one period to another. The witnesses indicated that this method had been used in Manitoba and British Columbia and had gone out of favour in these jurisdictions.

A second alternative method is to classify waterways, dams and reservoirs as being energy related. This method recognizes that certain portions of hydro plant were constructed for the purpose of storing water to make the resource available for the production of firm energy when needed. Investment in these facilities has, in some cases, been classified as being energy related.

On cross-examination, Company witnesses indicated that, due to inadequacies in historical records, they would not be able to make the appropriate breakdown of costs of hydro generating facilities and they had certain reservations as to the reliability of estimates.

The Board considers that the applicability of this method may be restricted to the Aishihik dam due to the run-of-the-river nature of the Whitehorse generating facility.

Another method used for classification of hydro facilities is based on a comparison of available energy under normal and adverse water conditions. Company witnesses indicated that this method would not be readily applicable in Yukon because of a significant shortage of hydrological data.

Company witnesses were also examined on their views of the fixed variable method proposed by Curragh. On cross-examination the witnesses explained that:

> "...the fixed variable method is appropriate at best in systems that are thermal based, ..." [Tr.345]

Company witnesses also stated that:

> "... it transmits a message that there is no behaviourial relationship between energy use and the costs that are being dealt with, ..."
> [Tr.345]

Company witnesses recognized that there were steps that could be taken to modify the fixed variable approach, such as Dr. Jackson's method of allocating 70% of the demand costs on the basis of coincident peak demands and 30% on the basis of energy. However, they stated:

> "There are lots of steps that ought to be taken after that to correct that message, but why start off with the wrong message?"
> [Tr.345]

With respect to Dr. Jackson's statement that the fixed variable approach was used in Alberta, counsel for YECL stated in his final submission that:

> "Alberta Power does not use a fixed variable method. Because of the capacity demand constraint thermal base system that exists in Alberta at this time, the results of using a cost causation method, which is why did we -- what was the planning for, and what was, why was the particular unit built, which is what Mr. Stout spent countless times discussing, when that cost causation principle is put into effect with the type of system in place in Alberta, the results may end up looking very close to a fixed variable, but Alberta Power does not use the fixed variable method."
> [Tr.789-790]

The Companies used what they described as "cost causation" for the purpose of classifying the cost of generating facilities between demand and energy. The position taken by the Companies was that the cause of costs related to the reasons for constructing the facilities in the first place, and did not in any way relate to the manner in which the facilities were operated. In arriving at the 40% demand/ 60% energy classification, the Companies relied on the classification of similar hydro facilities in British Columbia, Manitoba, Ontario and Quebec. The Companies' prefiled evidence and evidence on examination provided considerable data on the manner in which this comparative group of utilities operated their generating facilities. The witnesses were unable to provide the Board with any specific information relative to the manner in which these other utilities had planned their construction of generating plant.

It appears to the Board that, although the Companies take the position that cost causation relates to the original reason for constructing the generating facilities, the witnesses were not in a position to support their proposed ratio other than by an analysis of the use of the facilities by these other companies. This requires the Board to accept the premise that the actual operation by those utilities was in accordance with their planned operations. The Board, however, does not have any evidence to indicate that these two differ.

The Board notes that the City of Whitehorse supported the Companies' approach to the classification of hydro generating plant costs.

The Board considers the approach taken by YEC/YECL to the classification of hydro generating plant costs to be appropriate. The Board recognizes that the Companies have examined alternative methods of classification, and that they have given due recognition to practices prevailing in Canada by utilities with similar assets. The Board recognizes that the methodology adopted by the Companies reflects the fact that hydro facilities are normally built because of the low cost of energy from these plants. However, it considers that the fixed costs of hydro generation should not be ignored when considering the cost of energy produced therefrom.

Recommendation #2:
The Board recommends that the appropriate method of classifying the cost of existing hydro generating plant (excluding Whitehorse Unit #4) is 40% to demand and 60% to energy.

8.2.2 Classification of Hydro Generating Plant - Whitehorse Unit #4

YEC/YECL have taken the position that Whitehorse Unit #4 was constructed solely for the purpose of displacing high cost diesel generation. Company witnesses also stated that the unit did not add to the capacity of the Whitehorse generating plant, and thus did not increase the Companies' ability to meet customers' demand at the time of system peak. This position is supported by evidence proffered to this Board in March 19, 1982.

Dr. Jackson considered the cost of Whitehorse Unit #4 to be demand related solely for the reason that it represented a fixed cost. Under the fixed variable method advocated by Dr. Jackson, the reason for constructing the plant and the manner in which the plant is operated are not considered. Curragh also supported its position on the basis that Whitehorse Unit #4 is used during the off-peak period so that water can be stored at Aishihik and be used at the time of system peak.

The Board is persuaded by the evidence adduced during this review that the purpose of constructing Whitehorse Unit #4 was to displace high cost diesel generation and, accordingly, it is appropriate to classify the cost of Whitehorse Unit #4 as being energy related. However, the Board considers that the use of Whitehorse Unit #4 during the off-peak period may increase the capacity available at Aishihik during system peak and recommends that the Companies

be directed to perform a study of the impact of Whitehorse Unit #4 on the capacity available at Aishihik to meet demand at the time of system peak.

Recommendation #3:

Based on the available evidence, the Board recommends that the appropriate method of classifying the costs associated with Whitehorse Unit #4 is 100% to energy.

The Board also recommends that the Companies perform a study of the impact of Whitehorse Unit #4 on the capacity of Aishihik at the time of system peak and provide the results of the study to the Board at the time of their next general rate application for its further consideration.

8.2.3 Classification of Diesel Generating Plant

YEC/YECL classified the cost of diesel generating plant, whether operating on an isolated system or on the Whitehorse/Aishihik/Faro system, as being demand related. During the course of cross-examination, YEC/YECL witnesses acknowledged that diesel generating plant was built not only for the purpose of meeting peak capacity but also for the provision of energy, and that in theory a number of the alternative classification methods discussed above in the context of hydro generating plant might be used to classify a portion of diesel generating plant as being energy related.

However, the YEC/YECL witnesses indicated that diesel generating plant was typically classified as demand related in Canada, and that due to the relatively minor cost of diesel generating plant an alternative classification process would not yield a materially different result. The Board accepts the Companies' position on the classification of diesel generating plant.

Recommendation #4:
The Board recommends that the appropriate method of classifying costs associated with diesel plant is 100% to demand.

8.3 Allocation of Transmission Plant

YEC/YECL took the position that, inasmuch as the Whitehorse/Faro transmission line was constructed specifically for the purpose of serving the Faro mine operated by Cyprus Anvil, a substantial portion of the cost of the line should be allocated to the industrial class. YEC/YECL submitted that it was appropriate to allocate 85% of the cost of this line to Curragh, and relied in this connection on the June 1985 decision of the NEB respecting NCPC. As noted by the NEB in that decision:

> "Because of the unusual circumstances surrounding the construction of the transmission line from Whitehorse to Faro, where NCPC, as a result of an agreement between CAMC and the federal government, was instructed to build the transmission line, the Board recommends that this line be treated as a specific asset. The Board further recommends that 85 percent of the annual cost be assigned specifically to CAMC and that the remaining 15 percent be rolled in with the pooled costs in the Yukon hydro rate zone to be allocated to all customer classes based on their respective demands. The 85 percent figure for CAMC reflects the fact that, under this arrangement, CAMC would also be assigned its share of the pooled costs." [Page 43]

On cross-examination Company witnesses acknowledged that, at certain times of the year, the transmission line from Aishihik to Whitehorse (part of the Whitehorse/Aishihik/Faro transmission system) is used to supply Curragh and, accordingly, that Curragh benefits from the existence of the Whitehorse/Aishihik/Faro transmission system. Company witnesses also acknowledged that a more interconnected system can be expected to be more stable.

Company witnesses also explained during cross-examination that only the original cost of the Whitehorse/Faro line was being specifically assigned to Curragh, and that the costs of the rebuild of the Faro substation and other upgrades were pooled and allocated to all customer classes.

Dr. Jackson, on behalf of Curragh, submitted that either the transmission costs allocated to Curragh should be limited to 85% of the Whitehorse/Faro transmission line or, in the alternative, Curragh should be allocated its proportionate share of total transmission costs based on its proportion of total demand on the system at the time of system peak.

Dr. Jackson's evidence was that the cost of the Whitehorse/Faro line should be considered as a "sunk cost" which was being borne by other consumers in Yukon and Canadian taxpayers, and that these parties benefited at the time Curragh came onto the system to the extent that any costs in excess of incremental costs incurred as a result of Curragh being added to the system were recovered from Curragh.

The Board is persuaded that the Companies' position on this issue is reasonable. The Board is not satisfied that Curragh should be treated as an incremental customer for the purpose of the cost allocation study. Cost allocation studies typically consider the characteristics of customer classes being served by a utility and assign or allocate costs to reflect the manner in which the customer classes cause the costs to be incurred.

The Board is satisfied that Curragh receives a benefit from the existence of the transmission system and concurs with the conclusion reached by the NEB that, because of the unusual circumstances surrounding the construction of the transmission line from Whitehorse to Faro, the line should be treated as a specific asset. The Board also considers it appropriate that 85% of the annual cost of that line be assigned specifically to Curragh and that the remaining 15% be pooled with other transmission costs and borne by all customers, including Curragh.

Recommendation #5:
The Board recommends that the appropriate method of allocating transmission costs is to specifically assign 85% of the costs of the Whitehorse/Faro line to Curragh, and to allocate all remaining transmission costs to all customer classes, including Curragh, on the basis of demand at the time of system peak.

8.4 Classification of Generation Operating and Maintenance Expenses

The Companies classified their generation operating and maintenance expenses 50% to demand and 50% to energy based on the experience of YECL's parent company in Alberta. YEC/YECL witnesses acknowledged that the nature of the operating expenses in Yukon differ from those in Alberta due to the difference in the nature of the generating plant. This issue was not addressed by any of the Intervenors.

The Board is not satisfied that it is appropriate to import the classification ratios used by an electric utility in Alberta, whose generating plant is almost exclusively thermal, for the purpose of classifying operating expenses in Yukon where a sizable portion of the plant is hydraulic. Accordingly, the Board considers that it would be appropriate for YEC/YECL to perform a study to determine a more appropriate method of classifying generation operating and maintenance expenses between demand and energy. The Board recommends that, for current purposes, the 50/50 relationship is adequate.

Recommendation #6:

The Board recommends that the Companies be directed to perform a study to determine a more appropriate method of classifying generation O&M expenses and file the results of the study with the Board at the time of their next general rate application.

8.5 Marketing Expense

The Companies allocated marketing expense 85% on the basis of energy and 15% on the basis of the number of customers. The Companies placed heavier emphasis on energy sales as larger customers have more interaction with marketing than do smaller customers.

Dr. Jackson recommended that marketing costs should be allocated 50% on the basis of energy and 50% on the basis of the number of customers. Dr. Jackson supported his position on the basis that the primary focus and target of marketing is on customers and not on units of energy. Dr. Jackson acknowledged that the Companies may expend more marketing effort on the large customers, but in the absence of a more detailed tracking of marketing costs the allocation should be 50% customer / 50% energy.

The Board notes that the impact on customer classes of changing the allocation of marketing expenses from 85%/15% to 50%/50% is not significant. The Board considers the Companies' allocation of marketing expenses to be appropriate.

Recommendation #7:
The Board recommends that the appropriate method of allocating marketing expense is 15% on the basis of the number of customers and 85% on the basis of energy.

8.6 Classification and Allocation of Other Costs of Service

The Board notes that no cost of service issues, other than those discussed in Sections 8.1 to 8.5 of this report, were raised during the review. The Board has reviewed the Companies' classification and allocation of other costs of service and considers the methods used by the Companies to be appropriate.

> Recommendation #8:
> The Board recommends that the appropriate methods of dealing with cost of service issues, other than those discussed in Sections 8.1 to 8.5 of this report, are those proposed by the Companies.

9. RATE DESIGN

9.1 Revenue to Cost Ratios

YEC/YECL in their evidence indicated that, with the exception of the industrial rate class, given the nature of cost of service studies a target revenue to cost ratio range of 90% to 110% would be appropriate. The Companies based this range on their view that it was doubtful if any cost of service study could be considered accurate by more than plus or minus 10%.

YEC/YECL advised the Board that several regulatory regimes consider 95% to 105% to be a reasonable revenue to cost ratio target range for all classes. They indicated further that Manitoba Hydro had submitted targets which were initially 85% to 115%, with the provision for the subsequent narrowing to 90% to 110%. They indicated that, in contrast, the Ontario Energy Board has established a target revenue to cost ratio of 100%.

When questioned on cross-examination, Company witnesses indicated that there was no conflict between their position that industrials should have a revenue to cost ratio of 100% and that other classes should have a target revenue to cost ratio range of 90% to 110%, because demands for industrial customers were measured while the demands for other customer classes were typically not measured but rather estimated from the experience of other utilities.

The position advanced by Curragh on the subject of revenue to cost ratios is that a cost of service study provides a guide for rate making, and that other considerations may require pricing a customer at rate levels less than indicated by a fully distributed cost of service study. Dr. Jackson proposed that rates should be set to cover the incremental costs which the customer will impose on the utility.

The Board recognizes the difference in the determination of peak demands of industrials and other customer groups. However, the Board is not satisfied that the inaccuracies of the cost of service study of plus or minus 10% stated by the Companies are entirely due to this factor.

The Board is satisfied that, at the present time, a target range for revenue to cost ratios of 90% to 110% is satisfactory. However, it urges the Companies to take the necessary steps to improve the quality of their cost of service studies so that a target revenue to cost ratio of 95% to 105% would be attainable.

The Board also considers that to the extent possible, within the constraints of good rate setting practice, rates for the various customer classes should be altered over time to approach a 100% revenue to cost ratio and not the extremities of the range of reasonableness advocated by the Companies.

Recommendation #9:

The Board recommends that a target range for revenue to cost ratios of 90% to 110% be established for all customer classes other than the industrial class, and that the Companies take the necessary steps to improve the quality of their cost of service studies so that a target revenue to cost ratio of 95% to 105% will be attainable.

With respect to the industrial rate class, the Board notes from the Companies' evidence that revenue to cost ratios for large industrial customer classes typically are at or above 100%. The Board also recognizes that the recovery of 100% of costs from the industrial class is particularly important when this class represents some 43% of the Companies' energy output. If industrial customers representing 43% of the Companies' energy output are to be charged rates which do not recover the cost of serving them, then a substantial number of customers will be required to pay rates in excess of their cost.

The Companies indicated that they intend to move the industrial rate class revenue to cost ratio close to 100% at the time of their next general rate application.

The Board does not accept Curragh's position that rates should be based on incremental costs which customers impose on the utility. The application of an incremental approach to all customers of the utility would result in the utility collecting from its customers an amount which is substantially less than its total revenue requirement allowed by the Board.

Recommendation #10:
The Board recommends that a target revenue to cost ratio of 100% be established for the industrial rate class.

9.2 Phase-In of Rate Changes

YEC/YECL witnesses acknowledged that, over time, rates to certain customer classes should be adjusted to bring their revenue to cost ratios within acceptable bounds. They emphasized that there is no definitive period over which rates should be adjusted to accomplish this objective, and that factors such as the over-all rate increases required, the inflation rate, general economic conditions, specific economic circumstances of a particular rate class and recent rate history, should all be considered in determining the appropriate phase-in period.

None of the Intervenors in the proceeding commented on this issue.

The Board acknowledges that the factors outlined by the Company witnesses should be considered in determining an appropriate phase-in period for the purpose of bringing revenue to cost ratios within acceptable limits. However, the Board notes that it is important for the regulator to continuously monitor the progression of revenue to cost ratios toward the acceptable range in future general rate applications by YEC and YECL. The Board is not satisfied that, in the absence of compelling circumstances, revenue to cost ratios for certain customer classes should remain outside of the acceptable range for an extended period of time.

Recommendation #11:

The Board recommends that the changes to rates required to bring the revenue to cost ratios within the ranges established be phased-in over a reasonable period of time, and that the Board monitor the progression of revenue to cost ratios toward the acceptable range in future general rate applications by YEC/YECL.

9.3 Promotion of Economy and Efficiency in the Use of Electricity

The Board considers the efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decisions regarding the future and current use of electricity.

The Companies stated that runout rates reflecting long-run incremental costs, fuel cost adjustment riders, the past use of interruptible rates when appropriate conditions exist and recent amendments to the Curragh Resources contract all contributed to the promotion of economy and efficiency in the use of electricity.

Rate characteristics which could lead to the promotion of further economy and efficiency in the use of electricity were stated by YEC/YECL to include higher customer charges to reflect actual customer costs, more widespread use of demand charges, higher demand charges to reflect the higher marginal (as opposed to embedded) cost of supply, higher runout energy charges in the hydro rate zone to match long-run marginal costs, interruptible rates to provide "valley filling" and "peak shaving" and time differentiated rates, and the introduction of a special surcharge for space heating use.

9.3.1 Long-Run Marginal Costs

The Companies took the position that the consumer should be aware of the long-run marginal cost of supply to make rational decisions, and that the runout rate should reflect the long-run marginal costs. During cross-examination, Company witnesses indicated that the runout rate should at least reflect short-run incremental costs to promote efficiency.

Company witnesses explained that, although the Order-in-Council required the utilities to charge runout rates which reflected the short-run incremental costs in each rate zone, the actual runout rates being charged by the Companies were generally designed to reflect the long-run marginal costs which included not only the short-run incremental costs of fuel and other operating costs but also long-run costs including costs relating to future capacity additions.

Company witnesses acknowledged on cross-examination that no formal studies had been performed to determine long-run marginal costs for each rate zone in Yukon, however, the witnesses noted that the runout rate on the hydro zone was lower than the incremental cost of fuel and, accordingly, should be adjusted upward. It was also acknowledged that for the remaining rate zones the runout rate is in excess of short-run incremental costs and thus not in compliance with the OIC.

The Board acknowledges the Companies' objective of promoting economy and efficiency in the use of electricity by including long-run marginal costs in runout rates. The Board notes that, to the extent that runout rates include compensation for costs relating to future construction, either the Companies will earn revenue in excess of their revenue requirements or will find it necessary to reduce rates in other blocks in order to balance total revenues with the revenue requirements. Furthermore, if fixed costs incurred by the Companies are not recovered in the demand charges, fixed charges and charges in the first energy block, then an element of revenue instability is introduced.

The Board notes that Company witnesses indicated that in Yukon, because diesel generation is utilized, the difference between short-run incremental costs and long-run marginal costs is not that big.

The Board considers that runout rates should reflect short-run incremental costs in each of the rate zones as specified in the OIC and that fixed costs incurred by the Companies should be recovered by demand charges, fixed charges and energy charges in the first energy block. The Board recognizes that this will result in an increase in the hydro zone runout rate.

The Board also considers that the Companies should undertake a study for the purpose of identifying long-run marginal costs that should appropriately be included in runout rates, and the results of this study should be presented to the Board by the Companies at the time of their next general rate application. At that time, the Board should consider the appropriate manner in which long-run marginal costs should be reflected in runout rates.

It was noted that, on cross-examination, Company witnesses indicated that no provision was included in the rate to Curragh for the excess of long-run marginal costs over short-run incremental costs.

Recommendation #12:
The Board recommends that the runout rates for all zones should be adjusted to reflect short-run incremental costs, and that the Companies should undertake a study for the purpose of identifying long-run marginal costs that should be included in the runout rates for consideration by the Board.

9.3.2 Other Rate Design Factors Which Promote Economy and Efficiency in the Use of Electricity

During the course of cross-examination, YEC/YECL witnesses discussed the other factors that contributed to the promotion of economy and efficiency in the use of electricity. It was indicated that a fuel adjustment rider enabled the Companies to communicate the current cost of fuel to their customers in the form of rate adjustments, and that this knowledge of current costs by customers was of assistance in the promotion of economy and efficiency.

The Companies also indicated that existing rates to be charged to Curragh include a significant demand charge which encourages efficient use of capacity by Curragh as well as actual incremental diesel fuel and operating costs for energy consumption in excess of 18,784 kWh for each hour (averaged on a monthly basis).

During the course of the proceedings, the Companies and Intervenors raised the possibility of using interruptible rates, time-of-use rates and a special electric heating rate for the purpose of increasing economy and efficiency. On cross-examination, Company witnesses stated that interruptible rates had been used in certain circumstances in the past and are currently available on the Mayo hydro system due to a surplus of energy on that system. They explained that the use of interruptible rates where generation is by diesel would not promote economy and efficiency because the interruptible rate

would have to be equal to the runout rate in order to recover the cost of generation.

Company witnesses also explained that time-of-use rates would not be of assistance in promoting economy and efficiency if the energy was produced from diesel generating plants because the generating cost would not be altered by the time of use.

Company witnesses indicated that the Companies were presently contemplating introduction of a hookup charge of approximately $4,000 for service to new electric space heating customers. The witnesses also estimated that approximately 25% of existing residential customers in the hydro area were, to some extent, electric space heating customers.

A further issue discussed in the proceeding was the incidence of residential government customers who do not directly receive the bill related to their consumption. It was agreed that such an arrangement definitely had a negative impact on the promotion of economy and efficiency in the use of electricity.

The City of Whitehorse and residents from Haines Junction indicated that the Companies should carefully examine the size of the initial block of energy (1,000 kWh/month/residential customers and 2,000 kWh/month for general service customers) with a view to reducing it to provide an added incentive to all customers on the system to use electricity more wisely. Company witnesses indicated that this matter would require considerable study.

The Board considers that, to the extent possible, interruptible and time-of-use rates should be used if it can be established that their use will result in the promotion of economy and efficiency in the use of electricity. However, it appears to the Board that under current circumstances there is a very limited opportunity to use these rate features.

Recommendation #13:
The Board recommends that interruptible and time-of-use rates should be used if it can be established that their use will result in the promotion of economy and efficiency in the use of electricity.

The Board wishes to encourage the Companies to further study the introduction of a special surcharge for new electric space heating customers with a view to reducing inefficient and uneconomic use of electricity for space heating purposes. The Board would also encourage the Companies to investigate methods by which the use of electricity for space heating by existing customers can be equitably discouraged.

Recommendation #14:

The Board recommends that the Companies further study the introduction of a special surcharge for new electric space heating customers and report to the Board the results of this study at the time of their next general rate application.

The Board also recommends that the Companies investigate methods by which the use of electricity for space heating by existing customers can be equitably discouraged and report to the Board the results of this study at the time of their next general rate application.

The Board also would encourage the Companies to examine alternative billing mechanisms in consultation with government agencies to ensure that residential government customers are receiving appropriate price signals designed to encourage the wise use of electricity.

Recommendation #15:

The Board recommends that the Companies examine alternative billing mechanisms in consultation with government to ensure that residential government customers are receiving appropriate price signals.

The Board considers it appropriate that the Companies conduct studies to determine the optimum size of the first energy rate block and to propose, if considered desirable, an additional energy rate block to ensure that rates are designed to result in the maximum promotion of economy and efficiency in the use of electricity. The Board also considers that details of energy consumption by rate block and the related cost on customers' bills will promote the economic and efficient use of electricity.

Recommendation #16:

The Board recommends that the Companies be directed to conduct studies to determine the optimum size of the first energy block and propose, if considered useful, multiple energy blocks.

The Board also recommends that the Companies be directed to examine the feasibility of providing on customers' bills information with respect to energy consumption by rate block and the related cost.

9.4 How Can Rate Design Respond to Environmental or Other Costs Not Included in Cost of Service

On this issue, Company witnesses explained that the existing rate design does not reflect environmental or other costs that are not currently included in cost of service and that rates are designed to recover only the costs recognized in the approved revenue requirement.

Company witnesses explained that in some Canadian jurisdictions recognition is given to environmental and other costs by reflecting them in the criteria used for the planning of system additions. They explained that environmental costs are not recognized in traditional utility accounts, are virtually impossible to quantify and the subject is currently very controversial.

The Board considers that the Companies should be encouraged to continue to monitor ways in which rate design can be used to reflect environmental or other costs not included in the cost of service. The Companies should also be encouraged to consider this factor in their applications for capital expansion and in their general rate applications.

Recommendation #17:

The Board recommends that the Companies be encouraged to monitor ways in which rate design can be used to reflect environmental or other costs not included in cost of service, and the Companies should be encouraged to consider environmental costs in future general rate applications and capital expansion applications.

9.5 Extent to Which Rate Design Responds to the Current Costs Required to Develop New Power Sources

This issue has been dealt with at length in Section 9.3 above in the context of reflecting long-run marginal costs in consumer rates.

9.6 How Should Demand-Side Management Activity be Reflected in Rate Design

It was agreed by the parties that the subject of Demand-Side Management ("DSM") activities would be discussed at length at the upcoming capital hearing.

The Board considers that the subject of DSM activities of the Companies fall into three distinct categories. First, the criteria used in determining what DSM activities should be undertaken by the Companies; second, the treatment of DSM expenditures for the purpose of determining the Companies' revenue requirements; and third, the manner in which DSM capital expenditures, operating expenses and sales reductions should be reflected in the Companies' rate design. The Board considers it important that all three of these aspects be addressed, in detail, by the Companies at the time of their upcoming capital hearing.

Recommendation #18:

The Board recommends that, at the time of the Companies' upcoming capital hearing, the following should be addressed:

(i) criteria used in determining the investments in DSM activities;

(ii) the appropriate treatment of DSM expenditures for the purpose of determining the Companies' revenue requirements; and

(iii) the manner in which DSM capital expenditures, operating expenses and sales reductions should be reflected in rate design.

10. CURRAGH CONTRACT

Counsel for Curragh stated in argument that:

> "...Curragh submits that the board should recommend that rates to be charged to Curragh should be based on an arms-length negotiation between Curragh on the one hand and Y.E.C./Y.E.C.L. and the Yukon Territorial Government on the other. And that that contract be treated in the same way as the June 1st, 1991 amending agreement and 1986 contract had been treated, namely, that the governor in council direct the board that the rate should be those agreed upon at arms length. Curragh will be happy to come before the board when that contract is in an order in council for the G.R.A. and answer questions about that contract within reason."
> [Tr.772-773]

Counsel for Curragh also made the following statement at the conclusion of his argument:

> "Curragh rejects those arguments put forward by the company for the reasons that I have given earlier and projects it on the merits, and Curragh in addition requests the board to send this message to the Yukon Territorial Government. And this message, and I am instructed to give it in this way, is that Curragh regards Y.E.C./Y.E.C.L. proposals on costing to be nothing more than an attempt by Y.E.C./Y.E.C.L. to position itself for negotiations Curragh may be disposed to enter for the period after March 31'93. In other words, the game is that Y.E.C./Y.E.C.L. wants this board to adopt its views and then have you recommend that to the Yukon Territorial Government. The Yukon Territorial Government than presumably will make those Yukon law by order in council through direction to this board. Then in negotiations Y.E.C./Y.E.C.L. will come to Curragh and say, 'You have got to cover the costs as defined by law.' ... Curragh, for all the reasons I have given, does not believe that these principles are appropriate. They believe that you should have a level playing field of costs for the fixed variable method, and do not stack the deck against Curragh in the way the company is urging you to do, and the way this process enables them to urge you that you do.
>
> Curragh's position is that if this board and the Y.T.G. accept Y.E.C./Y.E.C.L.'s methodology, that Curragh will regard this as an unfair, unwelcoming and hostile action towards it by Yukon. Curragh cannot afford to pay more than it is paying under the existing agreement in G.R.A. at present, and Curragh will not feel bound in any way by any order in council cost definitions in planning future actions." [Tr. 786-787]

Counsel for the City of Whitehorse dealt with the same issue in his argument and stated:

> "Dealing with the matter of the current rate, we believe that Curragh ought to be part of the rates which this board adjudicates on. If after setting of the rates by this board Curragh then of its own volition goes to either level of the government, territorial or federal for assistance, then that's a matter for Curragh and the government. In the meantime in the setting of the rates by this board, it is for Curragh to come before this board with its rates and it should be paying its fair share in that respect." [Tr.764]

Counsel for YEC, in response to submissions by Curragh, stated:

> "The final point I would like to deal with, Madam Chair, is the issue raised by Dr. Jackson in his recommendation. And that is that he indicated that the board perhaps should take other considerations into account in deciding whether or not a certain rate that might come out of a cost of service study should be, should be set for a company like Curragh that was having, for example, financial difficulties. What I would like to say to that, Madam Chair, is that since any preferential rate that would be granted to any company or any customer on any basis would affect the other customer classes, if the board was inclined to want to get into that exercise, it would have to carefully analyse a significant amount of information to satisfy itself that indeed the allegation that was being made about financial problems was in fact true." [Tr.808-809]

As discussed earlier, the Board is satisfied that a revenue to cost ratio for the industrial class customers should be approximately 100%. The Board is not satisfied that Curragh should be given any special treatment in the procedure followed for the establishment of its rates as opposed to those charged to other customers of YEC/YECL.

Accordingly, the Board considers that, although certain aspects of the relationship between YEC/YECL and Curragh can be appropriately covered in a contract between those two parties, such a contract should not be determinative of the price to be charged by YEC/YECL. The Board concurs with the position of the City of Whitehorse that Curragh rates are a matter to be determined by the Board only after a public hearing. The Board also concurs with the representation of counsel for the City of Whitehorse and the submission by the City of Dawson that any subsidy flowing to Curragh from the Government of Yukon should be in the form of a direct subsidy and not by way of a special rate for electricity.

Recommendation #19:

The Board recommends that the rates to be charged to Curragh should be determined by the Board only after a public hearing.

RESPECTFULLY SUBMITTED
ON BEHALF OF THE
YUKON UTILITIES BOARD

E Walters

Edith D. Walters, Chairman

GLOSSARY OF TERMS

ALLOCATION:

The apportionment of the total cost of service between customer classes.

CAPACITY:

The load for which a generating unit, generating station or other electrical apparatus is rated either by the user or by the manufacturer.

CLASSIFICATION (COST):

The division of costs into components which reflect the relationship between the services provided by the utility and the principal cause of the related costs. Examples would be demand related, energy related and customer related.

COST OF SERVICE:

The total cost incurred to provide utility service, including expenses, taxes and return on investment. The cost of service may be thought of as an annual revenue requirement.

COST OF SERVICE STUDY:

An analytical process wherein the utility cost of service is functionalized, classified and allocated or assigned to the various customer classes.

DEMAND (ELECTRIC):

The rate of flow of electricity demanded at one point in time and the maximum size (capacity) of facilities required to serve the demands of electric customers, usually expressed in kilowatts.

COINCIDENT PEAK:

The sum of the demands of all customer classes at the time of system peak.

NON-COINCIDENT PEAK:

The sum of customer classes' peak demands irrespective of their time of incurrence.

DISTRIBUTION:

A network of electrical circuits which supply electricity to the customer from the transmission system.

ENERGY:

The consumption of electricity over a period of time by customers of an electric system, usually expressed in kilowatt hours.

FIXED COSTS:

Those costs that do not vary with the number of kilowatt hours supplied. Examples would be depreciation and return on investment.

FUNCTIONALIZATION:

The arrangement of costs according to major functions, such as production, transmission, distribution and general.

GENERAL RATE APPLICATION:

A request by a utility to a regulatory board to set new customer rates based on a forecasted revenue requirement for a specific test year(s).

KILOWATT:

One kilowatt equals 1,000 watts, where a watt is an electrical unit of real power or rate of doing work. One kilowatt is equivalent to approximately 1.34 horsepower.

KILOWATT HOUR:

The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatt hour equals 1,000 watt hours.

PEAKING GENERATION:

Generating equipment normally operated only during the hours of highest daily, weekly or seasonal loads, to meet a portion of the system load that is above the base load.

PEAK SHAVING:

Reducing customer demand at the time of system peak.

REVENUE REQUIREMENT:

The total of all revenues required to be collected from utility customers. Revenue requirement is determined as the total of the following costs:

- cash operating expenses
- depreciation
- income tax
- return on investment

REVENUE TO COST RATIO:

The ratio of revenues for a particular customer class to the cost of service for that particular customer class.

SUNK COST:

A cost resulting from an irreversible past decision.

SYSTEM PEAK:

The maximum aggregate demand imposed on the system by all customers.

TIME-OF-USE RATES:

Energy rates which vary by time of day and time of year, generally introduced to encourage shifting of demand.

TRANSMISSION:

Facilities provided to carry electricity from the point of generation to the distribution system.

VALLEY FILLING:

Shifting of consumption from times of high peak demand (Winter) to times of lower demand (Spring, Summer, Fall).

VARIABLE COSTS:

Those costs, such as fuel costs and variable maintenance costs, that vary with the number of kilowatt hours supplied.

SUMMARY OF RECOMMENDATIONS

The Board makes the following recommendations to the Commissioner in Executive Council:

1. That the Board be provided with the flexibility to react to future changes in circumstances, and to determine the appropriate cost of service and rate design practices to be used in Yukon.

2. That the appropriate method of classifying the cost of existing hydro generating plant (excluding Whitehorse Unit #4) is 40% to demand and 60% to energy.

3. That, based on the available evidence, the appropriate method of classifying the costs associated with Whitehorse Unit #4 is 100% to energy.

   That the Companies perform a study of the impact of Whitehorse Unit #4 on the capacity of Aishihik at the time of system peak and provide the results of the study to the Board at the time of their next general rate application for its further consideration.

4. That the appropriate method of classifying costs associated with diesel plant is 100% to demand.

5. That the appropriate method of allocating transmission costs is to specifically assign 85% of the costs of the Whitehorse/Faro line to Curragh, and to allocate all remaining transmission costs to all customer classes, including Curragh, on the basis of demand at the time of system peak.

6. That the Companies be directed to perform a study to determine a more appropriate method of classifying generation O&M expenses and file the results of the study with the Board at the time of their next general rate application.

7. That the appropriate method of allocating marketing expense is 15% on the basis of the number of customers and 85% on the basis of energy.

8. That the appropriate methods of dealing with cost of service issues, other than those discussed in Sections 8.1 to 8.5 of this report, are those proposed by the Companies.

9. That a target range for revenue to cost ratios of 90% to 110% be established for all customer classes other than the industrial class, and that the Companies take the necessary steps to improve the quality of their cost of service studies so that a target revenue to cost ratio of 95% to 105% will be attainable.

10. That a target revenue to cost ratio of 100% be established for the industrial rate class.

11. That the changes to rates required to bring the revenue to cost ratios within the ranges established be phased-in over a reasonable period of time, and that the Board monitor the progression of revenue to cost ratios toward the acceptable range in future general rate applications by YEC/YECL.

12. That the runout rates for all zones should be adjusted to reflect short-run incremental costs, and that the Companies should undertake a study for the purpose of identifying long-run marginal costs that should be included in the runout rates for consideration by the Board.

13. That interruptible and time-of-use rates should be used if it can be established that their use will result in the promotion of economy and efficiency in the use of electricity.

14. That the Companies further study the introduction of a special surcharge for new electric space heating customers and report to the Board the results of this study at the time of their next general rate application.

    That the Companies investigate methods by which the use of electricity for space heating by existing customers can be equitably discouraged and report to the Board the results of this study at the time of their next general rate application.

15. That the Companies examine alternative billing mechanisms in consultation with government to ensure that residential government customers are receiving appropriate price signals.

16. That the Companies be directed to conduct studies to determine the optimum size of the first energy block and propose, if considered useful, multiple energy blocks.

    That the Companies be directed to examine the feasibility of providing on customers' bills information with respect to energy consumption by rate block and the related cost.

17. That the Companies be encouraged to monitor ways in which rate design can be used to reflect environmental or other costs not included in cost of service, and the Companies should be encouraged to consider environmental costs in future general rate applications and capital expansion applications.

18. That, at the time of the Companies' upcoming capital hearing, the following should be addressed:

    (i) criteria used in determining the investments in DSM activities;

    (ii) the appropriate treatment of DSM expenditures for the purpose of determining the Companies' revenue requirements; and

    (iii) the manner in which DSM capital expenditures, operating expenses and sales reductions should be reflected in rate design.

19. That the rates to be charged to Curragh should be determined by the Board only after a public hearing.

REFERENCE: **Application, Page 4-18**

QUESTION:

a) Would the current lower prices for diesel fuel alter YEC's recommendation for this item?

ANSWER:

(a)

The level of the ERA needs to be set consistent with the price of diesel fuel in Yukon Energy's Revenue Requirement. To the extent the revenue requirement is changed to reflect "current lower prices for diesel fuel", then the ERA would be similarly updated.

Under the Rider F mechanism, differences between the GRA fuel price and actual fuel prices will affect the Rider F account and not YEC earnings.

As noted at page 4-18 of the Application, "the structure of the ERA is designed to ensure both that YECL receives a full pass through of the incremental costs of diesel generation (when diesel is on the margin) driven by increases in the volume of wholesale sales, and second to ensure that Yukon Energy is able to recover its costs (as required by OIC 1995/90 section 7(b)) when diesel generation is on the margin".

The problem created in the current situation, even with acceptance of all residential runoff rates as proposed in the Application, is that Yukon Energy would be severely prejudiced when diesel generation for whatever reason becomes needed to supply wholesale load growth. The approved run out rate today (and for at least 2009) for non-government residential service in the Hydro zone is lower than would apply based on the full short-term incremental cost of diesel; accordingly, Rate Schedule 42 as approved in the 1996/97 GRA needs to be amended to set an ERA charge that is not tied to the current approved run out rate for non-government residential service in the Hydro zone.

REFERENCE: Application, Page 6-1

In response, YEC/YECL jointly filed a required report with the Board in August 2005 that provided information on the revenue to cost ratios by customer class for both companies using the most recent cost of service allocation study, including comments on the implementation of a rate shift program over 10 years.

QUESTION:

a) Please provide a copy of that report.

b) When did the most recent COS study occur that was referenced in the above quote?

c) Was the previous COS study undertaken before the closure of the Faro mine?

d) Why has no action been taken with respect to Order 1996-7 with respect to a rate-rebalancing program?

ANSWER:

(a)

Please see Attachment 1 to this response which provides the 2005 Cost of Service Report, including the cover letter and Appendix A filed with the report. In addition, Attachment 2 provides the YEC/YECL October 27, 2005 response to intervenor comments on Attachment 1.

(b)

The 2005 Report provided as Attachment to YUB-YEC-1-23(a), notes that “the most recent full cost-of-service study for both Companies that was balanced (reflected overall system revenues equal to costs) was filed during the 1996/97 GRA for the year 1997.”

After the 1996/97 GRA hearing, a cost of service allocation assessment was undertaken by Yukon Energy as part of the 1998 application regarding the closure of the Faro mine.[1] As noted in the 2005 Report to the Board, this later filing was not a full cost of service but was undertaken to determine the "cost of service shortfall" due to the closure of the Faro mine. The study was based on 1997 GRA approved costs and revenues (excluding Faro mine shutdown impacts and a few other specific adjustments) and was utilized only to assess cost of service for the Faro mine during its partial years operations in 1997 and 1998. The shortfalls calculated using the study were adopted by the Board as part of the rate setting approach used in that proceeding.

The Power Purchase Agreement Application between Yukon Energy and Minto mine also included as Attachment A: 2008 Yukon Industrial Cost of Service which reviewed in detail the principles, methods, information and assumptions adopted to prepare the 2008 Yukon Industrial COS estimates used to determine the 2008 Firm Mine Rate included in the PPA application.

(c)

As noted in response to (b) above, the most recent full Cost of Service study for both companies was undertaken in relation to the 1996/97 GRA prior to the closure of the Faro mine.

(d)

This is reviewed briefly in Section 1.1.1 of the Application, when the Board addressed a motion to require both Yukon Energy and YECL to file a GRA. As a result, Order 2005-1 required YEC/YECL to prepare the report provided as Attachment 1 plus the subsequent response in Attachment 2.

In summary, as discussed in 2005, conditions since 1996 have not allowed this directive to be addressed. The key conditions in this regard prior to 2008 have been the absence of revenue requirement reviews, let alone concurrent reviews of both companies, and the prevailing impact of Yukon Government RSF subsidies (particularly to non-government residential customers) and the structure of such subsidies for many of these years.

[1] Yukon Energy Corporation: Revised 1997 and 1998 Rate Application to the Yukon Utilities Board Related to Board Order 1997-6 and Related to the Closure of the Faro Mine.

YEC/YECL in Attachments 1 and 2 state that a fundamental requirement for a rate shift program is the need for revenue requirement and billing determinants to be established for both companies for the same test period; in addition, the companies note the relevance of ongoing government bill relief in affecting timing of any such a rate shift program. Since 1996, the current 2008-2009 GRA filings by both companies are the first opportunity for the same test year revenue requirement and billing determinant requirement to be met – but today OIC 2008/149 further defers implementation of any such rate shift program until after 2012.

Please also see response to YUB-YEC-1-20.

YUKON ENERGY

The Yukon Electrical Company Limited
An ATCO Company

August 24, 2005

Mr. Brian Morris
Yukon Utilities Board
19-1114 First Avenue
Whitehorse, YT
Y1A 1A3

Board Order 2005-1 set out in section 4.0 a joint YEC/YECL requirement regarding cost-of-service information, as follows:

> The Board requires the Companies to jointly file a report by Thursday September 1, 2005, that provides information on the revenue to cost ratios by customer class for both Companies utilizing the most recent cost of service allocation study. If the report indicates that the revenue to cost ratios by customer class are outside the range of 90 percent to 110 percent, then the Companies are to provide their views on whether an updated cost of service allocation study should be undertaken or if a rate shift proposal can be made based on the most recent cost of service allocation study.

Most Recent Cost of Service Allocation Study

Attached is a Report on the Most Recent Cost of Service Study. This Report indicates that the most recent full cost-of-service allocation study for both Companies was filed with the Board during the 1996/97 GRA for the 1997 test year. This study indicated that the residential non-government class for both Companies was the only customer class with rates below 90 percent of costs (at 80.2% of the costs to serve them), and the general service government class was the only customer class for both Companies with rates above 110% (at 142.8% of the costs to serve them). All other remaining customer classes for both Companies were inside the 90% to 110% range.

The attached Report notes that a partial cost-of-service study for both Companies was prepared by Yukon Energy only for its *Revised 1997 and 1998 Rate Application to the Yukon Utilities Board Related to Board Order 1997-6 and Related to the Closure of the Faro Mine.* This 1998 study, however, was based on the 1997 GRA approved costs and revenues (excluding Faro mine shutdown impacts and a few other specific adjustments) and was utilized only to assess cost of service for the Faro mine during its partial year operations in 1997 and 1998.

The attached Report reviews implications for revenue to cost ratios for both Companies related to adjustments to costs and revenues since the 1996/97 GRA.

Companies' views on whether an updated study should be undertaken today

Based on the information as set out in the attached Report, the Companies do not view that a cost of service study is required to begin a rate shift program. This is for two reasons.

First, following the rate adjustments implemented in 1996, only two customer classes appear to have been routinely outside the 90%-110% revenue to cost ratio (R/C) range – residential non-government at well below 90% and general service government at well above 110%. It is unlikely that the revenue to cost ratios have improved since 1997 and 1998 for these two customer classes. The key first steps of any rate shift program will need to focus on directional improvements in the revenue to cost ratios for these two classes.

Second, although a cost of service study will be required to refine the ratios when each of the classes is approaching the 90%-110% range, these two customer classes are currently far outside the range targeted by the Board. Accordingly, in order to prevent giving rise to concerns over rate shock as noted below, it will likely take a number of years in any rate shift program to begin to approach the target range. There is no apparent need for a new cost of service study to begin these initial steps in any rate shift program.

Issues to be addressed with respect to a rate shift proposal

Although the lack of a recent cost of service study is not an impediment to the Board exercising its jurisdiction to initiate a rate shift program today, the Companies note that there are a number of other matters that suggest against initiating such a rate shift in the near term. A fundamental requirement to any rate shift program is the need for revenue requirement and billing determinants to be established for both companies for the same test period. This information has not yet been established. As well, the following three matters will need to be considered prior to designing or implementing any rate shift program.

1) **Rate relief (and Rate Redistribution Fund):** The 1996/97 GRA did not result in any material adjustments for rates to residential non-government customers. YEC/YECL argued in the 1996/97 GRA, in their Reply Argument at page 8, that this was appropriate (despite an R/C ratio below 90%) as "any movement toward the 90-110% target will only increase the amount of bill relief paid by the government and the residential customers will not see any change in their bills". The Board, in not moving to initiate a rate shift program at that time, acknowledged the constraints related to the then existing rate relief.

The situation regarding rate relief constraints has not materially changed from the 1996 situation. The Yukon Government recently announced the continuation of the Rate

Stabilization Fund (RSF) until March 31, 2007, and similar to the earlier rate relief programs, this mechanism prevents most residential non-government customers from seeing any related to rate shifts on their bills:

- **1997 rate relief and Residential customers:** Overall, 1997 rate relief levels yielded an effective R/C ratio (as to bills paid) for Residential Non-Government customers of 73% based on approved 1997 costs of service (costs per Exhibit 206 in the 1996/97 GRA hearing). This rate relief was focused on the customer charge and the first block energy use. Accordingly, the effective bill increase required for most residential customers to reach 90% R/C ratio based only on the 1997 GRA costs was far greater than appears solely upon inspection of Exhibit 206 (likely greater than 25%). This assessment ignores any need for additional rate increases after 1997 related to other factors such as closure of the Faro mine, higher fuel costs or other cost increases.

- **Current Rate Stabilization Fund Impacts:** The above 1997 revenue cost ratios after rate relief would need to be changed today to reflect current levels of RSF payments to residential non-government customers. The current RSF subsidies on a dollar value basis are well in excess of those received by customers in 1997. Given the current RSF program, there will not be any real impact on the bills paid by most residential customers under a rate shift program. Higher rates could be set for non-government residential customers, but this will not impact the customers' bills for any consumption under 1000 kW.h per month (a large majority of the current residential non-government consumption is below 1000 kW.h per month).

The Board's Order 1996-7 from the 1996/97 GRA also noted that the Companies are to design a rate shift program over a ten year period, but further noted that "these proposals may include the setting up of a Rate Redistribution Fund which would hold a portion of the total rate relief in a particular year so that it can be used in subsequent years to mitigate a rate increase to a specific class". This part of Order 1996-7 clearly linked rate shift proposals to the matter of rate relief removal. Under the current RSF, however, there is no basis whereby the Companies could establish a Rate Redistribution Fund as envisaged in Order 1996-7.

2) **Rate Shock:** The YEC/YECL Reply Argument in the 1996/97 GRA at page 8 also noted that "the Companies submit that the time period required to move the ratio into the target range is 10 years at the minimum and this time period must be reviewed continuously to ensure that the customers do not experience rate shock". When a rate shift program is considered, rate shock will remain a key constraint and suggested timeframes for transition will need to reflect this constraint.

In addition, given the degree of rate relief in place today, implementation of a rate shift program that raises residential non-government rates but not the underlying bills will only exacerbate the potential for "bill shock" for customers in the event that the RSF is

materially redesigned or terminated in future. It does not appear to be in customers' interests to increase their exposure to this financial shock.

3) **Rate Design:** The current structure of retail rates in Yukon results in three separate charges to each customer class in addition to any rate riders that are in place at a given time. For residential customers, the charges consist of a customer charge, a base energy rate and a runoff rate. For general service customers, the charges are a demand charge, a base energy rate and a runoff rate. Each of these components is required to be set based on principles set out in OIC 1995/90, with rates being established on an integrated basis for Yukon Energy and YECL customers.

Current rates reflect rate designs approved in the 1996/97 GRA combined with subsequently established rate riders (Rider J and Rider F). The current rates in Yukon (excluding rate riders) were set such that all "runoff" consumption (above 1000 kW.h for residential customer and above 2000 kW.h for general service customers) was priced in each rate zone based on the effective incremental cost of energy produced by diesel generation in that rate zone as forecast in the 1996/97 GRA.

When a rate shift program is designed and implemented, a key first task will be to determine the rate design approach to be used in implementing the rate shift, including the related requirements of OIC 1995/90. Based on previous rate designs, rate shift impacts as between customer classes would focus, after the runoff rates are established, on first block energy rates and customer charges or demand charges. A possible first assessment then would be the impact of adjusting the runoff block to move towards incorporating the current price of diesel fuel (which would affect all customers as runoff rates in each rate zone currently are equal between the various classes). This level of detail regarding rate design has not been considered by the Companies in recent years, and would likely be a necessary precondition to implementing a differential rate shift program at this time.

Issues to be addressed with respect to any new cost of service study

Preparation of a new cost of service study when directed by the Board will require a number of key matters to be satisfied that are not in place at this time. First, there will need to be an approved revenue requirement for each of the two utilities on a consistent test year basis as well as the determination of billing determinants and load characteristics by customer class. As YEC's recent application was for the 2005 test year only and YECL has not made an application recently, this information is not currently available.

Second, the methods employed in the Yukon integrated cost of service studies prepared to date (since 1989) have been effectively based on the system and its cost drivers and load profiles with the Faro mine as a customer. With the Faro mine closed and surplus hydro on the WAF system, it would be appropriate to review a number of the key methods (such as classification of generation and transmission assets) to ensure the cost of service approach properly tracks the costs imposed on the system by each class of

customer. The completion of the Mayo-Dawson transmission line will also require some assessment to ensure appropriate cost of service methodologies are applied in dealing with the costs on that system.

We trust this Report satisfies the requirements of Board Order 2005-1. Please feel free to contact us if you have any questions.

Yours truly,

David Morrison
President & CEO
Yukon Energy Corporation

Doug Tenney
General Manager
Yukon Electrical Company Ltd.

YUKON ENERGY

The Yukon Electrical Company Limited
An *ATCO* Company

Report on the Most Recent Cost of Service Study

Yukon Energy Corporation
and
Yukon Electrical Company Limited

August, 2005

Board Order 2005-1 set out in section 4.0 a joint YEC/YECL requirement regarding cost-of-service information. In respect of Cost of Service Study results, the Order states as follows:

> The Board requires the Companies to jointly file a report by Thursday September 1, 2005, that provides information on the revenue to cost ratios by customer class for both Companies utilizing the most recent cost of service allocation study.

This report provides an overview of the "most recent cost of service allocation study" for Yukon and the implications for revenue to cost ratios for both Companies related to adjustments to costs and revenues since the 1996/97 GRA.

Recent Cost of Service Studies

The most recent full cost-of-service study for both Companies that was balanced (reflected overall system revenues equal to costs) was filed during the 1996/97 GRA for the year 1997. The results of this cost-of-service study were provided as Exhibit 206 in the 1996/97 General Rate Application Hearing. The relevant sections of Exhibit 206 are attached as **Attachment A** (Attachment A excludes the detailed rate schedules that were included in Exhibit 206). This exhibit reflects the cost-of-service study filed in the original GRA application documents at Binder 2 Tabs 4 and 5, as updated for the negotiated settlement and final approvals given the Board in that GRA .

The information on the revenue to cost coverage (R/C) ratios by customer class for both Companies utilizing this most recent cost of service study allocation for 1997 is in summary as follows:

Table 1: Revenue to Cost Coverage (RCC) Ratios for 1997

	Final 1996/97 GRA - 1997		
Customer class for both Companies	**Costs** ($000)	**Revenue** ($000)	**RCC Ratios**
Residential Government	645	642	99.6%
Residential Non Government	17,178	13,777	80.2%
General Service Government	5,586	7,978	142.8%
General Service Non Government	8,665	9,507	109.7%
Industrial	14,985	14,983	100.0%
Street Lights	537	591	110.0%
Space Lights	150	165	110.0%
Total	47,746	47,643	100.0%

Source: 1996/97 GRA, Exhibit 206, Schedule C (including unbilled)

As indicated in Table 1, the R/C ratios for the Residential Non-Government and General Service Government were the only two results that were outside the 90:110% range. These R/C ratios reflect rates as approved by the Board[1].

After the 1996/97 GRA hearing, the only cost of service allocation assessment carried out was by Yukon Energy as part of its 1998 application regarding the closure of the Faro mine during January 1998 (the *Yukon Energy Corporation: Revised 1997 and 1998 Rate Application to the Yukon Utilities Board Related to Board Order 1997-6 and Related to the Closure of the Faro Mine*). The 1998 filing, which is reviewed below, did not constitute a full and balanced cost of service allocation study for all rate classes relevant for the purpose of this report.

The 1998 filing by Yukon Energy updated the 1996/97 GRA cost-of-service study on a limited-scope basis to reflect the 1997 and 1998 impact of the mine closure. The sole purpose of this updated cost-of-service study was to determine the "cost of service shortfall" related to the Faro mine; that is, to determine the full fair cost of service allocation to the mine in each of 1997 and 1998 given the actual consumption of the mine, as compared to the amounts actually paid by the mine. The shortfalls calculated using this study as filed by Yukon Energy were ultimately adopted by the Board as part of the rate setting approach in that proceeding, i.e., based on this cost of service, the Industrial rate class (of which the Faro mine was the only member) was assigned a cost of service shortfall for 1998 in accordance with Board Order 1998-5 of $3.298 million per Schedule 6D of Exhibit 83.[2]

Yukon Energy did not file details with the Board on its updated 1998 cost of service study, beyond the information relating to cost of service for the Industrial class. Accordingly, updated information was not filed for other customer classes such as the Residential Non-Government or Government General Service classes. Furthermore, this was not a fully balanced cost of service study (it reflected an overall cost-of-service revenue shortfall for the system), it incorporated various adjustments not ultimately adopted by the Board in that hearing, and it did not yet reflect the revenue impacts of rate changes approved in the 1998 hearing in the form of Rider J.

Implications of Adjustments after 1997

Rates today remain as set for 1997, subject only to the effects of Rider J (Faro mine closure rider) and Rider F (fuel cost adjustment rider). The most significant system adjustment since 1997 has been the closure of the Faro mine. In addition, fuel costs (which have approximately

[1] However, as a practical matter beyond Board approved rates, after rate relief funded by the Yukon Government for 1997, overall Residential Non-Government class bills would have covered approximately 73% of residential utility costs approved by the Board as set out in Table 1.

[2] The limited scope assessment in the 1998 filing (as provided for the Faro mine in Schedule 6D of Exhibit 83) compared to the 1996/97 GRA addressed a reduction in industrial loads at the Faro mine of 166,088 MW.h (from 180,000 MW.h forecast in the 1997 GRA), with a consequent reduction in industrial revenue of $13.728 million and a partially offsetting reduction in system costs (some of which the Board did not ultimately adopt).

doubled since the 1997 GRA numbers) and the completion of the Mayo-Dawson transmission facility are other significant changes.[3]

Overall, there is no reason to believe that these (or other) adjustments have reduced materially since the 1997 GRA the extent to which R/C ratios for the Residential Non-Government and General Service Government remain outside the 90:110% target range.

The closure of the Faro Mine in 1997 will impact on the cost of service studies for the consolidated Yukon system to result in the cost of service for each remaining customer class being adjusted to absorb a greater share of the Yukon's significant fixed costs for generation and transmission facilities. In response, Rider J has also increased the revenue to be collected from each remaining firm customer class. Under these circumstances, R/C ratios for customer classes would change only to the extent that the per cent rate and cost increases differ materially between customer classes.

- **Rate changes:** The rate change implemented in response to the Faro mine closure (Rider J) was implemented on an equal percentage basis to all customer classes. As a result, no material differential impact on revenue:cost ratios is expected from this rate change.

- **Changes in Allocated Costs:** No new cost of service allocation study has been performed based on the Faro closure in 1998. In 1993, when the Faro mine was previously closed, detailed cost of service information for each customer class for both Companies was presented to the Board for 1994 (Tab 5 of filings) with and without Faro mine electric power sales. The analysis demonstrated that closure of the Faro mine resulted in increased costs of service being assigned to each remaining customer class, with these cost increases ranging between 16 and 20 per cent (with Residential Non Government at the lower end of this range and Government Commercial at the higher end of this range). There is no reason to expect that the cost allocation impacts of the Faro mine closure in 1998 to be materially different from the closure in 1993. As a result, the closure of the Faro mine in 1998 was likely generally neutral to revenue:cost ratios.

On balance, no major R/C ratio changes are anticipated to result from the closure of the Faro mine for the two classes that were outside the target 90%-100% R/C range in the most recent cost of service study (1996/97 GRA analysis for 1997).

[3] Rate relief has also been adjusted during this period to in effect ensure that most Residential Non Government customers have not paid for rate increases (Rider J or F) that exceed 9% over their charges (after rate relief) in January 1997. For a Residential Non Government customer using 1,000 kW.h in a month, the effective bill ceiling after GST is $105.87 per month. For this same customer the bill without rate relief would approximate $141 per month with the Rider J and Rider F levels in place in spring 2005.

YUKON ENERGY

JUN 2 4 1996

YUKON ENERGY CORPORATION
#304 - 204 LAMBERT ST.
WHITEHORSE
YUKON Y1A 1Z4
Telephone (403) 667-5028
FAX (403) 668-3327

Our File: 2/825-00

Exhibit 206

June 19, 1996

Yukon Utilities Board
#19, 10014 - 1st Avenue
P.O. Box 6070
Whitehorse, Yukon Y1A 5L7

Attention: Mr. Brian Morris, Chair

Dear Sir:

RE: YEC/YECL 1996/1997 GENERAL RATE APPLICATION - BOARD ORDER 1996-7

Pursuant to Board Decision 1996-7 the Companies enclose herewith, for approval, tariff schedules in compliance with the Board's order. The attached Rate Design document also provides detailed supporting text and working tables that explain how the tariffs have been developed.

We have taken the liberty of alerting the Board's staff to this filing as it is the hope of the Companies to implement the approved rates on July 1, 1996. In order for us to achieve this target, it does require approval from the Board on or before June 24, 1996.

As the circumstances of the 1996/97 Rate Application were somewhat varied from previous applications in that the Board declined to allow the Companies to inaugurate interim refundable rates as of January 1, 1996, we have a unique situation to address. Riders are required to collect or refund amounts that various rate classes have underpaid or overpaid during the period January 1, 1996 to June 30, 1996. Details are set out in the attached Rate Design document.

Decision 1996-7 directed the Companies to design a rate shift program that would target revenue/cost ratios in the range of 90% - 110% over a 10 year period. The proposed tariff schedules for 1996 and 1997 will result in most classes falling within this target range throughout the next two years.

.../2

Further progress will be pursued after 1997 in moving Residential Non-Government and Government General Service ratios within the target ranges directed by the Board, subject to OIC directives relating to rate relief. The Companies will need time in future to consider options with respect to moving all ratios over the next ten years into the Board's target range.

If the Board or its staff have any questions, please contact Brian Milne at 633-7009.

Yours very truly,

YUKON ENERGY CORPORATION

William E. Byers, Q.C.
President

THE YUKON ELECTRICAL COMPANY LIMITED

C. Harvey Kerslake, P.Eng.
Vice-President and General Manager

/dm
c Barry McKinlay, Manager Rates & Finance - Electrical, BCUC (By Fax: (604) 660-1102)

C:\DATA\BILL\2808-LTR.DOC/6/19/96

2.2 Revenue to Cost Ratios

The Companies have recalculated the cost of service for each rate class in 1996 and 1997 to reflect the adjusted revenue requirements. Based on Decision 1996-7, the Companies have retained the cost of service methodology set out in the initial filing. OIC 1995/90 requires that rates charged to the industrial rate class must be sufficient to cover its cost of service. Decision 1996-7 directed that the residential revenue to cost ratio in 1997 be at least 80%, which was expected to occur without any changes to the non-government residential rates prior to elimination of government rate relief. The Companies were also directed to design a rate shift program that would target revenue to cost ratios in the range of 90% to 110% over a ten year period.

Based on the above considerations, the following is a summary of the existing and proposed revenue to cost ratios for each class (see Schedules B and C):

	Revenue/Cost Ratio		
Rate Class	Existing	Proposed 1996	Proposed 1997
Residential Government	102%	100%	100%
Residential Non Government *	84%	84%	81%
General Service Government	159%	133%	143%
General Service Municipal	137%	110%	110%
General Service Non Government **	137%	110%	110%
Industrial	87%	100%	100%
Street Lights	159%	110%	110%
Space Lights	123%	110%	110%

* In 1996, bill/cost ratio on average equals 72% after rate relief. In 1997, if the present rate relief program was fully retained, this ratio would equal 70% (the future of the present rate relief program beyond 1996 has not yet been determined).

** In 1996, bill/cost ratio on average equals 120% after rate relief at existing rates, proposed rate reductions remove rate relief for this class.

The industrial class revenue to cost ratio complies with OIC 1995/90 for each year. Residential non-government exceeds 80% in each test year without any material rate change at this time, as directed by Decision 1996-7. All other classes, except for General Service Government, have revenue to cost ratios for each year that will be within the target range directed by the Board. A reduction, toward the target, has also been achieved in the Government General Service ratio.

Yukon Energy Corporation
The Yukon Electrical Company Limited
1996/97 GRA Refile
Comparision of Costs and Revenues
1997

Costs and Revenues at Existing Rates	Forecast Costs ($000)	Forecast Revenue ($000)	Revenue / Cost Ratio (%)	Surplus/ (Shortfall) ($000)
Residential - Government	644.5	628.7	97.55%	(15.8)
Residential - Non Government	17,177.7	13,831.3	80.52%	(3,346.4)
General Service - Government	5,585.9	8,598.3	153.93%	3,012.4
General Service - Non Government	8,664.9	11,419.6	131.79%	2,754.8
Industrial	14,421.2	12,913.7	89.55%	(1,507.6)
Street Lights	537.3	829.1	154.32%	291.8
Space Lights	150.4	166.3	110.54%	15.9
Total Allocated Cost/ Revenue	47,181.8	48,386.9	102.55%	1,205.1
85% of WAF cost not allocated to Industrial	563.8	563.8	100.00%	0.0
Total Industrial	14,985.1	13,477.5	89.94%	(1,507.6)
Must be included in rate design				
Total Cost / Revenue	47,745.7	48,950.7		1,205.1
Costs and Proposed Revenues				
Residential - Government	644.5	644.5	100.00%	0.0
Residential - Non Government	17,177.7	13,831.3	80.52%	(3,346.4)
General Service - Government	5,585.9	7,999.0	143.20%	2,413.1
General Service - Non Government	8,664.9	9,531.3	110.00%	866.5
Industrial	14,421.2	14,421.2	100.00%	0.0
Street Lights	537.3	591.0	110.00%	53.7
Space Lights	150.4	165.5	110.00%	15.0
Total Allocated Cost/Revenue	47,181.8	47,183.8	100.00%	2.0
85% of WAF cost not allocated to Industrial	563.8	563.8	100.00%	0.0
Total Industrial	14,985.1	14,985.1	100.00%	0.0
Must be included in rate design				
Total Cost / Revenue	47,745.7	47,747.6		2.0
Forecast Growth in Unbilled Revenue		104.4		104.4
Costs and Revenues At Proposed Rates Considering Unbilled				
Residential - Government	644.5	641.9	99.60%	(2.6)
Residential - Non Government	17,177.7	13,776.5	80.20%	(3,401.2)
General Service - Government	5,585.9	7,978.2	142.83%	2,392.4
General Service - Non Government	8,664.9	9,506.7	109.72%	841.8
Industrial	14,421.2	14,419.7	99.99%	(1.6)
Street Lights	537.3	590.9	109.98%	53.6
Space Lights	150.4	165.4	109.98%	15.0
Total Allocated Cost/ Revenue	47,181.8	47,079.4	99.78%	(102.5)
85% of WAF cost not allocated to Industrial	563.8	563.8	100.00%	0.0
Total Industrial	14,985.1	14,983.5	99.99%	(1.6)
Must be included in rate design				
Total Cost / Revenue	47,745.7	47,643.2		(102.5)

YUKON ENERGY

The Yukon Electrical Company Limited
An ATCO Company

October 27, 2005

Mr. Brian Morris
Yukon Utilities Board
19-1114 First Avenue
Whitehorse, YT
Y1A 1A3

Mr. Morris,

RE: Joint Submission regarding the Most Recent Cost of Service per Order 2005-1

The Companies have received responses to the August 24, 2005 Report on the Most Recent Cost of Service Allocation Study from the Ad-Hoc Group of Businesses, Mr. McMahon and UCG. This reply addresses only the relevant matters raised in the submissions, organized using the same headings as the original YEC/YECL submission.

Most Recent Cost of Service Allocation Study

McMahon asserts at page 2 of his submission that "what was expected of the utilities was to take the 7 month period provided to rerun the existing cost allocation study using the most up to date cost and revenue information available to the utilities". This is incorrect. As noted in the Companies submission the Board direction in this regard in Order 2005-1 was as follows:

> "The Board requires the Companies to jointly file a report by Thursday September 1, 2005, that provides information on the revenue to cost ratios by customer class for both Companies utilizing the most recent cost of service allocation study."

The Companies provided the requested information utilizing the most recent Cost of Service Study which was from the 1996/97 GRA.

Companies' views on whether an updated study should be undertaken today

Further contrary to the McMahon's submission that the Board expected a new or rerun cost allocation study, Order 2005-1 explicitly asked the Companies "to provide their

views on whether an updated cost of service allocation study should be undertaken or if a rate shift proposal can be made based on the most recent cost of service allocation study."

On page two of the joint submission, the utilities made two points very clearly: 1) that there is no need for an updated cost of service study today to allow a rate shift proposal to be undertaken if so desired by the Board, and 2) that there are practical impediments to conducting a cost of service study in the near term.

On the matter of the need for the study now, the Companies submitted that no new cost of service study is required today to begin a rate shift program to target a 90-110% revenue to cost ratio range, as there is ample evidence that any such rate shift program simply needs to start with raising Non-Government Residential rates and lowering Government General Service rates. Also there is ample evidence that it will take a number of years of such adjustments (due to practical limitations of rate shock) before these classes will approach the 90-110% range. A cost of service allocation study will not be required until many years after the rate shift begins (i.e., until the ultimate range is being approached).

On the matter of impediments to conducting a study today, the companies were very clear in stating "A fundamental requirement to any rate shift program is the need for revenue requirement and billing determinants to be established for both companies for the same test period." This has clearly not yet happened. In the Companies' submission, the first step remains the review and approval of both Companies' revenue requirements prior to any attempt at providing an updated Yukon cost of service allocation study.

Mr. McMahon states that YECL's "annual report of its most recent year of operations" would "certainly be backed up by enough cost and revenue detail to be able to update the YECL-related data in the cost allocation study". He further states that actual utility results inserted into the historical cost allocation study for YECL and YEC for 2002, 2003 and 2004 would provide a better understanding of any movement in costs and revenues over the last few years. This is incorrect and entirely irrelevant to the issue at hand. Aside from the clear need to establish revenue requirements established by the Board, it is important to note that the actual results produced by the utilities do not include the types of load data regarding coincident and non-coincident demand by rate class and detailed billing determinants required for cost of service analysis. The preparation and determination of this specialized data is only performed as part of the rate design component of a General Rate Application.

Issues to be addressed with respect to a rate shift proposal

In relation to the Companies' comments on the issue of rate relief and its relevance to the cost of service debate McMahon asserts that "As the Board has determined in past decisions, it is not the Board's role to worry about rate relief since this is a matter of public policy".

McMahon's assertion is not supported by the evidence[1]. Firstly, it is not clear what past decisions McMahon is referencing. The Companies' outlined in their submission various quotes from the Board's 1996/97 GRA Decision that demonstrated that the Board was clearly aware of and considering the impacts of rate relief in its decisions. The Companies also noted that the Board need be aware that, given the degree of rate relief in place today, implementation of a rate shift program that raises Residential Non-Government rates but not the underlying bills will only exacerbate the potential for "bill shock" for customers in the event that the RSF is materially redesigned or terminated in future. The Companies reiterate that it does not appear to be in customers' interests to increase their exposure to this financial shock.

Issues to be addressed with respect to any new cost of service study

A number of other issues are mentioned in the intervenor submissions that require comment:

- UCG indicates that cost information is required "for each community by each ratepayer group". However, rates in Yukon are required to be set based on the territory as a single zone, pursuant to OIC 1995/90. Accordingly, there is no relevance nor benefit to rate setting from analyzing cost-of-service on a community-specific basis.

- McMahon suggests that implementation of a rate shift program should include consideration of "customer mitigation measures" such as a levelized or equal billing program, paying deposits in installments and promoting conservation and demand management initiatives. Although all these topics are relevant to utility regulation, none have any relevance to cost-of-service.

- McMahon asserts that "what may be needed is for an independent body (such as the BCUC)" to do a cost-of-service study and design a rate shift program. Such an approach would be entirely inconsistent with normal regulatory principles. It is the utilities that are required to produce cost studies (as required by their regulator) to demonstrate that their rates are just and reasonable. The Board has asked for and now received the Companies' comments. The Companies believe there is no need for, nor would there be any real benefit from, conducting a cost-of-service study or a rate shift program in the near term. Accordingly the Companies submit that the Board should reject McMahon's suggestion. However, if the Board determines that a cost of service study should be undertaken after the determination of revenue requirements and load data for both utilities, the

[1] Also note that the Yukon Government Energy Commission, via Mr. McMahon, intervened in the 1998 hearing and argued that the Board should not adopt certain YEC rate proposals due to the Yukon Government preparing to implement a new program (ultimately the RSF). The Board quoted Mr. McMahon in its Order 1998-5 in deciding not to implement the YEC rate proposals. It is clear that Mr. McMahon and the Board at that time saw it as relevant to the YUB to consider YTG rate relief programs when considering rate issues.

Companies will comply and produce any such reports or recommendations as the Board requires.

Yours truly,

David Morrison
President & CEO
Yukon Energy Corporation

Doug Tenney
General Manager
Yukon Electrical Company Ltd.

REFERENCE: **Application, Page 6-2**

QUESTION:

a) Based on the claims and counter claims, was YEC required to make further payments? If so where were the payments recorded? Where were legal fees associated with the process recorded?

ANSWER:

(a)

As a result of the negotiated settlement, YEC was required to pay $3 million to Chant Construction. This amount was paid by YDC on YEC's behalf. As well, YEC was required to release $263,813, representing funds held in trust for settlement of an insurance claim that occurred during construction. There was no net impact on YEC's income statement.

Legal expense associated with the defense of these claims is recorded as a regulatory loss on financial statements and, by direction of the YUB, is excluded from calculations of revenue requirement and regulatory results.

REFERENCE: Application, Page 6-4

OIC 2007/94 in effect defers, until after December 31, 2012, any cost of service based rate rebalancing adjustments or rate shifts affecting major industrial customers. It is noted as well that non-government residential customers are currently experiencing major bill increases due to the phasing out of the Yukon Government's Rate Stabilization Fund subsidies over the period July 2007 through July 2009, and that these changes seriously constrain the extent in the near term to which rate shift program changes could proceed to increase residential revenue to cost ratios.

QUESTION:

a) Without a COS study, how does YEC know, given the significant changes in Yukon since the last COS study, the potential direction of any rate shift changes?

b) In YEC's opinion, does a Phase II proceeding include more that rate design?

c) Without compliance of a COS study, what comfort does YEC have that Rate 35 appropriately covers its costs?

d) Without the direction of the COS study being completed, should the Board allow the continuance of Rate Schedule 35?

ANSWER:

(a)

The 2005 Cost of Service Report filed with the Board by YEC and YECL (provided as Attachment 1 to YUB-YEC-1-23(a)) notes at pages 2-3 as follows:

> The most significant system adjustment since 1997 has been the closure of the Faro mine. In addition, fuel costs (which have approximately doubled since the 1997 GRA numbers) and the completion of the Mayo-Dawson transmission facility are other significant changes.

The joint YEC/YECL report notes at page 3 that, "on balance, no major R/C ratio changes are anticipated to result from the closure of the Faro mine for the two classes that were outside the target 90%-100% R/C range in the most recent cost of service study (1996/97 GRA analysis for 1997)."

At this time, no different conclusion is anticipated. In all likelihood, a full Cost of Service study today would reflect relatively similar RCC ratios (in terms of which classes are below versus above the Zone of Reasonableness) as existed in 1997.

(b)

In YEC's view, Yukon regulatory experience indicates that a General Rate Application, as filed in the 1990s, in full addresses Revenue Requirements, Cost of Service, Rate Design, Electrical Service Regulations, and other issues as appropriate. It is not, however, required to deal with each of these issues at every GRA in the event there is no relevance to the topic or to the requested orders.

The concept of separate Phase I versus Phase II hearings has not been applied in Yukon in YEC's period before the YUB. There is no precedent in Yukon where the utilities have actually had a so called separate "Phase II" hearing. All COS and rate design matters relating to a GRA have been dealt with in one hearing. Given the desire to maintain regulatory costs at a level commensurate with the size of the jurisdiction and the number of ratepayers who must incur the costs, in YEC's view this distinction should be viewed as being of limited value if it means every GRA from here forward will require two or more hearings.

(c) and **(d)**

As noted in response to YUB-YEC-1-19 (b) and (c) secondary sales rates in Yukon are not cost-based but are instead based on value for service. Accordingly, the YUB has not previously sought to assess secondary sales rates such as Rate Schedule 32 based on any cost of service assessment – and the absence of such cost of service information has not prevented the Board to date from allowing the continuance of such rates. Similarly, given this essential difference between interruptible Rate Schedule 35 (with its ranking behind Rate Schedule 32 sales) and other non-interruptible retail rate schedules regulated by the YUB, the absence of a cost of service study would not prevent the Board from approving Rate Schedule 35. In any event, as noted in that response, YEC

and Minto must still develop the specific auditable reporting and control mechanisms required to be reviewed by the Board prior to the final approval of the rate.

REFERENCE: **Application, Page 6-6**

QUESTION:

a) Does YEC believe that Electric Service Regulations or Terms and Conditions of Service are a Phase II matter?

ANSWER:

(a)

YEC believes that ESRs and/or Terms and Conditions of Service are part of a full GRA review, although such matters are not always addressed in each GRA. However, the concept of separate Phase I versus Phase II hearings has not been applied in Yukon in YEC's period before the YUB. There is no precedent in Yukon where the utilities have actually had a so called separate "Phase II" hearing. All relevant matters have been dealt with in one hearing. Given the desire to maintain regulatory costs at a level commensurate with the size of the jurisdiction and the number of ratepayers who must incur the costs, YEC believes that it is highly preferred to address all relevant GRA matters in the same hearing.

Please also see response to YUB-YEC-1-25(b).

REFERENCE: **Report to Commissioner in Executive Council: Yukon Energy Corporation 20-Year Resource Plan**

QUESTION:

a) Subsequent to the 20-Year Resource Plan, has anything caused the status of the Marsh Lake storage project to change?

b) What is the current status and timing of the Aishihik Third Turbine project?

c) What steps has YEC taken with respect to the development of an Independent Power Producers policy?

ANSWER:

(a)

Yes.

Yukon Energy has undertaken studies to confirm the hydrology related to Marsh Lake water levels, and the Yukon Government has completed a Flood Assessment and Abatement Study.

Marsh Lake storage continues to be an attractive resource option, in the event it can be completed without any significant adverse effects on the local residents.

(b)

The Aishihik Third Turbine project is proceeding for an in-service in 2010.

(c)

The development of an Independent Power Producer's policy is being addressed by the Yukon Government as part of the recently released "Energy Strategy for Yukon".

REFERENCE: YEC Application, Page 1-7

In 2005, surplus hydro generation on WAF prior to secondary (interruptible) sales approximated 90 GWh/yr at normal flows; absent new industrial loads, some surplus hydro was forecast to remain at normal flows on both the WAF and Mayo-Dawson ("MD") grids until at least around 2020.

PREAMBLE:

The Board needs to get an understanding of surplus hydro generation.

QUESTION:

a) Please provide load duration curves for the Whitehorse hydro plant for the period 2005 to 2007.

b) Please provide load duration curves for the Aishihik hydro plant for the period 2005 to 2007.

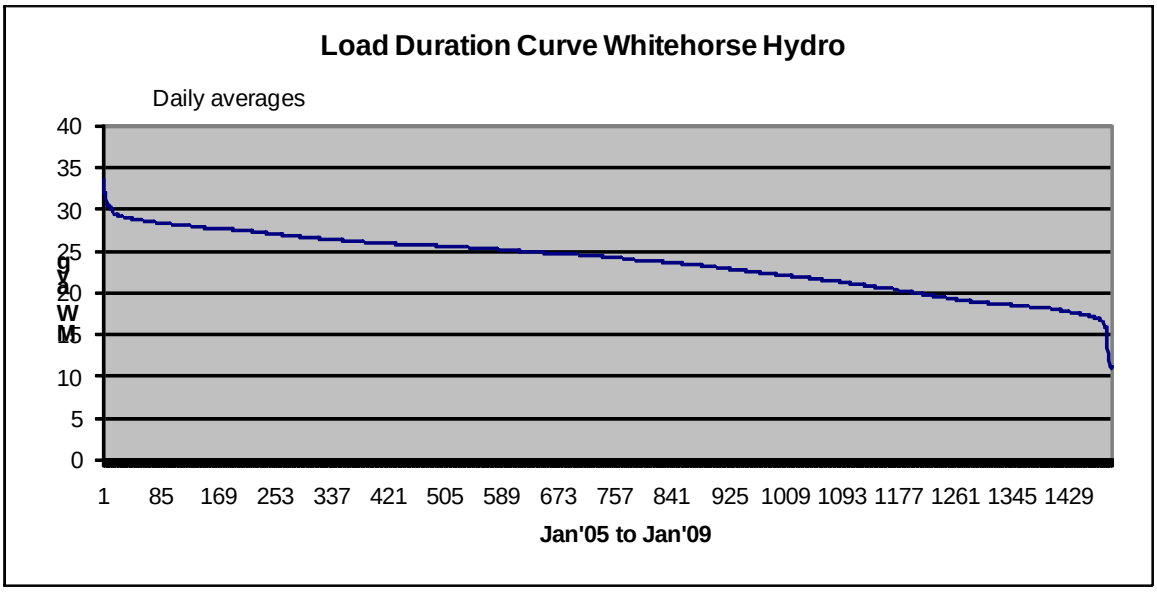
c) Please provide total hydro load duration curves on the WAF grid for the period 2005 to 2007.

d) Please provide total diesel load duration curves on the WAF grid for the period 2005 to 2007

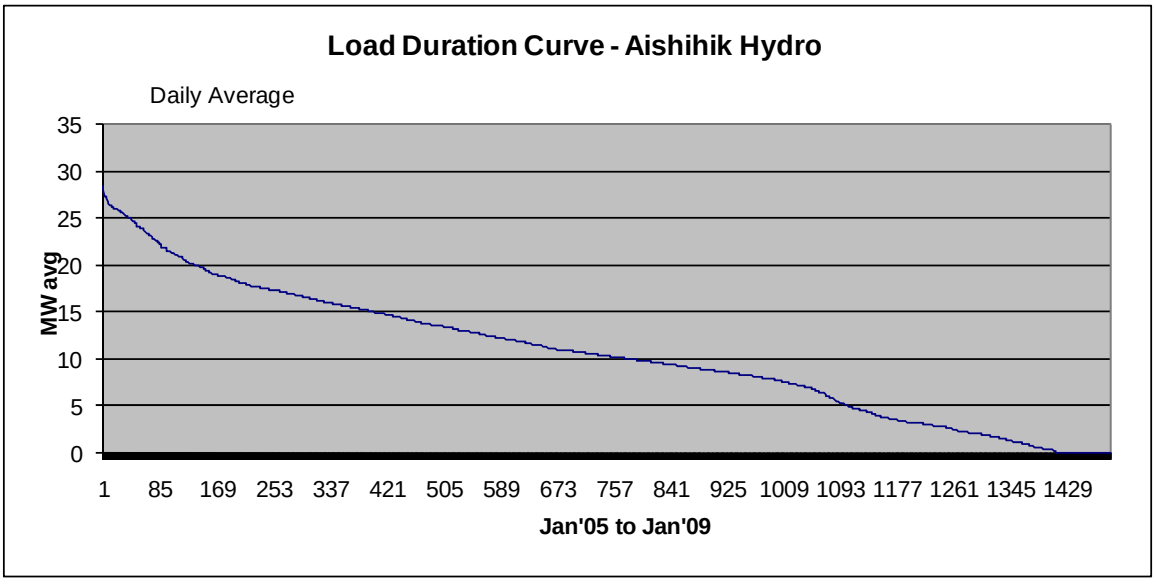
ANSWER:

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

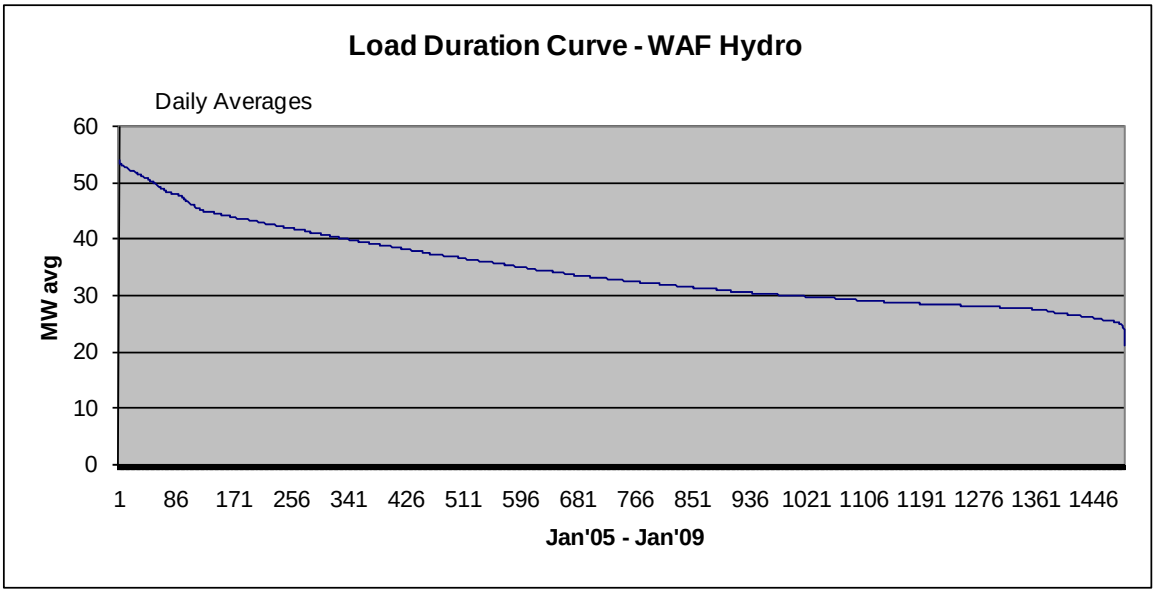
The load duration curve showing daily average generation from Whitehorse, Aishihik, diesel and total WAF load are provided below for the actual period January 2005 to January 2009.


Load Duration Curve Whitehorse Hydro
Daily averages
MW avg
40
35
30
25
20
15
10
5
0
1
85
169
253
337
421
505
589
673
757
841
925
1009
1093
1177
1261
1345
1429
Jan'05 to Jan'09

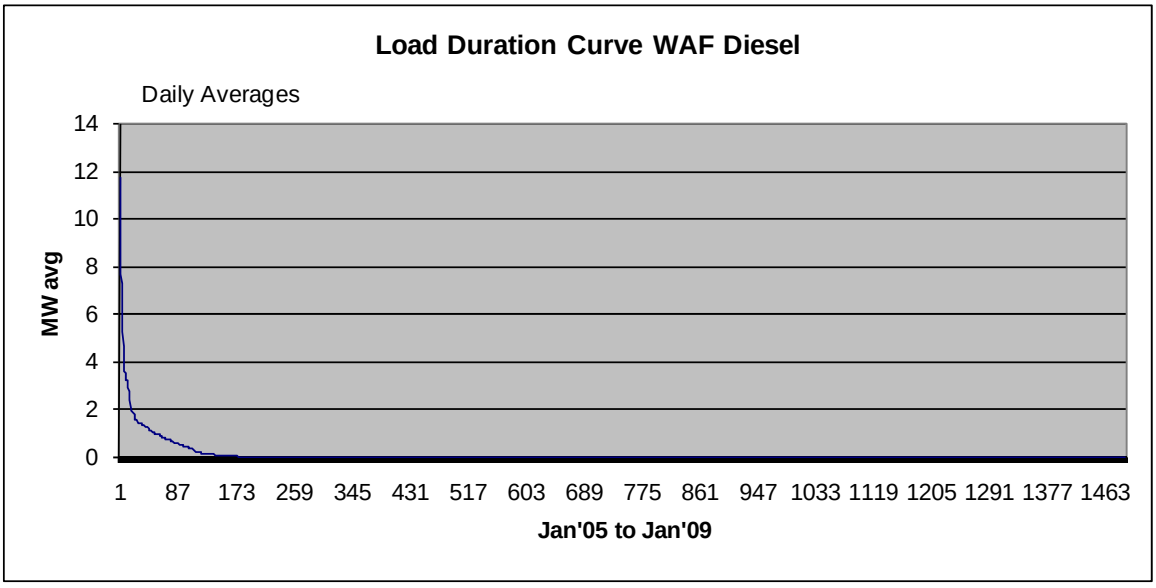
1
2


Load Duration Curve - Aishihik Hydro
Daily Average
MW avg
35
30
25
20
15
10
5
0
1
85
169
253
337
421
505
589
673
757
841
925
1009
1093
1177
1261
1345
1429
Jan'05 to Jan'09

3


Load Duration Curve - WAF Hydro
Daily Averages
MW avg
60
50
40
30
20
10
0
1 86 171 256 341 426 511 596 681 766 851 936 1021 1106 1191 1276 1361 1446
Jan'05 - Jan'09

1
2


Load Duration Curve WAF Diesel
Daily Averages
MW avg
14
12
10
8
6
4
2
0
1 87 173 259 345 431 517 603 689 775 861 947 1033 1119 1205 1291 1377 1463
Jan'05 to Jan'09

3

REFERENCE: YEC GRA Application, Page 1-8

Forecast oil prices for 2009 are materially above levels approved for the 2005 Yukon Energy revenue requirement. Higher oil prices increase test year overall Yukon power system costs to the extent that diesel generation is required in 2009, and highlight the potential importance of timely new renewable resource generation development to minimize any renewed requirements for baseload diesel generation on the WAF and MD grids.

PREAMBLE:

The Board wishes to understand the implications of the above statement.

QUESTION:

a) Considering that fuel prices have dropped significantly, does YEC wish to update its fuel-price forecast for the test period?

ANSWER:

(a)

YEC is not seeking to update its fuel price forecast at this time.

According to past practice, the proposed Application was filed using the best information available at the time. Fuel prices have been volatile since 2008 and are likely to remain uncertain for the future. Within the GRA process, the forecast is typically retained as filed with any subsequent adjustments made, as required, through the Rider F process.

REFERENCE: YEC GRA Application, Page 2-2

Yukon Energy hydro generation capability materially exceeded firm sales on both the WAF and Mayo systems after the Faro mine closure in 1998 on WAF and the 1989 closure of the United Keno Hill Mine (UKHM) on the MD system. However, given continued load growth on the WAF system, including new industrial load once grid service to Minto commences in October 2008, WAF surplus generation will have declined markedly by 2009 …

QUESTION:

a) Please provide annual hydro-capacity utilization percentages for the period 1998 to 2008.

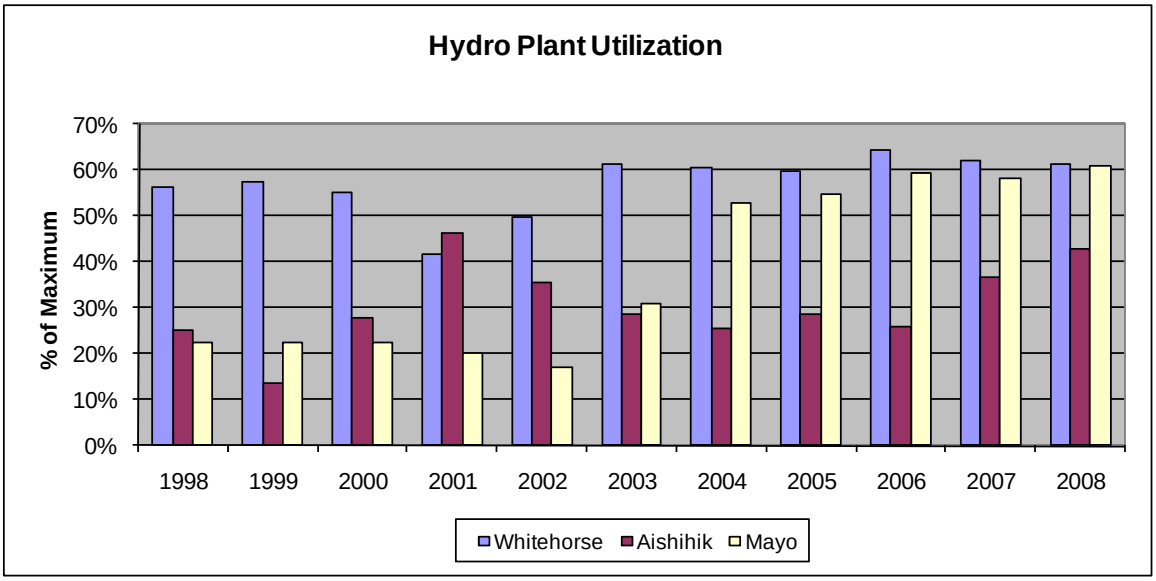
b) With respect to water availability, have drought conditions occurred over the period 1998 to 2008?

c) Considering that "… the forecast for the test years is based on continued ability to supply nearly the entire test generation forecast on both the WAF and MD grids from hydraulic generation (other than for "peaking" requirements):
   i. Describe in detail YEC's hydro plant maintenance programs.
   ii. During the forecast period, is any one hydro unit on the WAF or MD grids expected to be down for an extended or planned maintenance outage period?
   iii. Provide a detailed description of YEC's contingency plan should an extended and unplanned outage occur affecting one of its hydro units.
   iv. Please provide an explanation as to what is meant by the phrase "long-term average capability" of the installed hydraulic generation.

ANSWER:

(a)

Please see chart provided below.



Hydro Utilization is the ratio of the actual annual generation produced for a hydro unit divided by the generation that the unit could have produced if it were run at its rated capacity for the entire year, allowing, in YEC's case, for an average 3 % forced outage rate.

(b)

The lowest inflow year on record for the Aishihik system occurred in 1998, and the calendar year of 1998 would be termed a "drought" for the Aishihik drainage basin. The November 1, 1998 level on Aishihik was lower than the May 1 spring level by 6mm.

(c)

i. Each generator is taken down for a period of time each year. Maintenance issues are accumulated over the year of operation and a scope and schedule of work is developed for each unit. The duration of these outages varies dependent on the work to be done. Major outages occur every 8-10 years, or if other projects are planned that require extended outages. These projects would include runner replacements or bearing changes.

ii. The Aishihik plant will be down for an extended outage in 2009 for work that is part of the Aishihik 3rd Turbine project. It is expected the outage will be in

June or July. A detailed work plan has not been developed for this yet so no dates or duration have been established.

iii. YEC uses an N-1 criteria for backup generation availability, i.e., adequate generation from other sources must be available in the case of the largest impact failure on the system. In the case of the WAF grid it is loss of the Aishihik Generating Station or loss of L172 (30 MW in either case). YEC keeps sufficient diesel generation available to replace this level of loss of hydro generation. For the Mayo-Dawson grid, loss of the Mayo hydro plant is the largest possible and similar to the WAF grid, sufficient diesel is available to replace it.

iv. The phrase is meant to reflect that hydro generation capability depends on water flows (precipitation). A long-term average is used to take into account the variability in hydro generation capability due to variation in water availability.

REFERENCE: **YEC Application**

QUESTION:

a) Please provide annual numbers by unit that form the basis of YEC's long-term average hydro generation capability (WAF grid), as estimated in the 1996-97 GRA and updated to include the period 1998 to 2008.

b) Please describe what YEC terms as "extreme drought conditions". What are the probabilities of such an event occurring?

c) Considering that a) sustained base-loaded diesel generation units have average fuel efficiencies greater than diesel generation units that are used as peak shavers, and the current level of fuel prices, would YEC consider base-loading diesel generation as was done in the mid-1990s? Please explain.

ANSWER:

(a)

The actual annual energy production from each WAF Hydro Plant since 1998 is provided in the table below:

WAF Hydro Production 1998-2008

Year	Whitehorse Hydro Generation (GWh's)	Aishihik Hydro Generation (GWh's)	WAF Hydro Generation (GWh's)
1998	190.4	63.4	253.8
1999	194.7	38.4	233.1
2000	186.7	56.3	243.0
2001	141.1	107.4	248.6
2002	169.2	86.1	255.3
2003	208.3	61.4	269.7
2004	205.9	71.0	276.9
2005	202.0	80.7	282.6
2006	216.9	80.4	297.3
2007	206.4	98.1	304.5
2008	207.5	107.3	314.8
11-Year Average	193.6	77.3	270.9

The hydro facilities have generated during these years less than their long term average capability by an average of 80.2 GW.h per year over this 11-year span reflects the fact that this supply hydro exceeded actual firm and secondary energy sales and losses over this period.

Yukon Energy's annual numbers by unit or plant indicate generation that occurred based on load, water flows and unit availability. On WAF, Whitehorse unit peak capability occurs during summer and fall (peak water flows and spills) with greatly reduced capability during winter and early spring; in contrast, Aishihik unit peak capability is planned to occur during winter months and minimal generation normally planned during summer months. On Mayo-Dawson, the Mayo unit capability tends to reflect year round water flow availability.

Actual hydro unit generation in any year on WAF or Mayo-Dawson can be [and has been during many of the years since 1998] severely reduced due to reduced loads, i.e., due to factors unrelated to long-term average hydro generation at a higher system load level.

Yukon Energy's long-term average hydro estimate at the time of the 1996/97 GRA, given the load levels then being experienced, was 351 GW.h comprised of 105 GW.h for Aishihik and 246 GW.h for Whitehorse Rapids. The 1996/97 GRA long term average hydro energy capabilities were defined as follows on page 2-10 of that application:[1]

- Whitehorse Hydro Facility at 246.3 GWh per year and

- Aishihik Hydro Facility at 104.8 GWh per year

This resulted with a YEC WAF Hydro average generation capability of 351.1 GWh excluding the energy output from YECL's Fish Lake Hydro Facility. The average hydro generation capability was not broken down to individual units as there is flexibility in which units are run to meet specific load requirements and planned outages.

The only update to the 351 GWH value determined during the 1996/97 GRA was during the assessment of the Aishihik Water Licence renewal process, in which it was estimated (using hydrology models) that the terms of the new Aishihik Water Licence

[1] The period of record for the 1996/97 long term average hydro capability numbers used was 1976 to 1995.

would reduce the long-term average capability of this system by 3-6 GW.h depending on the terms of the Fish Act Authorization in effect at any given point in time.

These values are presently being updated as part of ongoing Resource Planning exercises, with the assistance of new system models. The long-term average capability is highly dependent on the loads on the system, and as such will vary under different future load conditions.

Hydro generation forecasts for the Application reflect that forecast loads are still below long-term average capability.

(b)

Yukon Energy noted the concept of “extreme drought conditions” in relation to secondary sales being curtailed during the test years. In this regard, LE-YEC-1-14 notes that even with 50% of average inflows at Aishihik sustained over a 1.5 year period, Yukon Energy would be able to continue secondary sales through the test year period.

The most extreme drought recorded at Aishihik was for 1998, when inflows were 36% of long-term average inflows for a 12 month period.

(c)

No, unless WAF load conditions were similar to those applicable in the mid-1990s, i.e., when diesel generation was on the margin throughout the year. Sustained baseload diesel generation was an efficient solution during the load conditions that prevailed in the mid-1990s.

The primary focus of system planning efforts and operational improvements at the present time is to minimize diesel use and undertake plans to avoid or minimize the need for diesel baseload generation. Units can only be run efficiently as “baseload” when they are relatively heavily loaded for sustained periods of time, which under current conditions results in more diesel generation than operations based on minimizing diesel generation.

REFERENCE: **Application, Tab 7 Schedule 8**

QUESTION:

a) Please detail what is included in “Trust Liability” and “Deferred revenue”.

ANSWER:

(a)

“Trust Liability” primarily includes Diesel Contingency Fund cash balance. Detailed explanation of Diesel Contingency Fund and how it functions are provided on page 9-11 of the Application. In forecast 2008 and 2009, the trust liability also includes scholarship funds and insurance proceeds held on behalf of others.

“Deferred revenue” includes amortized gain reserve on fire insurance proceeds received related to a fire at the Whitehorse Rapids Generating Station in 1997. As noted on page 9-11 of the Application, the gain is being amortized to income at the same rate as the replacement assets which approach was approved by the Board in Board Order 2000-3.

REFERENCE: **Application, Page 5-7**

QUESTION:

a) Does YEC consider a 161% increase in the cost for the Minto Spur acceptable?

b) What processes or reviews has YEC undertaken to prevent such low estimates from happening in the future?

c) Will the cost for the Minto Spur be subject to an audit from the federal government?

ANSWER:

(a)

The estimated cost of $3.83 million was prepared in the fall of 2006 as an input to the Power Purchase Agreement (PPA) negotiations and the basis for this amount was provided in the YUB review of the PPA in early 2007.

The Minto Spur project is a 27 km 25kV Spur Line from Minto Landing to Minto Mine, including a crossing of the Yukon River and substations as needed at Minto Landing and Mine Site.

The line cost estimate was prepared by YEC internal engineers after discussions with contractors and consulting engineers on recent experience. Based on these discussions, it was determined that a reasonable estimate of cost in 2005 dollars was $3.421 million. This was based on the following:

- $0.085 million/km for line construction times 27 km (clearing etc all included beyond planning); plus

- extra of $0.900 million for 350m Yukon River Crossing; plus

- allowance of $0.500 million for substation costs; plus

- 10% on all of the above for planning costs.

To arrive at 2008 in-service dollars, this estimate was escalated by 11.9%. This increased the estimate to $3.828 million. The escalation assumed the following:

- 2.5% inflation in 2006 and 3.0% in 2007.
- 6.0% escalation for interest during construction and further escalation.

Breaking out final ISD costs for comparison, the above break down roughly to:

- $2.93 million line construction
- $0.56 million for substation
- $0.35 million for planning

This estimate was provided to Minto Explorations as part of the PPA negotiations. Minto completed its own due diligence process and accepted this amount as reasonable.

At this point in the process, no engineering had been completed. Design engineers started in approximately March 2007, with updated estimates to the Board of Directors in June 2007. At this point the revised estimate for the Spur was $7.67 million determined as follows:

- Substation construction costs now $2.18 million (excluding project management and other owner costs;
- Line construction increased to $3.78 million;
- $0.960 million other owner costs during construction; and
- $0.760 for planning cost allocation.

At the September 2007 Board of Directors meeting, this estimate had increased to $8.8 million. This amount was based on tendered costs for most major components (excluding substations). The construction decision was based on this figure, not $3.83

million. Updated economics assessments confirmed that even with the final cost number, the project still yields Minto material cost savings over its life.

There were essentially two key contributing factors to this result:

(1) Line construction costs: At the time of the early estimates, it was assumed the cost of the spur line would be materially less per kilometer to construct than the higher-voltage main line.

(2) Substation costs: Engineered costs and costs of building in remote areas contributed to materially higher costs.

(b)

Yukon Energy intends to build on its experiences on the CS Stage 1 project to better ensure the accuracy of cost estimates in the future. This includes undertaking more analysis in initial estimates (pre-engineering) based on Yukon-specific experience. Of critical importance is the need to have detailed engineering and, where possible, contractor tenders included in estimates.

(c)

No. The costs of the Minto Spur will be subject to normal audit procedures conducted by the Office of the Auditor General as part of the annual audit process. YEC is not aware of any special audit process for this project at this time.