UTILITIES CONSUMER GROUP
(UCG)

REFERENCE: **Yukon Energy Corporation Profile (YEC Web Site), Mission Statement**

QUESTION:

According to its Mission statement, YEC undertakes a number of things including:

- "to be responsive to our customers and their changing needs and expectations"; and

- "to place priority on the fundamentals; that is, safe and reliable electrical services"

a) Please provide YEC's understanding of the expectations of its customers with respect to the affordability of electricity and customer expectations of what YEC should be doing to reduce electricity bills paid by Yukon ratepayers.

b) Please provide an analysis of YEC's 2005, 2006, 2007, 2008 and 2009 (forecast) operating and capital expenditures which identifies the amount and percentage of overall expenditures made on safety and reliability of service.

c) Please provide details of the planned and unplanned outages that have occurred in the Yukon in 2005, 2006, 2007 and 2008. This analysis should include but not be limited to duration of outages, the number of electricity consumers impacted and specifics on how much diesel generation (and its cost) was required to be provided to make up for lost hydro generated electricity.

d) Please provide details of any service reliability criteria that YEC uses as a policy guideline.

ANSWER:

(a)

Although Yukon Energy does not have direct survey information on overall "customer expectations" Yukon Energy's mission is to "provide a sufficient supply of safe, reliable electricity and related energy services to customers throughout the Yukon, while

following sound business practices and demonstrating leadership in protecting the environment".[1] To achieve these goals Yukon Energy must balance varying interests and concerns including the following points noted in Yukon Energy's mission statement:

- Be responsive to our customers and their changing needs and expectations;
- Commit to the safety and development of our employees;
- Be cost-effective in the utilization and investment of resources, always remembering that we are spending the customer's money and making long-term decisions;
- Place priority on the fundamentals; that is, safe and reliable electrical services;
- Demonstrate the value of Yukon-based public ownership and management;
- Act ethically and honestly treating employees, customers and others with fairness, dignity and respect; and
- Build enduring relations with Yukon First Nations.

In the current Application, Yukon Energy is returning benefits to ratepayers achieved through the successful completion of Stage 1 of the Carmacks-Stewart Transmission Project. Due to the provision of service to Minto mine through the negotiated Power Purchase Agreement, Yukon Energy has been able to provide for overall rate reductions. In addition long term infrastructure benefits are also being realized with the provision of service to Pelly Crossing (formerly served by diesel) and the completion of the first stage of the connection of the MD and WAF grids systems, allowing surplus energy available from either system to be utilized where the energy is needed.

(b)

Maintenance expenditures are by their nature, focused on ensuring the reliability of our assets. Section 3.3 of the application, beginning on page 3-5, defines the amount of maintenance dollars spent on production, distribution, transmission, etc matters. Safety

[1] http://www.yukonenergy.ca/about/profile/

spending is included in the application as part of Administration in section 3.3.5 beginning on page 3-10.

The table below categorizes safety and reliability capital projects for all projects over $50,000 (as set out in Table 5.2) by major category and year ($000s).

	2005	2006	2007	2008	2009
Major Projects					
Safety					
Reliability			407	4,698	750
Remainder			5,502	33,631	3,500
Total	0	0	5,909	38,329	4,250
Transmission					
Safety					
Reliability	1,120	689	340	50	870
Remainder					
Total	1,120	689	340	50	870
Distribution					
Safety		92			
Reliability			71	50	100
Remainder	1,167	486	236	575	575
Total	1,167	578	307	625	675
Generation					
Safety					
Reliability	440	1,743	1,430	823	639
Remainder					100
Total	440	1,743	1,430	823	739
General Plant & Equipment					
Safety	66	100	76	50	165
Reliability	779	962	763	909	902
Remainder	282	429	595	569	856
Total	1,127	1,491	1,434	1,528	1,923
Overall					
Safety %	2%	4%	1%	0%	2%
Reliability %	61%	75%	32%	16%	39%

(c)

Please see response to PWP/HML-YEC-1-13.

(d)

YEC does not use service reliability criteria as a policy guideline.

REFERENCE: October 6, 2008 Application, Page 3

YEC states "To promote economy and efficiency as directed by OIC 1995/90, Rider U rate reductions are therefore proposed (where feasible) only for first block rates".

REFERENCE: October 22, 2008 Letter from YEC to YUB

YEC states "Yukon Energy's interim rate proposals are directed at rate stability objectives, i.e., the Application seeks to implement one set of YEC-related rate adjustments for both 2008 and 2009 (starting with the interim rates), and to avoid use of across-the-board rate riders that are clearly not appropriate and contrary to current rate design requirements reflective of the 1996/97 GRA rate design structure as well as OIC 1995/90 rate directives**."**

QUESTION:

a) Please provide YEC's understanding of what is meant by "promote economy and efficiency" per OIC 1995/90.

b) Please explain YEC's proposal to use an across-the-board rider instead of establishing cost-based, rider-free base rates.

c) Please explain and illustrate the impact on base rates of eliminating each rider currently in use.

ANSWER:

(a)

YEC's understanding of "promote economy and efficiency" per OIC 1995/90 is drawn from the YUB's 1992 Report to the Commissioner in Executive Council, "Review of Cost of Service and Rates Charged to Electricity Customers in Yukon", as well as previous Board Orders (1993-7 and 1993-8 and 1996-7).

The 1992 Report provides at page 37, that "the board considers the efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decisions regarding the future and current use of electricity." In the report, the

Board recommended at page 40 that "the runout rates for all zones should be adjusted to reflect short-run incremental costs." In GRA applications approved by the Board since this report was produced, runout rates have been set based on the incremental cost of diesel generation in the respective rate zones.

(b)

Yukon Energy is not proposing to use an across-the-board rider. The net rate reduction is proposed to be implemented by way of Rider U, which is specific to each class so as to target only the first block energy sales.

Order-in-Council 2008/149 requires the Board to ensure that rate adjustments for retail customer classes apply equally, when measured as percentages. Thus, the rate reduction to be applied to retail customer classes through Rider U is applied to each rate class as an equal percentage reduction overall to the class. The implementation of Rider U is focused solely on the first block of consumption for each rate class.

(c)

Were each rider currently in use to be eliminated, base rates would need to be adjusted as required to provide for this lost revenue.

For instance, Rider J was established to recover a 1997 cost of service shortfall arising due to the closure of Faro mine. Rider J was not intended to be time limited nor to recover only the specific shortfall amounts. Were Rider J to be eliminated corresponding amounts would need to be recovered from the customer classes to which Rider J is currently applied. The specific adjustments to do this might vary, depending on the rate component for each class:

- Dealing with second block runoff rates, these would normally be set (increased in today's situation) per OIC 1995/90 to reflect the "economy and efficiency" requirements discussed above. This would normally be a first step in such a rate change process; accordingly, second block rates would not tend to be affected by removal of Rider J (although its removal would be taken into consideration if second block rates were being set lower than full "economy and efficiency" would otherwise stipulate). Increased second block rates would yield added revenue which might offset in part removal of Rider J.

- The balance of the class revenue requirement would then need to be collected through first block energy rates and any fixed charges (customer charge for residential and demand charge for general service). These billing components are already being charged for Rider J, which charge would now come off. The net impact of the overall change required would depend upon the extent to which added second block rates more than offset the removal of Rider J charges to second block rates, i.e., if the second block rate increase for a retail class more than offset the removal of Rider J charges to second block rates to that class, there would be room for an overall reduction to first block rate and/or fixed charges to that retail class.

- In light of OIC 2008/149, it would be necessary to ensure at this time that no change was made to the overall revenue to be collected from each retail rate class.

- Rider J does not affect Rate Schedule 39.

Similar considerations and approach would apply for removal of any other across-the-board percentage rider applicable to all firm retail billing components.

In contrast, Rider F (which is a charge per kWh applied to all energy sales) was established at the outset as a Deferral Fuel Price Account to capture variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA-approved fuel price. This rider would be required to continue per OIC 1995/90. However, at each GRA it is expected that “base rates” (the rate components reviewed above) would be adjusted to reflect the fuel price forecast for the GRA, and Rider F determination would restart from this new reference point. The relevant considerations for making such adjustments would basically be as set out above for removal of Rider J.

REFERENCE: October 6, 2008 Application, Page 3

YEC states "After all current riders, rebates and subsidies, but prior to GST, the net effects are as follows for retail residential and general service customer classes…"

QUESTION:

a) Please confirm that the impacts referenced are to the rates of YEC's customers and not to the rates of customers of Yukon Electrical Company Limited.

ANSWER:

(a)

Not confirmed. Pursuant to OIC 1995/90 (section 4(1)(b)) rates for each class of non-governmental retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers. The impacts noted are for all YEC and YECL customers throughout Yukon.

REFERENCE: October 6, 2008 Application, Page 4

YEC states "…in 2007, 84% of non-government residential monthly bills used no more than 1,300 kW.h".

QUESTION:

a) Please provide billing data used to determine this conclusion.

b) Please provide similar billing data and analysis for 2005, 2006 and 2008.

ANSWER:

(a)

For billing data used to determine the above, please refer to Table 4.11 of Tab 4 of the Application.

(b)

The table provided below provides billing data and analysis for 2005, 2006 and 2007.

Residential Non-Government

	2005	2006	2007
Average # of Customer Consuming <1,300 kW.h	11,191	10,336	11,240
Total # of Customers	13,035	12,146	13,340
%	86%	85%	84%

Note 1: "Number of Customers" = Average number of bills per month.
Note 2: 2008 data are not available.

REFERENCE: October 6, 2008 Application, Page 4

YEC states "With completion of CSTP Stage I and connection of the Minto mine, Yukon Energy's Whitehorse-Aishihik-Faro ("WAF") system is reaching a point where the material existing surplus hydro generation is becoming greatly diminished. Although sales of this surplus hydro at firm rates bring clear net benefits, evidenced by the rate reductions proposed in the Application, with ongoing load growth and expressed interest from other future industrial customers, the existing hydro generation is likely to be fully utilized within the next few years, necessitating new renewable supply sources in order to avoid reliance on high cost baseload diesel generation and the resulting GHG emissions issues."

QUESTION:

a) Please provide details of the dates of completion of the CSTP Stage 1 project and the connection of the Minto (Capstone) mine.

b) Please provide details of Minto billing data to date.

c) Please provide details of the "expressed interest from other future industrial customers" including anticipated load, timing of connection and location on system.

d) Please provide data which illustrates that "existing hydro generation is likely to be fully utilized within the next few years".

ANSWER:

(a)

Please see response to YUB-YEC-1-5, Commencement of Delivery as defined in the PPA occurred on November 22, 2008.

(b)

Please see response to PWP-YEC-1-16.

(c)

Please see response to CW-YEC-1-31(a).

(d)

Table 2.5 illustrates that hydro generation in 2009 is forecast at 340 GW.h, of which slightly less than 20 GW.h is serving secondary sales (including losses). Consequently, even with a total interruption of secondary sales, there is on the order of 320 GW.h of firm load in 2009.

Historic long term average hydro generation estimates of 351 GW.h, plus 5 GW.h for the Aishihik 3rd turbine, yield total long-term average hydro generation of 356 GW.h.

This surplus of approximately 36 GW.h at long-term average water flow levels is subject to reduction in the “next few years” by ongoing non-industrial load growth (on the order of 5 GW.h per year to as high as 10 GW.h per year), expected load increments at the Minto mine, the initiation of site reclamation activities at the Faro mine site, and potential new mining loads such as Carmacks Copper.

On the Mayo-Dawson system similar pressures indicate that, absent new renewable generation, a potential elimination of existing hydro surplus with the full resumption of commercial mining activities at Keno.

REFERENCE: October 6, 2008 Application, Page 5

YEC states "A total incurred cost of $0.643 million related to the regulatory review of Yukon Energy's 2006-2025 Resource Plan, as required by the Minister of Justice, to be amortized over 10 years consistent with the anticipated frequency of full Resource Plan updates."

QUESTION:

a) Please explain why this cost is not charged out to the capital projects reviewed as part of the Resource Plan.

ANSWER:

(a)

In accordance with past regulatory practice in the Yukon, major hearing related regulatory expenses are amortized over a given period associated with the hearing.

The Resource Plan hearing was not a hearing concerning the review of a particular project or projects per se, but a review of a comprehensive 20-Year Resource Plan for the Yukon. As such, and as discussed at page 3-17 and 3-18 of the Application, the costs of the Resource Plan proceeding are proposed to be amortized over 10 years (the anticipated period of time until another comprehensive Resource Plan will be prepared).

REFERENCE: October 6, 2008 Application, Page 5

YEC states "A total incurred cost of $0.243 million related to the regulatory review of the Minto Explorations Power Purchase Agreement, to be amortized over 12 years which is the currently anticipated economic life of the substantial terms of the PPA."

QUESTION:

a) Please explain why this cost is not charged directly to Minto (Capstone).

ANSWER:

(a)

The cost is not charged directly to Minto as there is no provision for such assignment of these costs in the YUB approved PPA. The costs also are not to be charged directly to Minto as part of their rate as the rate is fixed by OIC and not subject to revision to assign additional costs.

In each of orders 2007-7, 2007-8, 2007-9 and 2008-1, the Board directed Yukon Energy to record all hearing costs related to the PPA hearing, the Resource Plan hearing and the Part 3 hearing in a Hearing Reserve Account. As noted in Tab 6, page 6-7 of the Application, the noted hearing costs (including PPA hearing costs) were included in a Hearing Reserve Account and YEC is proposing to amortize PPA hearing costs over 12 years (the anticipated primary accounting life of the PPA).

REFERENCE: October 6, 2008 Application, Page 5

YEC states "A total incurred cost of $0.185 million related to the regulatory review of the Carmacks-Stewart Transmission Project ("CSTP") under Part 3 of the Public Utilities Act, as required by the Minister of Justice, to be amortized over 45 years consistent with the approximate average life for the project assets."

QUESTION:

a) Please explain why this cost is not charged to the CSTP.

ANSWER:

(a)

In each of orders 2007-7, 2007-8, 2007-9 and 2008-1, the Board directed Yukon Energy to record hearing costs related to the PPA hearing, the Resource Plan hearing and the Part 3 hearing in a Hearing Reserve Account.

As noted in Tab 6, page 6-7 of the Application, the noted hearing costs (including Part 3 hearing costs) were included in a Hearing Reserve Account and YEC is proposing to amortize Part 3 hearing costs over 45 years (the approximate life of the assets as per Yukon Energy's most recent depreciation study). The net effect of this treatment is equivalent to charging these amounts to the capital cost of the CSTP project.

REFERENCE: October 6, 2008 Application, Page 11

YEC states "Extension of efficient price signals to the General Service rate classes, however, will require future review as soon as feasible with YECL to assess rate redesign options that cannot be addressed in this Yukon Energy Application.

QUESTION:

a) Please provide details of planning and/or discussions held to date with YECL in this regard.

ANSWER:

(a)

Please see response to LE-YEC-1-4(a).

REFERENCE: October 6, 2008 Application, Pages 13 and 14

YEC states "Yukon Energy proposes that, as a first priority, future joint YEC/YECL attention be directed as soon as practicable at identifying and assessing rate design options for General Service rate classes as required to promote economy and efficiency in accordance with OIC 1995/90, taking into consideration current and near term forecast incremental system costs in Yukon in the same manner as such costs were considered by the Board and YEC/YECL in the 1996/97 General Rate Application. Yukon Energy further proposes that joint YEC/YECL action to prepare a Cost of Service Study be assigned a lower priority, with delayed timing as appropriate, to reflect the timely need to address the above near term rate design priorities that are not tied to Cost of Service Study assessments as well as the fact that OIC 2007/94 and the latest Rate Policy Directive in effect defer until after 2012 any cost-of-service based rate rebalancing adjustments or other rate shift programs affecting the percentage of overall rate revenues allocated to major industrial customers or to any retail customer class".

QUESTION:

a) Please explain how cost-based rates could be designed for review without going through a detailed cost of service study.

ANSWER:

(a)

In the quoted section of the Application, YEC provides proposals towards an orderly process for addressing relevant rate issues over the period leading to 2013, noting what rate changes can be addressed today (runoff rates) and what rate changes must be deferred now for implementation until after 2012 (namely rate changes, based on cost of service studies, that seek to change how much revenue is collected from each rate class).

Second block runout rates are not set based on the utility's revenue requirement or on an allocation of costs included in a cost of service study. Runout block rates are established based on the requirement provided in OIC 1995/90 (section 4(3)) and on rate design principles initially established by the Board subsequent to the 1992 Cost of Service and Rate Design proceeding, and approved in Orders 1993-8 and 1996-7.

These rate design principles provide that second block runout rates are to promote economy and efficiency through reflecting short-run incremental costs, which are not derived from a cost of service study. Pursuant to practice previously approved by the Board these incremental costs are based on the current cost of diesel in each of the rate zones.

Looking at what can be expected when a cost of service study is available, the following past experience is noted:

In past Yukon experience, “cost based rates” as tied to class revenue to cost ratios from a cost of service study, have been used to assess how much of the revenue requirement is to be recovered from certain rate classes. In this regard, cost-of-service studies had a material impact on overall industrial class rate levels after 1995, and provided guidance to reduce overall non-government General Service customer rates in the 1996/97 GRA. In contrast, as noted by the Board in the past, such cost-of-service studies to date have had limited impacts on overall rates for other major customer rate classes (e.g., non-government residential); similarly, cost of service information has had no material impact on setting fixed charges such as the residential monthly customer charge. To complete the picture, first block rates for retail classes in the past were set as the residual requirement to recover class revenue targets after deduction of forecast runoff rate block revenues and any fixed charge rate revenues.

REFERENCE: October 6, 2008 Application, Introduction, Page 1-2

When describing Rider J, YEC states "…that rider was set only to recover specific identifiable and major adverse impacts on Yukon Energy from the Faro mine closing".

QUESTION:

a) Please identify and quantify the specific adverse impacts that needed to be recovered / will need to be recovered through Rider J during 2005, 2006, 2007, 2008 and 2009.

b) Please provide the amount actually recovered through Rider J in 2005, 2006, 2007 and 2008.

c) Please identify rate classes that pay the Rider J. If there are classes that do not pay Rider J, please provide an explanation for their exclusion.

d) Please explain why YEC does not propose eliminating Rider J and simply recover cost of service through base rates.

ANSWER:

(a)

As noted in response to YUB-YEC-I-57 (provided during the 2005 Required Revenues and Related Matters hearing), Rider J was approved to cover both interim and permanent impacts on Yukon Energy due to the loss of the Faro mine in 1998. This is not a special purposes rider designed to yield targeted collections, but is a material part of Yukon Energy's general and normal revenues and rates.

As set out in detail in Order 2003-2, Rider J is not a mechanism to collect a given dollar value or shortfall, it is a means for Yukon Energy to collect revenues towards its general Revenue Requirement, exactly analogous to any other rate. Until such time as overall retail and wholesale rates in Yukon are redesigned to incorporate this approximately $6 million collection into base rates, Rider J is required to prevent Yukon Energy from experiencing shortfalls in excess of $6 million.

(b)

Schedule 11, at Tab 7 of the filing notes at line 46 actual amounts recovered through Rider J from 2005 through 2007. These amounts are as follows:

2005: $5.246 million
2006: $5.451 million
2007: $5.585 million

Actuals for 2008 are not currently available and will be supplied with the update filing.

(c)

Rider J is applicable to all electric service retail rates except for Rate Schedule 39 (Industrial Primary rate) and Rate Schedule 32 (Secondary Energy rate).

Rider J was implemented to deal with a net loss of recurring margin revenue that was used to cover both recurring and one-time system cost of service items after the Faro mine closed in 1997. The rate is not applicable to the Rate Schedule 32 customer as such sales are not firm sales and not linked to YEC's cost but rather to the customer's savings from reduced use of the alternative fuel (typically oil). The rider is not applicable to Rate Schedule 39 customers pursuant to OIC.

(d)

Yukon Energy is not undertaking a major re-design of rates at this time. Eliminating Rider J in order to recover amounts targeted by Rider J through base rates would require a re-design of rates.

REFERENCE: October 6, 2008 Application, Introduction, Page 1-3

YEC references the revenue to cost ratios report filed August 24, 2005 in response to a Board directive.

QUESTION:

a) Please identify any Board Orders or directions that resulted from this report.

b) Please provide an update to Table 1 of the August 2005 report which shows the actual revenue to cost ratios for 2005, 2006, 2007 and 2008.

c) Please explain YEC's position that a rate shift program could be properly designed without a current picture of how much of a shift is required by using the results of an updated cost allocation / rate design analysis.

d) Please explain YEC's position that potential rate impacts on customer classes could be determined without having the latest cost and revenue allocation data.

ANSWER:

(a)

No Board Orders or directions resulted from the report filed August 24, 2005.

(b)

Please see UCG-YEC-1-93.

(c) and **(d)**

Yukon Energy's position is that no rate shift program can be initiated prior to 2013.

In the event a rate shift program were possible, the joint report by YEC and YECL in 1995 (see attachment to YUB-YEC-1-23) indicated that the primary directionality for major adjustments required is quite clear. Based on that report, and the information therein, residential non-government rates would need to rise (likely to approximately the

level of residential government rates), and government General Service rates would need to be lowered (likely to the range of Non-government General Service). This is in part supported by the fact that the last full cost-of-service study (1997) indicated that the fully allocated costs of energy to each of these 4 classes (residential government, residential non-government, general service government, and general service non-government) are basically identical, the costs of demand-related costs are within 3% of each other, and the costs for customer related costs vary by less than $100/year among all four classes. Given this near identical cost profile, any change to costs resulting from developments since 1997 are likely to have applied almost equally to each class, resulting in likely very little relative change in revenue: cost coverage factors.

REFERENCE: October 6, 2008 Application, Introduction, Pages 1-2 and 1-3

YEC references the Board's January 15, 2007 report regarding YEC's 20-year Resource Plan 2006-2025.

QUESTION:

a) Please provide an update on all 2008 and 2009 capital projects that are expected to exceed $1 million in cost and what steps YEC has taken / what processes have been implemented to adhere to the Board's recommendation that the threshold for capital expenditures to be reviewed by the Board be set at $1 million.

b) Please identify all capital projects initiated in 2007, 2008 and 2009 for which YEC has submitted an application to the Minister per Part 3 of the *Public Utilities Act*.

c) Please provide an update on the Marsh Lake Fall / Winter Storage Licence Revision project that the Board removed from near term projects.

d) Please provide an update to YEC's development of an independent power producer policy recommended by the Board.

e) Please provide an update on YEC's participation in the Board's recommended study of the potential for DSM initiatives in the Yukon.

f) Please explain why no evidence has been submitted regarding the Board's recommendation that evidence be provided as to what other utilities provide for Maximum Company Investment and that Yukon utilities model theirs accordingly.

ANSWER:

(a)

All 2008 and 2009 capital projects that exceed $1 million are set out in Table 5.2 as "Major Projects" and are subject to Board review at this proceeding. Each of the projects has also been the subject of review at previous hearings (Resource Plan, Minto PPA, CSTP Part 3).

(b)

Carmacks-Stewart Transmission Project.

(c)

Please see YUB-YEC-1-27(a).

(d)

Please see YUB-YEC-1-27(c).

(e)

The noted recommendation was for the Government of Yukon to undertake an independent study. YEC is not aware of any such independent study having been commissioned in response to the Board's recommendation.

(f)

Please see Tab 6, page 6-6.

REFERENCE: October 6, 2008 Application, Introduction, Page 1-7

YEC references the installation of the Aishihik Third Turbine in 2010.

REFERENCE: Yukon Utilities Board Report on Yukon Energy Corporation 20-Year Resource Plan, January 15, 2007, Page 30

"The Board's analysis in Sections 4 and 5 above, which was conducted assuming the base-case load forecast, has shown that YEC's proposed expansion plan would be more economic than the alternative plan provided that the Aishihik third turbine is installed in 2013. It should be noted, however, that the addition of the third turbine under YEC's plan is not a capacity requirement determined by the planning criteria, but rather a requirement driven strictly by economic reasons, namely to offset future diesel generation that is expected to increase under the base-case load forecast. However, should the actual loads turn out higher or lower that the loads under the base-case forecast, the optimal timing of the third turbine would move earlier or later than 2013. Therefore, to minimize the uncertainty around timing of the third turbine, the final decision to proceed with this project should be made closer to the date when economic reasons indicate that the turbine is needed. Therefore, the Board recommends that this project not proceed until that time unless YEC can justify an earlier in-service date."

QUESTION:

a) Please identify the economic reasons that justify moving forward with this project in 2010.

b) Please identify the regulatory approvals that YEC will be seeking for this project and the timing of related applications.

c) Please describe the process used to identify projects that were potentially eligible for the $5 million Eco-trust fund.

d) Please identify the projects other than the Aishihik Third Turbine that were considered for funding through the $5 million Eco-trust fund and explain why they were not recommended and/or accepted for funding.

ANSWER:

(a)

The original economic rationale for proceeding with this project is as described in Appendix C of Yukon Energy's 20-Year Resource Plan. The feasibility of the project was further described in the PPA Application and in Yukon Energy's 2007 Part 3 Application concerning the Carmacks Stewart Transmission Project. Footnote 23 at page 15 of Yukon Energy's Part 3 Application related to the Carmacks Stewart Transmission Project notes as follows regarding the economic and technical feasibility of proceeding with the Aishihik 3rd Turbine project based on the Resource Plan assessments:

> The available evidence confirms the economic and technical feasibility of the Aishihik 3rd Turbine, which is already fully licensed. As discussed in footnote 7 in Attachment B to the PPA Application, "the Resource Plan assumes Aishihik 3rd Turbine capital costs at about $7 million (2005$); Appendix C of the January 2006 Resource Plan, however, indicates PV (2005$) life cycle capital and operating costs for this project at about $6 million for in-service in 2011 (this number would be slightly higher for in-service in 2010, and slightly lower for in-service in 2013), which is slightly more than incremental savings to 2025 as noted in Table B-1. This analysis of incremental savings in Table B-1, however, ignores full life benefits for Aishihik 3rd Turbine due to ongoing diesel generation cost savings after 2025. As demonstrated in Appendix C of the January 2006 Resource Plan Report, PV savings after 2025 (in 2005$) due to diesel generation displacement have been estimated to exceed $4 million. Overall, based on life cycle costs, the Aishihik 3rd Turbine is an economically attractive project yielding NPV ratepayer savings with the Minto mine even over the period to 2025 (these NPV savings tend to be slightly higher with Aishihik 3rd Turbine in service in 2013 versus 2010)."

Exhibit B-9 (provided as Attachment 1 to this response) filed during the 2007 Part 3 hearing process also provides a summary of updated Aishihik 3rd Turbine Assessment cases after consideration of the $5 million government contribution as then announced. Specifically, Table 2 in Exhibit B-9 shows the costs and benefits of this project with in-service in 2010 at a gross cost of $7.7 million, the $5 million government contribution, no CSTP Stage 2 in place, and only the Minto mine as a major new industrial load. NPV

ratepayer savings from the project under these assumptions were estimated at approximately $8 million over the project lifetime.

Based on this information, the YUB report to the Minister regarding the Part 3 review of the CSTP recommended that, “if Stage One of the CSTP were to go forward, then by implication, there is an accelerated need for the third turbine at Aishihik. The Board accepts the submissions that on an opportunity basis for diesel displacement, with connection of new mine loads, there is economic justification to accelerate the construction of the Aishihik third turbine. This view and recommendation is consistent with the view expressed by the Board in its 20-Year Resource Plan Report” [as quoted in Application at page 5-12.]

For further update on the effects of current project cost estimates and fuel prices, please see the response to YUB-YEC-1-36(h).

(b)

All regulatory approvals required to proceed with the project have been obtained.

(c) and **(d)**

On March 30, 2007, Canada announced $5 million in funding for the Yukon as part of a trust fund set up to help reduce greenhouse gas emissions and air pollutants, and the Yukon Government announced that the funds will be used for the Aishihik 3rd Turbine project. Eligibility for this funding was determined by the Yukon Government and Yukon Energy has no additional insight into the process by which the government identified and assessed projects eligible for the Eco-trust fund, or other projects that were considered and why they ultimately were or were not provided funding.

Summary of Aishihik 3rd Turbine Assessment Cases: Updated Appendix C (YEC Resource Plan: 2006-2025, dated January 2006) (2005$, $000s)

	IRR lifetime (%)	Ratepayer Costs/(Savings) (NPV) lifetime	Ratepayer Costs/(Savings) (NPV) 20 years	Years until beneficial rate impact	Years mines Contribute
Table 1: Aishihik 3rd Turbine at 2010 under Base Case Loads	17.50%	(6,690)	(1,736)	6	0
Table 2: Aishihik 3rd Turbine at 2010 with Minto at 32.5 GWh	22.84%	(7,959)	(3,005)	2	7
Table 3: Aishihik 3rd Turbine at 2010 with Minto at 32.5 GWh and CC at 48.0 GWh	61.46%	(10,803)	(5,849)	0	8
Table 4: Aishihik 3rd Turbine 2010 and CS Interconnection 2010 with Minto at 32.5 GWh and CC at 48.0 GWh	62.55%	(12,093)	(7,139)	0	8

Key Update Assumptions:
- $5 Million Funding for Aishihik 3rd Turbine
- Minto and Pelly Crossing Loads per PPA Application, Table B-3
- Secondary Sales cap, peaking dispatch and economic assumptions per PPA Application, Table B-3
- Marsh Lake Fall/Winter storage not included

B-9

1A: Basecase: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales **Base Case load forecast**
•Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenue Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	-	-	-	3.48	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	3.9	-	22	22	-	3.48	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	3.9	-	91	91	-	3.48	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	3.9	-	183	183	-	3.48	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	3.9	-	289	-	(289)	3.48	83	83	60	5	not assessed	65	2,729	77	2,806	2,741
2011	-	-	-	3.9	-	413	-	(413)	3.48	119	119	87	7	not assessed	94	-	79	79	(15)
2012	-	-	-	3.9	-	566	-	(566)	3.48	163	163	122	10	not assessed	132	-	80	80	(52)
2013	-	-	-	3.9	-	767	4	(763)	3.48	219	219	167	14	not assessed	181	-	82	82	(99)
2014	-	-	-	3.9	-	1,035	60	(975)	3.48	280	280	218	19	not assessed	236	-	84	84	(153)
2015	-	-	-	3.9	-	1,389	153	(1,236)	3.48	355	355	282	24	not assessed	306	-	85	85	(220)
2016	-	-	-	3.9	-	1,850	264	(1,586)	3.48	456	456	368	32	not assessed	400	-	87	87	(313)
2017	-	-	-	3.9	-	2,437	392	(2,045)	3.48	588	588	484	41	not assessed	526	-	89	89	(437)
2018	-	-	-	3.9	-	3,166	547	(2,619)	3.48	752	752	633	54	not assessed	687	-	91	91	(596)
2019	-	-	-	3.9	-	4,051	745	(3,306)	3.48	950	950	815	70	not assessed	885	-	92	92	(792)
2020	-	-	-	3.9	-	5,106	1,006	(4,099)	3.48	1,178	1,178	1,031	88	not assessed	1,119	-	94	94	(1,025)
2021	722	-	(722)	3.9	185	5,618	1,355	(4,263)	3.48	1,225	1,410	1,258	109	not assessed	1,368	-	96	96	(1,272)
2022	7,299	1,899	(5,400)	3.9	1,385	464	-	(464)	3.48	133	1,518	1,381	131	not assessed	1,513	-	98	98	(1,415)
2023	13,997	8,597	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	not assessed	1,409	-	100	100	(1,309)
2024	20,819	15,419	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	not assessed	1,437	-	102	102	(1,335)
2025	27,768	22,368	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	not assessed	1,466	-	104	104	(1,362)
2026	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	not assessed	1,495	-	106	106	(1,389)
2027	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	not assessed	1,525	-	108	108	(1,417)
2028	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	not assessed	1,555	-	110	110	(1,445)
2029	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	not assessed	1,587	-	113	113	(1,474)
2030	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	not assessed	1,618	-	115	115	(1,503)
2031	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	not assessed	1,651	-	117	117	(1,534)
2032	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	not assessed	1,684	-	119	119	(1,564)
2033	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	not assessed	1,717	-	122	122	(1,595)
2034	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	not assessed	1,752	-	124	124	(1,627)
2035	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	not assessed	1,787	-	127	127	(1,660)
2036	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	not assessed	1,822	-	129	129	(1,693)
2037	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	not assessed	1,859	-	132	132	(1,727)
2038	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	not assessed	1,896	-	135	135	(1,762)
2039	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	not assessed	1,934	-	137	137	(1,797)
2040	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	not assessed	1,973	-	140	140	(1,833)
2041	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	not assessed	2,012	-	143	143	(1,869)
2042	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	not assessed	2,052	-	146	146	(1,907)
2043	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	not assessed	2,093	-	149	149	(1,945)
2044	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	not assessed	2,135	-	152	152	(1,984)
2045	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	not assessed	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	not assessed	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	not assessed	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	not assessed	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	not assessed	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	not assessed	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	not assessed	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	not assessed	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	not assessed	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	not assessed	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	not assessed	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	not assessed	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	not assessed	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	not assessed	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	not assessed	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	not assessed	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	not assessed	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	not assessed	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	not assessed	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	not assessed	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	not assessed	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	not assessed	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	not assessed	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	not assessed	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	not assessed	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	not assessed	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	not assessed	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	not assessed	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	not assessed	3,792	-	269	269	(3,523)
PV (2005)	7.52%											8,896	832		9,728	1,899	1,012	2,911	(6,817)
																Internal Rate of Return			17.50%

1B : Aishihik 3rd Turbine Economics (65 years) - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	83	60	5	not assessed	65	42	204	77	323	258
2011	119	87	7	not assessed	94	42	200	79	321	227
2012	163	122	10	not assessed	132	42	197	80	320	188
2013	219	167	14	not assessed	181	42	194	82	318	137
2014	280	218	19	not assessed	236	42	191	84	317	80
2015	355	282	24	not assessed	306	42	188	85	315	9
2016	456	368	32	not assessed	400	42	185	87	314	(86)
2017	588	484	41	not assessed	526	42	182	89	312	(214)
2018	752	633	54	not assessed	687	42	178	91	311	(376)
2019	950	815	70	not assessed	885	42	175	92	310	(575)
2020	1,178	1,031	88	not assessed	1,119	42	172	94	308	(811)
2021	1,410	1,258	109	not assessed	1,368	42	169	96	307	(1,061)
2022	1,518	1,381	131	not assessed	1,513	42	166	98	306	(1,207)
2023	1,385	1,285	123	not assessed	1,409	42	163	100	305	(1,104)
2024	1,385	1,311	126	not assessed	1,437	42	159	102	303	(1,134)
2025	1,385	1,337	128	not assessed	1,466	42	156	104	302	(1,163)
2026	1,385	1,364	131	not assessed	1,495	42	153	106	301	(1,194)
2027	1,385	1,391	134	not assessed	1,525	42	150	108	300	(1,225)
2028	1,385	1,419	136	not assessed	1,555	42	147	110	299	(1,256)
2029	1,385	1,448	139	not assessed	1,587	42	144	113	298	(1,288)
2030	1,385	1,477	142	not assessed	1,618	42	140	115	297	(1,321)
2031	1,385	1,506	145	not assessed	1,651	42	137	117	296	(1,354)
2032	1,385	1,536	147	not assessed	1,684	42	134	119	296	(1,388)
2033	1,385	1,567	150	not assessed	1,717	42	131	122	295	(1,422)
2034	1,385	1,598	153	not assessed	1,752	42	128	124	294	(1,458)
2035	1,385	1,630	157	not assessed	1,787	42	125	127	293	(1,493)
2036	1,385	1,663	160	not assessed	1,822	42	122	129	293	(1,530)
2037	1,385	1,696	163	not assessed	1,859	42	118	132	292	(1,567)
2038	1,385	1,730	166	not assessed	1,896	42	115	135	292	(1,604)
2039	1,385	1,765	169	not assessed	1,934	42	112	137	291	(1,643)
2040	1,385	1,800	173	not assessed	1,973	42	109	140	291	(1,682)
2041	1,385	1,836	176	not assessed	2,012	42	106	143	291	(1,722)
2042	1,385	1,873	180	not assessed	2,052	42	103	146	290	(1,762)
2043	1,385	1,910	183	not assessed	2,093	42	99	149	290	(1,803)
2044	1,385	1,948	187	not assessed	2,135	42	96	152	290	(1,846)
2045	1,385	1,987	191	not assessed	2,178	42	93	155	290	(1,888)
2046	1,385	2,027	195	not assessed	2,222	42	90	158	290	(1,932)
2047	1,385	2,068	198	not assessed	2,266	42	87	161	290	(1,976)
2048	1,385	2,109	202	not assessed	2,311	42	84	164	290	(2,022)
2049	1,385	2,151	207	not assessed	2,358	42	80	167	290	(2,068)
2050	1,385	2,194	211	not assessed	2,405	42	77	171	290	(2,115)
2051	1,385	2,238	215	not assessed	2,453	42	74	174	290	(2,163)
2052	1,385	2,283	219	not assessed	2,502	42	71	178	291	(2,211)
2053	1,385	2,328	224	not assessed	2,552	42	68	181	291	(2,261)
2054	1,385	2,375	228	not assessed	2,603	42	65	185	291	(2,312)
2055	1,385	2,422	233	not assessed	2,655	42	62	188	292	(2,363)
2056	1,385	2,471	237	not assessed	2,708	42	58	192	293	(2,416)
2057	1,385	2,520	242	not assessed	2,762	42	55	196	293	(2,469)
2058	1,385	2,571	247	not assessed	2,817	42	52	200	294	(2,523)
2059	1,385	2,622	252	not assessed	2,874	42	49	204	295	(2,579)
2060	1,385	2,675	257	not assessed	2,931	42	46	208	296	(2,636)
2061	1,385	2,728	262	not assessed	2,990	42	43	212	297	(2,693)
2062	1,385	2,783	267	not assessed	3,050	42	39	216	298	(2,752)
2063	1,385	2,838	272	not assessed	3,111	42	36	221	299	(2,812)
2064	1,385	2,895	278	not assessed	3,173	42	33	225	300	(2,873)
2065	1,385	2,953	283	not assessed	3,236	42	30	230	302	(2,935)
2066	1,385	3,012	289	not assessed	3,301	42	27	234	303	(2,998)
2067	1,385	3,072	295	not assessed	3,367	42	24	239	305	(3,063)
2068	1,385	3,134	301	not assessed	3,435	42	21	244	306	(3,128)
2069	1,385	3,196	307	not assessed	3,503	42	17	249	308	(3,195)
2070	1,385	3,260	313	not assessed	3,573	42	14	254	310	(3,263)
2071	1,385	3,325	319	not assessed	3,645	42	11	259	312	(3,333)
2072	1,385	3,392	326	not assessed	3,718	42	8	264	314	(3,404)
2073	1,385	3,460	332	not assessed	3,792	42	5	269	316	(3,476)
PV (2005)		8,896	832		9,728	414	1,612	1,012	3,037	(6,690)
7.52%								20 year NPV (2006-2025)		(1,736)

Table 2A: Basecase: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales **Base Case load forecast with Minto 32.5GWh from 2009 - 2016**
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h.litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h.litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenue Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	-	-	-	3.48	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	3.9	-	22	22	-	3.48	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	3.9	-	91	91	-	3.48	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	3.9	-	775	775	-	3.48	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	3.9	-	1,024	57	(967)	3.48	278	278	199	17	not assessed	216	2,729	77	2,806	2,589
2011	-	-	-	3.9	-	1,347	142	(1,205)	3.48	346	346	254	22	not assessed	275	-	79	79	(196)
2012	-	-	-	3.9	-	1,752	244	(1,518)	3.48	436	436	326	28	not assessed	354	-	80	80	(273)
2013	-	-	-	3.9	-	2,283	360	(1,924)	3.48	553	553	421	36	not assessed	457	-	82	82	(375)
2014	-	-	-	3.9	-	2,926	496	(2,430)	3.48	698	698	542	46	not assessed	589	-	84	84	(505)
2015	1,282	-	(1,282)	3.9	329	2,421	665	(1,756)	3.48	505	833	660	59	not assessed	720	-	85	85	(634)
2016	7,174	1,774	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	not assessed	1,226	-	87	87	(1,139)
2017	-	-	-	3.9	-	2,543	415	(2,128)	3.48	612	612	504	43	not assessed	547	-	89	89	(458)
2018	-	-	-	3.9	-	3,293	575	(2,719)	3.48	781	781	657	56	not assessed	713	-	91	91	(623)
2019	-	-	-	3.9	-	4,202	780	(3,422)	3.48	983	983	843	72	not assessed	916	-	92	92	(823)
2020	-	-	-	3.9	-	5,280	1,053	(4,227)	3.48	1,215	1,215	1,063	91	not assessed	1,154	-	94	94	(1,060)
2021	2,413	-	(2,413)	3.9	619	4,126	1,415	(2,711)	3.48	779	1,398	1,247	113	not assessed	1,360	-	96	96	(1,264)
2022	8,990	3,590	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,260	121	not assessed	1,381	-	98	98	(1,283)
2023	15,688	10,288	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	not assessed	1,409	-	100	100	(1,309)
2024	22,510	17,110	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	not assessed	1,437	-	102	102	(1,335)
2025	29,458	24,058	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	not assessed	1,466	-	104	104	(1,362)
2026	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	not assessed	1,495	-	106	106	(1,389)
2027	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	not assessed	1,525	-	108	108	(1,417)
2028	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	not assessed	1,555	-	110	110	(1,445)
2029	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	not assessed	1,587	-	113	113	(1,474)
2030	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	not assessed	1,618	-	115	115	(1,503)
2031	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	not assessed	1,651	-	117	117	(1,534)
2032	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	not assessed	1,684	-	119	119	(1,564)
2033	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	not assessed	1,717	-	122	122	(1,595)
2034	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	not assessed	1,752	-	124	124	(1,627)
2035	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	not assessed	1,787	-	127	127	(1,660)
2036	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	not assessed	1,822	-	129	129	(1,693)
2037	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	not assessed	1,859	-	132	132	(1,727)
2038	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	not assessed	1,896	-	135	135	(1,762)
2039	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	not assessed	1,934	-	137	137	(1,797)
2040	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	not assessed	1,973	-	140	140	(1,833)
2041	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	not assessed	2,012	-	143	143	(1,869)
2042	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	not assessed	2,052	-	146	146	(1,907)
2043	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	not assessed	2,093	-	148	149	(1,945)
2044	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	not assessed	2,135	-	152	152	(1,984)
2045	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	not assessed	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	not assessed	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	not assessed	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	not assessed	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	not assessed	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	not assessed	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	not assessed	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	not assessed	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	not assessed	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	not assessed	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	not assessed	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	not assessed	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	not assessed	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	not assessed	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	not assessed	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	not assessed	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	not assessed	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	not assessed	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	not assessed	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	not assessed	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	not assessed	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	not assessed	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	not assessed	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	not assessed	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	not assessed	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	not assessed	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	not assessed	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	not assessed	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	not assessed	3,792	-	269	269	(3,523)
PV (2005)	7.52%											10,057	939		10,996	1,899	1,012	2,911	(8,085)
																Internal Rate of Return			22.84%

Table 2B: Aishihik 3rd Turbine Economics (65 years) - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast with Minto 32.5GWh from 2009 - 2016
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	278	199	17	not assessed	216	42	204	77	323	106
2011	346	254	22	not assessed	275	42	200	79	321	46
2012	436	326	28	not assessed	354	42	197	80	320	(34)
2013	553	421	36	not assessed	457	42	194	82	318	(139)
2014	698	542	46	not assessed	589	42	191	84	317	(272)
2015	833	660	59	not assessed	720	42	188	85	315	(404)
2016	1,385	1,119	107	not assessed	1,226	42	185	87	314	(913)
2017	612	504	43	not assessed	547	42	182	89	312	(235)
2018	781	657	56	not assessed	713	42	178	91	311	(402)
2019	983	843	72	not assessed	916	42	175	92	310	(606)
2020	1,215	1,063	91	not assessed	1,154	42	172	94	308	(846)
2021	1,398	1,247	113	not assessed	1,360	42	169	96	307	(1,053)
2022	1,385	1,260	121	not assessed	1,381	42	166	98	306	(1,075)
2023	1,385	1,285	123	not assessed	1,409	42	163	100	305	(1,104)
2024	1,385	1,311	126	not assessed	1,437	42	159	102	303	(1,134)
2025	1,385	1,337	128	not assessed	1,466	42	156	104	302	(1,163)
2026	1,385	1,364	131	not assessed	1,495	42	153	106	301	(1,194)
2027	1,385	1,391	134	not assessed	1,525	42	150	108	300	(1,225)
2028	1,385	1,419	136	not assessed	1,555	42	147	110	299	(1,256)
2029	1,385	1,448	139	not assessed	1,587	42	144	113	298	(1,288)
2030	1,385	1,477	142	not assessed	1,618	42	140	115	297	(1,321)
2031	1,385	1,506	145	not assessed	1,651	42	137	117	296	(1,354)
2032	1,385	1,536	147	not assessed	1,684	42	134	119	296	(1,388)
2033	1,385	1,567	150	not assessed	1,717	42	131	122	295	(1,422)
2034	1,385	1,598	153	not assessed	1,752	42	128	124	294	(1,458)
2035	1,385	1,630	157	not assessed	1,787	42	125	127	293	(1,493)
2036	1,385	1,663	160	not assessed	1,822	42	122	129	293	(1,530)
2037	1,385	1,696	163	not assessed	1,859	42	118	132	292	(1,567)
2038	1,385	1,730	166	not assessed	1,896	42	115	135	292	(1,604)
2039	1,385	1,765	169	not assessed	1,934	42	112	137	291	(1,643)
2040	1,385	1,800	173	not assessed	1,973	42	109	140	291	(1,682)
2041	1,385	1,836	176	not assessed	2,012	42	106	143	291	(1,722)
2042	1,385	1,873	180	not assessed	2,052	42	103	146	290	(1,762)
2043	1,385	1,910	183	not assessed	2,093	42	99	149	290	(1,803)
2044	1,385	1,948	187	not assessed	2,135	42	96	152	290	(1,846)
2045	1,385	1,987	191	not assessed	2,178	42	93	155	290	(1,888)
2046	1,385	2,027	195	not assessed	2,222	42	90	158	290	(1,932)
2047	1,385	2,068	198	not assessed	2,266	42	87	161	290	(1,976)
2048	1,385	2,109	202	not assessed	2,311	42	84	164	290	(2,022)
2049	1,385	2,151	207	not assessed	2,358	42	80	167	290	(2,068)
2050	1,385	2,194	211	not assessed	2,405	42	77	171	290	(2,115)
2051	1,385	2,238	215	not assessed	2,453	42	74	174	290	(2,163)
2052	1,385	2,283	219	not assessed	2,502	42	71	178	291	(2,211)
2053	1,385	2,328	224	not assessed	2,552	42	68	181	291	(2,261)
2054	1,385	2,375	228	not assessed	2,603	42	65	185	291	(2,312)
2055	1,385	2,422	233	not assessed	2,655	42	62	188	292	(2,363)
2056	1,385	2,471	237	not assessed	2,708	42	58	192	293	(2,416)
2057	1,385	2,520	242	not assessed	2,762	42	55	196	293	(2,469)
2058	1,385	2,571	247	not assessed	2,817	42	52	200	294	(2,523)
2059	1,385	2,622	252	not assessed	2,874	42	49	204	295	(2,579)
2060	1,385	2,675	257	not assessed	2,931	42	46	208	296	(2,636)
2061	1,385	2,728	262	not assessed	2,990	42	43	212	297	(2,693)
2062	1,385	2,783	267	not assessed	3,050	42	39	216	298	(2,752)
2063	1,385	2,838	272	not assessed	3,111	42	36	221	299	(2,812)
2064	1,385	2,895	278	not assessed	3,173	42	33	225	300	(2,873)
2065	1,385	2,953	283	not assessed	3,236	42	30	230	302	(2,935)
2066	1,385	3,012	289	not assessed	3,301	42	27	234	303	(2,998)
2067	1,385	3,072	295	not assessed	3,367	42	24	239	305	(3,063)
2068	1,385	3,134	301	not assessed	3,435	42	21	244	306	(3,128)
2069	1,385	3,196	307	not assessed	3,503	42	17	249	308	(3,195)
2070	1,385	3,260	313	not assessed	3,573	42	14	254	310	(3,263)
2071	1,385	3,325	319	not assessed	3,645	42	11	259	312	(3,333)
2072	1,385	3,392	326	not assessed	3,718	42	8	264	314	(3,404)
2073	1,385	3,460	332	not assessed	3,792	42	5	269	316	(3,476)
PV (2005)		10,057	939		10,996	414	1,612	1,012	3,037	(7,959)
7.52%								20 year NPV (2006-2025)		(3,005)

Table 3A: Basecase: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales **Base Case load forecast with Minto 32.5GWh from 2009 - 2016 & CC 48.0 from 2010 - 2017**
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h/litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h/litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenue Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	-	-	-	3.48	-	-	-	-	-	-	-	-	-
2007	-	-	-	3.9	-	22	22	-	3.48	-	-	-	-	-	-	-	-	-
2008	-	-	-	3.9	-	91	91	-	3.48	-	-	-	-	-	-	-	-	-
2009	-	-	-	3.9	-	775	775	-	3.48	-	-	-	-	-	-	-	-	-
2010	27,320	21,920	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	994	95	not assessed	1,089	2,729	77	2,806	1,717
2011	32,695	27,295	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,014	97	not assessed	1,111	-	79	79	(1,032)
2012	38,170	32,770	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	not assessed	1,133	-	80	80	(1,053)
2013	43,914	38,514	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	not assessed	1,156	-	82	82	(1,074)
2014	49,593	44,193	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	not assessed	1,179	-	84	84	(1,095)
2015	55,378	49,978	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	not assessed	1,202	-	85	85	(1,117)
2016	61,270	55,870	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	not assessed	1,226	-	87	87	(1,139)
2017	30,643	25,243	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,141	110	not assessed	1,251	-	89	89	(1,162)
2018	-	-	-	3.9	-	3,293	575	(2,719)	3.48	781	781	657	56	not assessed	713	-	91	91	(623)
2019	-	-	-	3.9	-	4,202	780	(3,422)	3.48	983	983	843	72	not assessed	916	-	92	92	(823)
2020	-	-	-	3.9	-	5,280	1,053	(4,227)	3.48	1,215	1,215	1,063	91	not assessed	1,154	-	94	94	(1,060)
2021	2,413	-	(2,413)	3.9	619	4,126	1,415	(2,711)	3.48	779	1,398	1,247	113	not assessed	1,360	-	96	96	(1,264)
2022	8,990	3,590	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,260	121	not assessed	1,381	-	98	98	(1,283)
2023	15,688	10,288	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,285	123	not assessed	1,409	-	100	100	(1,309)
2024	22,510	17,110	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	not assessed	1,437	-	102	102	(1,335)
2025	29,458	24,058	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	not assessed	1,466	-	104	104	(1,362)
2026	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	not assessed	1,495	-	106	106	(1,389)
2027	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	not assessed	1,525	-	108	108	(1,417)
2028	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	not assessed	1,555	-	110	110	(1,445)
2029	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	not assessed	1,587	-	113	113	(1,474)
2030	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	not assessed	1,618	-	115	115	(1,503)
2031	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	not assessed	1,651	-	117	117	(1,534)
2032	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	not assessed	1,684	-	119	119	(1,564)
2033	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	not assessed	1,717	-	122	122	(1,595)
2034	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	not assessed	1,752	-	124	124	(1,627)
2035	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	not assessed	1,787	-	127	127	(1,660)
2036	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	not assessed	1,822	-	129	129	(1,693)
2037	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	not assessed	1,859	-	132	132	(1,727)
2038	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	not assessed	1,896	-	135	135	(1,762)
2039	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	not assessed	1,934	-	137	137	(1,797)
2040	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	not assessed	1,973	-	140	140	(1,833)
2041	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	not assessed	2,012	-	143	143	(1,869)
2042	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	not assessed	2,052	-	146	146	(1,907)
2043	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	not assessed	2,093	-	149	149	(1,945)
2044	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	not assessed	2,135	-	152	152	(1,984)
2045	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	not assessed	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	not assessed	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	not assessed	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	not assessed	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	not assessed	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	not assessed	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	not assessed	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	not assessed	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	not assessed	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	not assessed	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	not assessed	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	not assessed	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	not assessed	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	not assessed	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	not assessed	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	not assessed	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	not assessed	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	not assessed	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	not assessed	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	not assessed	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	not assessed	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	not assessed	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	not assessed	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	not assessed	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	not assessed	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	not assessed	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	not assessed	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	not assessed	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	not assessed	3,792	-	269	269	(3,523)
PV (2005)	7.52%											12,639	1,202		13,840	1,899	1,012	2,911	(10,930)
																Internal Rate of Return			61.46%

Table 3B: Aishihik 3rd Turbine Economics (65 years) - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast with Minto 32.5GWh from 2009 - 2016 & CC 48.0 from 2010 - 2017
-Assuming Aishihik Third Turbine in Service in 2010

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus Benefits	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	1,385	994	95	not assessed	1,089	42	204	77	323	(766)
2011	1,385	1,014	97	not assessed	1,111	42	200	79	321	(790)
2012	1,385	1,034	99	not assessed	1,133	42	197	80	320	(813)
2013	1,385	1,054	101	not assessed	1,156	42	194	82	318	(838)
2014	1,385	1,076	103	not assessed	1,179	42	191	84	317	(862)
2015	1,385	1,097	105	not assessed	1,202	42	188	85	315	(887)
2016	1,385	1,119	107	not assessed	1,226	42	185	87	314	(913)
2017	1,385	1,141	110	not assessed	1,251	42	182	89	312	(939)
2018	781	657	56	not assessed	713	42	178	91	311	(402)
2019	983	843	72	not assessed	916	42	175	92	310	(606)
2020	1,215	1,063	91	not assessed	1,154	42	172	94	308	(846)
2021	1,398	1,247	113	not assessed	1,360	42	169	96	307	(1,053)
2022	1,385	1,260	121	not assessed	1,381	42	166	98	306	(1,075)
2023	1,385	1,285	123	not assessed	1,409	42	163	100	305	(1,104)
2024	1,385	1,311	126	not assessed	1,437	42	159	102	303	(1,134)
2025	1,385	1,337	128	not assessed	1,466	42	156	104	302	(1,163)
2026	1,385	1,364	131	not assessed	1,495	42	153	106	301	(1,194)
2027	1,385	1,391	134	not assessed	1,525	42	150	108	300	(1,225)
2028	1,385	1,419	136	not assessed	1,555	42	147	110	299	(1,256)
2029	1,385	1,448	139	not assessed	1,587	42	144	113	298	(1,288)
2030	1,385	1,477	142	not assessed	1,618	42	140	115	297	(1,321)
2031	1,385	1,506	145	not assessed	1,651	42	137	117	296	(1,354)
2032	1,385	1,536	147	not assessed	1,684	42	134	119	296	(1,388)
2033	1,385	1,567	150	not assessed	1,717	42	131	122	295	(1,422)
2034	1,385	1,598	153	not assessed	1,752	42	128	124	294	(1,458)
2035	1,385	1,630	157	not assessed	1,787	42	125	127	293	(1,493)
2036	1,385	1,663	160	not assessed	1,822	42	122	129	293	(1,530)
2037	1,385	1,696	163	not assessed	1,859	42	118	132	292	(1,567)
2038	1,385	1,730	166	not assessed	1,896	42	115	135	292	(1,604)
2039	1,385	1,765	169	not assessed	1,934	42	112	137	291	(1,643)
2040	1,385	1,800	173	not assessed	1,973	42	109	140	291	(1,682)
2041	1,385	1,836	176	not assessed	2,012	42	106	143	291	(1,722)
2042	1,385	1,873	180	not assessed	2,052	42	103	146	290	(1,762)
2043	1,385	1,910	183	not assessed	2,093	42	99	149	290	(1,803)
2044	1,385	1,948	187	not assessed	2,135	42	96	152	290	(1,846)
2045	1,385	1,987	191	not assessed	2,178	42	93	155	290	(1,888)
2046	1,385	2,027	195	not assessed	2,222	42	90	158	290	(1,932)
2047	1,385	2,068	198	not assessed	2,266	42	87	161	290	(1,976)
2048	1,385	2,109	202	not assessed	2,311	42	84	164	290	(2,022)
2049	1,385	2,151	207	not assessed	2,358	42	80	167	290	(2,068)
2050	1,385	2,194	211	not assessed	2,405	42	77	171	290	(2,115)
2051	1,385	2,238	215	not assessed	2,453	42	74	174	290	(2,163)
2052	1,385	2,283	219	not assessed	2,502	42	71	178	291	(2,211)
2053	1,385	2,328	224	not assessed	2,552	42	68	181	291	(2,261)
2054	1,385	2,375	228	not assessed	2,603	42	65	185	291	(2,312)
2055	1,385	2,422	233	not assessed	2,655	42	62	188	292	(2,363)
2056	1,385	2,471	237	not assessed	2,708	42	58	192	293	(2,416)
2057	1,385	2,520	242	not assessed	2,762	42	55	196	293	(2,469)
2058	1,385	2,571	247	not assessed	2,817	42	52	200	294	(2,523)
2059	1,385	2,622	252	not assessed	2,874	42	49	204	295	(2,579)
2060	1,385	2,675	257	not assessed	2,931	42	46	208	296	(2,636)
2061	1,385	2,728	262	not assessed	2,990	42	43	212	297	(2,693)
2062	1,385	2,783	267	not assessed	3,050	42	39	216	298	(2,752)
2063	1,385	2,838	272	not assessed	3,111	42	36	221	299	(2,812)
2064	1,385	2,895	278	not assessed	3,173	42	33	225	300	(2,873)
2065	1,385	2,953	283	not assessed	3,236	42	30	230	302	(2,935)
2066	1,385	3,012	289	not assessed	3,301	42	27	234	303	(2,998)
2067	1,385	3,072	295	not assessed	3,367	42	24	239	305	(3,063)
2068	1,385	3,134	301	not assessed	3,435	42	21	244	306	(3,128)
2069	1,385	3,196	307	not assessed	3,503	42	17	249	308	(3,195)
2070	1,385	3,260	313	not assessed	3,573	42	14	254	310	(3,263)
2071	1,385	3,325	319	not assessed	3,645	42	11	259	312	(3,333)
2072	1,385	3,392	326	not assessed	3,718	42	8	264	314	(3,404)
2073	1,385	3,460	332	not assessed	3,792	42	5	269	316	(3,476)
PV (2005)		12,639	1,202		13,840	414	1,612	1,012	3,037	(10,803)
7.52%								20 year NPV (2006-2025)		(5,849)

Table 4A: Basecase: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) - IRR based on cash flows ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales **Base Case load forecast with Minto 32.5GWh from 2009 - 2016 & CC 48.0 from 2010 - 2017**
-Assuming Aishihik Third Turbine in Service in 2010 and CS Interconnected in 2010

	Project Benefits														Project Costs			Net Costs
	Baseload diesel without project (MW.h)	Baseload diesel with project (MW.h)	Change in Baseload Diesel (MW.h)	efficiency (kW.h/litre)	litres saved (000s)	Peaking diesel without project (MW.h)	Peaking diesel with project (MW.h)	Change in Peaking Diesel (MW.h)	efficiency (kW.h/litre)	litres saved	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenue Benefits	Total project benefits	Capital Costs	O&M costs	SubTotal - Costs	Total Costs less Benefits (savings)
2006	-	-	-	3.9	-	-	-	-	3.48	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	3.9	-	22	22	-	3.48	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	3.9	-	91	91	-	3.48	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	3.9	-	775	775	-	3.48	-	-	-	-	-	-	-	-	-	-
2010	14,237	8,837	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	994	95	not assessed	1,089	2,729	77	2,806	1,717
2011	20,187	14,787	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,014	97	not assessed	1,111	-	79	79	(1,032)
2012	26,248	20,848	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,034	99	not assessed	1,133	-	80	80	(1,053)
2013	32,587	27,187	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,054	101	not assessed	1,156	-	82	82	(1,074)
2014	38,874	33,474	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,076	103	not assessed	1,179	-	84	84	(1,095)
2015	45,277	39,877	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,097	105	not assessed	1,202	-	85	85	(1,117)
2016	51,798	46,398	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,119	107	not assessed	1,226	-	87	87	(1,139)
2017	22,690	17,290	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,141	110	not assessed	1,251	-	89	89	(1,162)
2018	-	-	-	3.9	-	5,977	1,334	(4,643)	3.48	1,334	1,334	1,122	96	not assessed	1,218	-	91	91	(1,127)
2019	-	-	-	3.9	-	7,368	1,787	(5,581)	3.48	1,604	1,604	1,376	118	not assessed	1,493	-	92	92	(1,401)
2020	-	-	-	3.9	-	8,960	2,372	(6,589)	3.48	1,893	1,893	1,656	142	not assessed	1,798	-	94	94	(1,704)
2021	-	-	-	3.9	-	10,762	3,111	(7,652)	3.48	2,199	2,199	1,962	168	not assessed	2,130	-	96	96	(2,034)
2022	5,723	323	(5,400)	3.9	1,385	7,057	3,699	(3,358)	3.48	965	2,350	2,139	198	not assessed	2,335	-	98	98	(2,237)
2023	13,137	7,737	(5,400)	3.9	1,385	1,884	-	(1,884)	3.48	541	1,926	1,788	165	not assessed	1,954	-	100	100	(1,855)
2024	20,689	15,289	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,311	126	not assessed	1,437	-	102	102	(1,335)
2025	28,380	22,980	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,337	128	not assessed	1,466	-	104	104	(1,362)
2026	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,364	131	not assessed	1,495	-	106	106	(1,389)
2027	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,391	134	not assessed	1,525	-	108	108	(1,417)
2028	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,419	136	not assessed	1,555	-	110	110	(1,445)
2029	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,448	139	not assessed	1,587	-	113	113	(1,474)
2030	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,477	142	not assessed	1,618	-	115	115	(1,503)
2031	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,506	145	not assessed	1,651	-	117	117	(1,534)
2032	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,536	147	not assessed	1,684	-	119	119	(1,564)
2033	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,567	150	not assessed	1,717	-	122	122	(1,595)
2034	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,598	153	not assessed	1,752	-	124	124	(1,627)
2035	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,630	157	not assessed	1,787	-	127	127	(1,660)
2036	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,663	160	not assessed	1,822	-	129	129	(1,693)
2037	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,696	163	not assessed	1,859	-	132	132	(1,727)
2038	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,730	166	not assessed	1,896	-	135	135	(1,762)
2039	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,765	169	not assessed	1,934	-	137	137	(1,797)
2040	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,800	173	not assessed	1,973	-	140	140	(1,833)
2041	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,836	176	not assessed	2,012	-	143	143	(1,869)
2042	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,873	180	not assessed	2,052	-	146	146	(1,907)
2043	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,910	183	not assessed	2,093	-	149	149	(1,945)
2044	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,948	187	not assessed	2,135	-	152	152	(1,984)
2045	-	-	(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	1,987	191	not assessed	2,178	-	155	155	(2,023)
2046			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,027	195	not assessed	2,222	-	158	158	(2,064)
2047			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,068	198	not assessed	2,266	-	161	161	(2,105)
2048			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,109	202	not assessed	2,311	-	164	164	(2,147)
2049			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,151	207	not assessed	2,358	-	167	167	(2,190)
2050			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,194	211	not assessed	2,405	-	171	171	(2,234)
2051			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,238	215	not assessed	2,453	-	174	174	(2,279)
2052			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,283	219	not assessed	2,502	-	178	178	(2,324)
2053			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,328	224	not assessed	2,552	-	181	181	(2,371)
2054			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,375	228	not assessed	2,603	-	185	185	(2,418)
2055			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,422	233	not assessed	2,655	-	188	188	(2,467)
2056			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,471	237	not assessed	2,708	-	192	192	(2,516)
2057			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,520	242	not assessed	2,762	-	196	196	(2,566)
2058			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,571	247	not assessed	2,817	-	200	200	(2,618)
2059			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,622	252	not assessed	2,874	-	204	204	(2,670)
2060			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,675	257	not assessed	2,931	-	208	208	(2,723)
2061			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,728	262	not assessed	2,990	-	212	212	(2,778)
2062			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,783	267	not assessed	3,050	-	216	216	(2,833)
2063			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,838	272	not assessed	3,111	-	221	221	(2,890)
2064			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,895	278	not assessed	3,173	-	225	225	(2,948)
2065			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	2,953	283	not assessed	3,236	-	230	230	(3,007)
2066			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,012	289	not assessed	3,301	-	234	234	(3,067)
2067			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,072	295	not assessed	3,367	-	239	239	(3,128)
2068			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,134	301	not assessed	3,435	-	244	244	(3,191)
2069			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,196	307	not assessed	3,503	-	249	249	(3,255)
2070			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,260	313	not assessed	3,573	-	254	254	(3,320)
2071			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,325	319	not assessed	3,645	-	259	259	(3,386)
2072			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,392	326	not assessed	3,718	-	264	264	(3,454)
2073			(5,400)	3.9	1,385	-	-	-	3.48	-	1,385	3,460	332	not assessed	3,792	-	269	269	(3,523)
PV (2005)	7.52%											13,829	1,302		15,131	1,899	1,012	2,911	(12,220)
																Internal Rate of Return			62.55%

Table 4B: Aishihik 3rd Turbine Economics (65 years) - NPV impacts on ratepayers ($000s)

Diesel prices at $0.65/litre in 2005$, inflation at 2% per year, all present values to 2005, no assessment of benefits due to secondary sales - Base Case load forecast with Minto 32.5GWh from 2009 - 2016 & CC 48.0 from 2010 - 2017
-Assuming Aishihik Third Turbine in Service in 2010 and CS interconnected in 2010

	Project Benefits (Ratepayer Impacts)					Project Costs (Ratepayer Impacts)				Net Impacts
	total litres saved	Fuel cost savings (65 cents/litre in 2005$ plus inflation)	Diesel O&M Cost savings (1.6 cents/kW.h 2005$)	Secondary Sales Revenus	Total project benefits	Depreciation	Cost of Capital (Debt and Equity)	O&M costs	SubTotal - Costs	Net Ratepayer Impact (savings)
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	1,385	994	95	not assessed	1,089	42	204	77	323	(766)
2011	1,385	1,014	97	not assessed	1,111	42	200	79	321	(790)
2012	1,385	1,034	99	not assessed	1,133	42	197	80	320	(813)
2013	1,385	1,054	101	not assessed	1,156	42	194	82	318	(838)
2014	1,385	1,076	103	not assessed	1,179	42	191	84	317	(862)
2015	1,385	1,097	105	not assessed	1,202	42	188	85	315	(887)
2016	1,385	1,119	107	not assessed	1,226	42	185	87	314	(913)
2017	1,385	1,141	110	not assessed	1,251	42	182	89	312	(939)
2018	1,334	1,122	96	not assessed	1,218	42	178	91	311	(907)
2019	1,604	1,376	118	not assessed	1,493	42	175	92	310	(1,184)
2020	1,893	1,656	142	not assessed	1,798	42	172	94	308	(1,490)
2021	2,199	1,962	168	not assessed	2,130	42	169	96	307	(1,823)
2022	2,350	2,139	196	not assessed	2,335	42	166	98	306	(2,029)
2023	1,926	1,788	166	not assessed	1,954	42	163	100	305	(1,650)
2024	1,385	1,311	126	not assessed	1,437	42	159	102	303	(1,134)
2025	1,385	1,337	128	not assessed	1,466	42	156	104	302	(1,163)
2026	1,385	1,364	131	not assessed	1,495	42	153	106	301	(1,194)
2027	1,385	1,391	134	not assessed	1,525	42	150	108	300	(1,225)
2028	1,385	1,419	136	not assessed	1,555	42	147	110	299	(1,256)
2029	1,385	1,448	139	not assessed	1,587	42	144	113	298	(1,288)
2030	1,385	1,477	142	not assessed	1,618	42	140	115	297	(1,321)
2031	1,385	1,506	145	not assessed	1,651	42	137	117	296	(1,354)
2032	1,385	1,536	147	not assessed	1,684	42	134	119	296	(1,388)
2033	1,385	1,567	150	not assessed	1,717	42	131	122	295	(1,422)
2034	1,385	1,598	153	not assessed	1,752	42	128	124	294	(1,458)
2035	1,385	1,630	157	not assessed	1,787	42	125	127	293	(1,493)
2036	1,385	1,663	160	not assessed	1,822	42	122	129	293	(1,530)
2037	1,385	1,696	163	not assessed	1,859	42	118	132	292	(1,567)
2038	1,385	1,730	166	not assessed	1,896	42	115	135	292	(1,604)
2039	1,385	1,765	169	not assessed	1,934	42	112	137	291	(1,643)
2040	1,385	1,800	173	not assessed	1,973	42	109	140	291	(1,682)
2041	1,385	1,836	176	not assessed	2,012	42	106	143	291	(1,722)
2042	1,385	1,873	180	not assessed	2,052	42	103	146	290	(1,762)
2043	1,385	1,910	183	not assessed	2,093	42	99	149	290	(1,803)
2044	1,385	1,948	187	not assessed	2,135	42	96	152	290	(1,846)
2045	1,385	1,987	191	not assessed	2,178	42	93	155	290	(1,888)
2046	1,385	2,027	195	not assessed	2,222	42	90	158	290	(1,932)
2047	1,385	2,068	198	not assessed	2,266	42	87	161	290	(1,976)
2048	1,385	2,109	202	not assessed	2,311	42	84	164	290	(2,022)
2049	1,385	2,151	207	not assessed	2,358	42	80	167	290	(2,068)
2050	1,385	2,194	211	not assessed	2,405	42	77	171	290	(2,115)
2051	1,385	2,238	215	not assessed	2,453	42	74	174	290	(2,163)
2052	1,385	2,283	219	not assessed	2,502	42	71	178	291	(2,211)
2053	1,385	2,328	224	not assessed	2,552	42	68	181	291	(2,261)
2054	1,385	2,375	228	not assessed	2,603	42	65	185	291	(2,312)
2055	1,385	2,422	233	not assessed	2,655	42	62	188	292	(2,363)
2056	1,385	2,471	237	not assessed	2,708	42	58	192	293	(2,416)
2057	1,385	2,520	242	not assessed	2,762	42	55	196	293	(2,469)
2058	1,385	2,571	247	not assessed	2,817	42	52	200	294	(2,523)
2059	1,385	2,622	252	not assessed	2,874	42	49	204	295	(2,579)
2060	1,385	2,675	257	not assessed	2,931	42	46	208	296	(2,636)
2061	1,385	2,728	262	not assessed	2,990	42	43	212	297	(2,693)
2062	1,385	2,783	267	not assessed	3,050	42	39	216	298	(2,752)
2063	1,385	2,838	272	not assessed	3,111	42	36	221	299	(2,812)
2064	1,385	2,895	278	not assessed	3,173	42	33	225	300	(2,873)
2065	1,385	2,953	283	not assessed	3,236	42	30	230	302	(2,935)
2066	1,385	3,012	289	not assessed	3,301	42	27	234	303	(2,998)
2067	1,385	3,072	295	not assessed	3,367	42	24	239	305	(3,063)
2068	1,385	3,134	301	not assessed	3,435	42	21	244	306	(3,128)
2069	1,385	3,196	307	not assessed	3,503	42	17	249	308	(3,195)
2070	1,385	3,260	313	not assessed	3,573	42	14	254	310	(3,263)
2071	1,385	3,325	319	not assessed	3,645	42	11	259	312	(3,333)
2072	1,385	3,392	326	not assessed	3,718	42	8	264	314	(3,404)
2073	1,385	3,460	332	not assessed	3,792	42	5	269	316	(3,476)
PV (2005)		13,829	1,302		15,131	414	1,612	1,012	3,037	(12,093)
7.52%								20 year NPV (2006-2025)		(7,139)

REFERENCE: October 6, 2008 Application, Introduction, Page 1-9

YEC states that "Notwithstanding ongoing cost pressures, robust sales have allowed the Return on Equity ("ROE") earned in recent years by Yukon Energy to exceed the 9.05% level approved by the Board in 2005, permitting Yukon Energy to operate without any requirement for rate adjustments in the interim" and that actual ROE was 9.48% in 2005, 10.59% in 2006 and 9.45% in 2007.

REFERENCE: Yukon Utilities Board Report on Yukon Energy Corporation 20-Year Resource Plan, January 15, 2007, Page 50

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

REFERENCE: Hansard, Yukon Legislative Assembly, June 12, 2007
Archie Lang, Minister of Energy, Mines and Resources

"…and we're looking forward to a general rate application that will give money back to the consumers. At the end of the day, that will be a rate reduction for all ratepayers in the Yukon."

QUESTION:

a) Please provide the actual ROE for 2008.

b) Please provide a table that shows the allowed and actual ROE for 2005, 2006, 2007 and 2008 and the actual dollars associated with the under / over earnings. Please explain how these results have been weather normalized if applicable.

c) Please provide details of YEC's efforts to date to consider a performance-based regulation mechanism including earnings sharing.

d) Please describe mechanisms that would enable YEC to "give money back to the consumers" when earnings are higher than the levels determined as fair by the YUB.

ANSWER:

(a)

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

(b)

The requested table is provided below.

	Last Approved	2005 Actual	2006 Actual	2007 Actual
ROE	9.05%	9.46%	10.59%	9.45%
Difference in Earnings Compared to Last Approved ROE ($000)		227	868	229

The results have not been weather normalized, as this is not applicable to actual ROE results.

(c)

As noted in response UCG-YEC-1-32 provided during the 2005 Required Revenues and Related Matters proceeding, a multi-year performance-based regulatory framework is not currently in place in Yukon. Implementing this form of regulation would likely require

significant changes to the regulatory framework in the Yukon that have not yet been assessed. Yukon Energy has not assessed measures that the Yukon Government might adopt to bring in legislation or policy related to performance-based regulation.

(d)

The regulatory framework in the Yukon does not currently provide mechanisms that would enable Yukon Energy or YECL either (i) to "give money back to the consumers" where earnings are higher than Board-determined ROE's, or (ii) to "get more money from the consumers" where earnings are lower than Board-determined ROE's. Such an approach would in effect result in a guaranteed ROE - which is not an approach that YEC has advocated.

The current Application provides an example where the utility set out to secure material net benefits and to propose rate reductions that reflect the outcome.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-4

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

QUESTION:

a) Please provide a table showing load forecasts by customer class and by energy rate block for 2008 forecast, 2008 actual and 2009 forecast. Please explain how this data has been weather normalized if applicable.

b) Please provide a comparative table of the forecast and actual load forecast by customer class for 2005, 2006, 2007 and 2008. Please explain how this data has been weather normalized if applicable.

c) Please provide a comparative chart showing the differences between YEC's and YECL's load forecasts.

d) Please explain what discussions YEC has had with YECL to determine how best to forecast load in the Yukon.

ANSWER:

(a)

Yukon Energy does not forecast by energy rate block. Yukon Energy has relied upon YECL's forecast by rate block filed with their 2008/2009 General Rate Application.

For forecasts by customer class please see Schedule 11 in Tab 7 of the Application.

(b)

See table below.

Yukon Energy Corporation
Forecast and Actual Load by Customer Class - Company

Description	Forecast 2005	Actual 2005	*Variance %*	Forecast 2006	Actual 2006	*Variance %*	Forecast 2007	Actual 2007	*Variance %*
Residential									
Sales in MWh	10,201	10,169	*-0.32%*	10,271	10,665	*3.84%*	10,497	10,908	*3.91%*
General Service									
Sales in MWh	16,808	18,438	*9.69%*	17,805	17,037	*-4.31%*	17,531	17,507	*-0.14%*
Industrial									
Sales in MWh	0	0		0	0		0	0	
Street lights									
Sales in MWh	252	257	*2.23%*	256	270	*5.47%*	270	275	*2.01%*
Space lights									
Sales in MWh	13	14	*8.75%*	15	14	*-6.67%*	14	14	*3.03%*
Total Company - Firm Retail & Ind.									
Sales in MWh	27,274	28,878	*5.88%*	28,346	27,987	*-1.27%*	28,313	28,705	*1.38%*
Wholesale sales									
Sales in MWh	234,542	237,419	*1.23%*	241,862	251,861	*4.13%*	253,227	254,914	*0.67%*
Total Company - Firm									
Sales in MWh	261,816	266,296	*1.71%*	270,208	279,847	*3.57%*	281,541	283,619	*0.74%*
Secondary									
Sales in MWh	20,613	18,933	*-8.15%*	20,550	22,185	*7.96%*	21,183	24,225	*14.36%*
Total Company									
Sales in KWh	282,428	285,229	*0.99%*	290,758	302,032	*3.88%*	302,722	307,844	*1.69%*

Actual load data is from metered loads, and is not weather normalized.

(c)

The only rate class where YEC and YECL both prepare load forecasts is for wholesale purchases. Please see Table 2.1 at page 2-5.

(d)

Yukon Energy works with YECL annually to prepare business plan load forecasts for wholesale sales. Yukon Energy prepares its own load forecast for its customers without YECL input, as YECL has no knowledge of, or experience with, the loads in YEC served communities.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-5

YEC states that "Forecast industrial sales as provided in July 2008 by Minto Explorations Ltd. for the last three months of 2008 are 6,845 MW.h and forecast industrial sales for 2009 are 29,023 MW.h" and that "Based on Industrial Primary Rate Schedule 39 as provided for in OIC 2007/94, the forecast loads will pay an average of 10.36 cents per kWh in 2008 ($0.709 million) and 10.83 cents per kWh in 2009 ($3.142 million), excluding Rider F charges proposed to be set at 0.671 cents/kW.h in the August 25, 2008 Rate Schedule 39 filing with the Yukon Utilities Board".

QUESTION:

a) Please provide monthly details of Minto Exploration's (Capstone Mining's) electricity use, demand and bill component totals for 2008 (actual) and 2009 (forecast).

b) Please provide the calculations used to determine the average rates paid.

c) Please provide similar average rate calculations for the residential service classes for 2008 actual and 2009 forecast.

ANSWER:

(a)

Please see response provided to PWP-YEC-1-16(a).

(b) and **(c)**

See Table 2.1, and Excel spreadsheet for Tab 7 (Schedule 11) provided with response to CW-YEC-1-32. Actuals for 2008 will be provided with the anticipated update filing.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-7

YEC states that "On the MD grid, the Keno Hill property being developed by Alexco Resource Corp. ("Alexco") following its purchase of the UKHM assets in 2006, is not expected to be operational over the test years. Alexco has indicated plans to Yukon Energy that could potentially result in commencement of mining and milling operations at the Keno Hill property in early 2010, with a resultant electricity load in the 21-25 GW.h/yr range and a mine life of at least five years. Yukon Energy plans to discuss purchase power agreement arrangements with Alexco later this year".

QUESTION:

a) Please provide an update on discussions with Alexco and the forecast of electricity requirements.

ANSWER:

(a)

Please see response to LE-YEC-1-8; also see CW-YEC-1-31(a) with regard to information on forecast electricity requirement.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-8

YEC states that "A portion of the increase in general service sales during the test years is due to forecast sales to Alexco for bulk sampling operations as a general service customer on the MD system. Over the 2009 period Alexco is expected to commence bulk sampling operations at Keno Hill. The GRA forecasts that such operations will occur over the period from January 2009 to December 2009. The customer is not expected to exceed a 1 MW peak demand, and as such is classed as a general service customer for the purposes of bulk sampling operations. Yukon Energy anticipates approximately 3 GW.h of sales to Alexco during 2009 (1 GW.h of base load plus 2 GW.h for bulk sampling)".

QUESTION:

a) Please provide details of the monthly demand and energy sales levels expected to the Keno Hill operations in 2008 and 2009.

b) Please provide all correspondence with Alexco as well as internally generated reports or documents prepared for or by YEC related to the expected demand and energy requirements of the Keno Hill operations.

c) Please provide a comparative analysis of the monthly bills to Alexco in 2008 and 2009 assuming they are billed: (1) as a general service customer; and (2) as an Industrial Primary Service customer. Please provide calculations of the total bill including all applicable riders and taxes.

ANSWER:

(a)

The information as provided in the Application remains current, and reflects the level of detail that YEC is able to provide. The application notes as follows regarding forecast General Service sales (at Tab 2 page 2-8):

> A portion of the increase in general service sales during the test years is due to forecast sales to Alexco for bulk sampling operations as a general service customer on the MD system. Over the 2009 period Alexco is

expected to commence bulk sampling operations at Keno Hill. The GRA forecasts that such operations will occur over the period from January 2009 to December 2009. The customer is not expected to exceed a 1 MW peak demand, and as such is classed as a general service customer for the purposes of bulk sampling operations. Yukon Energy anticipates approximately 3 GW.h of sales to Alexco during 2009 (1 GW.h of base load plus 2 GW.h for bulk sampling).

(b)

The information provided in the Application at Tab 2, page 2-8 remains current. Internal documents related to providing service to specific customers are considered confidential and cannot be provided.

(c)

Alexco does not currently qualify as an industrial customer due to the nature of the operations currently being undertaken at the Keno Hill site and due to the current load (i.e., it does not exceed 1 MW). Alexco mining operations are not expected to commence until after the test year, at which time its load will be supplied under Industrial Rate Schedule 39.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-9

With respect to secondary sales, YEC states that "For test year 2008, forecast sales decline to 20,557 MWh, primarily due to equipment outages at a small number of the largest secondary customers through the early part of the year. In test year 2009, the availability of surplus power is expected to decrease with increased firm loads (including grid service to Minto Mine)".

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-9

With respect to secondary sales, YEC states that it has "rules in place, as approved by the Board pursuant to Rate Schedule 32 that interrupt secondary sales as required to ensure these sales are not served by high-cost diesel generation but only by surplus hydro".

QUESTION:

a) Please provide details of the monthly secondary sales levels and number of customers for 2005, 2006, 2007 and 2008.

b) Please provide a listing of secondary sales customers and their individual sales levels in the Yukon. If privacy legislation prevents the identification of these customers, please list them generically.

c) Please provide details of the periods during 2007 and 2008 that electricity was not available for secondary sales.

d) Please provide an estimate of the additional costs incurred by secondary sales customers when the secondary energy has not been available.

ANSWER:

(a)

The requested information is provided in the table below.

WAF Grid Monthly Secondary Sales Levels and Number of Customers

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	Customers	19	20	21	21	21	19	17	17	19	19	21	22
Actual	Sales (MWh)	1,395	1,254	1,581	2,060	1,435	1,316	981	1,173	1,376	1,894	2,171	1,726
2006	Customers	22	22	20	18	18	20	19	18	18	19	20	20
Actual	Sales (MWh)	2,429	1,658	1,847	2,086	1,583	1,306	1,257	1,217	1,545	1,836	2,186	2,605
2007	Customers	21	20	20	20	20	20	18	17	19	20	20	20
Actual	Sales (MWh)	2,716	2,421	2,288	2,428	1,822	1,471	1,499	1,156	1,489	1,786	2,363	2,126
2008	Customers	20	20	21	21	20	20	17	17	21	21	21	21
Forecast	Sales (MWh)	2,339	1,770	1,742	1,893	1,194	1,069	962	1,079	1,428	1,783	2,236	2,412

Mayo-Dawson Grid Monthly Secondary Sales Levels and Number of Customers

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	Customers	1	1	1	1	1	1	1	1	1	1	1	1
Actual	Sales (MWh)	83	88	56	69	31	22	0	1	26	46	72	77
2006	Customers	1	1	1	1	1	1	1	1	1	1	1	1
Actual	Sales (MWh)	102	83	90	61	39	24	5	0	26	37	73	89
2007	Customers	1	1	1	1	1	1	1	1	1	1	1	1
Actual	Sales (MWh)	107	94	104	56	30	24	19	3	28	42	72	80
2008	Customers	1	1	1	1	1	1	1	1	1	1	1	1
Forecast	Sales (MWh)	114	71	79	65	49	24	5	0	30	50	80	85

(b)

The requested information is provided in the table below.

Yukon Secondary Sales Customers and Individual Sales Levels (MWh)

Customer	2005 Actual	2006 Actual	2007 Actual	2008 Forecast	2009 Forecast
WAF Grid					
G-1	3,343	3,649	4,449	3,782	2,652
G-2	181	115	63	184	127
G-3	4,878	7,644	8,277	6,399	5,086
G-4	2,156	2,431	3,871	2,344	2,180
G-5	3,859	3,581	3,059	2,928	2,543
G-6	792	628	506	578	414
G-7	-	-	-	333	550
G-8	67	78	67	91	51
G-9	28	28	25	28	20
G-10	217	231	281	285	203
C-1	16	17	12	8	8
C-2	146	169	199	190	131
C-3	55	68	54	55	44
C-4	82	77	140	108	84
C-5	23	24	14	14	10
C-6	2	3	3	2	1
C-7	9	(0)	0	0	-
C-8	576	664	548	414	410
C-9	397	399	336	391	283
C-10	1,515	1,706	1,615	1,732	1,162
C-11	2	17	17	19	11
C-12	18	28	31	20	13
C-13	2	0	-	0	-
MD Grid					
MD-1	570	630	659	652	630
Total Sales	18,933	22,185	24,225	20,557	16,613

Note: G - Government; C - Commercial.

(c)

The periods during 2007 and 2008 that electricity was not available for secondary sales are as follows in the table below:

Secondary Sales Curtailments				
Year	**Reason**	**Suspended**	**Reinstated**	**Days**
2007	N/A	None	None	0
2008	Loss of WH3	20-Oct-08	7-Nov-08	18
	Low Temperatures	15-Dec-08	12-Jan-09	28

(d)

Please see response provided to CW-YEC-1-8(d).

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-9

With respect to secondary sales, YEC states "While Yukon Energy has in the past pursued opportunities to increase the sale of surplus power to general service secondary customers, this marketing effort is no longer active as future opportunities for secondary sales on the WAF system have become severely limited as winter peak demands approach levels that would require some peaking diesel generation. Similarly, limits on Mayo generation in future are also anticipated to result in reduced availability of secondary sales on the Mayo-Dawson system, and as such this rate offering is also not being actively marketed on that system".

QUESTION:

a) Please confirm that surplus power is available throughout the year.

b) Please provide details of the amount of surplus power available per month in 2005, 2006, 2007, 2008 and 2009 (forecast).

c) Please provide details of the costs incurred to actively market surplus power.

ANSWER:

(a)

Not confirmed. Surplus power is not available during peak (winter) periods when diesel generation is required to supply loads.

As noted in Tab 2 at page 2-9 and 2-10, since 2005 further increases in secondary sales quantities have not been aggressively targeted as the remaining surplus available on the system was diminishing. At page 2-10 it is noted that "while Yukon Energy has in the past pursued opportunities to increase the sale of surplus power to general service secondary customers, this marketing effort is no longer active as future opportunities for secondary sales on the WAF system have become severely limited as winter peak demands approach levels that would require some peaking diesel generation. Similarly, limits on Mayo generation in further are also anticipated to result in reduced availability of secondary sales on the Mayo-Dawson system, and as such this rate offering is also not being actively marketed on that system.

(b)

The requested information is provided in the table below. This information reflects only that portion of "surplus" power relevant to secondary sales loads – as noted elsewhere, the overall total surplus in 2005 far exceed this number and continues to exceed it today.

Surplus power provided (made available) per month for the period of 2005-2009 (MW.h)

	Actual 2005	Actual 2006	Actual 2007	Forecast 2008	Forecast 2009
January	1,478	2,530	2,822	2,453	288
February	1,341	1,741	2,515	1,841	80
March	1,637	1,936	2,392	1,821	2,351
April	2,129	2,146	2,484	1,958	2,087
May	1,467	1,622	1,852	1,243	1,755
June	1,338	1,330	1,496	1,093	1,291
July	981	1,263	1,518	967	972
August	1,174	1,217	1,159	1,079	1,064
September	1,402	1,571	1,517	1,458	1,295
October	1,940	1,873	1,829	1,833	1,783
November	2,243	2,259	2,434	2,316	2,023
December	1,803	2,694	2,207	2,497	1,624
Total	**18,933**	**22,185**	**24,225**	**20,557**	**16,613**

(c)

Surplus power is not actively being marketed and no costs are being incurred.

REFERENCE: October 6, 2008 Application, Sales and Generation, Page 2-12

YEC states "Separately, as noted to the Board in Yukon Energy's application for approval of the Minto PPA, Yukon Energy has determined that 6.4 MW of diesel capacity can be added to the system in a flexible manner through purchase of the currently installed diesel units at the Minto mine-site. While this purchase was a term of the Minto PPA, it is also highly advisable for a number of reasons, as set out in Tab 5, including reducing line losses, reducing diesel generation near major population centers such as Whitehorse, as well as being the least cost source of new capacity available to Yukon Energy. This purchase will be completed in 2008".

QUESTION:

a) Please confirm that the Minto PPA requires Minto (Capstone) to pay for all costs associated with the referenced diesel units at the mine if these units are required to supply the Minto (Capstone) mine site.

b) Please confirm that Minto (Capstone) is not required to pay any costs associated with the referenced diesel units if they are used by YEC to supply the grid.

c) Please explain the process YEC uses to determine the costs associated with the Minto diesel generators.

d) Please provide details of the costs incurred to operate the referenced diesel units in 2008 and who was responsible for the costs and reasons why.

ANSWER:

(a) and **(b)**

As noted in response to UCG-YEC-1-25 and UCG-YEC-2-35 provided during the PPA hearing, YEC is generally responsible for all costs of operating and maintaining the Diesel Units, except under the special circumstances addressed in Sections 4.8 and 10.4(b) of the Power Purchase Agreement with Minto.

Section 10.4 of the PPA provides that subject to 10.4(b), YEC will be responsible for operation and maintenance costs for the Diesel Units for so long as the Diesel Units are leased by YEC from Caterpillar or owned by YEC and remain at the Mine Site. Minto is fully responsible under Section 10.3(b) for all payments to Caterpillar for these units.

Section 10.4(b) provides that during any period when YEC is unable to provide Grid Electricity to the Mine, and YEC is also otherwise unable to use the Diesel Units to supply Electricity to the WAF grid, Minto may by providing written notice to YEC require that the Diesel Units be used to supply the Mine with Electricity with the sole cost to Minto being costs for fuel and operator assistance.

Section 4.8 provides Minto with similar rights and cost obligations if it notifies YEC that it requires the Diesel Units be used to supply the Mine with Electricity under certain circumstances where Minto considers its equipment at the Mine to be at risk of damage from the supply of Grid Electricity and YEC is also unable to use the Diesel Units to supply Electricity to the WAF grid.

(c)

The PPA sets out that the sole cost to be charged to Minto for use of the diesels pursuant to section 10.4(b) is for fuel and operator assistance. The costs of fuel will be based on the metered or estimated quantity of fuel consumed during such operation. Time for Minto operator assistance is charged out at cost.

(d)

Grid service to the Minto Mine did not commence until November 22, 2008. The Minto diesels were not required to provide grid service for the remainder of that year.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-2

YEC states "Completion of the Stage One CSTP, which contributes to these increased revenue requirements, is the key factor leading to an overall 2009 rate reduction (see Tab 4) due to additional revenues and cost savings derived from commencement of grid service to the Minto mine and Pelly Crossing."

QUESTION:

a) Please confirm that Yukon Electrical Company Limited is responsible for operating the diesel generators at Pelly Crossing and for distribution of power in the community.

b) Please provide details of the savings and costs to be realized at Pelly Crossing by YEC as well as by YECL as a result of the Stage One CSTP.

ANSWER:

(a)

Confirmed.

(b)

As noted in the YECL 2008/2009 GRA, completion of Yukon Energy's new transmission facilities to Pelly Crossing in 2008 enables YECL thereafter to secure approximately $600,000 ongoing fuel and other operating cost savings that are reflected in that Application's forecasts. This is based on actual 2007 fuel volumes (654,000 litres) and 2009 fuel price forecasts (89.33 cents per litre) in the YECL Application for Pelly Crossing (Exhibit B-4, Schedule 4.2 of that proceeding), YECL cost savings in 2009 after this community is connected to the grid would approximate $584,000 for fuel plus other savings for O&M costs (See also Grattan, YECL GRA Transcript page 281, lines 16-29).

As noted at page 2-3 of the Application Yukon Energy forecast an approximate 2,300 MW.h increase in annual wholesale sales to YECL due to the completion of the Stage 1 CSTP and the provision of grid service to Pelly Crossing.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-3

YEC states "The forecast Return on Rate Base cost increase from 2005 to 2009 of $1.241 million (13% increase) accounts for about 24% of the overall revenue requirement change from 2005 to 2009. Mid-year rate base increases by 8.5% from 2005 to 2009. Debt costs, as part of Return on Rate Base, increase by $1.287 million (about 30%); in contrast, equity return decreases by $0.046 million, due to the reduced return on equity forecast for 2009 (8.64%) compared to the equity return allowed in 2005 (9.05%) and actually earned in 2005 (9.46%)".

QUESTION:

a) Other than the Auditor General's review of the Mayo-Dawson transmission line project and regular internal audits, have there been any independent audits completed on YEC's operating and capital expenses or YEC's debt management program?

b) Please provide a copy of any independent audits conducted in 2005, 2006, 2007 and 2008.

ANSWER:

(a) and **(b)**

There have been no independent financial audits completed outside of normal year-end processes.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-16

YEC states "Yukon Energy's depreciation costs continue to be based on depreciation rates approved by the YUB in Order 2005-12".

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-3

YEC states "The forecast Depreciation and Amortization cost increase from 2005 to 2009 of $1.551 million (29% increase) accounts for about 30% of the overall revenue requirement change from 2005 to 2009. Over 50% of the Depreciation and Amortization cost increase is due to amortization cost increases, including costs for planning studies, regulatory activities and licensing costs related to Yukon Energy's ongoing generation and transmission requirements. Although fixed asset depreciation increases by $1.504 million (30%) from 2005 to 2009, net depreciation costs after customer contributions only increase by $0.733 million (about 16%), reflecting in part contributions to the CSTP costs from Minto Explorations, the Yukon Government and Yukon Development Corporation".

QUESTION:

a) Please confirm that the depreciation rates approved in Order 2005-12 were based on a study conducted by Gannett Fleming related to YEC's plant as of December 31, 2003.

b) Given Gannett Fleming's suggestion that the completion of full depreciation reviews should be undertaken every 3 to 5 years (per YEC's response to MCMAHON-YEC-1-16 in the 2005 Required Revenues and Related Matters proceeding), please explain why YEC did not undertake a depreciation study for this current application.

c) Please indicate when YEC intends to undertake its next full depreciation study.

ANSWER:

(a)

Confirmed. As noted in the depreciation study included at Tab 11 in the 2005 Required Revenues and Related Matters Application the calculated annual depreciation accrual rates presented in the report are related to the utility plant in service as of December 31, 2003.

(b)

Yukon Energy sought to manage the extent of studies and costs for regulatory filings. There are not expected material issues with the currently approved depreciation rates as established by the 2003 Gannett-Fleming Study, and as such there is no justification for incurring the expense of a further study at this time.

(c)

Yukon Energy currently has no plans to undertake a further depreciation study at this time.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-17**

YEC states "The largest component of deferred charges relates to planning and study costs, regulatory hearing costs and licencing costs related to maintaining licences of YEC's hydro facilities and air emission permits. The cost for amortization of deferred charges has increased $0.818 million, from $0.889 million in actual 2005 to $1.707 million forecast in 2009 as set out in Tab 5. The largest component of this increase since 2005 ($0.547 million) relates to planning and study costs, which is primarily studies of the existing system and options for expanding the quantity of renewable generation, as well as studies related to the safety and reliability of the system, the Minto Mine PPA negotiations, and other small projects, offset by the termination of amortization since 2005 on old study amounts as they become fully amortized".

QUESTION:

a) Please provide a detailed listing of all deferred charges, descriptions of the charges incurred and a description of the reason for incurring the costs for 2005 (allowed), 2005 (actual), 2006 (actual), 2007 (actual), 2008 (actual) and 2009 (forecast).

b) Please explain why "Minto Mine PPA negotiations" and the "PPA proceeding" would be a cost to be paid by ratepayers versus the Minto (Capstone) mine.

ANSWER:

(a)

For descriptions of all actual deferred charges incurred from 2005 through 2007 please see Tables 5.3 through 5.7 in Tab 5 of the Application. For 2005 Allowed charges please see Table 5.3 in Tab 5 of the 2005 Required Revenues and Related Matters Application.

Actuals for 2008 are currently not available.

(b)

Ratepayers secured significant benefits through the negotiation of the Power Purchase Agreement with Minto mine, through increased revenues from grid service to Minto mine and Pelly Crossing as well as long term infrastructure benefits through contributions to the CSTP.

Please see response to UCG-YEC-1-10. The PPA proceeding costs are not charged directly to Minto as there is no provision for such assignment of these costs in the YUB approved PPA. The costs also are not to be charged directly to Minto as part of their rate as the rate is fixed by OIC and not subject to revision to assign additional costs.

Also, YUB-YEC-1-10(b) notes that, “the Minto PPA negotiations are accounted for in this manner because it is considered to be a regulatory cost”.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-19; Table 3-14 – Cost of Capital**

QUESTION:

a) Please update this table by adding columns for 2005 Allowed and 2008 Actual.

b) Please confirm that without Board approvals since 2005, the capital structure, cost of debt and return on equity provisions included in the revenue requirement approved for 2005 remained the approved amounts for 2006 and 2007.

c) Please provide YEC's understanding of the YUB's role in determining and approving the deemed capital structure of YEC for rate-setting purposes.

ANSWER:

(a)

Table 3.14 from the 2008/2009 General Rate Application is revised below to include the "Approved 2005" information.

Table 3.14
Cost of Capital

					Forecast		Forecast	
	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Average Cost of Debt	5.12%	5.18%	5.47%	5.49%	5.67%	5.68%	6.16%	6.19%
Return on Equity	9.05%	9.46%	10.59%	9.45%	9.55%	8.64%	11.03%	8.64%
Average Cost of Capital	6.69%	6.89%	7.52%	7.07%	7.22%	6.86%	8.11%	7.17%

Actuals for 2008 cannot be provided at this time.

(b)

Not confirmed. There was no Board approved revenue requirement for 2006 and 2007, as they were not GRA test years.

Note, however, that YEC was ordered by the Board (in Order 2005-12) to file its financial forecast for each of 2006 and 2007 with the Board to confirm the need for the $292,000 drawdown of the Faro Dewatering Account in each year. In this regard, contrary to the suggestion in the question, there was “Board approvals” in respect of each year.

(c)

The Board has jurisdiction to determine a fair rate of return of Yukon utilities, and in this regard may (and does) assess the reasonableness of a utility’s capital structure.

Regulation of Yukon Energy to date has been based on the actual capital structure for the utility and as such there has been no “deemed capital structure”.

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-19

YEC states "Yukon Development has provided long-term advances totaling $40.032 million as at December 31, 2007, with interest rates ranging from 5.28% to 6.03%. Additional advances of $3.515 million from Yukon Development are forecast at December 31, 2008 and a further $5.043 million at December 31, 2009, with forecast interest rates of 5.28% to maintain the 60% debt and 40% equity balance" and that "Debt issued between Yukon Development and Yukon Energy is priced based on a "spread" over long Canada bonds of 120 basis points. The long Canada bond yield during the preparation of this filing was 4.08%, supporting a rate for new long term debt of 5.28%".

REFERENCE: Schedule 13 of Tab 7

QUESTION:

a) Please provide a detailed description of the purpose for each of the unsecured advances from YDC.

b) Please describe in detail the calculations of the interest rates attached to each of the unsecured advances from YDC. Please include references to all source documents.

c) Please explain how this method of interest calculation was determined.

d) Please provide all internally generated reports or documents prepared for or by senior management or otherwise related to the determination of method of interest calculation for the unsecured advances from YDC.

ANSWER:

(a)

The unsecured advances from YDC are to maintain an appropriate capitalization of Yukon Energy.

Yukon Energy's practice with respect to dividends and issuances of long-term debt is to declare dividends out of equity and issue long-term debt annually, as required in order to maintain a 60% debt: 40% equity capital structure at year end, while retaining a minimum of cash in the utility outside of amounts required to finance the ongoing capital program. These unsecured advances are required to maintain a 60:40 debt equity ratio and to address repayment of other debt during the course of each year.

(b)

The interest rates attached to the YDC advances are the Long-Term Benchmark Canada Bond Yields for December 31 of the respective year (as published on the Bank of Canada website) plus 120 basis points.

(c) and **(d)**

Please see CW-YEC-1-26(a).

REFERENCE: October 6, 2008 Application, Revenue Requirement, Page 3-19

YEC states "Yukon Energy has agreed to purchase the diesel units currently installed at the Minto mine (the "Minto Diesels") and finance the $2.24 million purchase price of these units with Minto over 7 years. The rate on this financing is 7.5%, equal to all interest rates on advances contained in the Minto Power Purchase Agreement ("PPA") as reviewed by the YUB in early 2007, and payments are equal blended principal and interest monthly. The outstanding balances on this advance total $2.179 million at year-end 2008 and $1.921 million in 2009, with interest costs of $0.042 million (partial year 2008) and $0.155 million (full year 2009) respectively".

QUESTION:

a) Please confirm that the 7.5% cost of capital rate incorporated into the Minto Power Purchase Agreement was deemed to be YEC's average weighted cost of debt and equity for new capital projects.

b) Please provide a calculation of YEC's actual average weighted cost of debt and equity for new capital projects in 2008.

ANSWER:

(a)

Confirmed.

(b)

YEC does not plan to borrow specific debt for individual capital projects. New capital secured for YEC in 2009 is forecast to cost 8.49% for equity, and 5.28% for debt, or an average of 6.56% at a 60:40 ratio.

As to actual 2008, Yukon Energy's proposed fair return on equity is 8.64% and 4.65% was the cost of new long-term debt declared at year-end 2008, which yields an average of 6.25% (at 60:40 debt:equity).

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-20**

YEC states: "In order to provide the 60% long-term debt component of the Mayo-Dawson project capital costs, and to ensure ratepayers would not be worse off in any year as a result of the Mayo-Dawson project than they would have been had Dawson remained on diesel fuel generation, Yukon Development provided an $18 million advance with flexible terms with respect to interest payable ("Mayo Dawson Note"). The forecast balance on the Mayo-Dawson Note is $15.607 million as at year-end 2008 and $15.157 million at year-end 2009. The face interest rate on the note is 6.55% and, due to the present substantial benefits to ratepayers arising from the Mayo-Dawson line given current and forecast diesel fuel prices, the full 6.55% face interest rate is forecast to be paid in 2008 and 2009".

QUESTION:

a) Please explain how the interest rate on the reference note was determined.

b) Given the ongoing reductions in interest rates, has YEC considered refinancing this debt at a more favourable interest rate?

ANSWER:

(a)

Please see response to LE-YEC-1-37.

(b)

No.

The Mayo-Dawson Note is long term debt incurred as a component of financing the Mayo Dawson Project. Consistent with its structure as long-term debt, the face interest rate on the note is fixed for the duration of the note.

Further, the provisions of the Mayo Dawson Note are designed to protect ratepayers in the event of underperformance of the line, ensuring ratepayers will not pay more in any year than they would have had Dawson remained on diesel generation. The 6.55% face interest on the promissory note is the Maximum Interest Payable, and actual interest in any given year can be adjusted downwards to ensure that ratepayers are not paying any more in any year of the Project than the costs that would have been payable had Dawson remained on diesel generation. Consequently, the lender (YDC) bears risks with respect to the performance of the line and its role in YEC's system. It is not expected that any outside lender would accept such terms in any refinancing.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-20**

YEC states: "The outstanding balance on the TD Canada Trust term note at year-end 2008 is $7.163 million and $6.471 million at year-end 2009. This note has an effective interest rate of 7.81% with equal blended monthly principal and interest payments, and is due in 2011".

QUESTION:

a) Given the ongoing reductions in interest rates, has YEC considered refinancing this debt at a more favourable interest rate?

ANSWER:

(a)

Please see response to LE-YEC-1-38.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-20**

YEC states: "Yukon Energy's cost of equity in 2009 is a function of the risks inherent in Yukon Energy's business, the returns that could be earned elsewhere with equity investments of equivalent risk, and the requirement in OIC 1998/32 that Yukon Energy receive a fair return on equity less 0.5%."

QUESTION:

a) To YEC's knowledge, have there ever been any discussions related to increasing the 0.5% adjustment to YEC's rate of return on equity as a means for reducing overall costs to be recovered from ratepayers? If yes, please provide details.

ANSWER:

(a)

To YEC's knowledge there have been no discussions related to changing the 0.5% overall adjustment to YEC's rate of return on equity.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-21**

YEC states: "In particular, in the 2005 proceeding, the fair ROE for test year 2005 was proposed by Yukon Energy to be set by reference to the British Columbia Utilities Commission ("BCUC") formulaic ROE approach, based on Yukon Energy receiving a 52 basis points premium due to its risk compared to low risk utility. This was accepted by the Board in Order 2005-12. As set out in Tab 8, Yukon Energy has maintained this same approach to set the proposed ROE for 2008, at 8.64%. For 2009, Yukon Energy proposes that the ROE be set using the same approach, based on the BCUC calculations to be completed approximately at the end of November, 2008, and that this ROE be incorporated in the requested approvals for 2009 at that time. For the purposes of this filing document, a 2009 "placeholder" ROE of 8.64% has been utilized, to be consistent with 2008".

QUESTION:

a) Please confirm that the BCUC has determined that the allowed return on common equity for a low-risk benchmark utility in 2009 is 8.47% which results in a proposed 8.49% ROE for YEC in 2009.

b) Please provide a calculation of YEC's average weighted cost of capital for 2009 assuming a proposed 8.49% ROE.

c) Please provide a calculation of YEC's return on rate base using an 8.49% ROE for 2009.

d) Please provide justification for YEC's proposed 52 basis points premium related to risk in 2008 and 2009. Please provide the qualifications of the person providing this justification.

e) In what way was YEC or data specific to YEC included in the statistical analysis or deliberations conducted by the BCUC when developing and then enhancing its formulaic approach? If YEC-related data used in BCUC deliberations, please provide details of utilities comparable to YEC that have been included in the BCUC's analysis.

ANSWER:

(a)

Please see response to LE-YEC-1-39(a) and YUB-YEC-1-15(d).

(b) and **(c)**

All other assumptions unchanged, using 8.49% for the test years would change the weighted average cost of capital in Schedule 4.C of Tab 7 of the Application from 7.17% to 7.11%. Similarly, with all other assumptions unchanged, the total return on rate base for the test years would change from $10.859 million to $10.768 million.

(d)

Please see discussion in 2005 Required Revenues and Related Matters Application related to the justification of the 52 basis point risk premium for Yukon Energy (at pages 8-4 to 8-6). This Application was reviewed by the Yukon Utilities Board in 2005 where the Board determined that the 52 basis point risk premium was appropriate.

Also see YUB-YEC-1-15(c).

(e)

Yukon Energy has previously noted in response to information request MCMAHON-YEC-1-32(c) (during the 2005 Required Revenues and Related Matters hearing) that, “YEC is not aware that the BCUC considered YEC or any YEC specific data in developing its approach to setting the return on equity for a benchmark utility”.

REFERENCE: **October 6, 2008 Application, Revenue Requirement, Page 3-21**

YEC states that the Deferred Fuel Price Account (Rider F) was "established pursuant to Order in Council 1995/90 section 8. This account captures all variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA-approved fuel prices. Pursuant to Board Order 2005-12, Yukon Energy also credits this account with all variations (positive or negative) in the ongoing quarterly adjustment to the prices of secondary sales, compared to the most recent GRA-approved price. As with the typical situation where final rates are put in place following the start of the test year, once final approvals are received for new test year fuel prices, Yukon Energy recalculates the balances in these accounts to ensure that all charges to the accounts are precisely equal to what would have occurred had the ultimate YUB approvals been known at the start of the first test year".

QUESTION:

a) Please confirm that Rate Schedule 39 for industrial customers includes a provision that Rider F is set to $0.00 for this class of customer.

b) Please provide a calculation of what the Rider F charge would be in 2007, 2008 and 2009 for industrial customers under Rate Schedule 39 if it was not eliminated by Order-in-Council.

c) Please calculate the total amount of Rider F revenue that would have been collected from the industrial class in 2007, 2008 and 2009 under Rate Schedule 39 if the rates calculated in (b) had been charged.

d) Please provide a calculation of Rider F for the residential and commercial classes for 2007, 2008 and 2009. Please fully explain any differences in the calculations for the different customer classes.

e) Please provide YEC's rationale for keeping secondary sales customers immune from Rider F.

f) Please identify when the referenced "most recent GRA-approved price" was set.

g) Please confirm that the benchmark upon which Rider F is determined would be adjusted to match fuel costs approved for 2008 and 2009 in this proceeding.

ANSWER:

(a)

Not confirmed. The Rider F for Rate Schedule 39 is set to $0.00 only for the "fuel price forecast filed November 20, 2006".

(b) and **(c)**

Yukon Energy did not serve any industrial customer under Rate Schedule 39 for 2007 and most of 2008. Service to Minto only commenced in late November, 2008. Since that time Minto has been paying a Rider F of 0.671 cents/kW.h, as set out in Yukon Energy's August 25, 2008 filing with the Board.

(d)

There is no difference in Rider F for individual firm retail customer classes. Rider F calculations reflect joint YEC/YECL forecasts of the overall Rider F account balances, as set out in filings made with the YUB when each change is made to Rider F. These assessments address fuel price variance impacts from the last GRA approved fuel price for each utility, and also YEC's secondary energy sale price variance impact from the last GRA approved energy sale price.

Rider F filings since February 2006 are included in Attachment 1 to this response, setting out the process for deriving the Rider F changes in each instance. The latest Rider F change will occur March 1, 2009 (when Rider F will be set to zero).

(e)

Secondary sales provided under Rate Schedule 32 are interruptible sales (not firm). Rates for this service are set to reflect the customer's alternative cost of heating (i.e., oil). There is no basis in this type of rate to include an additional Rider F charge.

(f)

The “most recent GRA-approved price” for YEC was set for 2005 by Order 2005-12 subsequent to the 2005 Required Revenues and Related Matters proceeding. Rider F is a consolidated rider with YECL; in the case of YECL the “most recent GRA-approved price” is presently the 1997 fuel price approved in the 1996/97 GRA.

(g)

Confirmed. It is anticipated that all charges and credits by YEC to the Deferred Fuel Price Account (the Rider F account) will be re-stated back to January 1, 2008 after a final Board order is received approving a 2008/2009 Revenue Requirement for Yukon Energy.

The Yukon Electrical Company Limited
An ***ATCO*** Company

February 7, 2006

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Acting Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90 and due to the increases in diesel fuel prices, The Yukon Electrical Company Limited and Yukon Energy Corporation are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from 0.7909 cents per kW.h to 1.2799 cents per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after March 1, 2006.

As of January 31, 2006, the Companies are owed approximately $635,000 in cumulative fuel price variance shortfalls. We also expect to incur, on average, approximately $240,000 per month in charges in excess of the forecast fuel prices currently included in rates.

As described in Yukon Energy's 2005 Revenue Requirements Application, this is the first Rider F calculation that includes a component for the variance between the forecast and actual secondary sales rates. As the actual 2005 rate was higher than the forecast rate, a favourable variance of $18,761 was created to offset the cumulative negative fuel variance. Between February 2006 and February 2007, a favourable secondary sales variance of approximately $211,000 has been forecast.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to February 28, 2007. As in the past, the Companies commit to review the situation on an ongoing basis to ensure the balance in the account and the collections from ratepayers is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Doug Tenney
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

The Yukon Electrical Company Limited
Yukon Energy Corporation
Rider F Calculation
As At January 31, 2006
(Forecast Implementation Date in CIS = March 1, 2006)

The Yukon Electrical Company Limited

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	
Due From (To) Customers - as at January 31, 2006					675,363
Feb-06	Estimated Net			50,000	
Mar-06	33.48	85.92	479,987	251,695	
Apr-06	33.84	83.75	454,098	226,627	
May-06	34.18	83.84	428,642	212,877	
Jun-06	33.58	83.03	442,714	218,936	
Jul-06	33.32	84.12	411,906	209,241	
Aug-06	32.79	83.20	458,014	230,874	
Sep-06	32.90	82.87	453,359	226,529	
Oct-06	33.97	82.36	447,008	216,329	
Nov-06	33.50	85.08	519,092	267,759	
Dec-06	33.26	84.94	568,107	293,624	
Jan-07	33.00	83.18	612,509	307,372	
Feb-07	34.00	83.35	561,654	277,151	
Sub total				2,989,012	2,989,012
YECL Shortfall					**3,664,375**

Yukon Energy Corporation

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	Secondary Sales Adjmt	
Due From (To) Customers - as at January 31, 2006						(39,554)
Feb-06	Estimated Net			(10,000)	(33,620)	
Mar-06	0.5995	80.00	21,231	16,858	(29,913)	
Apr-06	0.5995	72.06	20,409	14,584	(13,821)	
May-06	0.5995	72.06	19,520	13,949	(10,914)	
Jun-06	0.5995	72.06	21,602	15,437	(8,921)	
Jul-06	0.5995	72.06	24,449	17,471	(7,134)	
Aug-06	0.5995	72.06	22,837	16,319	(7,227)	
Sep-06	0.5995	72.06	24,852	17,759	(10,856)	
Oct-06	0.5995	72.06	19,473	13,916	(13,050)	
Nov-06	0.5995	72.06	20,682	14,779	(17,004)	
Dec-06	0.5995	72.06	22,730	16,243	(19,363)	
Jan-07	0.5995	72.06	24,383	17,424	(20,241)	
Feb-07	0.5995	72.06	22,773	16,274	(19,211)	
Sub total				181,014	(211,274)	(30,260)
YEC Shortfall						**(69,815)**

Combined YEC/YECL shortfall **3,594,561**

2006 - 2007 Forecast Retail Sales (kwh's) - March 1, 2006 - February 28, 2007

YECL	252,400,000	
YEC	28,453,016	
Total		280,853,016

Rider F rate - price per kwh (cents) to recover 100% of shortfall to February 28, 2007 **1.279872601**

The Yukon Electrical Company Limited
An ATCO Company

November 10, 2006

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Acting Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of a decrease in the automatic fuel price adjustment rider (Rider F) from 1.2799 cents per kW.h to .9638 cents per kW.h based on the attached forecast. The decrease will be effective for bills rendered on or after December 1, 2006.

Rider F collections since March 1, 2006 have reduced the accumulated deficit for fuel price variance down from $657,000 so that as of October 31, 2006, the Companies are owed approximately $35,000 in cumulative fuel price variance shortfalls. We expect to incur, on average, charges of approximately $245,000 per month in excess of the forecast fuel prices currently included in rates. This monthly fuel variance is forecast to be offset by a favorable Secondary Sales rate variance averaging $19,000 per month for a combined variance of $226,000 per month.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to November 2007. As in the past, the Companies commit to review the situation on an ongoing basis to ensure the balance in the account and the collections from ratepayers is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Doug Tenney
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

WHITEHORSE 2007
JEUX DU CANADA GAMES
OFFICIAL SUPPLIER - FOURNISSEUR OFFICIEL

100 – 1100 First Avenue, Whitehorse, YT Y1A 3T4 tel: 867-633-7000 or 1-800-661-0513 fax: 867-668-3965

WHITEHORSE 2007
JEUX DU CANADA GAMES

The Yukon Electrical Company Limited
Yukon Energy Corporation
Rider F Calculation
As At October 31, 2006
(Forecast Implementation Date in CIS = December 1, 2006)

The Yukon Electrical Company Limited

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	
Due From (To) Customers - as at October 31, 2006					34,538
Nov-06	Estimated Net			74,500	
Dec-06	33.26	83.56	568,107	285,767	
Jan-07	33.00	83.56	607,281	307,041	
Feb-07	34.00	83.56	561,654	278,356	
Mar-07	33.48	83.56	479,987	240,377	
Apr-07	33.84	83.56	454,098	225,778	
May-07	34.18	83.56	428,642	211,663	
Jun-07	33.58	83.56	442,714	221,268	
Jul-07	33.32	83.56	411,906	206,942	
Aug-07	32.79	83.56	458,014	232,534	
Sep-07	32.90	83.56	453,359	229,672	
Oct-07	33.97	83.56	447,008	221,671	
Nov-07	33.50	83.56	519,092	259,857	
Sub total				2,995,427	2,995,427
YECL Shortfall					**3,029,965**

Yukon Energy Corporation

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	Secondary Sales Adjmt	
Due From (To) Customers - as at October 31, 2006						-
Nov-06	Estimated Net			(50,000)	-	
Dec-06	59.95	78.68	11,374	2,130	(25,766)	
Jan-07	59.95	78.68	12,083	2,263	(27,665)	
Feb-07	59.95	78.68	11,114	2,082	(25,518)	
Mar-07	59.95	78.68	10,802	2,023	(23,373)	
Apr-07	59.95	78.68	10,167	1,904	(19,081)	
May-07	59.95	78.68	9,765	1,829	(15,380)	
Jun-07	59.95	78.68	10,793	2,021	(11,997)	
Jul-07	59.95	78.68	12,559	2,352	(9,232)	
Aug-07	59.95	78.68	11,657	2,183	(10,977)	
Sep-07	59.95	78.68	12,861	2,409	(15,320)	
Oct-07	59.95	78.68	9,557	1,790	(18,669)	
Nov-07	59.95	78.68	10,763	2,016	(23,430)	
Sub total				(24,997)	(226,408)	(251,404)
YEC Shortfall						**(251,404)**
Combined YEC/YECL shortfall						**2,778,560**

2006 - 2007 Forecast Retail Sales (kwh's) - December 1, 2006 - November 30, 2007

	YECL	260,000,000	
	YEC	28,301,881	
	Total		288,301,881
Rider F rate	- price per kwh (cents) to recover 100% of shortfall to November 30, 2007		**0.963767648**

The Yukon Electrical Company Limited
An ATCO Company

April 16, 2008

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from .9638 cents per kW.h to 1.233 cents per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after May 1, 2008.

Due to actual fuel prices being significantly higher than fuel prices provided for in rates, the diesel fuel price variance has increased over the past 4 months driving the deficit owing from ratepayers to the companies up to $224,616 at the end of March 2008. This variance will continue to grow with current and rising fuel prices at the existing Rider F rate of .9638 cents per kWh.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level through to April 2009. As in the past, the Companies commit to review the variables impacting Rider F on an ongoing basis to ensure the balance in the account and the collections from ratepayers is reasonable.

Yours sincerely,

The Yukon Electrical Company Limited

Jerome Babyn
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

The Yukon Electrical Company Limited
Yukon Energy Corporation
Rider F Calculation
As At March 31, 2008
(Forecast Implementation Date in CIS = May 1, 2008)

The Yukon Electrical Company Limited

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall		
Due From (To) Customers - as at March 31, 2008						224,616
Apr-08	Estimated Net			250,000		
May-08	33.73	96.56	446,685	280,651		
Jun-08	33.40	96.56	417,188	263,478		
Jul-08	34.92	96.56	420,249	259,050		
Aug-08	32.88	96.56	414,012	263,633		
Sep-08	33.94	96.56	433,963	271,764		
Oct-08	33.98	96.56	470,103	294,197		
Nov-08	34.16	96.56	547,955	341,932		
Dec-08	35.00	96.56	618,229	380,612		
Jan-09	33.43	96.56	576,926	364,217		
Feb-09	34.28	96.56	514,615	320,494		
Mar-09	35.38	96.56	522,506	319,693		
Apr-09	32.88	96.56	451,015	287,227		
Sub total				3,896,946		3,896,946
YECL Shortfall						**4,121,562**

Yukon Energy Corporation

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	Secondary Sales Adjmt	
Due From (To) Customers - as at March 31, 2008						-
Apr-08	Estimated Net			(45,000)	-	
May-08	59.95	88.66	17,992	5,166	(37,201)	
Jun-08	59.95	88.66	21,219	6,092	(30,665)	
Jul-08	59.95	88.66	23,017	6,608	(19,236)	
Aug-08	59.95	88.66	21,644	6,214	(21,576)	
Sep-08	59.95	88.66	23,794	6,831	(28,553)	
Oct-08	59.95	88.66	18,087	5,193	(35,660)	
Nov-08	59.38	81.70	46,124	10,295	(44,710)	
Dec-08	59.40	82.00	48,198	10,890	(48,235)	
Jan-09	59.42	82.21	49,749	11,336	(54,111)	
Feb-09	59.34	81.23	53,996	11,818	(51,142)	
Mar-09	59.34	81.26	54,246	11,890	(47,667)	
Apr-09	59.95	88.66	20,189	5,796	(48,644)	
Sub total				53,128	(467,400)	(414,272)
YEC Shortfall						**(414,272)**

Combined YEC/YECL shortfall **3,707,290**

2008-2009 Forecast Retail Sales (kwh's) - May 1, 2008 - April 30, 2009

YECL	271,266,000	
YEC	29,304,299	
Total		300,570,299

Rider F rate - price per kwh (cents) to recover 100% of shortfall to April 30, 2009 **1.233418745**

The Yukon Electrical Company Limited
An ***ATCO*** Company

July 10, 2008

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of an increase in the automatic fuel price adjustment rider (Rider F) from 1.233 cents per kW.h to 1.860 cents per kW.h based on the attached forecast. The increase will be effective for bills rendered on or after August 1, 2008.

Due to actual fuel prices being significantly higher than fuel prices provided for in rates, the diesel fuel price variance has continued to increase over the past 3 months driving the deficit owing from ratepayers to the companies up to $505,000 at the end of June 2008. This variance will continue to grow with current and rising fuel prices at the existing Rider F rate of 1.233 cents per kWh.

Based on the attached forecast, the Companies expect Rider F to continue at the new adjusted level until the completion of the General Rate Applications. At this point the Rider will be adjusted accordingly.

Yours sincerely,

The Yukon Electrical Company Limited

Jerome Babyn
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

Encl.

The Yukon Electrical Company Limited
Yukon Energy Corporation
Rider F Calculation
As At June 30, 2008
(Forecast Implementation Date in CIS = August 1, 2008)

The Yukon Electrical Company Limited

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall		
Due From (To) Customers - as at June 30, 2008						504,626
Jul-08	Estimated Net			150,000		
Aug-08	32.88	125.00	446,954	411,723		
Sep-08	33.94	125.00	438,421	399,243		
Oct-08	33.98	125.00	473,011	430,541		
Nov-08	34.16	125.00	502,146	456,157		
Dec-08	35.00	125.00	607,319	546,617		
Jan-09	33.43	125.00	504,558	462,026		
Feb-09	34.28	125.00	508,574	461,370		
Mar-09	35.38	125.00	490,743	439,826		
Apr-09	32.88	125.00	427,616	393,940		
May-09	33.73	125.00	400,548	365,579		
Jun-09	33.40	125.00	406,044	371,918		
Jul-09	34.92	125.00	400,198	360,507		
Sub total				5,249,447		5,249,447
YECL Shortfall						**5,754,073**

Yukon Energy Corporation

	Fuel Price in Rates	Forecast Fuel Price	Forecast Litres	Monthly Shortfall	Secondary Sales Adjmt	
Due From (To) Customers - as at June 30, 2008						-
Jul-08	Estimated Net				(45,000)	
Aug-08	59.95	95.05	22,630	7,943	(33,443)	
Sep-08	59.95	95.05	24,800	8,705	(44,257)	
Oct-08	59.95	95.05	19,207	6,742	(55,273)	
Nov-08	59.38	88.95	49,497	14,635	-	
Dec-08	59.40	89.18	51,456	15,323	-	
Jan-09	59.42	89.34	52,850	15,812	-	
Feb-09	59.34	88.52	57,831	16,876	-	
Mar-09	59.34	88.52	57,829	16,876	-	
Apr-09	59.95	95.05	21,195	7,439	-	
May-09	59.95	95.05	19,332	6,786	(58,592)	
Jun-09	59.95	95.05	22,321	7,835	(47,841)	
Jul-09	59.95	95.05	24,026	8,433	(30,126)	
Sub total				133,405	(314,531)	(181,126)
YEC Shortfall						**(181,126)**

Combined YEC/YECL shortfall			**5,572,947**
2008 - 2009 Forecast Retail Sales (KwH's) August 1, 2008 - July 31, 2009			
	YECL	271,179,000	
	YEC	28,466,374	
	Total		299,645,374
Rider F rate	Price per KWH (cents) to recover 100% of shortfall to July 31, 2009		**1.860**

The Yukon Electrical Company Limited
An ATCO Company

February 9, 2009

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 1A3

Attention: Ms. Wendy Shanks, Chair

Dear Ms. Shanks:

Pursuant to Section 8 of OIC 1995/90, Yukon Electrical Company Limited and Yukon Energy Corporation (the Companies) are hereby notifying the Board of a decrease in the automatic fuel price adjustment rider (Rider F) from 1.860 cents per kW.h to zero (0.0) cents per kW.h. The decrease will be effective for bills rendered on or after March 1, 2009.

Due to fuel price decreases since the last adjustment in August 2008, the diesel fuel price variance shortfall accumulated during 2008 has been recovered. There will be an estimated surplus in the Rider F account of $600,000 by the end of February 2009 (based on use of the last GRA fuel price of 1997 for YECL and 2005 for YEC). This surplus is forecast to be eliminated by the end of May with the revised lower Rider F rate.

The Rider will be materially impacted by the Board's imminent ruling on YECL's General Rate Application ("GRA"). Accordingly, Rider F will remain at the new adjusted level of zero at least until the Board's decision on that GRA is implemented. We expect this will not be until June 1st, given the timelines faced for the Compliance filing and lead time for rate changes in the billing system.

In the meantime, the Companies believe it is important to lower Rider F which will benefit ratepayers immediately.

Yours sincerely,

The Yukon Electrical Company Limited

Jerome Babyn
General Manager

Yukon Energy Corporation

David Morrison
President and CEO

REFERENCE: **October 6, 2008 Application, Revenue Requirement, page 3-21**

YEC states: "For the test years, no use of the DCF is forecast. The DCF has a balance of $0.856 million as at December 31, 2007 (including interest earned monthly); this balance is proposed to be retained in the fund as it is intended to be available in the event of a drought. The DCF will not be advanced in the "diesel on the margin" mode until such time as the system has firm loads that exceed the long-term average capability of the system over the course of a long period (many months to years). This will not occur until after secondary sales have been basically fully interrupted over the long-term on the WAF system. The DCF could be required in the event of a drought within the test years."

QUESTION:

a) Please confirm that secondary and industrial sales customers will not receive any benefits from the Diesel Contingency Fund.

b) Please describe how the DCF will be allocated if triggered.

ANSWER:

(a)

Confirmed for the test years as regards firm load customers.

The Diesel Contingency Fund is designed to stabilize the utility's costs of diesel that arise from fluctuations in generation related to higher or lower than average long-term hydro generation due to water availability. Under present firm load conditions, were a severe drought to arise giving rise to the requirement for diesel generation for baseload supply, the DCF would pay the utility for this quantity of diesel fuel (at GRA fuel prices). There would be no direct impact to firm retail or industrial customer rates. The GRA is intended to avoid the need for rates to fluctuate depending on test year water flow conditions.

Given that secondary sales would be interrupted prior to diesel generation being required for baseload purposes, the secondary sales customers would not benefit from

any DCF use. Further, as noted in the Application, the DCF does not protect the utility from loss of forecast secondary sales revenues due to drought conditions.

With respect to industrial customers, rates in the test years are fixed at the levels set out in OIC 2007/94 and consequently industrial rates would not in any event presently be subject to variation due to drought or flood conditions. The DCF protects the utility, however, from such changes in water flow conditions

(b)

Pursuant to the approved rules for the DCF, any withdrawals will be allocated to the cost of diesel fuel related to low water conditions.

REFERENCE: October 6, 2008 Application, Rates, Page 4-11

Table 4.4 – Equivalent Price of Electricity for Heating - August 13, 2008 Oil Prices

QUESTION:

a) Please update this table with current oil prices.

b) Please provide the referenced Yukon Housing Corporation data used to create Table 4.4.

ANSWER:

(a)

Below is the update to Table 4.4 with rates as at December 31, 2008.

Table 4.4 -Updated
Equivalent Price of Electricity for Heating – December 31, 2008 Oil Prices

	Whitehorse	Faro	Mayo	Dawson
Price of Furnace Oil December 31, 2008 ($/litre)	0.95	1.00	1.10	1.06
Oil price excluding GST	0.90	0.95	1.05	1.01
Equivalent Price of Electricity (cents/kW.h) at 80% efficiency furnace (excl GST)	0.1054	0.1113	0.1225	0.1174

(b)

Attachment 1 to this response provides the Yukon Bureau of Statistics document referenced to create Table 4.4. The relevant pages are pages 14, 16, 17, and 19.

Fuel Survey: December 2008

1 Retail Motor Fuel Prices in the Yukon

Average prices as of December 31st, 2008

	Self-serve		
	regular	premium	diesel
Whitehorse	86.8	93.9	109.1
Beaver Creek	99.9	104.9	121.9
Carcross	109.9	129.9	129.9
Carmacks	92.9	108.9	115.9
Dawson City	125.0	152.7	147.0
Destruction Bay	92.9	97.9	113.9
Haines Junction	90.9	95.9	111.9
Mayo	115.0	N/A	138.0
Pelly Crossing	102.9	-	119.9
Ross River	121.9	-	169.9
Tagish	89.9	99.8	107.8
Teslin	86.9	89.9	110.4
Watson Lake	104.9	114.9	118.9

	Full-serve			
	regular	premium	diesel	propane
Whitehorse	88.8	98.9	112.4	88.1
Dawson City	-	-	-	118.0
Destruction Bay	-	-	-	155.9
Haines Junction	94.9	-	116.9	108.9
Mayo	112.9	-	135.9	129.0
Tagish	-	-	-	98.0
Teslin	-	-	-	115.9
Watson Lake	-	-	159.9	126.4

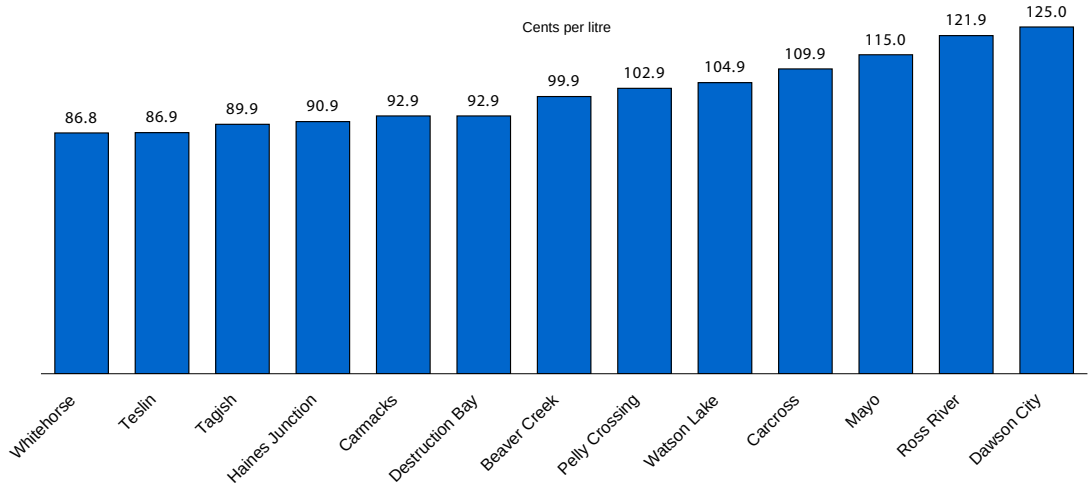
Note: All prices are Canadian cents per litre, including all applicable taxes.
"-" Indicates this service is not available in this community at this time.
"N/A" indicates this information is not available for the reporting period.

Current average gasoline prices for regular self-serve in the Yukon range from 86.8¢ per litre in Whitehorse to 125.0¢ per litre in Dawson City. The price for premium self-serve ranges from 89.9¢ per litre in Teslin to 152.7¢ per litre in Dawson City. The lowest price for self-serve diesel is in Tagish—107.8¢ per litre.

For full-serve regular gasoline, the average price ranges from 88.8¢ per litre in Whitehorse to 112.9¢ per litre in Mayo. The price for full-serve diesel ranges from 112.4¢ per litre in Whitehorse to 159.9¢ per litre in Watson Lake.

Whitehorse has the lowest price for propane, at 88.1¢ per litre, while Destruction Bay has the highest, at 155.9¢ per litre.

Average Retail Gasoline Prices
Regular Self-serve — December 31st, 2008

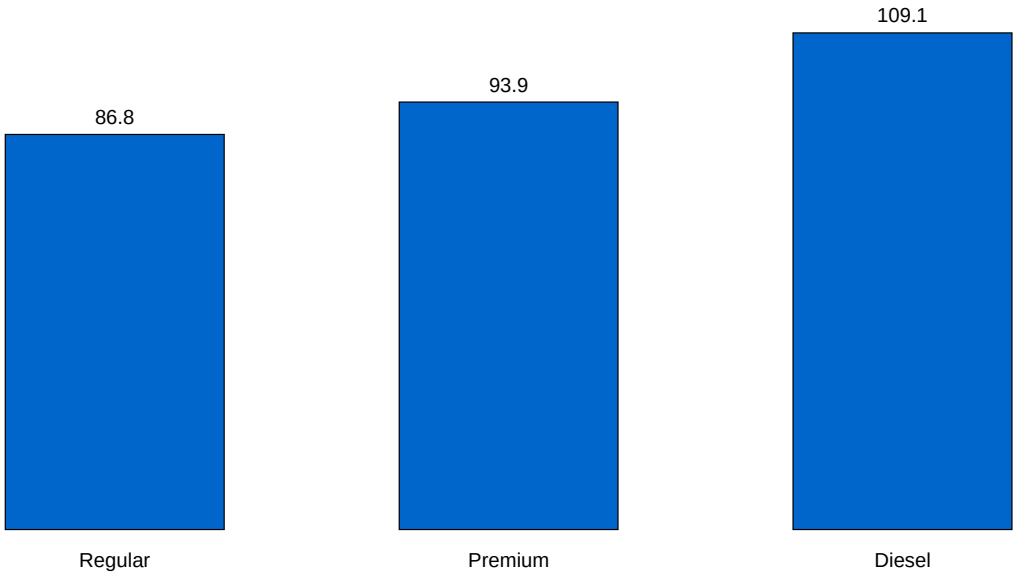


2 Retail Motor Fuel Prices — Whitehorse

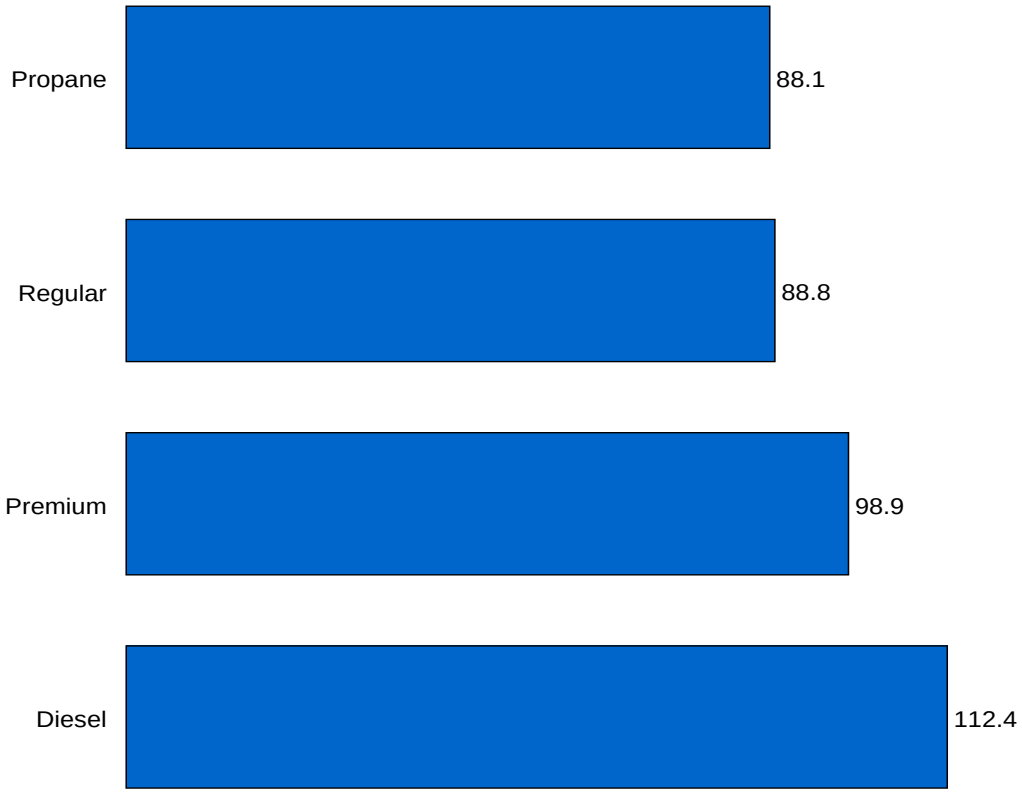
	Self-serve				Full-serve				
	regular	mid-grade	premium	diesel	regular	mid-grade	premium	diesel	propane
31-Dec-08	86.8	-	93.9	109.1	88.8	-	98.9	112.4	88.1
17-Dec-08	89.1	-	96.1	110.0	89.8	-	106.4	117.4	88.1
3-Dec-08	93.6	-	100.8	117.8	97.1	-	112.2	128.7	89.3
19-Nov-08	103.7	-	110.3	126.7	108.3	-	126.9	135.7	93.9
5-Nov-08	110.6	-	116.8	132.0	112.0	-	129.4	141.9	96.4
22-Oct-08	121.5	-	130.0	137.5	127.1	-	137.9	140.2	94.9
8-Oct-08	130.8	-	137.2	140.8	136.3	-	142.7	146.2	100.9
24-Sep-08	139.7	-	145.3	142.1	142.8	-	147.6	148.3	102.4
10-Sep-08	139.4	-	145.5	143.5	141.5	-	146.9	147.6	102.4
27-Aug-08	140.0	-	146.4	145.8	141.4	-	146.6	148.3	102.6
13-Aug-08	141.0	-	146.8	148.3	144.8	-	150.6	155.2	106.2
30-Jul-08	144.4	-	150.2	152.6	144.8	-	150.6	155.2	107.3
16-Jul-08	146.1	-	151.4	154.7	146.4	-	152.6	157.6	106.3
2-Jul-08	144.9	-	151.0	150.6	145.8	-	151.9	151.2	104.9
18-Jun-08	144.3	-	150.3	148.7	145.1	-	151.2	150.6	105.2
4-Jun-08	141.0	-	146.3	146.8	140.8	-	146.9	146.9	100.9
21-May-08	137.2	-	142.8	141.9	137.8	-	144.9	142.2	101.9
7-May-08	136.3	-	142.1	140.8	137.8	-	144.9	142.2	101.6
22-Apr-08	126.6	-	132.8	135.4	126.4	-	132.6	137.6	94.9
9-Apr-08	120.6	-	126.9	132.0	120.8	-	128.9	136.6	92.6
26-Mar-08	120.2	-	126.2	129.5	120.8	-	128.9	130.6	92.6
12-Mar-08	120.2	-	125.8	123.6	120.1	-	128.2	125.2	92.6
27-Feb-08	115.6	-	121.7	120.0	117.1	-	124.9	122.6	92.6
13-Feb-08	115.6	-	121.6	119.1	117.8	-	125.6	121.9	92.6
30-Jan-08	115.6	-	121.6	119.1	117.8	-	125.6	121.9	92.6
16-Jan-08	115.8	-	121.4	119.4	117.4	-	125.6	118.6	92.6
2-Jan-08	115.8	-	121.2	120.3	117.4	-	125.6	121.9	90.2
19-Dec-07	115.8	-	121.9	120.1	117.8	-	128.9	123.2	90.2
5-Dec-07	116.5	-	122.2	119.6	117.8	-	128.9	123.2	90.2
November '07	115.6	-	122.2	113.0	117.1	-	127.9	115.1	85.3
October '07	116.4	-	122.5	109.1	119.1	-	128.9	113.3	86.3
September '07	119.9	-	124.0	109.1	122.4	-	127.9	111.9	82.3
August '07	119.8	-	124.9	108.9	121.8	-	127.7	111.9	80.9
July '07	119.8	-	124.9	108.5	121.8	-	125.9	111.9	80.9
June '07	120.1	-	124.9	107.7	121.8	-	128.6	111.9	80.9
May '07	115.3	-	120.2	108.2	116.5	-	124.1	112.8	80.9
April '07	104.6	-	109.9	104.5	105.5	-	116.1	109.2	80.0
March '07	104.7	-	110.6	106.3	104.8	-	114.7	108.8	79.9
February '07	97.4	-	102.8	103.1	97.8	-	110.1	102.9	79.2
January '07	99.1	-	105.1	106.3	98.9	-	108.6	102.9	78.9
December '06	97.8	-	104.5	101.0	97.7	-	109.8	103.6	71.9
November '06	96.2	-	103.0	98.6	96.4	-	108.1	102.2	64.7
October '06	99.1	-	105.9	99.9	100.1	-	114.0	104.3	76.5
September '06	110.5	117.2	116.7	110.4	111.6	118.9	124.2	117.6	83.2
August '06	119.7	124.1	125.7	114.0	121.8	124.4	130.1	117.2	84.6
July '06	116.0	120.8	122.8	110.7	119.4	122.9	127.5	112.6	83.4
June '06	113.6	119.9	121.8	109.7	118.2	122.9	127.5	110.3	82.9
May '06	114.4	118.6	122.1	108.7	118.2	122.9	127.5	110.6	82.9
April '06	117.1	123.2	123.0	108.5	119.8	123.2	127.5	114.2	81.2
March '06	101.6	106.3	109.2	101.8	102.6	107.2	111.9	102.3	80.2
February '06	105.6	109.9	111.9	105.1	105.8	109.4	114.1	112.1	82.1
January '06	105.7	110.0	112.0	108.1	105.8	109.4	114.1	113.9	83.2

2 Retail Motor Fuel Prices — Whitehorse

Average Self-serve, as of December 31st, 2008 (cents per litre)



Average Full-serve, as of December 31st, 2008 (cents per litre)



3 Retail Motor Fuel Prices — Carmacks

	Self-serve			Full-serve
	regular	premium	diesel	propane
31-Dec-08	92.9	108.9	115.9	-
17-Dec-08	92.9	117.9	126.9	-
3-Dec-08	102.9	112.9	128.9	-
19-Nov-08	115.9	124.4	144.9	-
5-Nov-08	129.9	138.4	147.4	-
22-Oct-08	144.9	156.4	156.9	-
8-Oct-08	149.9	159.4	159.9	-
24-Sep-08	153.9	160.9	162.4	-
10-Sep-08	153.9	160.9	162.4	-
27-Aug-08	153.9	160.9	162.4	-
13-Aug-08	153.9	160.9	162.4	-
30-Jul-08	159.4	168.4	169.9	-
16-Jul-08	158.9	168.9	169.9	-
2-Jul-08	153.9	161.4	158.9	-
18-Jun-08	153.9	160.4	161.9	-
4-Jun-08	149.9	156.9	159.9	-
21-May-08	145.9	153.5	149.9	-
7-May-08	139.9	146.9	147.9	-
22-Apr-08	129.9	137.4	142.4	-
9-Apr-08	129.9	137.4	142.4	-
26-Mar-08	129.9	139.4	142.4	115.0
12-Mar-08	129.9	139.4	142.4	115.0
27-Feb-08	125.9	134.9	137.9	102.0
13-Feb-08	125.9	134.9	137.9	102.0
30-Jan-08	125.9	134.9	137.9	97.0
16-Jan-08	125.9	134.9	137.9	97.0
2-Jan-08	125.9	134.9	137.9	97.0
19-Dec-07	125.9	134.9	137.9	98.0
5-Dec-07	125.9	134.9	133.9	98.0
November '07	122.9	131.7	128.7	93.5
October '07	125.9	135.4	122.9	97.0
September '07	125.9	135.4	121.4	97.0
August '07	125.6	135.4	121.4	97.0
July '07	125.4	135.4	120.7	96.5
June '07	129.9	138.9	121.4	96.0
May '07	129.9	137.2	121.4	92.0
April '07	119.9	126.4	119.9	91.5
March '07	115.4	122.7	112.7	93.5
February '07	106.9	116.4	111.9	94.0
January '07	115.9	132.4	111.4	94.0
December '06	109.9	128.9	111.4	94.0
November '06	109.9	119.9	110.2	94.0
October '06	109.9	119.9	107.7	94.0
September '06	115.9	124.7	118.9	93.5
August '06	127.6	136.4	126.4	93.0
July '06	127.9	135.9	121.2	93.0
June '06	129.9	138.9	123.9	94.0
May '06	129.9	138.2	123.9	93.5
April '06	122.4	132.2	115.9	93.0
March '06	107.1	115.2	111.4	93.0
February '06	108.9	117.9	114.7	93.0
January '06	108.9	117.9	115.9	93.0

4 Retail Motor Fuel Prices — Dawson City

	Self-serve			Full-serve		
	regular	premium	diesel	regular	diesel	propane
31-Dec-08	125.0	152.7	147.0	-	-	118.0
17-Dec-08	127.0	159.5	149.7	-	-	N/A
3-Dec-08	141.3	155.0	154.3	-	-	120.0
19-Nov-08	147.6	158.3	160.0	-	-	120.0
5-Nov-08	151.3	161.9	160.2	-	-	120.0
22-Oct-08	155.0	161.9	165.4	-	-	120.0
8-Oct-08	164.6	174.1	169.4	-	-	120.0
24-Sep-08	168.6	173.6	169.5	-	-	120.0
10-Sep-08	168.6	173.7	171.2	-	-	120.0
27-Aug-08	168.4	173.4	171.5	-	-	126.0
13-Aug-08	171.7	176.9	176.0	-	-	126.0
30-Jul-08	170.9	177.2	177.0	-	-	126.9
16-Jul-08	170.9	174.5	177.0	-	-	126.0
2-Jul-08	167.7	174.2	173.0	-	-	126.0
18-Jun-08	165.9	172.5	172.0	-	-	121.0
4-Jun-08	163.1	168.7	170.7	-	-	121.0
21-May-08	161.3	165.7	166.2	-	-	121.0
7-May-08	159.7	163.6	161.2	-	-	121.0
22-Apr-08	152.2	155.8	158.6	-	-	121.0
9-Apr-08	145.2	149.0	151.0	-	-	113.0
26-Mar-08	145.7	148.0	147.0	-	-	99.9
12-Mar-08	140.8	148.1	139.2	-	-	99.9
27-Feb-08	140.1	146.7	138.2	-	-	99.9
13-Feb-08	140.1	146.7	138.2	-	-	99.9
30-Jan-08	139.7	146.7	138.3	-	-	99.9
16-Jan-08	139.7	146.7	138.3	-	-	99.9
2-Jan-08	139.4	147.2	139.0	-	-	99.9
19-Dec-07	138.4	147.2	139.0	-	-	99.9
5-Dec-07	138.2	146.0	136.3	-	-	99.9
November '07	139.7	147.3	136.1	-	-	99.9
October '07	139.7	147.3	135.0	-	-	99.9
September '07	140.4	147.5	134.1	-	-	99.9
August '07	140.8	147.5	134.5	-	-	99.9
July '07	141.1	147.5	134.6	-	-	97.9
June '07	142.1	147.2	133.9	-	-	97.9
May '07	140.1	146.9	134.2	-	-	97.9
April '07	132.6	140.1	131.1	-	-	97.9
March '07	125.1	132.8	130.5	-	-	97.9
February '07	121.9	129.1	129.1	-	-	97.9
January '07	122.0	127.9	126.8	-	-	97.9
December '06	119.3	123.6	120.1	-	-	97.9
November '06	119.8	124.3	120.8	-	-	98.2
October '06	122.5	127.3	122.8	-	-	98.5
September '06	130.3	135.1	129.1	-	-	98.5
August '06	136.5	142.2	130.8	-	-	98.5
July '06	134.4	139.8	129.2	-	-	98.2
June '06	133.7	139.1	129.0	131.5	130.0	96.8
May '06	133.5	139.2	130.3	129.0	126.0	95.0
April '06	133.6	139.6	128.8	125.0	123.0	94.0
March '06	121.9	128.4	125.6	119.0	120.0	86.5
February '06	123.2	129.2	126.2	117.0	126.5	86.5
January '06	123.2	129.1	126.0	110.0	125.0	86.5

5 Retail Motor Fuel Prices — Haines Junction

	Self-serve			Full-serve		
	regular	premium	diesel	regular	diesel	propane
31-Dec-08	90.9	95.9	111.9	94.9	116.9	108.9
17-Dec-08	94.9	99.9	116.9	94.9	116.9	108.9
3-Dec-08	99.9	104.9	121.9	99.9	131.9	108.9
19-Nov-08	107.9	112.9	127.9	117.9	134.9	108.9
5-Nov-08	115.9	129.0	131.9	126.9	139.9	108.9
22-Oct-08	124.0	128.9	141.5	135.9	142.9	108.9
8-Oct-08	145.7	152.6	147.3	135.9	142.9	108.9
24-Sep-08	146.0	153.5	147.3	142.9	147.9	108.9
10-Sep-08	147.3	155.9	150.9	142.9	147.9	108.9
27-Aug-08	151.5	160.9	155.0	142.9	149.9	108.9
13-Aug-08	151.7	161.2	155.9	142.9	149.9	108.9
30-Jul-08	153.9	162.2	160.2	149.9	158.9	108.9
16-Jul-08	155.2	163.9	160.7	149.9	158.9	108.9
2-Jul-08	153.2	162.9	159.0	146.9	156.9	108.9
18-Jun-08	153.0	162.6	158.0	146.9	154.9	108.9
4-Jun-08	145.9	155.2	153.9	140.9	151.9	105.9
21-May-08	145.9	155.2	149.4	140.9	151.9	105.9
7-May-08	145.7	154.9	149.2	140.9	151.9	105.9
22-Apr-08	133.7	143.2	143.2	130.9	135.9	105.9
9-Apr-08	125.3	133.7	137.6	122.9	131.9	105.9
26-Mar-08	124.0	132.5	127.3	117.9	120.9	92.9
12-Mar-08	124.0	132.5	123.6	117.9	120.9	92.9
27-Feb-08	117.5	122.9	121.5	117.9	120.9	92.9
13-Feb-08	117.9	122.9	120.9	117.9	120.9	92.9
30-Jan-08	117.5	122.9	121.5	117.9	120.9	92.9
16-Jan-08	117.5	122.9	121.5	117.9	120.9	92.9
2-Jan-08	117.5	122.9	121.5	117.9	120.9	92.9
19-Dec-07	121.3	130.4	122.9	117.9	116.9	92.9
5-Dec-07	121.3	130.4	122.9	117.9	116.9	92.9
November '07	122.4	130.4	119.4	117.9	116.9	83.9
October '07	122.6	131.6	119.3	120.4	116.9	83.9
September '07	125.0	133.8	119.4	122.9	116.9	83.9
August '07	125.7	134.6	119.4	122.9	116.9	83.9
July '07	125.7	134.6	119.4	122.9	116.9	83.9
June '07	125.7	134.6	119.4	122.9	116.9	79.5
May '07	124.2	133.6	118.8	119.9	116.9	79.5
April '07	119.3	128.8	117.9	114.4	115.4	79.5
March '07	108.2	115.9	109.3	108.9	110.4	79.5
February '07	106.7	114.4	108.6	105.9	115.9	79.5
January '07	106.4	114.2	111.3	105.9	115.9	79.5
December '06	106.0	113.9	107.0	105.9	105.9	79.5
November '06	106.0	113.9	106.0	105.9	105.9	79.5
October '06	106.9	114.9	107.9	105.9	105.9	79.5
September '06	116.9	124.1	117.9	114.9	114.9	79.5
August '06	125.5	133.2	118.2	125.2	116.6	79.5
July '06	121.2	128.3	115.0	119.9	114.4	79.5
June '06	120.4	127.4	114.3	117.9	112.9	79.5
May '06	118.7	128.9	115.4	118.9	112.9	79.5
April '06	120.7	127.7	115.7	116.9	111.4	79.5
March '06	107.9	115.4	111.9	105.9	105.9	79.5
February '06	110.4	116.9	110.4	110.9	109.4	79.5
January '06	110.9	116.9	110.9	110.9	107.9	79.5

6 Retail Motor Fuel Prices — Mayo

	Self-serve			Full-serve			
	regular	premium	diesel	regular	premium	diesel	propane
31-Dec-08	115.0	N/A	138.0	112.9	-	135.9	129.0
17-Dec-08	123.5	123.0	147.5	112.9	-	135.9	129.0
3-Dec-08	132.5	141.0	147.5	138.9	-	160.9	129.0
19-Nov-08	137.0	141.0	151.5	138.9	-	160.9	129.0
5-Nov-08	151.5	157.0	156.5	138.9	-	160.9	129.0
22-Oct-08	155.5	157.0	158.0	153.9	-	166.9	129.0
8-Oct-08	161.0	167.0	158.0	166.9	-	166.9	129.0
24-Sep-08	162.5	167.0	159.5	169.9	-	169.9	129.0
10-Sep-08	162.5	167.0	159.5	166.9	-	166.9	129.0
27-Aug-08	164.5	167.0	161.5	169.9	-	188.3	129.0
13-Aug-08	166.5	172.0	164.5	169.9	-	169.9	129.0
30-Jul-08	166.5	172.0	164.5	169.9	-	183.3	129.3
16-Jul-08	166.5	172.0	164.5	169.9	-	169.9	129.9
2-Jul-08	162.5	172.0	160.5	167.9	-	157.9	102.9
18-Jun-08	162.5	172.0	160.5	163.9	-	159.9	99.2
4-Jun-08	153.5	165.0	155.0	159.9	-	159.9	129.1
21-May-08	153.5	165.0	155.0	159.9	-	159.9	99.2
7-May-08	153.5	165.0	146.0	149.9	-	159.9	99.2
22-Apr-08	147.5	153.0	143.5	149.9	-	159.9	99.2
9-Apr-08	139.5	147.0	136.5	149.9	-	159.9	99.2
26-Mar-08	139.5	147.0	136.5	139.9	-	138.5	99.2
12-Mar-08	137.5	140.9	129.0	139.9	-	138.5	99.2
27-Feb-08	136.9	140.9	128.9	139.9	-	138.5	99.2
13-Feb-08	136.9	140.9	128.9	139.9	-	138.5	99.2
30-Jan-08	136.9	140.9	128.9	139.9	-	138.5	99.2
16-Jan-08	136.9	140.9	128.9	139.9	-	138.5	99.2
2-Jan-08	136.9	140.9	128.9	139.9	-	138.5	99.2
19-Dec-07	136.9	140.9	128.9	139.9	-	138.5	92.9
5-Dec-07	136.9	140.9	128.9	139.9	-	122.9	99.2
November '07	136.9	140.9	128.9	139.9	-	126.0	99.2
October '07	136.9	140.9	128.9	139.9	-	122.9	99.2
September '07	136.9	140.9	128.9	138.0	-	125.5	99.2
August '07	136.9	140.9	128.9	138.0	-	125.5	99.2
July '07	136.9	140.9	128.9	134.9	-	123.4	99.2
June '07	136.9	140.9	128.9	137.4	-	123.2	99.2
May '07	132.9	132.9	124.9	128.2	-	125.2	92.3
April '07	128.9	132.9	120.9	118.8	-	122.9	92.3
March '07	120.9	132.9	120.9	117.4	-	122.9	92.3
February '07	120.9	132.9	120.9	113.9	-	122.9	92.3
January '07	120.9	132.9	127.9	115.1	-	121.2	92.3
December '06	112.9	132.9	115.9	114.9	-	120.4	92.3
November '06	112.9	132.9	115.9	115.9	-	120.4	92.3
October '06	117.9	132.9	121.9	117.9	-	122.9	92.3
September '06	125.9	132.9	127.9	134.9	-	128.9	92.3
August '06	128.2	132.9	128.2	134.1	-	128.6	92.8
July '06	124.9	132.9	124.9	128.4	-	127.4	93.2
June '06	124.9	132.9	124.9	124.4	-	127.4	93.2
May '06	124.9	132.9	124.9	124.4	-	127.4	92.3
April '06	119.9	132.9	123.4	119.9	-	127.4	92.3
March '06	112.2	132.9	121.9	115.4	-	127.4	92.3
February '06	110.9	132.9	121.9	115.4	-	127.4	92.3
January '06	116.9	132.9	125.9	115.4	-	127.4	92.3

7 Retail Motor Fuel Prices — Teslin

	Self-serve				Full-serve
	regular	mid-grade	premium	diesel	propane
31-Dec-08	86.9	-	89.9	110.4	115.9
17-Dec-08	89.9	-	93.9	115.4	115.9
3-Dec-08	98.4	-	101.9	122.4	115.9
19-Nov-08	107.4	-	110.9	128.9	115.0
5-Nov-08	120.4	-	118.9	133.9	115.0
22-Oct-08	129.9	-	133.9	144.4	115.9
8-Oct-08	137.4	-	138.9	144.4	115.9
24-Sep-08	141.4	-	143.0	146.9	115.0
10-Sep-08	141.4	-	143.9	147.4	115.9
27-Aug-08	142.4	-	147.9	149.4	115.9
13-Aug-08	144.4	-	145.9	152.4	115.9
30-Jul-08	146.9	-	150.9	155.4	110.0
16-Jul-08	147.9	-	150.9	155.9	115.0
2-Jul-08	145.9	-	148.9	152.4	115.0
18-Jun-08	145.9	-	149.9	152.4	115.0
4-Jun-08	139.4	-	142.9	148.9	110.0
21-May-08	138.9	-	142.9	144.4	110.0
7-May-08	137.4	-	139.9	142.4	100.0
22-Apr-08	127.9	-	130.9	137.4	100.0
9-Apr-08	122.9	-	124.9	134.4	100.0
26-Mar-08	120.9	-	126.9	129.4	90.0
12-Mar-08	118.9	-	122.9	124.9	90.0
27-Feb-08	115.9	-	121.9	120.9	90.0
13-Feb-08	115.9	-	121.9	120.9	90.0
30-Jan-08	115.9	-	121.9	120.9	90.0
16-Jan-08	115.9	-	121.9	120.9	90.0
2-Jan-08	115.9	-	121.9	120.9	90.0
19-Dec-07	115.9	-	121.9	120.9	90.0
5-Dec-07	115.9	-	121.9	120.9	90.0
November '07	116.7	-	121.9	114.2	90.0
October '07	118.8	-	123.9	108.3	90.0
September '07	121.9	-	126.9	112.4	90.0
August '07	121.9	-	126.9	111.4	90.0
July '07	121.9	-	126.9	111.4	90.0
June '07	121.4	-	125.9	111.4	90.0
May '07	116.7	-	119.9	109.9	90.0
April '07	109.4	-	113.9	107.9	90.0
March '07	100.9	-	103.9	104.8	90.0
February '07	98.9	-	103.9	106.4	90.0
January '07	101.1	-	105.9	109.6	90.0
December '06	97.7	-	102.9	101.4	90.0
November '06	96.9	-	102.9	101.4	90.0
October '06	103.2	-	107.4	104.2	90.5
September '06	113.3	117.0	117.5	114.5	90.0
August '06	120.8	123.6	126.6	115.4	90.0
July '06	116.7	118.4	121.4	109.4	90.0
June '06	112.9	115.9	118.9	108.7	90.0
May '06	112.9	115.9	118.9	106.4	89.0
April '06	119.0	121.5	123.5	104.2	84.9
March '06	101.9	104.9	106.9	106.4	95.9
February '06	105.9	107.9	109.9	111.7	95.4
January '06	105.9	107.9	109.9	112.9	91.4

8 Retail Motor Fuel Prices — Watson Lake

	Self-serve			Full-serve		
	regular	premium	diesel	regular	diesel	propane
31-Dec-08	104.9	114.9	118.9	-	159.9	126.4
17-Dec-08	109.9	119.9	129.9	-	159.9	126.4
3-Dec-08	109.9	119.9	129.9	-	159.9	126.4
19-Nov-08	116.9	126.9	136.9	-	159.9	126.4
5-Nov-08	123.9	133.9	140.9	-	159.9	126.4
22-Oct-08	133.9	143.9	140.9	-	159.9	126.4
8-Oct-08	138.9	153.9	142.9	-	159.9	126.4
24-Sep-08	146.4	155.9	146.9	-	159.9	122.2
10-Sep-08	147.9	157.9	147.9	-	159.9	118.9
27-Aug-08	147.9	157.9	147.9	-	159.9	118.9
13-Aug-08	152.4	159.4	153.9	-	159.9	118.9
30-Jul-08	152.4	157.9	153.9	-	159.9	118.9
16-Jul-08	152.9	163.5	159.4	-	159.9	118.6
2-Jul-08	151.4	157.9	156.4	-	159.9	118.9
18-Jun-08	151.4	157.9	158.4	-	159.9	118.6
4-Jun-08	143.4	150.9	151.9	-	149.9	118.0
21-May-08	142.4	149.9	150.9	-	143.9	118.0
7-May-08	142.9	149.9	147.9	-	143.9	107.9
22-Apr-08	138.9	146.9	145.9	-	139.9	110.0
9-Apr-08	135.9	143.9	140.9	-	139.9	105.5
26-Mar-08	130.9	138.9	140.9	-	133.9	99.5
12-Mar-08	129.9	138.9	134.9	-	120.9	89.9
27-Feb-08	128.9	137.9	131.9	-	120.9	89.9
13-Feb-08	126.9	133.9	129.9	-	120.9	89.9
30-Jan-08	126.9	139.9	129.9	-	120.9	89.9
16-Jan-08	126.9	137.9	129.9	-	120.9	89.9
2-Jan-08	126.9	137.9	135.9	-	120.9	89.9
19-Dec-07	125.9	134.4	131.9	-	120.9	89.9
5-Dec-07	124.9	135.9	133.9	-	120.9	89.9
November '07	121.2	132.4	119.7	-	120.9	89.9
October '07	121.4	133.4	115.9	-	120.9	89.9
September '07	120.9	133.2	116.9	-	120.9	89.9
August '07	124.1	132.7	115.8	-	120.9	89.9
July '07	123.7	132.1	115.2	-	120.9	89.9
June '07	125.7	133.4	115.7	-	120.9	89.9
May '07	123.3	129.3	115.6	-	120.9	89.9
April '07	114.6	121.3	114.9	119.9	120.9	89.9
March '07	109.9	117.2	110.6	116.9	113.9	89.9
February '07	109.9	117.6	111.5	116.9	113.9	89.9
January '07	109.9	118.6	113.1	116.9	117.9	89.9
December '06	109.9	118.4	106.6	116.9	117.9	89.9
November '06	109.9	118.7	106.9	116.9	117.9	89.9
October '06	113.4	121.9	110.4	116.9	117.9	89.9
September '06	123.4	129.2	118.4	128.9	121.9	89.9
August '06	125.7	131.8	119.4	128.9	121.9	89.9
July '06	123.5	128.8	117.4	128.9	119.9	89.9
June '06	119.9	125.7	114.3	120.9	117.9	89.9
May '06	119.9	125.7	113.9	120.9	117.9	89.9
April '06	117.3	124.1	115.3	118.9	117.9	89.9
March '06	109.6	118.2	113.2	112.9	117.9	89.9
February '06	109.6	118.2	115.6	112.9	117.9	89.9
January '06	109.6	118.2	115.6	112.9	117.9	89.9

9 Retail Motor Fuel Prices — Other Yukon Communities

	Beaver Creek Self-serve		
	regular	premium	diesel
31-Dec-08	99.9	104.9	121.9
17-Dec-08	99.9	104.9	121.9
3-Dec-08	104.9	109.9	127.9
19-Nov-08	118.9	123.9	140.9
5-Nov-08	129.9	134.9	145.9
22-Oct-08	137.9	142.9	151.9
8-Oct-08	148.9	153.9	152.9
24-Sep-08	152.9	157.9	152.9
10-Sep-08	152.9	157.9	158.9
27-Aug-08	152.9	157.9	158.9
13-Aug-08	152.9	157.9	158.9
30-Jul-08	155.9	169.0	166.9
16-Jul-08	160.9	165.9	168.9
2-Jul-08	157.9	162.9	166.9
18-Jun-08	155.9	161.9	162.9
4-Jun-08	150.9	155.9	162.9
21-May-08	150.9	155.9	156.9
7-May-08	150.9	155.9	156.9
22-Apr-08	138.9	143.9	146.9
9-Apr-08	132.9	137.9	140.9
26-Mar-08	133.9	138.9	142.9
12-Mar-08	133.9	138.9	126.9
27-Feb-08	128.9	133.9	126.9
13-Feb-08	128.9	133.9	126.9
30-Jan-08	128.9	133.9	126.9
16-Jan-08	128.9	133.9	126.9
2-Jan-08	N/A	N/A	N/A
19-Dec-07	128.9	133.9	126.9
5-Dec-07	128.9	133.9	126.9
Nov '07	128.9	133.9	122.9
Oct '07	128.9	133.9	122.9
Sep '07	130.1	133.9	123.7
Aug '07	131.3	133.9	124.4
Jul '07	131.3	133.9	122.9
Jun '07	130.8	133.9	124.0
May '07	129.5	132.4	124.0
Apr '07	126.9	128.4	124.4
Mar '07	124.6	120.9	121.2
Feb '07	123.3	120.9	120.4
Jan '07	123.3	120.9	123.9
Dec '06	120.3	120.9	121.1
Nov '06	120.3	120.9	120.3
Oct '06	122.3	120.9	120.4
Sep '06	127.3	126.9	123.4
Aug '06	130.4	137.6	123.8
Jul '06	126.7	133.4	122.9
Jun '06	125.9	131.9	122.4
May '06	124.2	126.0	121.7
Apr '06	124.4	131.0	119.9
Mar '06	118.0	119.2	118.0
Feb '06	124.5	120.9	125.0
Jan '06	124.8	120.9	123.5

	Burwash Landing Full-serve	
	regular	diesel
31-Dec-08	-	-
17-Dec-08	-	-
3-Dec-08	-	-
19-Nov-08	-	-
5-Nov-08	-	-
22-Oct-08	-	-
8-Oct-08	-	-
24-Sep-08	149.9	148.9
10-Sep-08	149.9	148.9
27-Aug-08	155.9	165.9
13-Aug-08	155.9	165.9
30-Jul-08	158.9	165.9
16-Jul-08	158.9	165.9
2-Jul-08	158.9	165.9
18-Jun-08	153.9	165.9
4-Jun-08	153.9	165.9
21-May-08	143.9	150.9
7-May-08	143.9	150.9
22-Apr-08	N/A	N/A
9-Apr-08	N/A	N/A
26-Mar-08	N/A	N/A
12-Mar-08	N/A	N/A
27-Feb-08	N/A	N/A
13-Feb-08	N/A	N/A
30-Jan-08	N/A	N/A
16-Jan-08	N/A	N/A
2-Jan-08	129.9	129.9
19-Dec-07	N/A	N/A
5-Dec-07	129.0	127.0
Nov '07	N/A	N/A
Oct '07	N/A	N/A
Sep '07	129.9	127.4
Aug '07	129.9	126.9
Jul '07	127.9	126.9
Jun '07	126.9	126.9
May '07	121.9	121.9
Apr '07	N/A	N/A
Mar '07	N/A	N/A
Feb '07	106.9	109.9
Jan '07	106.9	109.9
Dec '06	106.9	109.9
Nov '06	106.9	109.9
Oct '06	109.5	111.9
Sep '06	120.5	117.5
Aug '06	129.9	119.9
Jul '06	N/A	N/A
Jun '06	122.5	N/A
May '06	N/A	N/A
Apr '06	N/A	N/A
Mar '06	N/A	N/A
Feb '06	N/A	N/A
Jan '06	N/A	N/A

9 Retail Motor Fuel Prices — Other Yukon Communities

	Carcross Self-serve		
	regular	premium	diesel
31-Dec-08	109.9	129.9	129.9
17-Dec-08	109.9	129.9	129.9
3-Dec-08	109.9	129.9	129.9
19-Nov-08	109.9	129.9	129.9
5-Nov-08	129.9	139.9	135.9
22-Oct-08	129.9	133.9	135.9
8-Oct-08	136.9	149.9	147.9
24-Sep-08	136.9	149.9	147.9
10-Sep-08	145.9	149.9	149.9
27-Aug-08	145.9	149.9	149.9
13-Aug-08	145.9	149.9	157.0
30-Jul-08	N/A	N/A	N/A
16-Jul-08	149.9	154.9	159.9
2-Jul-08	149.9	154.9	159.9
18-Jun-08	149.9	154.9	159.9
4-Jun-08	149.9	159.9	159.9
21-May-08	149.9	157.9	157.9
7-May-08	144.9	149.9	149.9
22-Apr-08	134.9	139.9	144.9
9-Apr-08	129.9	138.9	142.9
26-Mar-08	125.9	132.9	141.9
12-Mar-08	123.0	129.9	126.0
27-Feb-08	119.9	129.9	121.9
13-Feb-08	119.9	129.9	121.9
30-Jan-08	119.9	124.9	121.9
16-Jan-08	119.9	124.9	121.9
2-Jan-08	119.9	124.9	121.9
19-Dec-07	119.9	129.9	121.9
5-Dec-07	119.9	124.9	119.9
Nov '07	115.0	124.9	117.9
Oct '07	121.3	127.4	116.4
Sep '07	124.2	129.9	114.9
Aug '07	124.9	129.9	114.9
Jul '07	129.9	136.9	121.9
Jun '07	129.9	136.9	121.9
May '07	124.9	134.9	121.9
Apr '07	115.9	125.9	121.9
Mar '07	110.9	120.9	118.4
Feb '07	105.9	115.9	114.9
Jan '07	105.6	125.2	114.9
Dec '06	99.7	129.9	110.9
Nov '06	99.5	129.9	110.9
Oct '06	113.9	129.9	121.9
Sep '06	119.9	129.9	124.9
Aug '06	123.2	133.6	123.2
Jul '06	121.9	129.9	119.9
Jun '06	120.9	129.9	119.9
May '06	120.9	129.9	119.9
Apr '06	119.9	127.9	116.4
Mar '06	104.9	114.6	114.4
Feb '06	106.9	117.9	117.9
Jan '06	108.9	119.9	121.9

	Destruction Bay Self-serve			Full-serve
	regular	premium	diesel	propane
31-Dec-08	92.9	97.9	113.9	155.9
17-Dec-08	96.9	101.9	118.9	155.9
3-Dec-08	101.9	106.9	123.9	155.9
19-Nov-08	112.9	117.9	132.9	155.9
5-Nov-08	120.9	125.9	136.9	155.9
22-Oct-08	128.9	133.9	142.9	160.0
8-Oct-08	136.9	141.9	146.9	160.0
24-Sep-08	146.9	151.9	146.9	155.9
10-Sep-08	146.9	151.9	152.9	106.9
27-Aug-08	146.9	151.9	152.9	106.9
13-Aug-08	146.9	151.9	152.9	106.9
30-Jul-08	149.9	154.9	160.9	110.0
16-Jul-08	141.9	156.9	162.9	110.0
2-Jul-08	151.9	156.9	160.9	106.9
18-Jun-08	151.9	156.9	156.9	106.9
4-Jun-08	144.9	149.9	156.9	106.9
21-May-08	144.9	149.0	150.9	106.9
7-May-08	149.0	149.0	150.0	106.9
22-Apr-08	132.9	141.9	140.9	106.9
9-Apr-08	129.9	135.9	138.9	106.9
26-Mar-08	130.9	135.9	139.9	106.9
12-Mar-08	130.9	135.9	123.9	106.9
27-Feb-08	125.9	130.9	123.9	106.9
13-Feb-08	125.9	130.9	123.9	106.9
30-Jan-08	125.9	130.9	123.9	106.9
16-Jan-08	125.9	130.9	123.9	106.9
2-Jan-08	125.9	130.9	123.9	106.9
19-Dec-07	125.9	130.9	123.9	106.9
5-Dec-07	125.9	130.9	123.9	106.9
Nov '07	125.9	130.9	119.9	106.9
Oct '07	125.9	130.9	119.9	106.9
Sep '07	125.9	130.9	119.9	106.9
Aug '07	125.9	130.9	119.9	106.9
Jul '07	125.9	130.9	119.9	106.9
Jun '07	125.9	130.9	119.9	106.9
May '07	122.9	130.4	119.9	108.4
Apr '07	117.4	126.4	119.9	109.9
Mar '07	112.4	121.4	113.4	108.4
Feb '07	109.9	119.9	111.9	106.9
Jan '07	109.9	117.9	118.9	106.9
Dec '06	109.9	117.9	111.4	106.9
Nov '06	109.9	117.9	109.9	101.0
Oct '06	110.9	117.9	110.8	98.9
Sep '06	117.9	123.9	117.9	98.9
Aug '06	127.6	133.9	118.9	98.9
Jul '06	122.9	128.9	116.9	98.9
Jun '06	122.9	128.9	112.9	94.4
May '06	122.9	128.9	112.9	94.4
Apr '06	122.9	128.9	112.9	89.9
Mar '06	108.9	119.9	108.9	89.9
Feb '06	112.9	118.9	113.9	89.9
Jan '06	112.9	118.9	113.9	89.9

9 Retail Motor Fuel Prices — Other Yukon Communities

	Pelly Crossing	
	regular	diesel
31-Dec-08	102.9	119.9
17-Dec-08	115.9	137.9
3-Dec-08	115.9	137.9
19-Nov-08	126.9	149.0
5-Nov-08	139.0	149.0
22-Oct-08	147.9	159.9
8-Oct-08	153.9	164.9
24-Sep-08	159.9	164.9
10-Sep-08	159.9	164.9
27-Aug-08	159.9	174.9
13-Aug-08	159.9	174.9
30-Jul-08	159.9	174.9
16-Jul-08	159.9	169.9
2-Jul-08	159.9	169.9
18-Jun-08	154.9	169.9
4-Jun-08	149.9	159.9
21-May-08	149.9	159.9
7-May-08	139.9	149.9
22-Apr-08	139.9	149.9
9-Apr-08	139.9	149.9
26-Mar-08	129.9	139.9
12-Mar-08	129.9	139.9
27-Feb-08	129.9	139.9
13-Feb-08	129.9	139.9
30-Jan-08	129.9	139.9
16-Jan-08	129.9	149.9
2-Jan-08	129.9	139.9
19-Dec-07	129.9	132.9
5-Dec-07	N/A	N/A
Nov '07	129.9	124.9
Oct '07	129.9	124.9
Sep '07	129.9	124.9
Aug '07	129.9	125.6
Jul '07	129.9	124.9
Jun '07	129.9	124.9
May '07	129.9	124.9
Apr '07	119.9	124.9
Mar '07	111.4	124.9
Feb '07	108.9	124.9
Jan '07	116.9	129.9
Dec '06	111.9	113.9
Nov '06	111.9	113.9
Oct '06	111.9	113.9
Sep '06	117.9	120.4
Aug '06	128.2	126.6
Jul '06	129.9	124.9
Jun '06	124.9	119.9
May '06	118.9	119.9
Apr '06	124.9	119.9
Mar '06	109.6	117.2
Feb '06	112.9	119.9
Jan '06	112.9	119.9

	Ross River	
	regular	diesel
31-Dec-08	121.9	169.9
17-Dec-08	121.9	169.9
3-Dec-08	121.9	169.9
19-Nov-08	145.9	169.9
5-Nov-08	145.9	169.9
22-Oct-08	161.9	169.9
8-Oct-08	161.9	169.9
24-Sep-08	161.9	169.9
10-Sep-08	161.9	169.9
27-Aug-08	161.9	169.9
13-Aug-08	161.9	169.9
30-Jul-08	161.9	169.9
16-Jul-08	161.9	169.9
2-Jul-08	161.9	169.9
18-Jun-08	N/A	N/A
4-Jun-08	147.9	156.9
21-May-08	147.9	156.9
7-May-08	147.9	156.9
22-Apr-08	142.9	151.9
9-Apr-08	135.9	151.9
26-Mar-08	135.9	151.9
12-Mar-08	135.9	151.9
27-Feb-08	128.9	132.9
13-Feb-08	128.9	132.9
30-Jan-08	128.9	132.9
16-Jan-08	128.9	132.9
2-Jan-08	128.9	132.9
19-Dec-07	129.9	132.9
5-Dec-07	N/A	N/A
Nov '07	128.9	132.9
Oct '07	128.9	132.9
Sep '07	128.9	127.9
Aug '07	128.9	121.9
Jul '07	128.9	121.9
Jun '07	123.9	113.9
May '07	123.9	113.9
Apr '07	119.9	124.9
Mar '07	119.9	124.9
Feb '07	119.9	124.9
Jan '07	119.9	124.9
Dec '06	119.9	124.9
Nov '06	119.9	124.9
Oct '06	119.9	124.9
Sep '06	129.9	129.9
Aug '06	132.2	127.2
Jul '06	132.4	121.9
Jun '06	127.9	121.9
May '06	121.9	123.9
Apr '06	115.9	119.9
Mar '06	115.9	119.9
Feb '06	115.9	119.9
Jan '06	115.9	122.9

	Tagish Self-serve			Full-serve
	regular	premium	diesel	propane
31-Dec-08	89.9	99.8	107.8	98.0
17-Dec-08	97.9	99.8	118.4	106.0
3-Dec-08	106.9	114.8	122.9	106.0
19-Nov-08	117.2	136.8	132.4	106.0
5-Nov-08	122.4	136.8	139.4	106.0
22-Oct-08	130.9	136.8	146.4	106.0
8-Oct-08	136.9	146.8	144.9	106.0
24-Sep-08	141.4	146.8	149.9	106.0
10-Sep-08	140.9	149.8	146.4	106.0
27-Aug-08	142.9	149.8	149.4	106.0
13-Aug-08	145.9	149.8	153.4	106.0
30-Jul-08	147.4	154.8	155.9	106.0
16-Jul-08	148.4	154.8	155.9	106.0
2-Jul-08	148.4	154.8	155.9	106.0
18-Jun-08	148.4	154.8	155.9	106.0
4-Jun-08	142.9	146.8	148.9	106.0
21-May-08	140.9	142.8	145.9	106.0
7-May-08	139.9	139.8	145.9	106.0
22-Apr-08	129.8	133.8	139.8	106.0
9-Apr-08	122.9	130.8	132.9	96.0
26-Mar-08	122.9	127.8	127.4	96.0
12-Mar-08	122.9	127.8	127.4	96.0
27-Feb-08	120.4	127.8	122.4	96.0
13-Feb-08	120.4	127.8	122.4	96.0
30-Jan-08	120.4	127.8	125.9	95.0
16-Jan-08	122.4	127.8	123.9	85.0
2-Jan-08	122.4	127.8	122.9	85.0
19-Dec-07	122.4	127.8	125.9	85.0
5-Dec-07	122.4	127.8	125.9	85.0
Nov '07	124.9	N/A	118.9	89.0
Oct '07	121.4	127.8	115.9	85.0
Sep '07	122.4	127.8	115.9	85.0
Aug '07	121.7	127.8	115.4	85.0
Jul '07	121.4	127.8	114.4	85.0
Jun '07	120.7	127.8	113.9	85.0
May '07	115.4	122.3	114.4	85.0
Apr '07	111.4	116.8	112.9	85.0
Mar '07	107.4	108.8	110.9	85.0
Feb '07	104.4	104.8	110.2	85.0
Jan '07	105.2	104.8	113.7	85.0
Dec '06	107.4	104.8	111.2	85.0
Nov '06	104.9	105.8	108.4	85.0
Oct '06	105.2	108.3	109.4	85.0
Sep '06	114.2	121.8	113.7	85.0
Aug '06	122.4	116.7	-	-
Jul '06	120.9	113.2	-	-
Jun '06	118.4	111.4	-	-
May '06	117.4	113.0	-	-
Apr '06	108.9	110.5	-	-
Mar '06	102.6	109.3	-	-
Feb '06	107.9	113.0	-	-
Jan '06	108.4	114.9	-	-

10 Residential Fuel Prices in the Yukon

Average prices as of December 31st, 2008

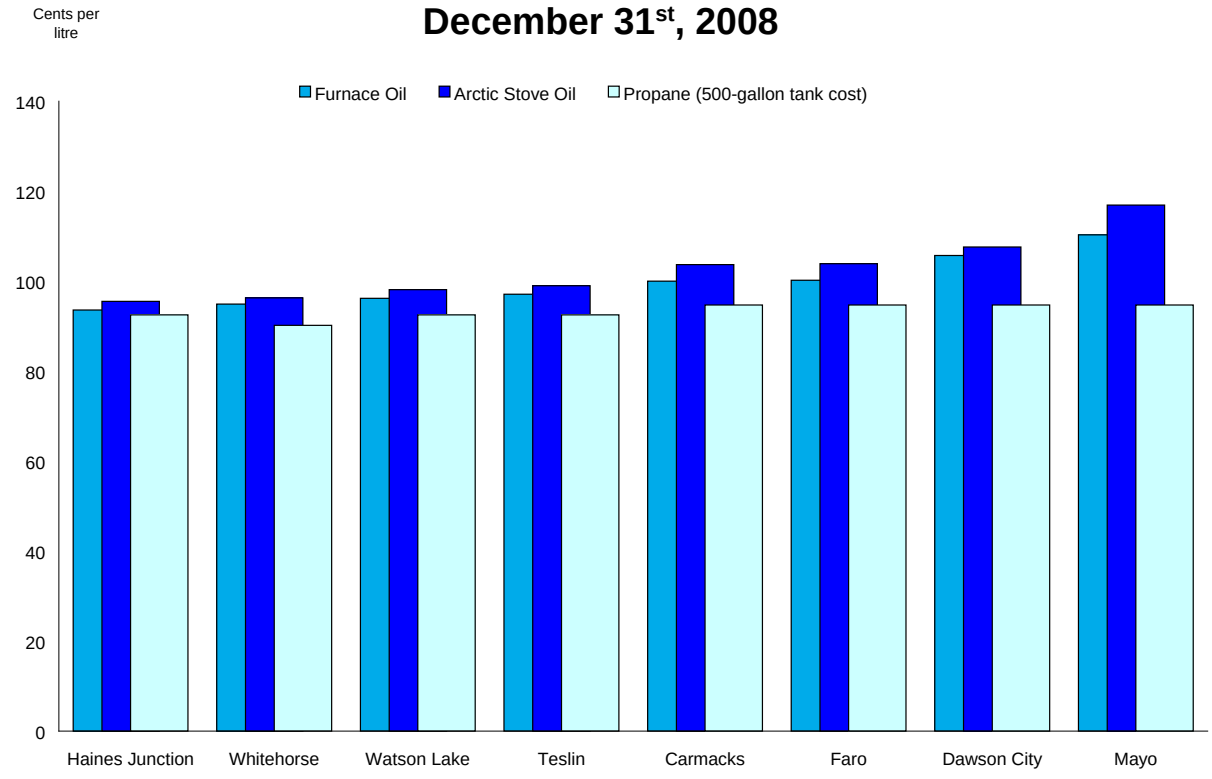
	Residential Heating Fuels		
	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
Whitehorse	94.9	96.3	90.2
Carmacks	100.0	103.7	94.7
Dawson City	105.7	107.6	94.7
Faro	100.2	103.9	94.7
Haines Junction	93.6	95.5	92.5
Mayo	110.3	116.9	94.7
Teslin	97.1	99.0	92.5
Watson Lake	96.2	98.1	92.5

Notes: All prices are Canadian cents per litre, including all applicable taxes.
"N/A" indicates this information is not available for the reporting period.

Average prices for residential furnace oil in the Yukon range from 93.6¢ per litre in Haines Junction to 110.3¢ per litre in Mayo. The price of arctic stove oil varies from 95.5¢ per litre in Haines Junction to 116.9¢ per litre in Mayo. Whitehorse had the lowest propane price at 90.2¢ per litre, while Carmacks, Dawson City, Faro and Mayo had the highest at 94.7¢ per litre.

Price discounts may apply to seniors, members of unions or service groups, or for quick payment. Ask your fuel supplier for details.

Average Residential Heating Fuel Prices December 31st, 2008



11 Residential Heating Fuel Prices — Whitehorse

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	94.9	96.3	90.2
17-Dec-08	97.9	101.2	90.2
3-Dec-08	108.0	111.6	88.6
19-Nov-08	117.0	120.7	92.1
5-Nov-08	125.9	129.2	94.1
22-Oct-08	131.0	134.4	95.8
8-Oct-08	135.0	138.3	95.8
24-Sep-08	132.4	135.9	98.5
10-Sep-08	135.7	139.3	97.4
27-Aug-08	134.9	138.3	97.9
13-Aug-08	139.1	142.3	97.9
30-Jul-08	140.0	143.5	97.9
16-Jul-08	146.9	150.4	99.0
2-Jul-08	144.0	147.2	99.9
18-Jun-08	142.4	145.6	99.9
4-Jun-08	139.0	141.9	97.3
21-May-08	137.9	141.7	107.1
7-May-08	130.1	133.5	93.5
22-Apr-08	127.7	131.1	93.5
9-Apr-08	125.1	128.5	93.5
26-Mar-08	122.7	125.8	93.5
12-Mar-08	116.8	120.0	88.2
27-Feb-08	112.5	115.7	88.2
13-Feb-08	109.3	112.4	88.2
30-Jan-08	109.6	112.4	88.2
16-Jan-08	112.9	116.3	86.1
2-Jan-08	112.6	115.8	83.5
19-Dec-07	113.4	116.6	82.0
5-Dec-07	112.6	115.8	78.9
November '07	106.5	109.6	77.3
October '07	99.8	103.2	73.8
September '07	99.0	102.3	73.0
August '07	97.9	101.6	72.1
July '07	95.5	99.2	70.7
June '07	95.8	99.2	70.4
May '07	97.3	100.4	70.4
April '07	99.8	103.0	69.6
March '07	98.0	101.1	68.8
February '07	96.4	99.4	68.8
January '07	98.0	101.1	67.0
December '06	92.6	95.9	65.4
November '06	87.6	91.0	65.4
October '06	87.0	90.4	66.3
September '06	92.5	95.9	66.3
August '06	105.4	108.7	68.4
July '06	99.7	103.1	70.0
June '06	97.8	101.2	67.7
May '06	95.5	98.9	67.7
April '06	95.6	99.5	73.2
March '06	88.2	92.0	65.2
February '06	91.0	95.1	65.2
January '06	94.3	98.4	63.1

12 Residential Heating Fuel Prices — Carmacks

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	100.0	103.7	94.7
17-Dec-08	104.2	107.9	94.7
3-Dec-08	111.6	115.3	94.7
19-Nov-08	124.3	128.0	98.9
5-Nov-08	131.2	134.9	102.1
22-Oct-08	137.1	140.2	106.3
8-Oct-08	137.1	140.2	106.3
24-Sep-08	137.1	140.2	111.6
10-Sep-08	138.6	142.0	112.7
27-Aug-08	138.6	142.0	113.7
13-Aug-08	150.3	153.5	113.7
30-Jul-08	150.3	153.5	113.7
16-Jul-08	146.1	156.9	113.7
2-Jul-08	146.1	156.9	109.2
18-Jun-08	143.9	147.1	109.2
4-Jun-08	143.9	147.1	109.2
21-May-08	132.3	135.5	109.2
7-May-08	132.3	135.5	109.2
22-Apr-08	129.1	132.3	109.2
9-Apr-08	129.1	132.3	109.2
26-Mar-08	124.9	128.0	109.2
12-Mar-08	118.5	121.7	98.6
27-Feb-08	114.3	117.4	98.6
13-Feb-08	114.3	117.4	98.6
30-Jan-08	117.4	120.6	98.6
16-Jan-08	117.4	120.6	94.3
2-Jan-08	117.4	120.6	94.3
19-Dec-07	117.4	120.6	94.3
5-Dec-07	117.4	120.6	92.2
November '07	106.9	110.1	89.0
October '07	102.6	105.8	89.0
September '07	102.6	105.8	87.4
August '07	102.6	105.8	85.4
July '07	102.6	105.8	84.4
June '07	102.6	105.8	83.8
May '07	101.5	104.7	83.8
April '07	101.5	104.7	82.7
March '07	101.5	104.7	81.5
February '07	101.5	104.7	81.5
January '07	102.6	110.4	78.1
December '06	96.2	100.5	76.8
November '06	90.9	95.2	76.8
October '06	91.7	96.0	76.6
September '06	96.9	101.2	76.6
August '06	108.4	112.7	77.3
July '06	101.3	105.6	77.3
June '06	100.3	104.6	78.9
May '06	101.3	105.6	75.1
April '06	99.7	104.0	73.2
March '06	95.2	99.5	73.2
February '06	96.0	100.3	73.2
January '06	98.8	104.5	73.2

13 Residential Heating Fuel Prices — Dawson City

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	105.7	107.6	94.7
17-Dec-08	110.5	112.4	94.7
3-Dec-08	122.2	124.0	94.7
19-Nov-08	132.8	134.6	98.9
5-Nov-08	138.9	140.7	102.1
22-Oct-08	141.8	143.4	106.3
8-Oct-08	142.3	146.0	106.3
24-Sep-08	142.3	146.0	111.6
10-Sep-08	143.6	147.3	112.7
27-Aug-08	143.6	147.3	113.7
13-Aug-08	148.9	152.6	113.7
30-Jul-08	154.8	158.5	113.7
16-Jul-08	152.6	156.4	113.7
2-Jul-08	150.5	153.7	109.2
18-Jun-08	151.6	152.6	109.2
4-Jun-08	151.6	152.6	109.2
21-May-08	139.9	146.8	109.2
7-May-08	139.9	143.1	109.2
22-Apr-08	132.9	137.0	109.2
9-Apr-08	132.9	132.7	109.2
26-Mar-08	128.7	126.9	109.2
12-Mar-08	120.5	123.7	98.6
27-Feb-08	118.1	120.5	98.6
13-Feb-08	116.8	120.5	98.6
30-Jan-08	121.3	122.1	98.6
16-Jan-08	116.3	120.0	94.3
2-Jan-08	116.3	120.0	94.3
19-Dec-07	116.3	120.0	94.3
5-Dec-07	116.3	120.0	92.2
November '07	115.1	118.8	91.2
October '07	114.0	117.7	91.2
September '07	114.0	117.7	89.6
August '07	114.0	117.7	87.9
July '07	114.6	117.7	87.4
June '07	114.0	117.7	86.8
May '07	113.5	117.2	86.8
April '07	113.5	117.2	85.2
March '07	112.4	116.1	83.6
February '07	111.4	115.1	83.6
January '07	110.6	113.8	80.3
December '06	105.5	109.3	79.0
November '06	102.3	106.6	79.0
October '06	103.5	107.8	78.7
September '06	112.5	116.8	78.7
August '06	119.0	122.7	79.5
July '06	111.3	115.6	79.5
June '06	111.3	115.6	77.4
May '06	108.1	112.4	76.3
April '06	110.4	114.8	75.3
March '06	106.3	110.6	75.3
February '06	109.2	113.5	75.3
January '06	111.3	115.6	75.3

14 Residential Heating Fuel Prices — Faro

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	100.2	103.9	94.7
17-Dec-08	104.4	108.1	94.7
3-Dec-08	111.8	115.5	94.7
19-Nov-08	124.6	128.3	98.9
5-Nov-08	131.4	135.2	102.1
22-Oct-08	137.3	140.5	106.3
8-Oct-08	137.3	140.5	106.3
24-Sep-08	137.3	140.5	111.6
10-Sep-08	139.9	143.1	112.7
27-Aug-08	139.9	143.1	113.7
13-Aug-08	150.5	153.7	113.7
30-Jul-08	150.5	153.7	113.7
16-Jul-08	146.3	149.5	113.7
2-Jul-08	146.3	149.5	109.2
18-Jun-08	144.2	147.3	109.2
4-Jun-08	144.2	147.3	109.2
21-May-08	132.5	135.7	109.2
7-May-08	132.5	135.7	109.2
22-Apr-08	129.3	132.5	109.2
9-Apr-08	129.3	132.5	109.2
26-Mar-08	125.1	128.3	109.2
12-Mar-08	118.7	121.9	98.6
27-Feb-08	114.6	117.8	98.6
13-Feb-08	114.6	116.7	98.6
30-Jan-08	117.7	120.8	98.6
16-Jan-08	117.7	120.8	94.3
2-Jan-08	117.7	120.8	94.3
19-Dec-07	117.7	120.8	94.3
5-Dec-07	117.7	120.8	92.2
November '07	107.5	110.3	91.2
October '07	102.8	106.0	91.2
September '07	102.8	106.0	89.6
August '07	102.8	106.0	87.9
July '07	102.8	106.0	87.4
June '07	102.8	106.0	86.8
May '07	101.8	104.9	86.8
April '07	101.8	104.9	85.2
March '07	101.8	104.9	83.6
February '07	101.8	104.9	83.6
January '07	103.2	107.1	80.3
December '06	101.8	100.7	79.0
November '06	101.8	95.4	79.0
October '06	97.2	96.2	78.7
September '06	97.2	101.4	78.7
August '06	108.6	112.9	79.5
July '06	101.5	105.8	79.5
June '06	101.5	105.8	77.4
May '06	101.5	105.8	75.3
April '06	99.9	104.2	73.2
March '06	95.5	99.7	73.2
February '06	96.2	100.5	73.2
January '06	100.5	104.8	73.2

15 Residential Heating Fuel Prices — Haines Junction

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	93.6	95.5	92.5
17-Dec-08	97.8	99.7	92.5
3-Dec-08	107.1	109.0	92.5
19-Nov-08	119.0	120.9	96.8
5-Nov-08	122.5	124.3	102.1
22-Oct-08	127.0	128.6	104.2
8-Oct-08	131.0	136.1	104.2
24-Sep-08	130.2	134.5	109.5
10-Sep-08	132.3	137.0	110.6
27-Aug-08	131.8	135.5	111.6
13-Aug-08	140.5	142.8	111.6
30-Jul-08	147.7	146.5	111.6
16-Jul-08	145.5	150.8	111.6
2-Jul-08	141.3	145.8	107.1
18-Jun-08	140.2	144.7	107.1
4-Jun-08	139.2	141.5	107.1
21-May-08	131.5	136.1	107.1
7-May-08	130.7	133.1	107.1
22-Apr-08	128.3	132.9	107.1
9-Apr-08	125.9	130.2	107.1
26-Mar-08	119.0	124.2	107.1
12-Mar-08	115.9	121.8	96.5
27-Feb-08	109.8	115.2	96.5
13-Feb-08	108.2	111.3	96.5
30-Jan-08	112.7	112.6	96.5
16-Jan-08	113.7	115.4	92.2
2-Jan-08	113.7	116.5	92.2
19-Dec-07	114.6	119.3	92.2
5-Dec-07	113.7	116.8	90.1
November '07	106.4	111.2	89.0
October '07	100.1	99.6	86.5
September '07	98.9	101.6	87.4
August '07	97.7	100.7	85.8
July '07	96.9	99.8	85.3
June '07	96.5	98.4	84.7
May '07	96.8	99.5	84.7
April '07	98.5	101.4	83.1
March '07	97.6	101.4	81.5
February '07	96.0	98.5	81.5
January '07	98.7	102.2	78.1
December '06	90.3	94.0	76.8
November '06	87.1	89.7	76.8
October '06	89.1	91.9	76.6
September '06	97.9	98.6	76.6
August '06	105.6	109.4	77.3
July '06	99.9	104.2	77.3
Jun '06	98.7	102.5	75.3
May '06	97.6	100.1	74.2
April '06	95.7	99.7	73.2
March '06	93.0	96.1	73.2
February '06	92.3	94.9	73.2
January '06	95.7	98.2	73.2

16 Residential Heating Fuel Prices — Mayo

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	110.3	116.9	94.7
17-Dec-08	114.6	128.0	94.7
3-Dec-08	122.0	131.8	94.7
19-Nov-08	137.7	140.8	98.9
5-Nov-08	141.6	144.2	102.1
22-Oct-08	147.4	149.5	106.3
8-Oct-08	147.4	154.8	106.3
24-Sep-08	147.4	154.8	111.6
10-Sep-08	150.1	153.3	112.7
27-Aug-08	150.1	153.3	113.7
13-Aug-08	160.7	163.9	113.7
30-Jul-08	160.7	163.9	113.7
16-Jul-08	156.5	159.6	113.7
2-Jul-08	156.5	159.6	109.2
18-Jun-08	154.3	152.0	109.2
4-Jun-08	154.3	146.5	109.2
21-May-08	142.7	142.6	109.2
7-May-08	133.9	139.8	109.2
22-Apr-08	132.3	138.2	109.2
9-Apr-08	130.2	136.8	109.2
26-Mar-08	128.0	128.8	109.2
12-Mar-08	125.0	126.1	98.6
27-Feb-08	125.0	126.6	98.6
13-Feb-08	123.8	125.4	98.6
30-Jan-08	127.8	128.2	98.6
16-Jan-08	127.8	128.2	94.3
2-Jan-08	127.8	128.2	94.3
19-Dec-07	127.8	128.2	94.3
5-Dec-07	127.8	123.8	92.2
November '07	117.3	118.5	91.2
October '07	113.0	115.1	91.2
September '07	114.5	114.5	89.6
August '07	113.7	115.0	87.9
July '07	114.3	115.0	87.4
June '07	113.0	113.9	86.8
May '07	111.5	112.6	86.8
April '07	111.5	112.8	85.2
March '07	111.3	112.3	83.6
February '07	111.5	112.6	83.6
January '07	110.8	112.1	80.3
December '06	105.4	106.9	79.0
November '06	103.6	105.0	79.0
October '06	106.5	107.9	78.7
September '06	112.1	113.5	78.7
August '06	118.7	120.4	79.5
July '06	112.8	114.2	79.5
June '06	110.9	112.3	77.4
May '06	110.9	112.3	76.3
April '06	109.2	110.9	75.3
March '06	109.5	110.9	75.3
February '06	110.1	111.5	75.3
January '06	112.5	113.9	75.3

17 Residential Heating Fuel Prices — Teslin

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	97.1	99.0	92.5
17-Dec-08	105.1	107.0	92.5
3-Dec-08	111.6	119.1	92.5
19-Nov-08	124.3	125.5	96.8
5-Nov-08	131.2	130.5	102.1
22-Oct-08	137.1	140.2	104.2
8-Oct-08	137.1	137.4	104.2
24-Sep-08	137.1	140.2	109.5
10-Sep-08	138.6	142.9	110.6
27-Aug-08	138.6	142.9	111.6
13-Aug-08	150.3	153.5	111.6
30-Jul-08	150.3	153.5	111.6
16-Jul-08	146.1	149.2	111.6
2-Jul-08	146.1	149.2	107.1
18-Jun-08	143.9	147.1	107.1
4-Jun-08	143.9	147.1	107.1
21-May-08	132.3	135.5	107.1
7-May-08	132.3	131.8	107.1
22-Apr-08	129.1	129.2	107.1
9-Apr-08	129.1	129.2	107.1
26-Mar-08	124.9	122.3	107.1
12-Mar-08	118.5	116.5	96.5
27-Feb-08	114.3	114.4	96.5
13-Feb-08	114.3	114.4	96.5
30-Jan-08	117.4	116.0	96.5
16-Jan-08	117.4	120.6	92.2
2-Jan-08	116.5	118.1	92.2
19-Dec-07	117.4	120.6	92.2
5-Dec-07	117.4	115.4	90.1
November '07	106.9	108.5	89.0
October '07	102.6	105.8	89.0
September '07	102.6	104.8	87.4
August '07	102.6	105.1	85.8
July '07	102.6	105.8	85.3
June '07	102.6	105.8	84.7
May '07	101.5	104.7	84.7
April '07	101.5	103.5	83.1
March '07	101.5	102.7	81.5
February '07	101.5	102.2	81.5
January '07	103.3	101.8	78.1
December '06	96.2	96.4	76.8
November '06	90.9	93.2	76.8
October '06	91.7	94.7	76.6
September '06	96.9	101.2	76.6
August '06	108.4	110.8	77.3
July '06	101.3	105.6	77.3
June '06	101.3	105.6	75.3
May '06	101.3	105.6	74.2
April '06	99.7	104.0	73.2
March '06	95.2	99.5	73.2
February '06	96.0	100.3	73.2
January '06	100.3	104.5	73.2

18 Residential Heating Fuel Prices — Watson Lake

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
31-Dec-08	96.2	98.1	92.5
17-Dec-08	98.3	101.2	92.5
3-Dec-08	104.7	108.7	92.5
19-Nov-08	114.7	118.7	96.8
5-Nov-08	121.4	125.9	102.1
22-Oct-08	131.4	135.1	104.2
8-Oct-08	134.0	137.7	104.2
24-Sep-08	131.8	135.6	109.5
10-Sep-08	134.5	138.3	110.6
27-Aug-08	134.8	139.1	111.6
13-Aug-08	142.8	146.5	111.6
30-Jul-08	146.4	150.2	111.6
16-Jul-08	149.4	153.2	111.6
2-Jul-08	146.6	150.5	107.1
18-Jun-08	145.1	148.9	107.1
4-Jun-08	143.7	147.5	107.1
21-May-08	137.9	141.7	107.1
7-May-08	134.4	138.2	107.1
22-Apr-08	131.7	134.8	107.1
9-Apr-08	131.0	134.8	107.1
26-Mar-08	128.2	131.9	107.1
12-Mar-08	123.7	127.6	96.5
27-Feb-08	118.2	122.0	96.5
13-Feb-08	112.8	116.6	96.5
30-Jan-08	113.9	117.7	96.5
16-Jan-08	115.2	119.4	92.2
2-Jan-08	116.2	120.0	92.2
19-Dec-07	118.7	122.5	92.2
5-Dec-07	117.1	120.9	90.1

	Furnace Oil	Arctic Stove Oil	Propane (500-gallon tank cost)
November '07	107.3	111.1	89.0
October '07	101.4	105.5	89.0
September '07	100.9	104.7	87.4
August '07	99.9	103.0	85.8
July '07	98.5	102.2	85.3
June '07	98.6	101.9	84.7
May '07	98.5	101.8	84.7
April '07	99.7	103.0	83.1
March '07	100.8	104.1	81.5
February '07	98.5	101.4	81.5
January '07	100.4	103.6	78.1
December '06	91.4	95.3	76.8
November '06	87.5	91.3	76.8
October '06	88.4	92.2	76.6
September '06	92.6	96.3	76.6
August '06	105.4	109.4	77.3
July '06	100.5	104.9	77.3
June '06	98.3	102.7	75.3
May '06	98.9	103.4	74.2
April '06	96.8	101.2	73.2
March '06	91.0	95.4	73.2
February '06	92.1	96.5	73.2
January '06	97.4	102.3	73.2

Information collected by The Yukon Bureau of Statistics for the Department of Economic Development.

Next release: January 29th, 2009

Yukon
Executive Council Office
Bureau of Statistics

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REFERENCE: October 6, 2008 Application, Rates, Page 4-12

YEC states "It is also important to note that without proper economic signals there may be a tendency in new construction for electric heating to be preferable to customers due to the lower capital cost of electric heating (baseboards) compared to oil (furnaces)".

QUESTION:

a) Please describe the discussions that YEC has had with builders and land developers concerning the "proper economic signals" they feel are required.

b) Please provide YEC's cost analysis for the installation of electric heating versus oil-fired heating. Please provide the source of any referenced data.

ANSWER:

(a)

To be clear, the "proper economic signals" noted are required by the current Rate Policy Directive in place in the Yukon (OIC 1995/90) and not just by Yukon Energy. Yukon Energy is bringing forward a GRA Application that respects the direction provided by OIC 1995/90.

OIC 1995/90 requires that the Board fix runoff rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency. As noted at page 4-12 of the Application, current runoff rates for residential customers in the Hydro and Large Diesel rate zone communities (including all riders) are only 14.39 cents/kWh. Were the rate design approaches for runoff rates approved by the Board during 1996/97 GRA to be strictly applied the target runoff rates would be closer to 37.37 cents/kWh. The Application provides a modest increase to ensure runoff rates better reflect the OIC and past Board direction related to runoff rates.

Please see the response to UCG-YEC-1-59(b) in respect of discussions with builders and land developers.

(b)

Installing baseboard heating is less costly than installing oil heating, but no specific capital cost estimates are available to YEC. The Board Report to the Commission in Executive Counsel provided after the 1992 Resource Plan hearing provides that, “it was clearly demonstrated during the course of the proceeding that electric heating uses more resources than direct combustion of fuels. Although the capital cost of installing electric heating is less than for direct combustion fuels, in the long run electric heating is more expensive.”

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "…electricity prices today should at least be in the 20-22 cents/kW.h range (i.e., at least 25 to 40% higher than oil heating costs) to promote in the short term "economy and efficiency" by once again starting to discourage electric heating. Further, given the system realities these rates should be planned now to be set in the near term at even higher levels (e.g., in excess of 30 to 35 cents per kW.h based on the current GRA diesel fuel price forecasts), if the rate design principles adopted by the Board in the 1996/97 GRA are to be followed in the future".

QUESTION:

a) Please update YEC's 20-22 cents per kWh price range based on current heating oil costs. Please provide details of source data used for calculations.

b) Please identify bill impacts if YEC's estimate of where rates should be (i.e., 30-35 cents per kWh) is realized.

c) Please provide the calculations and sources of data for YEC's conclusions.

d) Please provide details of the rate rebalancing efforts by BC Hydro that were initiated in 2007 by the BC Utilities Commission.

ANSWER:

(a)

The target range has not changed.

In the GRA, Yukon Energy only sought to move second block rates a modest amount towards the full efficient level of 37.37 cents/kW.h At today's diesel prices of approximately 76 cents/litre at Whitehorse (per CW-YEC-I-16), the full required level is approximately 24.8 cents/kW.h,[1] still above the 20-22 cents/kW.h targeted by Yukon Energy.

[1] 76 cents/litre divided by 3.6 kW.h/litre plus 10% for system losses plus 1.6 cents/kW.h for non-fuel variable O&M expense.

(b)

Bill impacts by class will be $0, as any increases in the second block rate will be offset by decreases in the first block rate.

(c)

Please see **(a)** above.

(d)

Yukon Energy does not have specific knowledge of the process or efforts expended in BC, but notes the following information collected from the BCUC and BC Hydro website:

BC Hydro filed its Rate Design Application (its first since 1991) with the BC Utilities Commission (BCUC) on March 15, 2007.

Filing of the Application was followed by a three-and-a-half month regulatory review process directed by the BCUC.

On October 26, 2007, the BCUC issued its decision on BC Hydro's 2007 Rate Design Application. On February 20, 2008, BC Hydro filed an application for reconsideration on the rebalancing component of the RDA. BC Hydro sought to suspend the rate rebalancing orders due to pending provincial legislation to set aside the Order. Components of the RDA not relating to the rate rebalancing were approved by the BCUC and came into effect on April 1, 2008.

On March 7, 2008, the BCUC approved BC Hydro's request to suspend the implementation of the rate rebalancing portion of the RDA decision.

For more information on process and outcomes please see link to BC Hydro's website provided below:

http://www.bchydro.com/planning_regulatory/regulatory/rate_design_application.html?WT.mc_id=rd_ratedesign

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "In the residential class, by far the minority of sales are made at the second block rates. As shown in Table 4.9, less than 20% of the residential energy sold in Yukon at second block rates for the non-government class, and only slightly higher (approximately 23%) for the government class"

QUESTION:

a) Please provide the billing data upon which YEC has determined the distribution of residential energy sales by rate block.

ANSWER:

(a)

Please see Table 4.9 which notes forecast 2009 Second Block energy sales for Residential Non-Government customers at 19.53% of total sales for the class. This is based on:

- YEC sales per its GRA forecast; and

- YECL sales per YEC's wholesale forecast included in the Application (which includes a 1.2% escalation in Hydro Zones compared to YECL's 2009 GRA forecasts, and YECL forecast values in all non-hydro communities).

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "This can be done by establishing an offsetting decrease to first block rates so as to ensure the residential share of overall electricity charges remain the same".

QUESTION:

a) Please confirm that YEC is not suggesting that the residential class' share of YEC's actual cost of service nor residential bills will remain the same.

b) Please explain why YEC is maintaining the current rate block structure given the variation in seasonal use and the adverse impacts identified for users of more electricity.

ANSWER:

(a)

As noted previously in responses UCG-YEC-1-13, and UCG-YEC-1-15, the Residential Class' share of the actual cost of service that would otherwise exist will remain the same. Pursuant to the direction provided by OIC 2008/149, the rate decrease will be applied in equal percentages across each class.

Individual residential bills will vary, depending on the energy use profile of the customer.

(b)

Yukon Energy is not proposing any such rate redesign in this Application regarding seasonal use, as any such proposals would go far beyond what YEC sees as feasible to address as a near term priority.

Aspects of the current block structure are imposed by government OIC (1995/90). Section 4(2) of that OIC notes as follows:

> 4(2) the Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and

such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.

While the OIC would provide for some upward adjustment to the rate block structure, i.e., the runoff block may be set higher than 1,000 kWh, such a change to the currently approved rate design would need to be undertaken jointly by YEC and YECL.

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "…the General Service class is dominated by sales at second block rates (approximately 71% of sales in the non-government class, and 87% of sales in the government class)".

QUESTION:

a) Please provide the billing data upon which YEC has determined the distribution of general service energy sales by rate block.

ANSWER:

(a)

Please see Table 4.9 which shows the forecast 2009 Second Block energy sales for General Service Non-Government customers. This is based on:

- YEC sales per its GRA forecast; and

- YECL sales per YEC's wholesale forecast included in the Application (which includes a 1.2% escalation in Hydro Zones compared to YECL's 2009 GRA forecasts, and YECL forecast values in all non-hydro communities).

REFERENCE: October 6, 2008 Application, Rates, Page 4-13

YEC states "…when dealing with a large and relatively non-homogenous group, rate structures that impose a notable inverted structure require careful attention given the range of impacts on the different profiles of customers in the class. For example, in order to provide fair price signals it may require establishing multiple general service rate subclasses, or further rate blocks. Yukon Energy does not believe that it is practical to properly analyze and implement an appropriate rate design package in a Yukon Energy Revenue Requirement proceeding".

QUESTION:

a) Please explain whether this current proceeding is to address a general rate application or a revenue requirement application.

b) Please explain how the YUB can ignore the issue of the non-homogenous ratepayer groups identified by YEC in this application when making decisions on the rate issues proposed by YEC.

ANSWER:

(a)

The requested approvals are as set out at pages 3 to 5 of Yukon Energy's 2008/2009 General Rate Application.

(b)

Yukon Energy is not suggesting the Board ignore any issues. Yukon Energy is only noting that the required information to undertake General Service rate redesign is not available to it or the Board in this proceeding, and that the matter of redesigning general service rates requires extensive data only available to YECL. Consequently, as noted at Tab 6 of the Application (page 6-4 to 6-5) Yukon Energy proposes "as a first priority" that future joint attention by YEC and YECL be directed towards identifying and assessing rate design options for the General Service rate classes to promote economy and efficiency in accordance with OIC 1995/90.

Yukon Energy is seeking approval of only the first steps in addressing necessary runoff rate adjustment issues that are ultimately required for all customer classes. The current proposal is limited to a partial adjustment to the Residential Class runoff rate, such that it better accords with the direction provided by OIC 1995/90 and the rate design approach established by the Board subsequent to the 1992 Cost of Service and Rate Design proceeding and affirmed in the 1996/97 General Rate Application.

As noted in the Application (at page 4-13), it is practical at this time to address this concern as it related to Residential customer classes since the minority of residential sales (less than 20%) are in the second block. Material rate design issues would need to be addressed prior to implementing any runout rate adjustments to general service class rates since sales for this group of customers are predominantly in the second block.

REFERENCE: October 6, 2008 Application, Rates, Page 4-14

YEC states "In conclusion, although it is patently clear that run out rates must be changed, a second block level today for residential customers based on 2009 diesel price forecasts and full implementation of 1996/97 GRA principles is not reasonably achievable in one rate change, given obvious potential rate impacts to individual customers of a required 160% increase in the Hydro/Large Diesel zone runoff rate. However, a more gradual transition to higher runoff rates based on the cost of diesel generation is both necessary and feasible today for the residential classes, with a first step designed to increase Hydro zone residential runoff rates by 40 to 50%, i.e., to the 20 to 22 cents/kW/h range net of GST".

QUESTION:

a) Please explain how a gradual and stable transition to cost-based rates can be realistically and fairly designed without first establishing the actual level of cost based rates.

b) Please provide an analysis of how the proposed runoff rates compare to the actual marginal cost of providing electricity.

ANSWER:

(a)

The above referenced quote from the Yukon Energy Application does not reference a transition towards any form of embedded cost-based rates, but a transition towards more efficient price signals that meet the requirements of OIC 1995/90. This transition is not linked to establishing cost of service for each rate class.

As discussed in responses to UCG-YEC-1-13, and UCG-YEC-1-15, an embedded cost of service is not relevant or appropriate to any necessary adjustments to runout rates to ensure that such rates better reflect rate design principles approved by the Board (most recently in Order 1996-7). Based on their relevant considerations reviewed, runout rates must be set to ensure economy and efficiency by reflecting short term incremental energy costs for each rate zone.

(b)

As noted at pages 4-11 and 4-12 of the Application, applying the same rate design approach for 2009 as approved in the 1996/97 GRA would yield target runoff rates for hydro zone communities of approximately 37.37 cents/kW.h. The current effective runout rate for the Hydro zone is only 14.39 cents/kWh and as such does not meet the requirements of OIC 1995/90 or the rate design principles previously established by the YUB. The applied for increase in the runout rate provides for a gradual transition to higher runoff rates based on the cost of diesel generation by modestly adjusting hydro zone residential runout rates upwards to the 21 cents/kWh range (net of GST) as shown in Table 4.7.

REFERENCE: October 6, 2008 Application, Rates, Page 4-14

YEC states "With the completion of the Carmacks-Stewart Transmission Project and the connection of the Minto mine, Yukon Energy is able to implement substantial rate reductions for all retail customer classes throughout Yukon. For 2009, this reduction totals $1.334 million, or 3.48% of total Yukon-wide base rate revenues as forecast by Yukon Energy".

QUESTION:

a) Please provide the cost and revenue data used to determine the $1.334 million benefit to non-industrial customers.

b) Please provide a breakdown of the data contain in Table 4.6 between YEC and YECL.

c) Please provide a table similar to the table provided in response to part (b) for 2008 benefits.

ANSWER:

(a)

Please see Table 4.1 provided at page 4-3 of Tab 4 of the Application which sets out Yukon Energy's revenue required from Rates for 2008 and 2009.

(b)

Please see Table 4.9 provided in Tab 4 of the Application.

(c)

Please see response to (a) above. Table 4.1 provides Yukon Energy Revenue Requirement from Rates for both 2008 and 2009.

REFERENCE: October 6, 2008 Application, Rates, Page 4-17

YEC states "Yukon Energy proposes to implement a system-wide revenue-neutral adjustment to firm residential non-government and residential government rates for both Yukon and YECL retail customers".

QUESTION:

a) Please confirm that the application should read "…rates for both YEC and YECL retail customers".

b) Please provide an explanation for YEC's interpretation of OIC 2008/149 that rate adjustments designed and proposed only by YEC are supposed to be (i) revenue neutral and (ii) applicable to customers of both YEC and YECL.

c) Please provide details of discussions and correspondence between YEC and YECL on YEC's rate design proposals.

ANSWER:

(a)

Confirmed.

(b)

Yukon utilities can address rate changes only if they are applicable to customers of both utilities, i.e., YEC's rate reduction benefits all Yukon retail customers. The test of revenue neutrality relates to an added requirements when changing retail rates prior to 2013.

Order-in-Council 1995/90 at section 4(1)(b) provides that "rates for each class of non-government retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited Customers." The recent OIC (2008/149) amends OIC 1995/90 to add section 2.1(1) which set out that "The Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers."

(c)

Please see LE-YEC-1-4 and YUB-YEC-1-20.

REFERENCE: October 6, 2008 Application, Rates, Page 4-21 and 4-22

Table 4.9 – Primary Sales by YEC/YECL Rate Class & Billing Determinants - 2009 Existing Rates.

Table 4.10 – Primary Sales by YEC/YECL Rate Class & Billing Determinants - 2009 with Proposed Rate Rebalancing.

QUESTION:

a) Please explain why YEC accepted YECL's sales forecast except within the hydro zones (to which YEC added a 1.2% escalation factor).

ANSWER:

(a)

Yukon Energy has no experience with, nor reason to dispute, YECL's forecasts for isolated diesel-served communities.

REFERENCE: **October 6, 2008 Application, Rates, Pages 4-23, 4-24, 4-26, 4-27**

Table 4.11 – Bill Comparisons: 2009 Proposed Rates vs. Existing – Residential Non-Government

Table 4.12 – Bill Comparisons: 2009 Proposed Rates vs. Existing – Residential Non-Government (Absent RSF)

Table 4.14 – Bill Comparisons: 2009 Proposed Rates vs. Existing – General Service Non-Government

Table 4.15 – Bill Comparisons: 2009 Proposed Rates vs. Existing – General Service Non-Government (Absent RSF)

QUESTION:

a) Please update the referenced tables assuming that the first energy block for residential customers is 1100, 1200 and 1300 kWh and the first block for general service customers is 2200, 2400 and 2600 kWh.

ANSWER:

(a)

While YEC has general information on the consumption of the various rate classes throughout Yukon, the precise information about bill determinants as required to answer the above question can only be derived from YECL data that is not available to YEC.

The implementation of such a change would require material rate redesign of YEC and YECL rates to ensure the full revenue requirement of both utilities was collected. For example, as second block energy is presently sold at a higher price than first block energy, increasing the size of the first block (and reducing the number of units sold at second block prices) would lead to a requirement to raise the rate for the first block to collect the same revenues from the class. The same situation arises for Rider U calculations (in that increasing first block sales will decrease Rider U).

REFERENCE: **October 6, 2008 Application, Rates, Appendix 4.1 – Rate Schedules**

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

QUESTION:

a) Please provide a copy of YEC's current Electric Service Regulations as approved by the YUB.

b) Please provide any analysis that YEC has made to verify that the miscellaneous charges (e.g., connection fees, reconnection charge, meter test fee, late payment charge, dishonoured cheque charge, maximum company investments) within the Electric Service Regulations are still appropriate given associated costs.

c) Please explain how customers resolve billing or service disputes with provider (i.e., does the service provider make final decision or is there an independent arbitrator available besides the Yukon Utilities Board?).

d) Please explain how a dispute is to be brought to the YUB and if there are informal processes available.

e) Has YEC ever been involved in a dispute with a residential customer that has been taken to the YUB? If yes, please describe the circumstances and process.

f) Please provide YEC's rationale for not having a Customer Bill of Rights as is the case in many other jurisdictions.

ANSWER:

(a)

Please see Attachment 1 to this response.

(b)

This type of analysis is not available and cannot be provided.

(c)

Yukon Energy works with customers to resolve all issues raised by customers to the extent possible. Customers who are dissatisfied with a decision or treatment by Yukon Energy relative to a regulated activity are directed to contact the YUB.

(d)

Part 4, Sections 44-49 of the Public Utilities Act describes the process for complaint notification and settlement.

(e)

YEC is not aware of any dispute with a residential customer that has been taken to the YUB.

(f)

Yukon Energy (and YECL) provide regulated service under an approved set of Electrical Service Regulations. The ESRs set out the rights and obligations of customers and the utility.

YUKON ENERGY CORPORATION

AND

THE YUKON ELECTRICAL COMPANY LIMITED

ELECTRIC SERVICE REGULATIONS

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YUKON ENERGY CORPORATION

AND

THE YUKON ELECTRICAL COMPANY LIMITED

ELECTRIC SERVICE REGULATIONS

1. INTERPRETATION

1.1 Definitions

Unless the context requires otherwise, the following words and phrases, whenever used in these Regulations, the Electric Service Tariff or an application, contract or agreement for service, shall have the meanings set out below.

"billing demand" - the demand upon which billing to a customer is based.

"Board" - the Yukon Utilities Board.

"Company" - The Yukon Electrical Company Limited or Yukon Energy Corporation.

"connected load" - the sum of the capacities or ratings of the electric energy consuming apparatus connected to a supplying system.

"construction contribution" - the difference between the cost of extending the Company's facilities to serve a customer and the maximum Company investment specified in Schedule B.

"customer" - means a person, firm, corporation, association or organization which has applied for or is receiving the provision of service by the utility. This would include joint tenants whether or not their name appears on the application.

"demand" - the rate at which electric energy is delivered by the Company (expressed in kilowatts, kilovoltamperes or other suitable unit) at a given instant or averaged over any designated period of time.

"energy" - electric energy (expressed in kilowatt hours).

"extraordinary circumstances" - circumstances not reasonably within the control of the Company, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, and any other cause, whether of the kind herein enumerated or otherwise.

"facilities" - a physical plant (including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery).

"family dwelling" - a residential dwelling unit which is not a multiple dwelling, consists of single family living quarters having in one self-contained unit at least sleeping quarters, a kitchen and bathroom (see definition of "multiple dwelling").

"in-service date" - the date on which the customer specifies service is to be available or the date the service is actually available, whichever is later.

"interconnected system" - those portions of the Company's facilities which are connected to the Whitehorse/Aishihik/Faro (WAF) power grid or to the Mayo-Dawson grid.

"isolated system" - those portions of the Company's facilities which do not form part of the interconnected system.

"load" - the demand and energy delivered to or required at any point of delivery.

"load factor" - the ratio of the average demand (in kilowatts) supplied during a designated period to the peak or maximum load (in kilowatts) occurring in the period. To express load factor as a percentage:

(a) multiply the energy used in the period by 100;
(b) multiply the maximum demand by the number of hours in the period; and
(c) divide (a) by (b).

"multiple dwelling" - a residential building containing more than one residential dwelling unit.

"point of delivery" - the point at which the Company's service conductors are connected to the wires or apparatus of a customer.

"power factor" - the ratio of the highest metered kilowatt demand in a billing period to the highest metered kilovoltampere demand in that same billing period.

"service" - the delivery of energy by the Company at the demand required by a customer.

2. INTRODUCTION

2.1 Board Approval

These regulations have been approved by the Board.

The Company may amend these regulations by filing a notice of amendment with the Board. Included in the notice to the Board shall be notification of which customer groups are affected by the amendment and an explanation of how affected customers will be notified of the amendments. The amendment will take effect 120 days after such notice is filed unless the Board orders otherwise.

2.2 Electric Service Tariff

These regulations are the Electric Service Regulations referred to in the Company's Electric Service Tariff and form part of the Electric Service Tariff.

2.3 Effective Date

These regulations come into force on October 18, 2005, and replace the Company's previous Electric Service Regulations. Whenever the Board approves an amendment to these Regulations, revisions will be issued, with the effective date of the amendments indicated on the top of each affected page.

3. GENERAL PROVISIONS

3.1 Regulations Prevail

These regulations apply to the Company and to every customer.

No agreement can provide for the waiver or alteration of any part of these regulations unless such agreement is first filed with and approved by the Board.

3.2 Ownership of Facilities

The Company remains the owner of all facilities it provides to serve the customer, unless a contract between the Company and customer specifically provides otherwise.

Payment made by customers for costs incurred by the Company in installing facilities does not entitle customers to ownership of any such facilities, unless a contract between the Company and the customer specifically provides otherwise.

3.3 Use of Energy

Unless otherwise provided in a contract with the Company, a customer shall not sell energy provided by the Company unless the Company has first given written consent.

3.4 Customer Extensions

A customer shall not extend service facilities beyond property owned or occupied by the customer.

3.5 Customer Generation

A customer must sign an agreement with the Company if he/she wishes to use service.

a) in parallel operation with; or
b) as supplementary, auxiliary or stand-by service to any other source of electric energy.

3.6 Frequency and Voltage Levels

The Company will make every reasonable effort to supply energy at 60-Hertz alternating current. The voltage levels and variations will comply with the Canadian Standards Association standards and as specified in Schedule A.

Some voltage levels set out in Schedule A may not be available at all locations served by the Company.

4. APPLICATION FOR AND CONDITIONS OF SERVICE

4.1 General Requirements

To enable the Company to provide the requested service, applicants for service shall supply information regarding their load and preferred supply conditions.

An applicant shall be required to sign an application or a contract for service and may be required to provide credit information or references.

4.2 Conditions of Service

Before connecting any service, the Company will inform the customer if there are any special conditions that must be satisfied.

4.3 Connection Fee

Whenever a connection is made, the customer will pay a non-refundable connection fee of either:

(a) $15 if the connection is made during the Company's regular business hours; or

(b) an amount not to exceed the Company's actual costs if the connection is made at any other time, which shall be included in the customer's first billing (save and except that, where the customer has paid a construction contribution for the service, the connection fee shall be deemed to be included in the construction contribution).

4.4 Application of Rate Schedules

Whether or not a Customer has signed an application or contract for service, the Regulations and the rate schedule applicable to the service supplied by the Company shall apply. In addition to payments for electric service, the customer is required to pay the Company the amount of any tax or assessment levied by any tax authority on electric service delivered to the customers.

4.5 Extensions to Electric Heat Customers

On isolated systems, service for electric space heating purposes may be supplied to customers only with the prior written permission of the Company.

4.6 Multiple Dwellings

Each individual unit within a multiple dwelling will be served as a separate point of delivery unless the Company agrees otherwise. The Company and the customer may agree that one bill will be issued covering all individual units in a multiple dwelling. Where the Company and a customer have agreed that service to a multiple dwelling shall be delivered through a single point of delivery, the applicable general service (non-residential) rate will apply to the service.

4.7 Totalized Metering

Normally, the Company will issue a separate bill for each point of delivery.

When service is provided through multiple points of delivery to a customer's plant site consisting of centralized processing facilities or product transportation facilities located on lands leased or owned by the customer, where such multiple points of delivery are located within a radius of half a mile of each other, the customer and Company may agree that the demand and energy at each point of delivery be totalized and only one bill issued for each billing period.

The customer shall pay the incremental metering cost associated with totalized metering.

4.8 Consolidated Billing

The Company will issue a separate bill for each point of delivery. However, the customer and Company may agree that the Company will issue one bill totaling charges for service delivered at more than one point of delivery.

4.9 Security Deposit

The Company may require any customer who has not established a satisfactory credit rating with the utility and cannot provide evidence of employment or who has been disconnected or where a current-limiting device has been installed, to provide a security deposit which shall not exceed the Company's estimate of the customer's total bills for any three-month period.

The Company will pay simple interest on the security deposit from the date the deposit is paid, at a rate of interest equal to the rate fixed for the most recent rate of the Yukon Landlord and Tenant Act and such interest will be credited to the customer's account on the first billing following December 31 of each year.

The Company may refund a security deposit when the customer has established a satisfactory payment history over a 12-month period or when the customer's service is terminated. Any interest owing at the time a security deposit is refunded will be included in the refund or credited to the customer's account.

4.10 Use of Security Deposit

If a customer fails to pay any amount billed, the Company may apply all or any portion of that customer's security deposit to the unpaid amount.

When the Company has to take this step, the customer may be required to pay a security deposit up to the maximum amount allowed in regulation 4.9.

4.11 Delay in Taking Service - Other than Subdivision

Except in the case of a customer who requests service to a subdivision if service is not taken within 30 days of the in service date, the Company may begin billing the customer for the minimum amount specified in the appropriate rate schedule or as specified in the contract between the Companyand the customer, whichever is greater.

4.12 Extension of Service

If the Company's estimated costs of extending facilities at the request of a customer are less than the maximum Company investment specified in Schedule B for the type of service provided, the customer will not be required to make any contribution.

In all other cases, an agreement for payment of the construction contribution must be made between the customer and the Company before any work on the extension is commenced.

4.13 Underground Subdivision Extensions

Underground subdivision extensions shall be undertaken subject to the conditions set out in Schedule C.

4.14 Conversion from Overhead to Underground Service

When a customer requests that existing Company facilities be converted from overhead to underground, the customer will be charged for all costs incurred by the Company in connection with the conversion, including the following:

(a) the estimated cost of removing the existing facilities, less the estimated salvage value, plus

(b) the estimated cost for the installation of the new underground facilities, less any applicable increase in Company investment as specified in Schedule B.

4.15 Temporary Service

Where the Company reasonably believes that a requested service will be temporary, it may require the customer requesting the service to pay the Company's total estimated cost of installation and removal of the service, plus the cost of unsalvageable material.

The Company may require that such payment be made before the temporary service is installed.

4.16 Mobile Homes

Service shall normally be provided to mobile homes through separate points of delivery, based on the applicable residential rate schedule.

Service provided to common use areas (e.g., laundry facilities) in a mobile home park shall be separately metered and billed at the applicable general service rate.

In mobile home parks or trailer courts where the Company reasonably believes homes are temporary, the Company may elect to provide service only through the point of delivery billed to the mobile home park or trailer court.

4.17 Relocation of Company Facilities

The Company may require a customer to pay all reasonable costs incurred by the Company in relocating any Company facility at the customer's request.

If requested by the Company, the customer shall pay the estimated cost of the relocation in advance.

4.18 Reconnection or Restoration of Service

This section applies when the Company is asked to reconnect or restore service to a customer whose service was previously restricted by a current-limiting device or discontinued (whether at the request of the customer or not).

This section does not apply when a customer's service was disconnected for safety reasons. (See regulation 11.2)

Before reconnecting or restoring service, the customer shall pay:

(a) any amount owing to the Company;

(b) a collection charge of $45 if the reconnection is made during the Company's normal business hours, or, in any other case, an amount not exceeding the Company's actual cost of reconnection;

(c) the security deposit, if any, required under regulation 4.9;

(d) the minimum monthly bill for each month of disconnection, if service is reconnected within 12 months of disconnection for all rate schedules and service except seasonal service.

4.19 Construction Contribution Cost Sharing

Existing electrical customers may be entitled to cost sharing of the construction contribution for their extension, in accordance with the following terms. "Cost Sharing" refers to the procedure of having new customers who connect to an existing facility for which someone else has paid a contribution, assessed their share of that cost, which is then refunded to the existing customer.

Construction contributions share costing will be administered for a five year term commencing December 31 of the year of construction of the original extension. The utility will not administer refunds of less than $50.00.

5. RIGHTS OF WAY AND ACCESS TO FACILITIES

5.1 Easements

The customer shall grant, or cause to be granted, to the Company, without cost to the Company, such easements or rights-of-way over, upon or under the property owned or controlled by the customer as the Company reasonably requires to provide service to such customer, including extensions thereof.

5.2 Right of Entry

The Company's employees or agents shall have the right to enter a customer's property at all reasonable times for the purpose of installing, maintaining, monitoring and removing the Company's facilities and for any other purpose incidental to the provision of service.

The customer shall provide the Company with reasonable access to Company facilities located on the customer's property.

5.3 Vegetation Management

The customer shall permit the Company to manage vegetation on the property owned or controlled by the customer to maintain proper clearances and reduce the risk of contact with the Company's facilities.

The Company shall endeavor to notify a customer before such work is performed.

5.4 Interference with Company's Facilities

Customers shall not place any structures that would interfere with the proper and safe operation of the Company's facilities or which would adversely affect compliance with any applicable legislation.

5.5 Customer Brushing

Customers requesting service that requires new electrical facilities/powerlines, shall be responsible for brushing to Company specification along with providing an unobstructed access to each structure.

6. METERS

6.1 Installation

The Company shall provide, install and seal all meters necessary for measuring the energy supplied to a customer, unless otherwise specifically provided in a contract with the customer.

Each customer shall provide and install a CSA-approved meter receptacle or other CSA-approved facilities suitable to the Company for the installation of the Company's meter or metering equipment.

6.2 Location

Meter locations shall be approved by the Company based on type of service and convenience of access to the meter. Where a meter is installed on a customer-owned pole, the pole shall be provided and maintained by the customer as required by the Canadian Electric Code and any other applicable legislation.

6.3 Meter Tests and Adjustments

The Company may inspect and test a meter at any reasonable time.

At the request of a customer, and upon payment of a $25 fee, the Company shall arrange for a meter to be tested by an official designated for that purpose by Industry Canada or such other federal government agency as may, from time to time, be designated for the purpose.

If a test determines that the meter is not accurate within the limits set by government standards, the customer's bill will be adjusted accordingly. Where it is impossible to determine when the error commenced, it shall be deemed to have commenced three months before the test or on the date of the meter installation, whichever occurred later.

In the event that an adjustment is required, the $25 shall be refunded.

6.4 Energy or Demand Diversion

If under any circumstances, a person prevents a meter from accurately recording the total demand or energy supplied, the Company may disconnect the service, or take other appropriate actions.

The Company may then estimate the demand and amount of energy supplied but not registered at the point of delivery. The customer shall pay the cost of the estimated demand and energy consumption plus all costs related to the investigation and resolution of the diversion.

7. METER READING AND BILLING

7.1 Reading and Estimates

Customers' bills will be based on meter readings made by the Company from time to time or on estimates for those billing periods when the meter is not read.

Whenever a bill is based on an estimate, an adjustment to reflect actual usage will be made after the meter is next read.

7.2 Proration of Initial and Final Billings

The amount of any initial and final charges, other than energy, may be prorated, based upon the ratio of the number of days that service was provided to a customer in the billing period to the total number of days in the billing period.

The Company may elect not to charge a customer for the billing period if, during that period, demand was five kilowatts or less, service was provided for five days or less and energy consumption was five kilowatt hours or less.

For all new accounts, the Company may add the charges for service provided during the initial period to the bill for the following billing period.

7.3 Payment of Accounts

Payment of a bill for service is due when rendered and payable by the date indicated on the bill.

Failure to receive a bill does not release a customer from the obligation to pay the amount owing for any service provided by the Company.

7.4 Late Payment Charge

The Company may add a service charge equal to 1.0% per month (effectively 12.68% per annum) on any overdue amount.

7.5 Dishonored Cheques

The Company may add a service charge of $20 to a customer's bill in respect of any cheque returned by the customer's bank for any reason.

7.6 Outstanding Charges

The Company may add to the customer's bill any outstanding charges owing to the Company (e.g. construction contribution, account receivable charges, former overdue accounts etc.).

8. SERVICE CHANGES

8.1 Notice by Customer

A customer shall give to the Company reasonable prior written notice of any change in service requirements, including any change in load to enable the Company to determine whether or not it can supply such revised service without changes to its facilities.

When a residential customer operates a business or commercial undertaking (collectively, a "business") in the customer's residence and when that business consumes electric energy, the customer shall notify the company of that fact. When the company is notified of business energy consumption, or has reasonable grounds to suspect business energy consumption, the company may request the customer to provide full particulars of all business energy consumption at the residence. The customer shall promptly provide the requested particulars. When the provided particulars confirm business energy consumption at the residence or when the customer provides inadequate or no particulars, the company may commence charging a general service rate for all energy provided. The general service rate shall apply until the customer has, to the company's reasonable satisfaction, caused separate metering systems to be installed for accurate and segregated recording of residential and business energy consumption at the residence (and, if such metering is installed, then the general service rate would apply only to the metered business energy consumption).

8.2 Responsibility for Damage

The customer shall be responsible for all damage caused to the Company's facilities as the result of the customer changing service requirements without the Company's permission.

8.3 Changes to Company facilities

If the Company must modify its facilities to accommodate a customer load or service change, the customer shall pay for all costs in connection with such modification including the following costs:

(a) the estimated cost of removing the existing facilities, less the estimated salvage value, less

(b) any applicable increased Company investment.

9. COMPANY RESPONSIBILITY AND LIABILITY

9.1 Continuous Supply

The Company shall make all reasonable efforts to maintain a continuous supply of energy to its customers, but the Company cannot guarantee an uninterrupted supply of energy.

9.2 Planned Outages

The Company reserves the right to interrupt, discontinue or reduce the supply of energy to any customer to allow for repairs and improvements to its facilities.

The Company shall endeavor to give prior notice to customers who will have service interrupted and will endeavor to ensure that such interruptions are as short and infrequent as circumstances permit.

9.3 Company Liability

The Company shall not be liable for any loss, damage, expense, charge, cost or liability of any kind (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising out of or in any way connected with any failure, defect, fluctuation, reduction or interruption in the provision of service by the Company to its customers. For the purpose of the foregoing and without otherwise restricting the generality thereof, "direct physical loss, injury or damage" shall not include loss of profits, loss of earnings, or any other similar damage or loss whatsoever, arising out of or in any way connected with the failure, defect, fluctuation, reduction or interruption in the provision of service to a customer.

9.4 Extraordinary Circumstances

Should the Company be unable, because of extraordinary circumstances, to provide a continuous supply of energy to a customer, the Company's responsibilities, so far as they are affected by the extraordinary circumstances, shall be suspended during the duration of such circumstances. Where practical, the Company shall give notice to the affected customers of such extraordinary circumstances.

10. CUSTOMER RESPONSIBILITY AND LIABILITY

10.1 Provide Permit

The customer shall provide permits, licences and authorizations prior to commencement of service or any change of service requirements at any point of delivery.

10.2 Customer Responsibility

The customer shall be responsible for the installation and condition of all facilities on the customer's side of the point of delivery.

The customer shall indemnify and save harmless the Company from and against any claim or demand for injury to persons or damage to property arising out of or in any way connected with the use of the service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the Company, its employees and agents.

The customer shall be responsible for any damage to Company facilities located on the customer's premises where the damage is caused by the negligent acts or omissions or willful misconduct of the customer or anyone permitted by the customer to be on the premises.

10.3 Protective Devices

The customer shall be responsible for determining whether the customer needs any devices to protect his equipment from damage that may result from the provision of service by the Company. The customer shall provide and install any such devices.

10.4 Service Calls

The Company may require a customer to pay the actual costs of a customer-requested service call if the source of the problem is the customer's own facilities.

11. TERMINATION OF SERVICE

11.1 Customer-requested Termination

Except where otherwise provided in a written agreement between the Company and a customer, a customer may, at any time, give the Company reasonable notice (in writing) that he wishes to terminate his service. Upon receipt of such notice, the Company shall read the customer's meter within a reasonable time, and, shall use its best efforts to read the customer's meter at the time requested by the customer. A customer shall pay for all service provided to the time of such reading.

A customer is responsible for all service provided until notice of termination is given and the meter is read.

11.2 Company Termination for Safety or Technical Reasons

The Company may, without notice, terminate a customer's service where, in the Company's opinion:

(a) the customer has permitted the wiring of his/her facilities to become hazardous; or
(b) the wiring of the customer's facilities fails to comply with applicable law; or
(c) the use of the service may cause damage to the Company's facilities or interfere with or disturb service to any other customer.

The Company will reconnect the service when the safety problem is resolved and when the customer has provided, or paid the Company's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance.

11.3 Company Termination Other Than For Safety

The Company, or anyone acting under its authority, may, upon giving at least 48 hours' notice to the customer, terminate the customer's service or install a current-limiting device to restrict the service to such customer if the customer:

(a) violates any provision of these regulations or of the Company's tariff;
(b) tampers with any service conductors, meters, seals or any other facilities of the Company;
(c) neglects or refuses to pay the charges for service due to the Company within 30 days of the date the bill for such service was rendered;
(d) violates the provision of any contract or rate schedule applicable to the service;
(e) changes service requirements without the permission of the Company; or
(f) makes fraudulent use of the service being provided.

11.4 Removal of Facilities

Upon termination of service, the Company shall be entitled to remove any of its facilities located upon the property of the customer and to enter upon the customer's property for that purpose.

SCHEDULE A
STANDARD SUPPLY SPECIFICATIONS

The Company's standard supply specifications, which are in accordance with Canadian Standards Association standard CAN-C235-83, are as follows:

(a) Residential:

240/120 V	- single phase, three wire - secondary conductors are supplied by the Company - overhead or, in designated areas, underground conductors

(b) General Service:

240/120 V	- single phase, three wire - overhead secondary conductors are supplied by the Company - underground secondary conductors are supplied by the customer
208 Y/120 V	- three phase, four wire - overhead secondary conductors are supplied by the Company - underground secondary conductors are supplied by the customer
480 Y/277 V	- three phase, four wire - overhead secondary conductors are supplied by the Company for loads 15 KVA to 300 KVA - overhead secondary conductors are supplied by the customer for loads 300 KVA to 1,500 KVA
600 Y/347 V	- three phase, four wire - underground secondary conductors are supplied by the customer for loads 150 KVA to 2,500 KVA; and
4160 Y/2400 Y	- three phase, four wire, 2,000 KVA to 10,000 KVA - overhead secondary conductors are supplied by the customer

SCHEDULE B
MAXIMUM COMPANY INVESTMENT

1. (a) **"Cost"** means the estimated cost of materials, labour, equipment, expenses, and any other direct costs incurred by the Company in extending Service to a Point of Delivery.

   (b) **"Annual Cost"** means the estimated cost of generating and transmitting electric energy to the Customer, operating and maintaining the facilities constructed to serve the Customer and the fixed charges, including return, income tax and depreciation, on the cost of facilities constructed to serve the Customers.

2. Subject to the provisions of paragraph 3 of this Schedule B, the maximum **cost** which the Company will incur to extend service to a point of delivery (herein referred to as the "Maximum Company Investment") shall be determined as follows:

   (a) **Residential Service:**
   $900 per single family dwelling; and
   $450 per Multiple Dwelling Unit

   (b) **General Service:**
   $400 per kilowatt of estimated billing demand, which shall not be less than five kilowatts, provided that if the estimated life is less than 25 years or seasonal the Company investment will be reduced proportionally, then the Maximum Company Investment shall be determined in the manner described in paragraph 3;

   c) **Municipal Street Lighting:**
   $700 per light

   d) **General Service – Secondary:**
   One half of one year of forecast retail sales revenues.

   At the end of one year of service the Company will re-assess whether the customer's estimates of their consumption were accurate, and will collect from the customer (or refund) any contributions, based on the Maximum Company Investment rules then in place in paragraph 2 or paragraph 3, that are required if the loads are significantly different than originally estimated.

3. The Maximum Company Investment for an extension of service not specified in paragraph 2, and the Maximum Company Investment in any extension of service, whether or not specified in paragraph 2, the Load characteristics of which are expected to vary materially from the average for that type of service, shall be determined on the basis of a detailed analysis of the **Annual Cost** of such extension and the revenue expected to be derived therefrom. If the **Annual Cost** of serving a customer is higher than the revenue expected to be received from such service, then the Maximum Company Investment shall be the **Cost** of the extension less the present value of the annual amounts over the expected life of the service by which the **Annual Cost** is expected to exceed the revenue.

SCHEDULE C
CONDITIONS FOR UNDERGROUND SUBDIVISIONS

The Company shall extend service by underground conductor lines upon and subject to the following terms and conditions (**"developer"** means the person or party who has requested the underground service):

(a) No service is then available in the area to be served by such extension, and not less than 25 single family dwellings (or such lesser number as may be agreed to by the Company) will be connected to such extension (the "underground service area"), each of which is situated upon said subdivision;

(b) All permanent service in the underground service area shall be provided exclusively through underground conductor lines;

(c) The developer shall provide, without cost to the Company, such rights-of-way, easements, utility corridors and transformer locations as the Company may require for the installation, operation and maintenance of such extension, which the developer shall keep free and clear of any buildings, structures, fences, pavement, trees or any other obstructions which may hinder the Company in installing, maintaining or removing its facilities;

(d) The Company shall not be obligated to install such extension until it is reasonably satisfied that the extension will not thereafter be damaged or interfered with, and, in any event, any costs incurred by the Company in relation to the relocation, reinstallation or as a result of damage to such extension shall be paid by the developer;

(e) Service, for purposes other than residential use and street lighting, may be provided from such extension only with the consent of the Company;

(f) In relation to the standard underground service, the developer shall cause to be provided a meter socket and service conductor protection from sixty centimeters below grade level to the line side of the meter socket and will ensure the installation of a service having a 200 ampere capacity. Non-standard services will be subject to prior written approval by the utility;

(g) The developer shall provide to the Company a certified copy of the registered plan of subdivision and final construction plans showing the location and elevation of sidewalks, curbs and gutters, and underground utilities together with such evidence as the Company may reasonably require to the effect that all rules and regulations applicable to the development have been or will be compiled with by the developer;

(h) Survey stakes indicating grades and property lines shall be installed and maintained by the developer;

(i) The surface of the ground for a distance of not less than one point five (1.5) meters on each side of the alignments for the underground conductor lines shall be graded by the developer to within eight (8) centimeters of a final grade;

(j) Unless otherwise agreed to by the Company, the developer shall provide a survey for the location of transformers, street light bases and cable routing, as required;

(k) Sidewalks, curbs and gutters may be constructed by the developer but no other permanent improvements shall be made until approved by the Company.

(l) Costs related to the installation of distribution system infrastructure shall be the responsibility of the developer; and

(m) The Company investment will be applied toward the individual customer service connection in accordance with "Schedule B".

In addition, the service shall be subject to such other conditions as may be specified by the Company from time to time.

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REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-4

YEC states "Stage Two of the CSTP entails construction of a new 138 kV transmission line of approximately 74 km from Pelly Crossing to Stewart Crossing, including new substations at Pelly Crossing and Stewart Crossing. Stage Two of the project is anticipated to occur concurrent with the development of a second industrial customer, either Carmacks Copper mine owned by Western Copper Corporation, or the reopening of the Elsa/Keno mine now owned by Alexco Resource Corp."

REFERENCE: December 8, 2008 Hansard, Yukon Legislative Assembly

Mr. Morrison: The Carmacks-Stewart line — when we went to the Yukon Utilities Board two and a half years ago with the project as a whole, we anticipated that the costs for the second phase would be about $30 million. My guess is, at the moment — because I don't know much more than that; we haven't had engineers look at tendering equipment or anything — because costs over this period have gone up, it's probably closer to $40 million.

QUESTION:

a) Please identify any costs that have been incurred to date with respect to Stage Two of the CSTP.

b) Please provide an update on the expected total cost for this project.

ANSWER:

(a)

The Corporation has incurred approximately $0.850 million with respect to Stage 2 of CSTP. These costs generally relate to allocation of overall CSTP/MS costs related to pre-2008 YESAB screening, preliminary engineering, permitting, consultation and related owner's costs.

(b)

No further update is available since the reference noted in the question.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-11

YEC states "These units can be run without any emissions impact in Whitehorse".

QUESTION:

a) Please provide the data that supports this statement concerning the Minto (Capstone) diesels.

ANSWER:

(a)

The Minto mine is located 240 km north of Whitehorse. Given the distance, running the diesel units in Minto is not expected to have any emissions impact on Whitehorse.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-12

YEC states that work on the Faro Mirrlees Diesel (FD1) Recommissioning began in 2007 and will be completed in 2008, with $0.407 million in costs in 2007 and $1.158 million budgeted for 2008. The project is expected to be complete in 2008.

QUESTION:

a) Please provide a breakdown of all budgeted and actual costs (i.e., project development, preliminary engineering, regulatory costs, etc.) associated with the Faro Mirrlees Diesel Recommissioning. Please provide an explanation of variances from budget and the timing of when the expenditures occurred.

b) Please confirm whether an application for an energy project certificate or energy operation certificate associated with this project was ever forwarded to the Minister per Part 3 of the *Public Utilities Act*. If not, then please elaborate on why this application was not made.

c) Please identify any regulatory reviews of this project other than the cursory review as part of YEC's 20-Year Resource Plan.

d) Please provide details on efforts made by YEC to sell the Faro diesel generator to another party and the reasoning behind these efforts.

ANSWER:

(a)

Please see response to YUB-YEC-1-36(d).

(b)

No.

The Public Utilities Act provides that energy project certificates (required pursuant to section 37 of the Act) and energy operation certificates (required pursuant to Section 38 of the Act) are only required for a "regulated project" as defined under Section 36 of the

Act. A "regulated project" as defined "means any energy project that the Commissioner in Executive Council considers to be significant in the matter of any form of energy and, by order, designates as a regulated project." The Commissioner in Executive Council did not designate the Faro Mirrlees project as a regulated project.

(c)

No other regulatory reviews were required or undertaken with regard to this project.

The technical feasibility of rehabilitating the retired Faro Mirrlees was discussed in the 20-Year Resource Plan (filed as Exhibit B-16 in that proceeding). The Board reviewed the project as part of the Resource Plan and recommended that the rehabilitation of the Mirrlees proceed in its report to the Commissioner in Executive Council filed January 15, 2007.

The Board noted as follows at page 34 of its Report to the Minister:

> …new capacity should be added to the WAF system as soon as possible.
>
> The Board is of the view that, of all the projects that have been discussed in this proceeding, refurbishments of existing diesel units are the only options that could be implemented in a relatively short period of time to alleviate the current shortfall situation in the WAF system. Furthermore, the Board concurs with YEC that the previously retired Mirrlees unit, currently situated at the Faro plant, should be the one to proceed first, as it would contribute 5 MW of capacity and could be started at any time without impacting the rest of the existing capacity. Therefore, the Board recommends that YEC proceed with refurbishing the Faro unit as expeditiously as possible.

(d)

In the time period for planning the Faro Mirrlees project, YEC did not actively market the unit to any other party.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-14

YEC states that the Land Management and Easement Project ($100,000 in each of 2008 and 2009) will "secure easements for Yukon Energy's distribution lines over 2008 and 2009".

QUESTION:

a) Please provide details of the specific easements being secured.

b) Please provide details of budget actually spent in 2008.

c) Please confirm that the budget for securing easements would be less of a contributor to YEC's revenue requirement if this budgeted amount was removed and a deferral account was established to collect actual easement costs as they are incurred for disposition in a subsequent year.

ANSWER:

(a)

The purpose of this project is as follows: to obtain the agreement of property owners, and to register the resulting easements with the Land Titles Office, in locations where a YEC-owned line or piece(s) of equipment are located on, or pass over, property owned by others. This includes residential, commercial and industrial properties

Easements have been sought for both primary and secondary distribution lines and equipment. The main areas of focus have been the YEC distribution systems in Faro, Mayo and Dawson. Of the estimated 3600 easements required about 750 have been completed and registered.

(b)

Spending on this project in 2008 was $97,675.

(c)

Not confirmed. The amounts are already capital in nature and consequently depreciated over time.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-15

YEC states that budgets for Vehicle Purchases ($209,000 in 2008 and $288,000 in 2009) are based on three service bodies "expected to need replacing" in 2008 and two service bodies "expected to need replacing" in 2009.

QUESTION:

a) Please provide details of budget actually spent in 2008.

b) Please confirm that the budget for vehicle purchases would be less of a contributor to YEC's revenue requirement if this budgeted amount was removed and a deferral account was established to collect actual vehicle purchase costs as they are incurred for disposition in a subsequent year.

ANSWER:

(a)

Please see the table provided below which provides actual 2008 spending.

2008 Vehicle Purchases

Description	Total
Truck - Ford F-150 XL White	34,391
Truck - Dodge 2500 Ram Pickup	43,239
Truck - Chevrolet Silverado Lt	33,077
Total	110,707

(b)

Not confirmed. The amounts are already capital and consequently depreciated over time.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-16

YEC states that the budget for the development of a Disaster Recovery Plan / Business Continuity Plan ($150,000 in 2008 and $75,000 in 2009) is an important part of an overall framework for identifying and managing risk.

QUESTION:

a) Please confirm whether YEC has an existing disaster recovery plan and/or business continuity plan. If yes, please identify when it was developed, the costs incurred and how thee costs were treated from a recovery perspective.

b) Please provide details of budget actually spent in 2008.

ANSWER:

(a)

Yukon Energy does not currently have a Disaster Recovery Plan, and expenditures are being incurred during the test years to develop a plan.

(b)

Details on the amounts spent in 2008 related to the Disaster Recovery Plan/ Business Continuity Plan are provided below.

Cost Type	Total 2008 ($000)
Consultants	60
Travel	9
AFUDC	1
ES&G	3
Grand Total	**73**

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-17

YEC states that the budget for the replacement of its Financial Systems Software ($125,000 in 2008, $450,000 in 2009 and $425,000 in 2010) will involve the completion of replacement system needs assessment, a product review and the presentation of recommendations to the Board of Directors in 2008 and implementation beginning in 2009.

QUESTION:

a) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

b) Please provide details of budget actually spent in 2008.

ANSWER:

(a)

For the purposes of this application this project will be in WIP at the end of 2009.

(b)

Details on amounts spent in 2008 related to the replacement of the Financial Systems Software are provided below.

Cost Type	2008 ($000)
Consultants	64
Labour	3
ES&G	2
AFUDC	2
Grand Total	**71**

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-17

YEC states that the budget for an Electronic Document Management ($125,000 in 2008, $100,000 in 2009 and $100,000 in 2010) will be spent on a records management consultant in 2008 to assess records management issues and propose solutions with implementation starting in 2009.

QUESTION:

a) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

b) Please provide details of budget actually spent in 2008.

c) Please provide a copy of the assessment of the records management consultant and describe any research they conducted into the electronic document repositories now in use by various energy regulators throughout Canada.

ANSWER:

(a)

For the purposes of this application this project is excluded from the calculation for the determination of ratebase as the project remains in WIP at the end of 2009.

(b)

Details on the amounts spent related to the Electronic Document Management in 2008 are provided below.

Cost Type	2008 ($000)
Consultants	16
Materials	30
AFUDC	1
ES&G	2
Grand Total	50

(c)

No report has been prepared.

REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-20;

YEC states that the Mayo B hydro generation enhancement project ($1.7 million in 2008 and $6.5 Million in 2009 has been identified as a potential priority near term hydro generation expansion opportunity.

REFERENCE: **December 8, 2008, Hansard, Yukon Legislative Assembly**

Mr. McRobb: Still with capital plans, the officials mentioned **Mayo B**, which of course is an enhancement of the existing facility to provide a greater amount of generation. Can the officials indicate what the anticipated cost, timelines and process are for that facility?

Mr. Morrison: Well, timelines are difficult because it depends on where loads are and, with this mining environment, things are shifting a little bit. But the costs that we have seen so far, which are very expensive, are **$100 million**.

Mr. McRobb: And does that cover basically all of the expenses to upgrade the facility itself, including any shoreline mitigation or improvements to the transmission line or anything? Can the officials comment on that?

Mr. Morrison: To be clear, it **doesn't include the cost of a transmission line**. That's something separate. Secondly, it does cover all of the costs, as we know it, for the purposes of upgrading the capacity of the Mayo plant. I want to be clear, though, that from our perspective — we haven't looked at shoreline mitigation. We haven't made any decision that would, at least in the current plan, even include the possibility of shoreline mitigation.

QUESTION:

a) Please provide cost details and descriptions of components of the proposed Mayo B hydro generation enhancement project.

b) Please provide details on costs incurred to date, during the 2008 and 2009 test years, and estimated for subsequent years.

c) Please explain how this project fits in with YEC's 20-Year Resource Plan.

d) Please explain the treatment of this project for rate base purposes and the timing of it being added to rate base.

e) Please explain why Mayo B is now on the potential priority near term expansion opportunities when it was not even on the radar during the review of the 20-Year Resource Plan process.

ANSWER:

(a)

The components of the Mayo B Hydro Generation Enhancement Project are set out in the attached newsletter (provided as Attachment 1 to this response). Cost estimates provided in the 20 year Resource Plan were $101 million (2005$) (approximately $116 million in 2012$). These estimates are presently being updated.

(b)

The Application at page 5-20 notes forecast costs for 2008 and 2009 as $1.7 million and $6.5 million respectively. Budgets are subject to ongoing review. The total project cost, if developed, has been estimated at approximately $120 million; the net cost to Yukon Energy will depend on contributions from government, which are yet to be determined.

(c)

Mayo B was included in the 2006 Yukon Energy 20-Year Resource Plan filing (at Appendix B) as part of an inventory of hydro project options. As noted at page B-1 of the Resource Plan, the projects included in Appendix B represented "the primary alternatives identified to date based on review of the numerous studies conducted in Yukon." Mayo B was specifically discussed as one of a group of small projects being considered (within the 5 to 10 MW range) at page B-10 where the following was noted regarding the project:

> The existing hydro site at Mayo has the potential to be enhanced by various changes in configuration, either to develop further head below the existing reservoir or an expansion of capacity utilizing the same head. This leads to multiple potential alternatives. However, as a supply option

> to WAF, these various projects are only of relevance if the Carmacks-Stewart transmission line is previously in service. The full capability of various potential Mayo enhancements to supply an interconnected WAF and MD system (as opposed to MD on its own) has not been fully studied, and should be re-examined in the event that the interconnection proceeds.
>
> One configuration alternative considered is a 10 MW, 48 GW.h, $101 million (2005$) variation based on a separate conveyance route from the existing reservoir to a new plant lower in elevation than the existing plant, which would be able to operate in parallel with the existing plant. This concept has an initial LCOE of 11.2 cents/kW.h. Various other concepts require further study. However, although work is still in preliminary stages, it must be recognized that it is possible no credible facility enhancements of this type exist at Mayo.

The Resource Plan noted that small hydro projects in the range of 5-10 MW were potential candidates for development under Chapter 5 forecasts under the 25 MW industrial scenario or larger. These projects could also potentially be part of a development plan under the larger 40 MW scenario.

(d)

This project will be in Work-in-Progress until it is complete (the earliest possible in-service date is 2011 or 2012), at which time the net cost to YEC for the project will be included in rate base.

(e)

As noted in **(c)** above, Mayo B was included in the 20-Year Resource plan as potential small hydro project to address industrial development scenarios described in Chapter 5 of the Resource Plan. Reviews carried out in 2007-2008 to identify priority projects to provide 50 to 100 GWH/yr of new renewable energy within the 2010 to 2015 period identified Mayo B as the largest single source of such new energy, with good prospects to be in-service between late 2011 and 2012.

Yukon Energy Corporation
2008-2009 General Rate Application
UCG-YEC-1-89(a) Attachment 1

YUKON ENERGY

PROPOSED MAYO HYDRO ENHANCEMENT PROJECT (MAYO B)

What is involved?

Electrical loads in Yukon are increasing. By 2011, Yukon Energy expects to need additional renewable power to help minimize the use of diesel to generate electricity. As outlined in Yukon Energy's 20-Year Resource Plan (found at www.yukonenergy.ca), the first priority for increasing renewable energy is through enhancements to existing hydro facilities. As such, Yukon Energy is looking at enhancing the existing Mayo hydro plant, a potential project referred to as Mayo B.



Mayo control structure

What are the benefits?

Yukon Energy is the primary generator of power in Yukon. As electrical load grows in Yukon, the opportunity exists to develop additional renewable energy rather than serve those loads with diesel. The Mayo B project, if developed, will help reduce the future need for running diesel, and enable Yukoners to offset greenhouse gas emissions of up to 28,000 tonnes a year.

Regulatory Approvals/Reviews

No decisions have been made at this time to proceed with this proposed project. Yukon Energy first plans to consult with local governments, stakeholders and the public. Before any project regarding Mayo B moves ahead, government permits and approvals would be required for land use, activities affecting water bodies, and other activities.

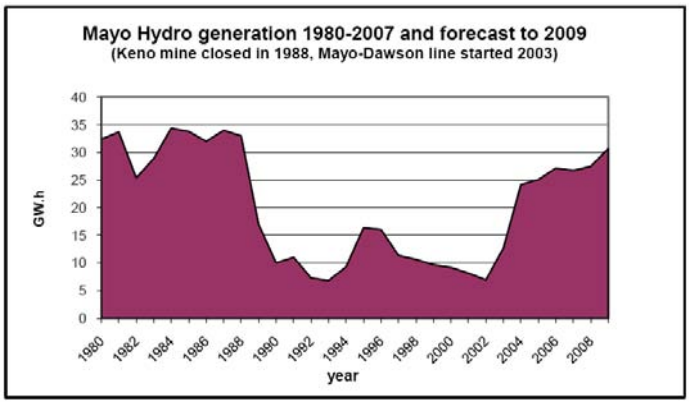
Environmental and socio-economic assessment would be needed under the *Yukon Environmental and Socio-Economic Assessment Act (YESAA*). An Executive Committee Screening of the project would be done by the Yukon Environmental and Socio-Economic Assessment Board (YESAB). In addition, the project would need a new or revised water licence from the Yukon Water Board.

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The existing Mayo facility—page 2
Proposed Mayo B project—page 3
Detailed map—page 4
Project components/options—page 5
Have your say—page 6

The Existing Facility

Operation of the Mayo facility



The Mayo hydro facility supplied the loads of both the Keno mine and the community of Mayo from 1951 until the mine closed in 1988/89. During this period, the plant typically operated at full capacity, and the storage range at Mayo Lake was largely used each year. After the closure of the mine and up until the Mayo-Dawson line was energized in 2003, the plant generated power only for local loads in Mayo and Keno. Since the Mayo-Dawson line went into service, the plant has also provided power to Dawson and Stewart Crossing. The Mayo hydro facility continues to operate below its full capability. The existing plant has an annual generation capability of just over 40 gigawatt hours (GWh) each year. Regardless of whether the Mayo B project is developed, the Mayo facility will return to operating at its full potential as loads grow and new mines go into production, including using the full range of Mayo Lake storage.

.

Components of the existing Mayo hydro facility

Wareham Lake: the original project involved construction of a 32 metre high earthen dam that created Wareham Lake. The dam controls the lake levels within a licensed range. From the lake, water passes through an intake structure and a tunnel (approximately half a kilometre) to the generating station.



Wareham Lake spillway



Existing Mayo plant

Generating Station: located on the Mayo River, the plant has two generating units of approximately 2.7 megawatts each, which operate with 36 metres of 'head' or vertical drop between Wareham Lake and the existing generating station.

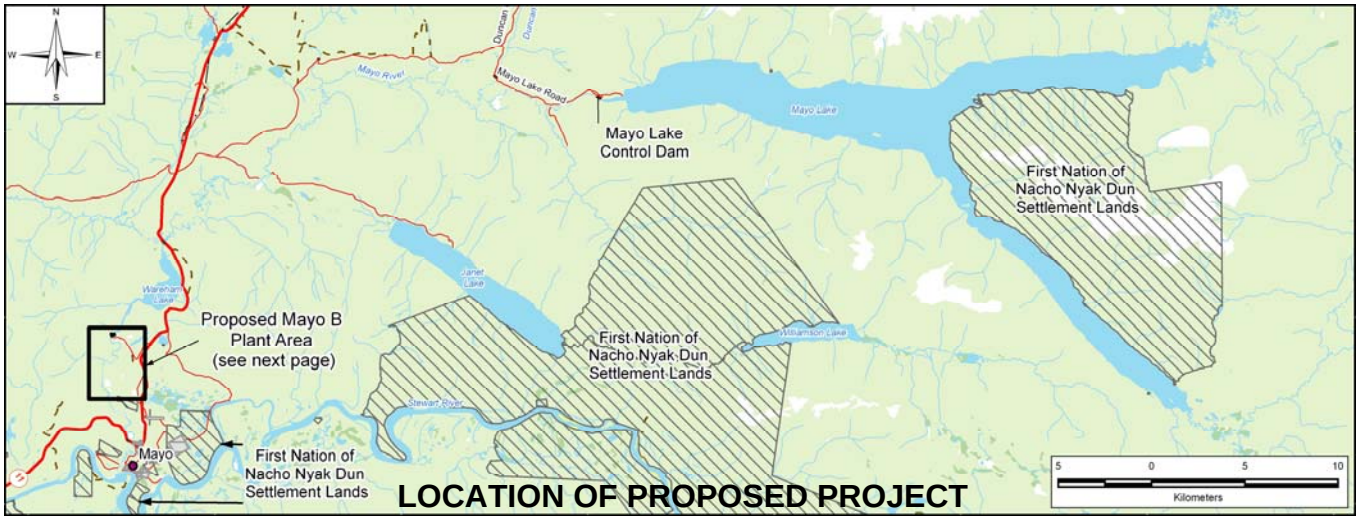


Mayo Lake

Mayo Lake Water Storage: approximately 40 to 50 kilometres upstream of Wareham Lake, the Mayo Lake dam provides the ability to control the level of Mayo Lake. Yukon Energy's water license sets a fixed maximum controlled lake level. Yukon Energy is permitted to release water to lower the lake from this level (draw it down) by 2.5 metres, which it typically does in the winter. The released water flows to Wareham Lake where it is used to generate power. The Mayo Lake dam is a six metre high rock-filled wood structure that was rebuilt in 1988/89.

The Proposed Mayo B Project

No decisions have been made at this time to proceed with the project. Any decision to proceed will only occur after meaningful consultation with all stakeholders in the Yukon and all permits and approvals are obtained.



LOCATION OF PROPOSED PROJECT

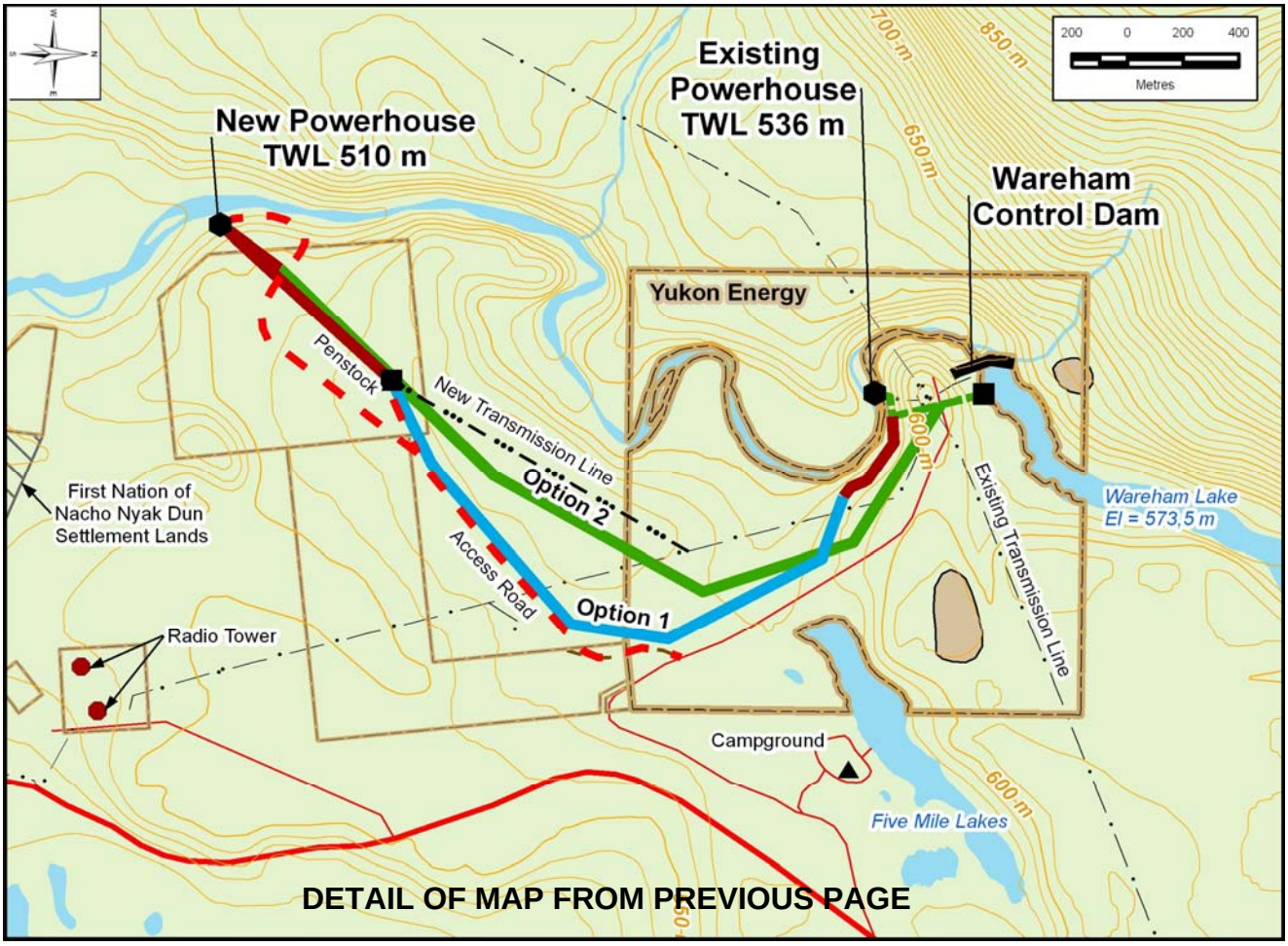
The proposed Mayo B project involves construction of a new powerhouse about three kilometres downstream from the existing powerhouse. The project will approximately double the amount of energy that can be generated from the Mayo River. No changes would be required at Wareham Lake or to the Wareham dam. The current plan is to maintain the existing power house for use as required in the future.

Yukon Energy is proposing to enhance the storage at the Mayo dam by lowering the current licensed minimum level for Mayo Lake. This would allow up to one metre of additional winter drawdown range, leading to a lower spring level than is currently permitted in the water licence. With the large natural spring inflows to the lake, this lower lake level would be temporary each spring.

Mayo B would be developed to help supply Yukon-wide power loads, which is conditional upon the completion of Stage 2 of the Carmacks-Stewart Transmission Project to interconnect the Mayo-Dawson and WAF (Whitehorse-Aishihik-Faro) systems.

Dam safety

The existing Mayo hydroelectric facilities are inspected to ensure the safety of the operation. This includes routine inspections (day to day observations, monthly checklist-driven inspections, and 24 hour equipment monitoring), annual formal inspections by Yukon Energy engineering staff, and an independent dam safety review every five years as per Canadian Dam Association guidelines and current licence requirements. The most recent five-year review was completed in November 2005.



Studies to date

Field studies on the local environment (water, land, wildlife, heritage resources) have been done and preliminary information collected on how people use the area or may be affected by the project.

The following studies have been completed:
-Geotechnical studies (test holes) to assist in determining which project options are feasible;
-Specific aquatic information on the use of the Mayo River by Chinook salmon and the use of Mayo Lake by lake trout, to enable Yukon Energy to address potential effects on the aquatic environment; and
-A heritage resources assessment has been completed.

The collection and analysis of data is on-going and will be used to help predict the potential effects of Mayo B on the existing environment and assist in shaping the project details.

The project concept is still being developed. Results of the public consultation process will help shape the project.

Project Components and Options

There are four parts to the Mayo B proposed project:

New Powerhouse

The new powerhouse will result in a total head or drop in elevation (between Wareham Lake and the new powerhouse) of 65 metres. By developing more head, the same water can be used to generate more power. It would include two to three turbines with a plant capacity of approximately 13 mega-watts. The plant would be large enough to allow most of the river flow to be used to generate power, compared to the existing plant that results in some of the water being spilled or wasted.

The powerhouse would be set back from the river and would be built on a bedrock foundation. Its tail-race (a component of the powerhouse that directs the flow of water once it has passed through the turbines) would extend to the Mayo River.

Water Diversion Options

A major part of the Mayo B project would be the construction of a mechanism to divert water from the existing intake to a new powerhouse.

Option 1 *- canal and/or penstock (see map page 4)*
Moving water at or near the land surface using a canal and/or a penstock (a pipe likely buried about one to two metres beneath the surface). This conveyance would begin at the existing intake tunnel and be approximately three kilometres long. It would follow the land contours before heading off the ridge into the new powerhouse.

Option 2 *- tunnel (see map page 4)*
Moving water using an underground tunnel approximately 3.5 metres in diameter and 3,200 metres long. It would be buried 65 to 100 metres below the ground surface tapping into the existing tunnel near the intake at Wareham Lake. Located near the new powerhouse, the tunnel would convert to a penstock that would run about 200 metres into the powerhouse.

Water Storage Improvements

Revising the licensed drawdown range at Mayo Lake (from 2.5 metres today to 3.5 metres) requires very little change to the Mayo Lake dam. Some of the pipes that release water would need to be re-placed with larger pipe, to allow the lower storage range to be used.

Additional Infrastructure

-New all-weather access road along the Option 1 alignment to the new powerhouse.
-Possible changes to the sub-station at the existing Mayo generating station
-Distribution line to new plant
-Pits for sand and gravel if Option 1 is chosen
-Site for stockpiling tunnel rock if Option 2 is chosen
-Temporary work camp for 50-75 people for up to two years

Construction activities would include clearing, tunnelling and/or penstock excavation, and heavy equipment operations associated with building an access road and power house.

Opportunities for Public Engagement

Public involvement is important to help Yukon Energy plan and shape the Mayo B Project, and to help YESAB carry out its environmental and socio-economic assessment of potential project effects. Yukon Energy's consultations to date with key stakeholders in the vicinity of Mayo (First Nation of Nacho Nyak Dun, Village of Mayo and the Mayo Renewable Resources Council) focused on summer and fall field study issues. More consultation opportunities are now planned with the First Nation of Nacho Nyak Dun, key stakeholders in the Mayo and Whitehorse areas, and the broader Yukon public. Future consultation will occur in the New Year after Yukon Energy's filing with YESAB.

Public Involvement Opportunities Before a Filing with YESAB

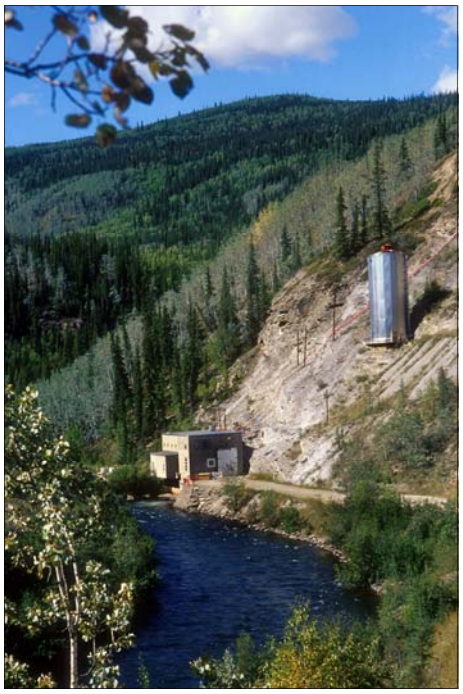
Project Introduction and Issues Identification

Potential Project Effects and Mitigation

Public Communication After a Filing with YESAB

Fall 2008
Yukon Energy is currently introducing the project and seeking feedback on issues of concern, planning options, potential project effects and mitigations.

First Quarter 2009



Existing Mayo generating plant



Mayo control structure

Comments? Questions?

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REFERENCE: October 6, 2008 Application, Capital Projects, Page 5-22

YEC states that the Aishihik Water License Renewal project ($167,000 in 2008 and $130,000 in 2009) includes monitoring the fish populations in Aishihik Lake and undertaking a subsistence fishery monitoring program.

QUESTION:

a) Please provide details of budget actually spent in 2008.

b) Please explain how the Aishihik 3rd Turbine project can be initiated prior to completion of this water license renewal.

ANSWER:

(a)

Amounts spent in 2008 on Aishihik Water License Renewal project are as noted in the table below:

Actual Spending for Aishihik Water Licence Renewal Project

Cost Type	2008 Spending
AFUDC	$ 1,781
Consultants	$ 55,659
Courier/Freight	$ 361
ES&G Build-up	$ 6,367
Legal	$ 1,050
Materials	$ 12,230
Regular Time	$ 3,246
Outside Services	$ 37,631
Grand Total	**$ 118,325**

The costs are associated with the following 3 projects:
Aishihik License Annual Payment
Aishihik Heritage Mitigation
Aishihik Fish Monitoring

(b)

The current Aishihik water license authorizes Yukon Energy to install a third turbine and associated appurtenances with a maximum generating capacity of 7 MW at the facility. No further licences are necessary.

REFERENCE: **October 6, 2008 Application, Capital Projects, Page 5-28 to 5-32; Tables 5.3 through 5.7 - Continuity Schedule of Planning and Study Costs**

QUESTION:

a) Please identify any current or planned capital projects to which these planning and study costs are associated.

ANSWER:

(a)

These costs are not associated with any committed current or planned project.

The cost of planning activities or studies that do not result in any specific project being undertaken are amortized as planning and study costs.

Planning and study costs incurred that lead to commitments to a specific capital project being implemented are included in the costs of the specified project.

REFERENCE: October 6, 2008 Application, Board Directives, Page 6-1

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

QUESTION:

a) Please update the August 2005 revenue to cost ratios report using proposed revenue requirement data available for 2008 and 2009. Revenues should be based on existing rates and utility proposed rates.

b) Please update the August 2005 revenue to cost ratios report using proposed revenue requirement data available for 2008 and 2009. Revenues should be based on existing rates and rates assuming that residential rates use a first energy block of 1300 kWh.

ANSWER:

(a) and **(b)**

The requested information cannot be provided. The 2005 cost-of-service report did not, at that time, update revenue to cost ratios as to complete such an update for all classes requires a full cost of service study to be performed.

REFERENCE: October 6, 2008 Application, Board Directives, Page 6-4

YEC states that "OIC 2007/94 in effect defers, until after December 31, 2012, any cost of service based rate rebalancing adjustments or rate shifts affecting major industrial customers".

QUESTION:

a) Please confirm that while the YUB's hands have been tied with respect to rates it can approve for the industrial customers, nothing in OIC 2007/94 prevents the Board from investigating cost of service issues or determining the parameters for a rate rebalancing program.

ANSWER:

(a)

The Board was provided with specific direction via the OIC. The OIC is clear that Cost of Service cannot be useful for rate design purposes at this time and will not become useful until rates are set for the period after 2012. The OIC does not have to specify what logically follows from its directions, i.e., that there is no practical reason to investigate cost of service issues or determining the parameters for a rate rebalancing program at this time given the direction provided by OIC 2008/149.

Yukon Energy proposes that such a review would occur towards 2012, as noted in the January 6, 2009 Workshop Presentation.

Please see also YUB-YEC-1-20.

REFERENCE: October 6, 2008 Application, Board Directives, Page 6-6

With respect to Maximum Utility Investment, YEC states that "Yukon Energy is continuing to examine options, based on the current PPA experience with Minto, where joint partnership of industry, Yukon Energy and the Yukon Government can best enable development of critical new bulk power supply infrastructure in a cost effective manner as regards all Yukon ratepayers".

QUESTION:

a) Please describe the efforts that YEC have made to address Maximum Utility Investment since Board Order 2007-5 was issued on April 30, 2007.

b) Please provide an estimate on the amount of time that YEC staff and consultants have spent on this issue.

ANSWER:

(a)

The matter was addressed in part during the Part 3 review process concerning the CSTP. To date this issue has not received further material attention.

(b)

No estimate of time is available.

REFERENCE: **October 6, 2008 Application, Board Directives, Page 6-8; Table 6.1 - Cost Awards 2007-7, 2007-8, 2007-9 and 2008-1**

QUESTION:

a) Please confirm that the cost award amount for UCG's lawyer should be $19,517.52 for the Resource Plan and $7,189.98 for the PPA proceeding.

ANSWER:

(a)

Confirmed. Table 6.1 provided in Tab 6 incorrectly added the total of all GST costs awarded in Order 2007-9 to Resource Plan Costs ($1506.46). This total amount should be divided between the Resource Plan and the PPA hearing with $406.98 of GST added to PPA hearing costs and $1099.48 added to Resource Plan costs. The sum of the two proceedings is correct.

REFERENCE: **October 6, 2008 Application, Board Directives, Tab 7; Schedule 2 – Computation of Allowance for Working Capital**

QUESTION:

a) Please confirm that the calculation on line 5 is based on a net revenue lag calculated for 2005.

b) Please provide the actual net revenue lag for 2005, 2006, 2007 and 2008. Please provide the detailed calculations used to determine these revenue lags and the sources of data used in these calculations.

ANSWER:

(a) and **(b)**

Please see YECL-YEC-1-10.