IN THE MATTER OF YUKON ENERGY CORPORATION AND YUKON ELECTRICAL COMPANY 2009 PHASE II RATE APPLICATION AND YUKON ELECTRICAL COMPANY RIDER D APPLICATION TO THE YUKON UTILITIES BOARD

FINAL ARGUMENT

YUKON ENERGY CORPORATION

OCTOBER 22, 2010

TABLE OF CONTENTS

LIST OF TABLES

YUKON ENERGY CORPORATION ("YUKON ENERGY" or "YEC") AND

YUKON ELECTRICAL COMPANY ("YUKON ELECTRICAL" or "YECL")

2009 PHASE II RATE APPLICATION ("APPLICATION")

AND

YUKON ELECTRICAL RIDER D APPLICATION ("RIDER D APPLICATION")

TO THE YUKON UTILITIES BOARD ("YUB" or "BOARD")

YUKON ENERGY CORPORATION FINAL ARGUMENT

PREFACE

OVERVIEW OF APPLICATIONS

Yukon Energy and Yukon Electrical ("the Companies'") filed a joint 2009 Phase II Rate Application (the "Application") on February 19, 2010 in accordance with Board Order 2009-8. The Application provided an up-to-date 2009 Cost of Service Study ("COSS"), proposed adjustments to rates, and proposed changes to Terms and Conditions of Service (previously known as "Electric Service Regulations").

The Application's COSS and proposed rate adjustments were based on the approved Consolidated Firm Rate Revenue Requirement of $50.833 million, consistent with Board-approved 2009 revenue requirements for each Company as set out in Board Orders 2009-5 (YECL final revenue requirement) and 2009-10 (YEC final revenue requirement). Based on approved load forecasts for 2009 and current OICs, rate design options examined in the Application may affect bills of different customers within a retail customer class, but cannot affect the total revenues collected for each retail class or the total revenues collected by each utility.

The Companies diligently worked together to present a uniform and consistent approach in the joint Application. Where this goal was not achieved, the Application and responses to Interrogatories identified the different views of the Companies. Prior to the hearing, the Companies filed a joint letter (Exhibit B9) setting out their agreement on all outstanding COSS and Terms and Conditions matters. A joint YEC-YECL panel addressed all matters other than rate design. Separate panels for each Company addressed rate design matters, confirming a wide number of rate design recommendations on which there is joint agreement and directing attention at the specific outstanding differences as reflected in three different retail rate options.

The Yukon Electrical Rider D Application continued to be a separate application from the Companies' joint Application, and was addressed by each Company's separate rate design panel.

SUMMARY OF DECISIONS REQUESTED

In sum, reflecting the evidence of the Companies as at the hearing, approval of the Board is requested for the following joint proposals of the Companies:

Jointly Supported Matters

1. **2009 Cost of Service Study** – Approval of the 2009 COSS as filed in Tab 3 of the Application, including the related methods as proposed, subject to adjustments and/or corrections noted in Exhibit B9 (for distribution related cost to Industrial) and LE-YEC-1-7(a) (for Mayo cost classification correction).

2. **Terms and Conditions of Service** – Approval of the revised terms under which the Companies provide service to customers as detailed in Tab 5 of the Application, including proposed Maximum Company Investment levels, subject to modifications noted in Exhibit B9 (for section 4.15 of the Terms and Conditions, for MILs in Schedule B of the Terms and Conditions, and for Industrial Maximum Company Investment in Schedule B).

Phase II Matters Addressed by Separate Rate Design Panels

3. **Jointly Supported Rate Design Matters** – Approval of the following rate-related matters is jointly supported by the Companies, with rate adjustments to take effect as soon as is practical after Board approval of a compliance filing by the Companies (the Companies are not proposing to apply rates retroactively):

    a) **Incremental cost of diesel generation** – Updated incremental cost of diesel generation (at retail meters) in each rate zone for 2009 based on approved GRA fuel prices as set out in Table 2 of the Application, and the proposed consolidation of the hydro, large diesel and small diesel zones into a single average incremental cost ($27.99 cents/kW.h) to use in assessing runoff rates in these rate zones for at least the current Application.

    b) **Rate adjustments** – These include the following joint rate proposals as set out in the Application and Exhibit B12:

        i. Amend Rate Schedules for **Residential Non-Government** (1160, 1260, 1360, 1460 for the respective zones) and **Residential Government** (1180, 1280, 1380, 1480) to provide for the non-government and government residential rate classes:

            - An adjusted rate design that includes, at this time, a new equalized second energy block that is the same for all rate zones for use from 1,001 to 2,500 kW.h/month, and a runoff energy block for use in excess of 2,500 kW.h per month with a common rate for all zones other than Old Crow; and
            - An adjusted base **customer charge** of $14.65 per month for non-government and $18.47 per month for government.

The Companies have provided two separate options at the hearing (Options B and C) for the amended base energy rates for the residential classes (see below for Yukon Energy recommendation).

ii. Amend Rate Schedules for **General Service Non-Government and Municipal Government** (2160, 2170, 2260, 2270, 2360, 2370, 2460, 2470) and **General Service Federal and Territorial Government** (2180, 2280, 2380, 2480) to provide for the non-government and government general service rate classes:

- An adjusted rate design that includes, at this time:
  - A new equalized second energy block that is the same for all rate zones for use from 2,001 to 15,000 kW.h per month;
  - A new equalized third energy block that is the same for all rate zones for use from 15,001 to 20,000 kW.h per month; and
  - To provide for a future separate "Large General Service" rate or class applicable to a relatively few number of customers (on the order of 100 government and non-government combined), an average cost fourth and final energy block with varying rates by rate zone for use in excess of 20,000 kW.h per month.
- An adjusted base **demand charge** of $7.39/kW per month for non-government and $12.31/kW per month for government;
- An adjusted **second block energy charge** in all rate zones of 12.88 cents per kW.h for non-government and 12.97 cents per kW.h for government; and
- **Fourth block energy charges** for government and non-government of:
  - 12.66 cents per kW.h for the hydro and large diesel rate zones;
  - 15.22 cents per kW.h for the small diesel rate zone; and
  - 31.72 cents per kW.h for Old Crow.

The Companies have provided two separate options at the hearing (Options B and C) for the other amended base energy rates for the general service classes (see below for Yukon Energy recommendation).

iii. Amend Rate Schedules for **Street Lighting (61, 66, 67)** and **Sentinel Lighting (75, 76)** to adjust base rates by an equal percentage of 23.123% to reflect the proposed elimination of Riders J and R from current customer bills.

iv. Amend **Industrial Rate Schedule 39** to incorporate wording in the rate schedule to clarify the operation of Rider F to this customer class, as approved in Order 2009-10.

v. Amend **Wholesale Rate Schedule 42** (wholesale sales to Yukon Electrical):

- To adjust the base energy rate that applies throughout Yukon (as required to reflect adjusted retail base rates and removal of Rider J and R – the specific number required will vary depending on the retail rate option approved by the Board); and
- To amend the Energy Reconciliation Adjustment (the "ERA") to confirm that ERA charges to YECL will be adjusted on a monthly basis, as

stipulated, only during the months when diesel generation is on the margin at normal long-term average water flows on the hydro zone.

vi. Amend **Wholesale Rate Schedule 51** to provide for a single energy-only rate at the same level as the base Rate Schedule 42 that applies to all firm Yukon Energy purchases from Yukon Electrical throughout Yukon.

vii. Cancellation of the earlier **Rate Schedules 33, 38 and 40**, each of which relates solely to unique circumstances of previous industrial customers, and do not have relevance today.

viii. Elimination of **Riders J and R** from current customer bills.

ix. No changes today to the Secondary Energy rate schedules (32 and 43) or to Riders A (Multiple Residence Service) or B (Unmetered General Service Flat Rate).

4. **Yukon Energy Recommended Retail Rate Proposal** – On the remaining 2009 Phase II Rate Application rate design matters where a joint proposal was not achieved by the Companies, based on Exhibits B12 and B14 and the evidence at the hearing, Yukon Energy recommends as follows:

a) **Runoff energy rates for residential and general service retail classes** – A minimum initial runoff rate to be approved at this time at 71.5% of 2009 incremental cost of diesel, with a longer-term commitment to move the runoff rate up to 100% of the incremental cost of diesel as soon as is reasonable, resulting in the following energy rates to be approved at this time:

i. 20 cents per kW.h for the third energy block for all residential and general service rate schedules, other than the Old Crow third block runoff energy residential rate; and

ii. 43.98 cents per kW.h for the Old Crow third block runoff energy residential rate.

b) **First and second block residential energy rates** – To reflect Yukon Energy's priority focus throughout its 2008-2009 GRA filing on the need today for an adjusted runoff rate of at least 20 cents per kW.h, an adjusted Option C residential **second block energy rate** is recommended at 13.00 cents per kW.h for non-government and government in all rate zones so as to provide no adverse rate changes today for any residential customer use up to 2,500 kW.h per month; as a result, the adjusted residential **first block energy rate** is 11.93 cents per kW.h for non-government and 17.54 cents per kW.h for government.

c) **First Block general service energy rates** - As set out in Exhibit B12 for Option C, an adjusted rate in all rate zones of 9.41 cents per kW.h for non-government and 18.88 cents per kW.h for government.

d) **Future residential rate block adjustments** – At the next GRA by either Company, a first priority for future rate adjustments for residential class rates be to move the third rate block starting point down from 2,501 kW.h per month.

e) **Wholesale Rate Schedule 42 ERA** – In the event that the non-government residential runoff rate in the hydro zone is less than 80% of the approved incremental cost of diesel generation for that zone, the ERA incremental charge to be set at 100% of the approved incremental cost of diesel generation adopted to assess runoff rates for that zone (e.g., 27.67 cents/kW.h based on the Application).

YECL's Separate Rider D Application

5. **YECL Rider D Application** - For the reasons set out in this Argument, Yukon Energy recommends that the Board does not approve the Rider D Application or any modified version of the Rider D Application:

   a) **Placeholder Rider D that YECL has filed should not be approved** - The Rider D Application as filed is only a "placeholder" and as such;

      i. Provides nothing useful or meaningful for the Board to review or approve at this time;
      ii. There is no need for the Board to consider this matter today; and
      iii. Any approval of the Rider D Application may only serve to fetter the Board in its review of these matters if and when so required in future proceedings.

   b) **Broader issues need to be addressed before any such implementation mechanism is considered** – Given the material disconnect between the cost of diesel and the revenue both utilities collect when diesel is on the margin -- whether that be in the hydro zones or diesel served communities -- the Board should direct the Companies, prior to any future GRA by either Company, to work together diligently to address diesel costs variances related solely to unforecast load growth variance in Yukon, focusing on identifying when and how it would be appropriate to adopt deferral account or rider mechanisms that would avoid or defer the need for new phase I GRAs.

OVERVIEW OF YUKON ENERGY FINAL ARGUMENT

The amount of evidence in this hearing is substantial. In addition to the 261 pages of materials relating to the extensive public consultation undertaken in this matter included in Appendix 7.1), there are in excess of 400 information requests, 20 undertakings and approximately 650 pages of transcript. To date, there have been over 50 exhibits, and 3 Board Orders flowing from the Application.

Accordingly, all evidence necessary for the Board to address the Orders requested orders is in the record. While there were 5 registered intervenors, only 3 actively participated at the oral proceeding (PWP provided interrogatories but did not otherwise appear, and Keith Lay provided a written submission but did not appear at the proceeding). Leading Edge ("LE") was the only intervenor to provide a written submission as pre-filed testimony and appear at the hearing, and LE's evidence (as well as the submission of Keith Lay) focused on rate design issues.

Yukon Energy's Final Argument provides the support from the record for the requested decisions, focuses on the extensive evidence examined within the scope of the Board's review of the Application, and includes the following major sections:

- Jointly Supported Matters;
- Matters Addressed by Separate Rate Design Panels; and
- YECL's Separate Rider D Application.

To the extent that the Board and intervenors examined certain issues with respect to specific parts of the joint Phase II Application or the YECL Rider D Application through interrogatories or cross-examination, Yukon Energy has attempted in this argument to address the apparent concerns raised. Yukon Energy's filings, the answers to the many interrogatories, and other evidence submitted (including undertakings) fully address all such concerns, and fully support the reasonableness and necessity of the requested or recommended Board decisions.

1.0 JOINTLY SUPPORTED MATTERS

The Companies' joint panel addressed the jointly supported matters of the Application, namely the joint Cost of Service study in Tab 3 and the jointly proposed Terms and Conditions in Tab 5. Each of these matters is addressed separately below in Sections 1.1 and 1.2 respectively.

1.1 COST OF SERVICE STUDY

In Tab 3 of the Application, the Companies provided a single joint cost of service ("COS") study with a description of the proposed changes to the COS methods previously utilized. The material in Tab 3 also includes updated revenue/cost ("R/C") ratios for all rate classes receiving firm service based on the 2009 Consolidated Firm Rate Revenue Requirement for the Companies as set out in Tab 2, and reviews where applicable of updated COS methods applicable in Yukon in light of changes on the system since 1996/97.

- Yukon Energy took the lead in preparation of material related to the review and update of bulk power cost of service methods; including changes to classification for transmission and certain generation assets (Mayo Plant and Aishihik Plant) taking into consideration changes on the system since the 1996/97 GRA.

- Yukon Electrical took the lead in preparing materials in respect of distribution cost of service study and the Energy Demand and Loss Analysis (Appendix 3.3 of the Application).

The Companies do not consider that any party took issue with the overall methodology used in the 2009 Cost of Service Study. Specific details of issues raised are discussed below.

As noted in the Application (pages 3-1 to 3-3) the COS methodology used to prepare the 2009 COS study in Appendix 3.1 follows standard approaches utilized by similar utilities in Canada and uses a three step process of functionalization, classification and allocation to determine the Cost of Service for each rate class. The methodology for the 2009 COS update also largely reflects past principles and methods adopted by the Companies and approved by the Board (as reviewed in Appendix 3.4 of the Application). Individual methodology changes were reviewed in the Application for bulk power cost classification (generation and transmission), distribution cost classification and cost allocation methods.

The 2009 COS study included in the Application allocated approved 2009 Firm Rate Revenue Requirement Consolidated Costs for the Companies to each customer firm rate class and compared these costs for each rate class against the respective approved revenues for 2009 to be received from each rate class. Overall, as noted at page 2 of the Application, the COS results were summarized as follows for 1997 and 2009:

Table 1:
Revenue to Cost (R/C) Ratios by Rate Class – 1997 and 2009 (%)

Customer Class	1997 Final Approved	2009
Residential Government	100%	105%
Residential Non Government	81%	79%
General Service Government	143%	144%
General Service Non Government	110%	117%
Industrial	100%	109%
Street Lights	110%	69%
Sentinel Lights	110%	148%

As expected, the values as reported for the residential non-government customer class and general service government class have not changed significantly since the 1996/97 GRA: residential non-government continues to have an R/C ratio well below the 90% to 110% zone of reasonableness (at 79%) and general service government continues to have a R/C ratio well above the zone of reasonableness (at 144%). The summary of COS results also indicates that the industrial class has an R/C ratio of 109% compliant with OIC 1995/90 which requires the industrial class ratio to be at least 100%.

While material changes were noted in the streetlights and sentinel lights classes, explanations were provided as to the causes that lead to these changes.[1]

After filing of the Application the record has noted certain adjustments or corrections to the COS analysis of R/C ratios as filed. Exhibit B9 noted an adjustment to remove certain distribution related costs that had been assigned to the industrial class (as reviewed in Exhibit B16, this correction will increase the industrial R/C ratio from 109% to approximately 112%, while the net effect on other class R/C ratios is expected to be less than 0.2%). The response to LE-YEC/YECL-1-7(a) indicated that the COS as filed inadvertently classified Mayo hydro plant 100% to energy rather than the old 60% energy and 40% demand classification (correction of this error will change the class R/C ratios by only about 0.2%-0.3%, with these slight increases to R/C ratios for residential classes and slight reductions to R/C ratios for general service and industrial classes).

[1] For streetlights, the lower R/C ratio reflects the fact that average costs have increased considerably since the 1996/97 GRA, reflecting several factors (transcript, pages 44-45). For sentinel lights, the higher R/C ratio reflects the small growth in sentinel lights over the last 12 years. For further discussion see YECL's argument.

The fact that the majority of the major customer classes have not seen material changes over the extended period since the last Cost of Service Study does raise a question regarding whether updated Cost of Service Studies are required when rates are adjusted following future revenue requirement applications by either Company, or whether less frequent updates would be sufficient. The Companies anticipate that they would make submissions to the Board in this regard as part of the preparation of future revenue requirement or rate adjustment applications.

1.1.1 BULK POWER CLASSIFICATION METHODS (PRODUCTION AND TRANSMISSION)

Bulk Power Methods used to prepare the 2009 Cost of Service study in Appendix 3.1 are consistent with standard approaches adopted by similar utilities in Canada and largely reflect past principles and methods adopted by the Companies and approved by the Board[2]. The Companies proposed that classification of all bulk power generation and transmission assets remain as classified in the 1996/97 COS (including treatment of Whitehorse plant[3], Whitehorse Unit #4[4], Wind[5] and Diesel generation) except for the following adjustments proposed to reflect new developments since the 1996/97 GRA:

- **Aishihik Hydro Plant** - The Companies proposed to change the classification of hydro plant at Aishihik from 40% Demand and 60% Energy[6] to 100% Energy. This is addressed at pages 3-5 to 3-6 of the joint Phase II Rate Application, in response to CW-YEC/YECL-1-2; LE-YEC/YECL-1-3; LE-YEC/YECL-1-6; UCG-YEC/YECL-1-11; YUB-YEC/YECL-1-4(c), and in discussion at transcript pages 106-14; 175-84.

- **Transmission Assets** - The Companies proposed to change the classification of transmission from 100% Demand[7] to 100% Energy. This is addressed at pages 3-7 to 3-9 of the joint Phase II Rate Application, in response to CW-YEC/YECL-1-4(a); CW-YEC/YECL-1-5; CW-YEC/YECL-1-6; LE-YEC/YECL-1-4(c); LE-EYC/YECL-1-5; YUB-YEC/YECL-1-3; YUB-YEC/YECL-1-6, and in discussion at transcript pages 70-74; 121-24.

- **Mayo Hydro Plant** - The Companies proposed to change the classification of hydro plant at Mayo from 40% Demand and 60% Energy to 100% Energy. This is addressed at pages 3-6 of the joint Phase II Rate Application, in response to CW-YEC/YECL-1-3, LE-YEC/YECL-1-6, LE-

[2] A review of bulk power methods applied in Yukon since the 1992 Cost of Service and Rate Design review was provided in Appendix 3.4.

[3] Other Hydro (including Whitehorse Units #1, #2, and #3) - Classified 40% to Demand and 60% to Energy (see Application at page 3-6).

[4] The classification of Whitehorse Unit #4 at 100% to energy (as adopted in past COS) was addressed in the Application at page 3-5 and page 3.4A-7 to 3.4A-8; in YUB-YEC/YECL-1-4(i), and discussed in the transcript at pages 186-88.

[5] The classification of wind generation is addressed in the Application at page 3-7, in YUB-YEC/YECL-1-5(f) and in the transcript at pages 115-16; (no changes from the 1996/97 COS are recommended in the current application and the Companies in the current COS continue to classify wind as 100% to Energy, based on the fact that wind facilities are not assumed to provide reliable firm winter capacity, but provide energy and reduce fuel cost year round).

[6] Proposed by the Companies and recommended by the Board in 1992 and subsequently approved in Order 1993-8 and 1996-7; the change is proposed due to material changes in circumstances on the system since the 1996/97 GRA.

[7] As noted in Appendix 3.4 (footnote 29) , excluding specific assignment to the Faro mine, transmission costs in previous COS were classified 100% to demand at the time of the system peak, without any consideration as to assigning any share to energy.

YEC/YECL-1-7(a), UCG-YEC/YECL-1-12, YUB-YEC/YECL-1-4(a), and YUB-YEC/YECL-1-5 (g); and in discussion at transcript pages 161-65; 167-68.

The above three bulk power classification changes were thoroughly addressed by the parties through interrogatories and cross examination. Given this attention, the related issues are reviewed in some detail below under the following headings:

- Bulk Power Classification not based on "Typical" Use;
- New Developments Since 1996/97 – Relevance to Bulk Power Classification; and
- Balancing Considerations re: Practicality and Implications for 2009 COS study Results.

In summary, the Companies note that the Application was required to provide an up-to-date COS study that provides accurate revenue-to-cost ratios for all rate classes. In this regard, update to the bulk power COS classification to reflect new developments since 1996/97 constitutes a key element of the 2009 COS study – and the evidence confirms that the proposed changes reflect new developments in Yukon while continuing to reflect standard approaches utilized by similar utilities in Canada. Accordingly, the Companies submit that the methods and approaches in the Application should be approved by the Board as filed.

1.1.2 Bulk Power Classification not based on "Typical" Use

As noted in the Application, interrogatory responses and as discussed in cross examination, the COS classifies bulk power costs primarily based on the rationale for investment in plant and the underlying load characteristics on the system that drive the requirement for investment in a particular asset. In this regard, key issues in the Yukon context (based on past COS practice as approved by the Board as well as standard approaches adopted by similar utilities in Canada) include:

- Classification of bulk power generation and transmission costs to "Demand" to reflect investments made to provide reliable capacity at the time of the system winter peak; and
- Classification of bulk power generation and transmission costs to "Energy" to reflect investments made to avoid the need for diesel energy (kW.h) generation.

In the previous COS approved by the Board in the 1990s, the classification of the Whitehorse #4 generation unit was a prime example of the above approach. At that time, this unit was the major "new" and most expensive bulk power cost on the system. It was classified 100% to energy based on its characteristics, i.e., the rationale for the investment in this asset was solely to displace diesel energy generation and, based on the evidence at that time, this unit also did not contribute any added reliable capacity to the WAF grid at the time of the system winter peak (this determination being based on non-typical drought conditions as that, based on practices of other similar hydro utilities, is the relevant water flow condition when assessing "reliable" capability of hydro units).

Based on the same considerations, in classifying bulk power costs for the 2009 COS the Companies did not focus on how a particular asset is "typically" used[8]. As noted, "use" would "be less of a factor than why it was built, what is the planning basis for the plant, what type of costs, what type of economic justification arises or what type of cost does the plant offset…[9]". The following examples were noted in this regard (see discussion on transcript pages 214-16):

- **Wind Units** - As noted, wind tends to be used to supply energy as and when available, and may "typically" provide energy and demand at peak times; however, none of the costs for a wind unit are classified to demand because the system cannot be planned on the basis of wind being reliably available to provide demand at times of system peak.

- **Diesel Units** - As noted, the grids include a substantial compliment of diesel generation plant that is required to be installed and maintained to be available specifically to ensure reliable supply (meet demand requirements at time of system winter peak). However, these units are not used for operational purposes on a day to day basis, "*they're typically not used at all. They're typically sitting there just waiting for the day when they need to be used, and the capacity planning criteria underlines why they're needed*[10]." At transcript pages 161-62, the Joint Panel testified that while the diesel plants operationally serve both demand and energy requirements, the components that make up the cost of the plants are classified differently; whether a diesel plant is in an isolated community or the grid, the diesel engines (and the investment made in the diesel plant and engines) are classified 100% to demand, while the diesel fuel used to operate the engines is classified 100% to energy.

- **Mayo Dawson Transmission Line -** As noted, while this line supplies both energy and demand, the premise underlying the business case for the project was to supplant the requirement to operate diesel units to supply energy (i.e., to avoid costs for diesel fuel) on an ongoing basis in Dawson (as well as Stewart Crossing) through making lower cost hydro generation available. In summary, the premise for the project was "to try to find a way to save on energy costs by building a transmission line, and this line is designed for that purpose. The economic -- from an economic perspective; from a driving factor; from a rationale perspective. It's not necessarily linked to the same sort of core engineering design where you have to look at different characteristics of how that line might operate under normal circumstances or extreme circumstances, or you know, system interruptions or that sort of thing". Accordingly, to reflect these investment realities, the Mayo Dawson transmission Line costs in the Application were classified 100% to energy, ensuring that the costs of the line were treated in the COS in the

[8] The approach to bulk power classification as discussed in the Application at pages 3-3 and 3-4; in CW-YEC/YECL-1-3(a); LE-YEC/YECL-1-2 and on the transcript at pages 112-13; 117-20; this evidence notes that classification methods for bulk power reflect consideration of a number of factors including the following: how any given asset or class of assets is used; what type of loads on the system increase the required level of investment in the particular type of asset (i.e., what is the basis for the investment); and what would be the alternative system cost profile absent the assets (i.e., what are the benefits of the asset to the system).

[9] See discussion transcript pages 214-16.

[10] Transcript page 215, lines 13-17.

same way as the costs of the diesel energy generation (the costs that were avoided due to this project).

In short, consistent with normal utility practice and past experience in Yukon, the Companies focused on factors other than "typical" use when assessing bulk power cost classification methods to be adopted for new developments since the 1996/97 GRA.

1.1.3 New Developments since 1996/97 – Relevance to Bulk Power Classification

The Application, Interrogatory responses and cross-examination note that the cost drivers and load characteristics present in 1996/97 (and that underlined bulk power classifications at that time) are materially different with regard to certain plant than the types of cost drivers and load characteristics that exist today and that underlie the adjustments included in the Application[11].

Major developments on the system affecting bulk power COS assessment (including classifications adjustments) in the 2009 COS study are summarized below:

1. **Loss of Faro mine** – loss of major, high load factor industrial load and resulting availability of surplus hydro on WAF grid; this change provided an opportunity to develop the secondary sales program.

    a) **Loss of high load factor industrial load** - Compared to 1996/97, current industrial customer loads (Minto and, more recently, Alexco) have a much smaller impact on the system and addition of loads such as Alexco will not drive material changes in COS results. These are much smaller loads, and do not have a similar high load factor or coincident peak impact, when compared to the Faro forecast load in the 1996/97 GRA. Further, industrial customers today have rates locked in until 2012, and are paying approximately 110% of their COS costs (Discussed at transcript pages 93-96).

    b) **Available surplus hydro and increased opportunity for secondary sales** – Secondary sales were not a factor on the system in the 1996/97 GRA; however, with the closure of Faro and significant available surplus hydro generation the secondary sales program was considerably expanded by 2005 (when a new rate was approved). The relevance of the issue to the matters before the Board is as follows:

        i. The secondary sales rate is an optional offering to customers that is available as and when surplus hydro generation is available. It is not a firm rate and Yukon Energy does not plan its system or invest materially in bulk power assets in order to provide service under this rate schedule. Accordingly, secondary sales are not treated as a separate rate class in the COS (there is no "allocation of costs" to these customers) but are solely treated as incidental revenues.

[11] Developments on the system since 1996/97 are discussed in the Application at Tab 1; and in the transcript at page 210-12.

ii. The Companies in the COS applied secondary sales revenues as a 100% offset to energy costs, reducing the firm rate revenues required to be collected from the retail and industrial customer classes. Classification of secondary sales revenues is addressed at pages 3-9 and 3-10 of the joint Phase II Rate Application in response to CW-YEC/YECL-1-7, CW-YEC/YEC-1-23 and CW-YEC/YECL-1-24; and in discussion at transcript pages 25-28; and 49-53.

Since the secondary sales rate offering is only available when there is surplus power, diminished available surplus hydro due to ongoing non-industrial load growth since 1996/97, as well as the addition of new industrial loads, means that the availability of this rate offering is being reduced. As noted on the transcript at pages 50-53 the secondary sales rate was cut off as of September 1, 2010 due to low water conditions and is not expected to be available over the course of this winter.

2. **Material increases in diesel price and cost of supplying energy on the system** - Current diesel fuel prices are more than 2½ times more expensive than when the 1996/97 GRA was undertaken. As noted in the Application at page 3-4, the emphasis for utility cost changes since 1996/97 (and continuing into the future) is on the materially increased costs of generating the energy, particularly as load growth increasingly drives towards diesel fuel being required for baseload purposes on the hydro grid systems.

   While the cost of supplying increased energy loads using diesel has nearly tripled since 1996/97, the costs to ensure the ability to reliably meet short–term demand peaks (by increasing the installed reliable generating capacity of the system) has remained relatively low. Bulk power classifications weighted towards energy in the 2009 COS reflect the predominant impact from the cost of supplying incremental energy (either baseload diesel costs or the higher cost of new renewable sources of supply).

3. **Adoption of new capacity planning criteria in 20-Year Resource plan, including the adoption of a new N-1 criteria** – The adoption of the new capacity planning criteria impacts bulk power COS in a number of ways, including the following impacts on the Aishihik generation and transmission:

   a) Under the new capacity planning criteria, the benefits the Aishihik generation and the related Aishihik transmission provide to peak winter demand are not considered to be available in the N-1 situation (which currently drives WAF capacity planning requirements) because Aishihik is connected to the WAF grid by a single non-redundant transmission interconnection and the loss of this connection constitutes the N-1 situation on WAF today[12]. Although Aishihik plant normally contributes to carrying loads at peak

[12] The biggest loss of generation on WAF today at winter peak would be 30 MW following a failure of the Aishihik transmission line; this loss would be far greater than the loss during winter peak of the biggest generator (which currently is a 15 MW generator at Aishihik). As a result, and as noted in the Resource Plan, without twinning of the Aishihik Transmission Line (in order to provide for redundancy), none of the current or any added Aishihik capacity is recognized under the N-1 WAF capacity planning criteria.

times, having available demand from Aishihik facility "most of the time[13]" does not allow YEC to avoid the requirement to invest in other reliable demand capacity to meet WAF grid winter peak load.

b) Given the capacity planning criteria it is reasonable to treat Aishihik plant similar to other facilities such as wind or IPPs that cannot be relied upon to provide demand under all contingencies and classify it 100% energy (as discussed in YUB-YEC/YECL-1-5(d) and (f))[14]. At transcript page 178, lines 24-25 and page 179, lines1-20 it is noted as follows: *"if somebody came along and added 10 megawatts to this system, would it drive people to build more out at Aihsihik? It wouldn't. It wouldn't link the investment out at Aishihik to that load. It would drive people to add diesel units, which is why diesel units become a demand related driver or potentially to look at, in combination with energy, to add hydro on this side of the Aihsihik line. You wouldn't try to serve that 10 megawatt pure peak load by adding units out at Aishihik. If somebody brings kilowatt hours to the system, you can deliver it whenever you want. It wouldn't drive you to add capacity. It would - - it might drive you to add hydro on an economic basis or to run diesel fuel, and that's why those become things that you put much more to energy. And so for those reasons, when you have a plant similar to Aishihik, you can't rely on at peak times, even though it tends to generate at peak times – similar to wind; similar to IPPs - - you would still try to think about them as primarily if not entirely, an energy-related resource because they are not an investment; they're not a plant that is driven by those pure peek [sic] loads."*

This issue related to the N-1 capacity planning criteria and classification of bulk power costs to supply peak demand is clearly demonstrated by a recent operational example. The January 29, 2006 outage underlined the fact that while Aishihik (and the transmission line connecting Aishihik and Whitehorse) is available to provide capacity and energy "most of the time", it cannot be relied upon in an N-1 event; (as noted at pages 177-79 of the transcript).

4. **Material investment in transmission infrastructure and interconnection of loads previously served by diesel generation** – Completion of the Mayo Dawson Transmission line ("MDTL") Project and Carmacks-Stewart Transmission Project ("CSTP") led to connection to the hydro grid system of Dawson, Pelly and other loads that had previously relied upon resident diesel generation. Investment in this transmission infrastructure was solely premised on energy benefits resulting from connecting diesel-served loads to the grid system (and reducing the requirement for costly diesel generation in communities such as Dawson, Stewart Crossing and Pelly Crossing). This system reality drives changes in how transmission assets are considered and classified in the 2009 COS compared to the 1996/97 COS. Important considerations in this regard include:

[13] LE-YEC/YECL-1-2 and CW-YEC/YECL-3-(b) acknowledge that Aishihik plant typically contributes to the system's ability to serve peak loads - since commissioning the MD transmission line in 2003 Mayo Hydro generation has provided on average 95% of the MD winter peak load and would be expected to contribute at approximately 94% for the winter peak for 2010.

[14] Notes that wind facilities in Canada are typically classified as 100% energy as they cannot be relied upon to provide capacity (at time of system peak).

a) **Older transmission assets were not driving costs in 1996/97 -** Keeping in mind that 85% of transmission costs for the line between Whitehorse and Faro at that time assigned directly to the Faro mine[15], changes to transmission classification (to consider energy cost or a load-factor based allocation) were not considered a priority in 1996/97 based on the conditions at that time. This is very different from the current situation where there has been material recent investment in transmission which has an important effect on overall costs requiring further consideration in COS.

b) **New transmission assets were justified based on the economics of supplying loads that would otherwise rely on costly diesel generation with available lower cost surplus hydro generation on the grid system -** This change affects not only the classification of the new transmission assets, but also affects classification of existing Mayo hydro generation assets. In 1996/97 the Mayo plant only served local Mayo and Keno loads. Due to completion of the MDTL, the Mayo Plant now serves a larger complement of formerly isolated communities that previously relied upon resident diesel generation to supply baseload requirements. Therefore, given this new reality the primary function of the Mayo Plant in the 2009 test year is to provide energy that offsets the need to rely on local diesel generation in isolated communities with resident diesel units[16]. The economic benefit profile of having the hydro plant, versus not having this plant in these circumstances, is heavily dependent today on energy cost savings (kW.h) and not its capacity contribution (MW). More particularly:

   i. The presence of this hydro plant does not drive any cost savings in terms of diesel plant (YEC still needs diesel plant as before in Mayo and Dawson as backup); and
   ii. The presence of this hydro plant drives material savings in diesel fuel (energy) by replacing the need to consume diesel fuel in the previous diesel-served communities (and that diesel fuel being saved was classified as 100% energy).

c) **Due to the integration of remote hydro generation with diesel served communities such as Dawson, transmission assets are now viewed as "generation integration transmission" -** As noted at transcript page 73, lines 12-18 "*if the sole function of that transmission is to bring that generation to the load, the transmission is effectively an extension of the generation plant. That's a relatively accepted method in cost of service. It's cited in the types of manuals you'll see for preparing costs of service, and it's used in - - in many places. We see it used in other jurisdictions as well".* Examples of generation integration transmission were discussed in Interrogatories (YUB-YEC/YECL-1-6) and in cross-examination at transcript pages 70-73. It was noted, for example, that the rationale for now classifying transmission in Yukon

[15] It was noted (transcript page 185) that when COS was reviewed in the 1990's the focus was on Whitehorse Unit #4 and a few other matters receiving attention at that time. At transcript page 191 – "And just in the context of the '90s, the issue that -- one of the big issues of that particular example that you just gave -- reflected was Whitehorse No. 4 unit. That was the new unit. It was the, I don't know, the $50 million out of a $95 million asset that Yukon Energy bought when it got the [NCPC] asset".

[16] These diesel units remain available to provide capacity benefits as required, but are no longer typically used to provide energy.

100% to energy is quite similar to the rationale used in Manitoba to classify the HVDC lines that connect remote northern generation to southern population centres.

d) **Since the transmission assets serve as an extension of the generation assets (connecting it to loads at a distance from the location of the generation plant), the classification of transmission mirrors the generation asset -** As noted at transcript pages 73-74, "*so you start with the premise that transmission's linked to generation, and then you say, this generation's 100 percent energy; ergo, the transmission's 100 percent energy. That's not entirely different than what we're talking about here for a good part of the transmission system.*[17]*"* With regard to Aishihik plant it was noted, *"we've got an underlying rational for Aishihik being treated 100 percent energy. As a result that transmission bringing Aishihk generation to the load centres would similarly follow.*[18]*"*

5. **Reduction of WAF and MD surplus and change in mix of loads** – Since the 2008/2009 Phase I GRAs, attention has been focused on the diminishing surplus generation available on the grids to address continuing load growth. Non-industrial loads have continued to grow and are a larger component on the system compared to industrial loads when the Faro mine was on the WAF grid in 1996/97. In addition, page 212, lines 3-12 of the transcript also notes a number of high load factor general service customers added to the system since 1996/97. Further, given the recently increasing load, the surplus of the WAF and MD surplus is quickly being reduced. This reality drives the following considerations:

   a) Notwithstanding investment in renewable generation projects such as Mayo B, expensive baseload diesel is expected to become a component of system supply on an ongoing basis in the near term. At the present time, increases in energy requirements (kW.h) drive expensive diesel fuel consumption on the diesel systems, and similarly drive the WAF (Whitehorse-Aishihik-Faro) system and ultimately the interconnected WAF and MD (Mayo Dawson) systems towards the need to consume expensive diesel fuel generation for base load supply (as opposed to only peaking diesel).

   b) The types of methodology changes included in the 2009 COS tend to recognize more of an energy weighting in the remaining assets on the system than was the case in the 1996/97 COS; this drives costs allocated to the industrial customer class up and drives the revenue cost coverage ratio for this class down. By contrast, methodology changes raised in interrogatories and cross-examination (focused for the most part on keeping the status quo allocations for transmission [100% demand], and Aishihik plant and Mayo plant [40% demand and 60% energy]) tend to reduce costs allocated to the industrial class and consequently raise the R/C ratio of that class (e.g., instead of being 109% before corrections noted earlier, the R/C ratio for this class before corrections would be 111% to 113%).

[17] Page 73 lines 21-25.

[18] Page 74 lines 2-5.

c) In the 2009 COS, the differences between industrial and other classes as regards sensitivity to classification methods are not as acute as in 1996/97 COS when the Faro mine was on the system;

i. The Faro Mine was discussed in the hearing as the classic example of a customer that would be very sensitive to classification factors (it was noted generally that such industrials, due to their high load factors, have a much larger share of the overall energy on the system than of peak coincident demand)[19]. In relation to the 1996/97 COS it was noted that the Faro Mine was approximately 43% of the energy on the system and 29.99% of demand on the system. As a result, the Faro mine would pay 30 cents of every dollar allocated to demand and 43 cents of every dollar allocated to energy. Thus, there was a relatively major split between demand and energy affecting the industrial customer/class at that time. Other classes experienced the opposite effects due to the demand/energy split at that time, and benefited in their overall COS by higher classification allocations to energy.

ii. In 2009, energy classification allocations lead to 41 cents of every dollar allocated to energy going to residential non-government. In contrast, demand classification allocations lead to about 48 cents of every dollar allocated to demand going to residential non-government, i.e., this class today is not as sensitive as in 1996/97 regarding how bulk power costs are classified as between energy and demand. Response to LE-YEC/YECL-1-6 and transcript pages 169-70 and 189-91 addressed impact of changes today on industrial class due to moving costs from demand to energy.

In summary, given the above material changes on the system, the Companies noted in Tab 3 of the Application, in interrogatories and in cross examination that appropriate generation and transmission classification factors for 2009 focus on the relative energy benefit of each asset – consequently, there is less focus on capacity benefits that an asset may provide (noted at page 3-4 of the Application and discussed at transcript pages 193-97).

1.2 BALANCING CONSIDERATIONS RE: PRACTICALITY AND IMPLICATIONS FOR 2009 COS RESULTS

The Companies acknowledged during the hearing and in the IRs certain specific instances where bulk power classifications could be done differently than proposed, but noted the net effect of such changes on R/C ratios for 2009 would be very small and that such additional changes were not practical in the circumstances. The following are noted in this regard:

- Whitehorse Unit #4 that 4 MW of the 20 MW could arguably be subject to the same demand/energy classification as the balance of Whitehorse units 1, 2, and 3. (see discussion in Application page 3-5 and on transcript at page 187) – “it’s just a question of practicality.”

[19] See discussion at pages 189-90.

- As noted at transcript pages 187-88, there are some transmission assets where a demand/energy split could be debated, but such changes would not be material (i.e., split would still be materially weighted towards energy) or have a material impact (R/C ratios would be affected only incrementally (within 1% ranges for residential non-government)) and would materially increase the complexity of the COS analysis.

For the above items, given the complexity involved in re-classification and the small impact such re-classification would have on cost allocations and R/C ratios, the suggested additional adjustments were not considered practical.

In implementing changes to bulk power methods the focus in the Application was placed on implementing changes to classifications that recognized material changes on the system at this time:

- Even if the proposed classification changes as set out in the Application have a net effect today on R/C ratios that is relatively small (1% change for residential, and 2-3% change for industrial [20]), as noted at transcript pages 167-68, the Board directed that the Companies produce a cost of service study with accurate revenue cost ratios, and *"the driver is trying to do a cost-of-service study that accurately and fairly represents the system*[21]*"..."it would undermine the result to just -- fail to acknowledge these key system conditions*[22]*."*

- Further, at transcript page 168, lines 2-24, "*at a very simple level, if somebody's asking me from an oversight point of view, you know, if it doesn't make any difference, why should you do it, my comment back is: You don't know it doesn't make any difference until you do it. And if it makes sense, do it and report on it. Don't start trying to prejudge in advance what you're talking about. Secondly, the customer characteristics on the system today may be quite different five years from now if there are more industrials like we used to have. So get it right, and it will help the people that come later to make sure that they've got an accurate approach. If we get another customer on the system like a large industrial, and there's some indication that we're going to have more of them as time goes along, and they have high load factors, what we're talking about here could be very important as to how much costs are paid -- are assumed to be assigned to the different customer groups. So, you know, it's just -- in the end, we end up reporting a lot of answers that say, it didn't make much difference. And my reaction to that is as you're hearing it right now: Yes, that's interesting, but it's not determinative."*

1.3 DISTRIBUTION COS METHODS

In relation to the Distribution COS Methods, Yukon Energy supports the methods and analysis as provided by Yukon Electrical, subject to comments on certain issues related to the distribution cost

[20] With the industrial class that is there today (materially different characteristics than Faro mine) changes driven by proposed classification weighted towards energy would drive R/C ratio changes in the range of 2 to 3 percentage points. (See transcript page 189).

[21] Transcript page 167, lines 4-6.

[22] Transcript page 167, lines 17-18.

allocation to the industrial class, and the Energy Demand and Loss Analysis ("EDLA"). These two specific issues, which are reviewed briefly below, were resolved by the Companies in the September 30, 2010 filing (Ex. B-9).

- **Distribution cost allocation to the industrial class** - As noted in Exhibit B-9, (p. 3-4) the Companies agree that costs functionalized as distribution that relate to activities that are in fact beneficial to the overall system and all customers, should be allocated in part to the industrial class (e.g., Public Information, Customer Accounting, General Plant and Administration and General); but costs that relate to assets functionalized as distribution (e.g., poles and wires) should not be allocated to the industrial class. The joint agreement of the Companies went on to reflect the details of the proposed changes to the distribution cost of service. The Companies propose that the Board accept the agreed upon resolution to this matter and note that the above changes in the Cost of Service would be reflected in the compliance filing following the Board's Decision.

- **EDLA –** In Exhibit B-9, the Companies noted the material change in the general service load factors since the 1997 COS identified as a result of the application of the methods used in the 1997 approved COS, and that there is no Yukon specific data to support any such change in load characteristics. The Companies recommended in Exhibit B-9 that the Board accept the COS ratios as reported in the GRA filing for this proceeding (arising from the use of the ATCO Electric Alberta data), as being based on the most readily available data and in recognition that the COS will not determine rate changes at this time, and stated that in their next COS study the Companies will re-evaluate this issue to ensure the results are consistent with the load characteristics in Yukon.

During the hearing, in response to questions on the matter of general service load and coincident peak (CP) factors and the absence of Yukon-specific load studies, each of the Companies' representatives discussed this issue further. Both Companies noted the very high costs (in millions of dollars) to develop Yukon-specific load data similar to what is available for major southern utility systems, as well as the absence of relevant infrastructure in Yukon, and accordingly did not support carrying out such studies in Yukon (transcript, pages 88; pp 157-158; pp 240-247). In the absence of such studies, however, the Companies have not to date agreed upon how in future they "will re-evaluate this issue to ensure the results are consistent with load characteristics in Yukon" (transcript p246-247). The specific matter discussed regarding EDLA focused on the general service load and CP factors which affect allocations of, among other costs, the bulk demand costs.

At the hearing, in response to various questions about this matter, representatives of both Companies explained the difference of opinion YEC and YECL have on using the Alberta based information.

The concern raised by Yukon Energy was that the change since the 1996/97 GRA (i.e., the much higher general service CP Load Factor in the current study) may not reflect Yukon realities, in which case the current study would be under-allocating demand costs to the general service class (and the R/C ratio would be too high). Yukon Energy provided comments during the hearing as to cross-checks that were

done in Yukon at the time of earlier joint COS studies to address such concerns, but were not done in the current study.

For its part Yukon Electrical indicated that it did not share YEC's concerns and commented on its reservations about going beyond EDLA (transcript pp 88-92; pp 158-160; pp 242-247). Notwithstanding their difference in opinion the Companies have committed to work together to resolve that issue prior to the next COS study.

It should be noted that this discussion regarding general service load CP factors did not suggest similar material concerns related to Yukon-specific load data as it may affect industrial or other customer class R/C ratios derived from the 2009 COS study.

1.4 TERMS AND CONDITIONS OF SERVICE

Yukon Energy supports the proposed Terms and Conditions, including proposed MILs, as provided by Yukon Electrical, subject to comments on two specific issues addressed in Exhibit B-9 and discussed briefly below:

1. **Rewording Section 4.15 - Reconnection** – In Exhibit B9, the Companies noted agreement with the following proposed changes to this section 4.15 of the Terms and Conditions of service include the following text:

   "If Service is reconnected within 12 months of disconnection, with the exception of seasonal Service:

   a) For Major Industrial and General Service customers with peak demands greater than 500 kW the Customer shall pay the minimum monthly bill for each month of disconnection.
   b) For all other customers, the Company may request that the Customer pay the minimum monthly bill for each month of disconnection."

   Intervenors did not raise any material issues with the above change jointly proposed by the Companies in Exhibit B-9. The Companies request that the Board approve this updated wording, as filed.

2. **Maximum Investment Levels (MIL's) – Schedule B** – Exhibit B-9 set out agreement on proposed changes to retail MIL's for 2011 and 2012 as well as the following three specific elements of agreement relating to this matter:

   a) **Adoption of 10-Principles** - In relation to the 10 principles, these are to be interpreted based on appropriate Yukon precedents, current rate policy and principles of rate regulation adopted in Yukon. The following additional points were noted in Exhibit B-9:

      i. The adoption of the principles for MILs that are derived from Alberta practice does not mean the Companies are proposing wholesale adoption of the

ongoing decisions of the Alberta regulator or utilities as to implementation of the principles.

ii. If adopted these principles will be interpreted by the YUB based on the application of its jurisdiction in the Yukon context, and looking at utility practice as relevant throughout Canada[23].

b) **Adoption of Average Cost Standard** - As noted in Exhibit B-9, "*the Companies agree to adopt an average cost standard for determining MILs, as opposed to the current revenue-based standard. This agreement goes to the reference point used to assess MILs and not to the adoption of any specific MIL level relevant to this reference point. Agreement to adopt the average cost standard does not mean, for example, using 100% of cost as a long term "standard" for MILs that the Companies should be moving towards".*

c) **Amendment to Schedule B, section 3 re: Industrial MILs** – The Application (pages 5-8 to 5-11) and subsequently filed materials (correspondence dated September 30, 2010 - Exhibit B-9) address Maximum Company Investment approach for Industrial customers. Exhibit B-9 and discussion in cross-examination (transcript pages 273-78) note that adoption of an average cost standard as opposed to a revenue standard also would require changes in the proposed text for the Industrial Maximum Company Investment, in Schedule B, section 3, as follows:

> "The maximum cost which the Corporation will incur to extend Service to a Point of Delivery shall be determined for Industrial Service, in the manner specified in an agreement with the Industrial Customer and subject to approval by the Board."

The principles relied upon by YEC since 1996/97 (and previously reviewed by the YUB in the 2007 Minto PPA hearing) to inform industrial capital cost contributions to be included in PPA's with individual customers seeking grid service are set out at pages 5-8 to 5-11 of the Application. As noted in the Application and in discussion at this hearing this approach secures material contributions from the new Industrial customer and does not seek to ensure that all expected benefits are invested in providing the extension to that customer [Transcript pages 273-78].

> *"With respect to industrials, which is what this section is referring to, what it says there is it will be done in relation to a contract with the customer, and there's a fair bit more discussion in relation to the premise and the principles for setting up such a contract in tab 5. It's not meant to be based whatsoever on costs for any other jurisdictions. It's ideally -- and if the framework is set there, and it's -- Tab 5 sets out the policy framework -- not even linked to costs in Yukon per se.*

[23] Transcript page 30, lines 13-20 notes the principles are to be applied taking into account Yukon conditions and Yukon ongoing decision by this Board as well as the experience in other regulatory areas as relevant to such decisions in the future.

> *It's linked to - I'm looking at top of page 11, the policy focuses on maximizing potential industrial customer investment to new transmission facilities developed to extend service to them as well as to retain direct assignment of annual capital-related transmission costs for extending facilities where appropriate based on past practice in Yukon. So it's a lengthy write-up to deal with the fact that when you're dealing with industrial customers, what you're really trying to do is find the right way to have them pay for their share of the connection. It's not -- it's -- not like residentials where you hook up a lot of customers and you've got to figure out how to balance one against the other in terms of what company invests. With industrial customers you're hooking up one or two and whatever the company invests is ultimately going to be paid for by that customer, either up front or through allocations in the cost-of-service study or through fixed charged assigned to their bill, and the emphasis is on trying to do that in the way that best protects other ratepayers."*
>
> *"With regard to the above MIL matters, the Companies request that the Board approve the adoption of these principles and standards for MILs as addressed in Exhibit B-9 did not appear to attract Intervener opposition during the course of this proceeding. However, during the hearing, the City of Whitehorse asked the Companies if they are amenable to adopting a "one step process" and moving to 2012 the proposed retail MIL levels effective January 1 2012, and the Companies confirmed that they would have no objection to that proposal (transcript pages 30-32)."*

During the course of questioning from Board Counsel, an issue was raised with respect to Section 9.4 of the proposed Terms and Conditions regarding Company Liability (Transcript pages 165-166). This matter was further addressed in response to an Undertaking (Exhibit B-26) filed on October 12, 2010.

> *"The Companies were asked to review the wording of this section of the terms and conditions (transcript page 170) to determine if it was possible to further simply the language. In Exhibit B-26, the Companies noted that on the advice of counsel the wording should not be changed. This is primarily due to the fact that this key provision of the terms and conditions establishes the scope of potential liability that the Companies could be exposed to. In the view of the Companies, this is a critical provision that is required to be clear and concise from a legal point of view. The interpretation of this provision is most likely to be questioned in the context of a legal dispute. As such, the Companies are of the view that it is critical that this provision remain concise and clear from a legal point of view. The Companies are not aware of any customer complaints regarding this wording. As such, the Companies submit that no change to the proposed wording is required".*

2.0 MATTERS ADDRESSED BY SEPARATE RATE DESIGN PANELS

2.1 OVERVIEW

As directed in Board Order 2009-8, the Companies worked diligently to present rate design recommendations that comply with previous Board directions and current OICs, including key directions in the OICs to allocate throughout Yukon the benefits of lower cost heritage grid generation and transmission assets (currently implemented through first block retail rates approved in the 1996/97 GRA), and to set retail runoff rates to address economy and efficiency rate principles and directives throughout Yukon by reflecting incremental costs of higher cost non-renewable generation in each rate zone.

The current proceeding marks the first opportunity in over 14 years to review base rates for firm electric service in Yukon. As noted in Exhibit B-14, key challenges arising today from this protracted lack of rate review include the need to:

- Eliminate current general purpose rate Riders J and R, together equal to 23.123%, by adjusting retail base rates to fully reflect approved 2009 revenue requirement costs;
- Adjust base rates within each retail class to address economy and efficiency rate principles and directives consistent with current OICs and previous Board directions, including the need to adjust runoff rates in light of approved 2009 incremental costs based on current fuel prices that are over 2.5 times the levels last approved for runoff rates in the 1996/97 GRA; and
- Address the greatly widened gap between incremental costs per kW.h and heritage costs per kW.h.

Taking into account OIC directives, including the requirement today to maintain current revenue:cost ratios for each retail customer class, the 2009 Phase II Rate Application addressed rate adjustments that are feasible and appropriate at this time taking into account current and expected future conditions.

Based on approved forecast loads for 2009, rate design options examined in the Application may affect bills of different customers within a retail customer class, but cannot affect the total revenues collected from each retail class or the total revenues collected by each utility[24].

The Companies agreed on most of the rate-related changes to recommend to the Board – these jointly supported rate matters are reviewed first below in Section 2.2.

Notwithstanding the many joint rate recommendations, the Companies were not able to finalize one specific final residential or general service rate package to be recommended in the Application. At the hearing, three options were reviewed on this matter – the initial range of options (Options A and B) presented by YEC in the Application, and a new preferred Option C that YEC provided on October 1, 2010 (Exhibit B-12).

[24] As noted in the Application at page 2-2, the 2009 firm rate revenue requirement at approved forecast loads is calculated assuming a corrected Rider J at 12.597% versus the currently approved Rider J at 12.46%.

Section 2.3 below reviews YEC's recommended retail residential and general service rate design option, a modified version of Option C (changes affect only residential customer classes), for initial implementation today and the road map applicable for future rate adjustments. This recommended option is reviewed in the context of the issues raised by YECL and other parties during the proceeding.

2.2 JOINTLY SUPPORTED RATE MATTERS

Throughout the development of the Phase II Application, and the subsequent pre-hearing stages, the Companies have openly and diligently considered the issues at hand in respect of rate design and the options available to deal with these issues. As reviewed below, in most cases the Companies are in agreement. In particular, the following key areas of agreement are noted on major rate design issues:

- **Principles of rate design** - The Companies agree on normal utility principles of rate design as previously adopted in Yukon with specific criteria that represent differing and sometimes conflicting objectives to be balanced in determining just and reasonable rates. [See Tab 4YEC pages 4-11 and 4-12 and Tab4YECL pages 4-6 and 4-7].

- **Incremental costs of diesel generation** - The Companies agree on the updated incremental costs of diesel generation in each rate zone for 2009 based on applying the same short-term incremental cost determinations used by the Board to set 1996/97 GRA runoff rates in each rate zone. The incremental costs is based on approved GRA fuel prices as set out at Table 2 of the Application, and the proposed consolidation of the hydro, large diesel and small diesel zones into a single average incremental cost ($27.99 cents/kW.h) to use in assessing runoff rates in these rate zones for at least the current Application.

- **Retail rates other than for Residential and General Service** - For all classes other than residential and general service customers, the Companies have a common set of other retail rate proposals in the Application. This includes elimination of Riders J and R, rate proposals for street lighting and sentinel lighting, the Industrial Rate Schedule 39 adjustments, continuation of secondary rate schedules and Riders A and B, and cancellation of earlier rate schedules 33, 38 and 40.

- **Residential and General Service Rate Block Changes** - For residential and general service customers, the Companies are in agreement that the present structure of rates in Yukon, with multiple inclining rate blocks, should continue. Further, the Companies agree that the existing rates with only two rate blocks do not provide a sufficient structure to address the overall rate priorities and objectives today – as a result three rate blocks are proposed for all residential and, for all practical effect, almost all general service customers.

    - **For General Service customers,** a common rate block structure was recommended by the Companies, with the new 2nd block for use from 2001 to 15,000 kW.h/month, a new equalized 3rd block for use from 15,001 to 20,000 kW.h/month wherein incremental costs are reflected, and average cost runoff rates today for all use in excess of 20,000 kW.h/month for each General Service rate class in order to provide for a future "Large General Service" class applicable to a relatively few customers (on the order of 100).

- **For Residential customers,** a common 1st rate block was recommended for use up to 1000 kW.h/month, but different options were provided for the 2nd and 3rd rate blocks (e.g., Option A with 2nd block up to 1,500 kW.h/month, Option B with 2nd block up to 2,500 kW.h/month)

- **Retail runoff rate** - With respect to the runoff rate, the Companies spent considerable time considering the appropriate approaches to address the OIC requirement for "economy and efficiency".

  - Both Companies recognized that diesel costs play an important role in determining the runoff rate, but at the same time both Companies recognized that simple application of 100% of diesel costs in the runoff rate was likely excessive at this time, particularly given the relatively small degree of diesel generation required on the grid systems in the particular test year in question (2009) and the opportunity to use a lower percentage (below 100%) to help phase in the transition required at the present time after 14 years with no specific changes to the run off rates.
  - The Companies differ in their ultimate recommendation as to what percentage of diesel price to reflect in the runoff rate today.

- **Residential Customer Charge not change** - Both Companies recognize that the residential customer charge today is well below the fixed cost of a residential customer on the system. Given the other considerations that are present in this proceeding, neither Company is suggesting an adjustment to the effective customer charge at this time.

- **Seasonal or time of use rates not recommended** - Both Companies recognized that a possible option to address the present need for transition was to consider seasonal or time of use rates; however, after review of the logistical issues that arise, the Companies agreed these options were not a practical or preferred approach at this time.

- **Wholesale Rates** - Both Companies agree to certain necessary adjustment to amend Wholesale Rate Schedule 42 (wholesale sales to Yukon Electrical):

  - To adjust the base energy rate that applies throughout Yukon (as required to reflect adjusted retail base rates and removal of Rider J and R – the specific number required will vary depending on the retail rate option approved by the Board) [as noted in YEC's opening statement at transcript page 288] in the event that non-government residential runoff rate in the hydro zone is less than 80% of short-term approved incremental generation costs in that zone, YEC has proposed that the ERA charge be set at YEC's full incremental cost of diesel generation as approved for that zone;
  - To amend the Energy Reconciliation Adjustment (the "ERA") to confirm that ERA charges to YECL will be adjusted on a monthly basis, as stipulated, only during the months when diesel generation is on the margin at normal long-term average water flows on the hydro zone. [The manner in which the ERA works was addressed at transcript page 413-14; 416-17; 448-54; Board Order 1999-4 approving the Rate Schedule 42 Settlement Agreement is provided in Exhibit B-20]. Wording changes related to the ERA portion of Rate Schedule 42 were discussed at Transcript page 452-53 – and YEC noted its views with the specific proposed

wording included in the Rider D Application. YEC has subsequently further reviewed this matter and notes its agreement on the above wording]; and

- Both Companies agree to amend Wholesale Rate Schedule 51 to provide for a single energy-only rate at the same level as the base Rate Schedule 42 that applies to all firm Yukon Energy purchases from Yukon Electrical throughout Yukon.

Beyond the above specific rate design matters, the Companies also indicated to the Board broad agreement on the path required for future rate adjustments beyond the current hearing. For example, Yukon Electrical indicated broad agreement with Yukon Energy:

- On the goal to move in future to recover 100% of incremental diesel generation costs and being comfortable with the runoff rate approach in this regard (Transcript page 401); and
- That if nothing is done to send consumers some signals today, Yukon is going to be faced with a larger problem in the future, whether it be rate shock or revenue stability issues. In this regard the Companies agree on the general need for a staged approach to get tools in place today as it would be very tough to do it next time there is a similar rate hearing opportunity. (Transcript pages 520-22).

2.3 YUKON ENERGY RECOMMENDED RETAIL RATE PROPOSAL

Yukon Energy has consistently, throughout Phases I and II of the 2008/2009 GRA, sought to re-establish efficient price signals for the retail runoff rate in the 20 to 22 cent per kW.h range in order to reflect both the very material increase in diesel prices since the 1996/97 GRA (when runoff rates were adjusted to reflect the then approved forecast fuel prices) and the reality that diesel energy generation will also likely be once again on the margin within the near term (i.e., by 2012) in the hydro zone.

The current effective retail runoff rate today (excluding a slight Rider F rebate at 0.09 cents per kW.h), at 12.85 cents per kW.h in the hydro and large diesel rate zones, is less than 50% of the 2009 incremental supply costs (Exhibit B-14, page 4). Today's runoff rate, which applies to all monthly use over the first rate block (e.g., over 1,000 kW.h/month use for all residential) is also 10.7% lower than the effective rate of 14.39 cents per kW.h for such use in the hydro and large diesel rate zones with all riders two years ago, in September 2008[25].

Options to address these issues have been thoroughly canvassed during the current proceeding, including Options A and B which reflected respectively runoff rates at 80% (22.39 cents per kWh excluding Old Crow) and 50% (13.99 cents per kW.h excluding Old Crow) of the 2009 incremental supply costs, and LE's and YEC's more recent proposals (YEC's Option C) at 71.5% of the 2009 incremental supply costs (20.00 cents per kW.h excluding Old Crow).

Yukon Energy is recommending in this Argument a modified version of Option C whereby the 20 cent runoff rate is implemented today with no residential rate increase impacts relative to current bills for any

[25] Mr. Maissan noted this September 2008 rate in cross exam of YECL – it reflects the higher Rider F at that time (at 1.86 cents per kW.h), as well as a slightly higher YEC Rider J (before YEC's approved 2.46% rate reduction) and the interim YECL Rider R at only 5%.

monthly use before 2,500 kW.h/month (i.e., the start of the interim residential runoff rate block). The modifications made to the earlier Option C only affect residential classes – Yukon Energy's recommended Option C as it affects general service classes remains as presented in Exhibits B-12 and B-14. Yukon Energy has focused on this modified version of Option C to highlight its prime interest, namely to secure a runoff rate today of at least 20 cents per kW.h as a first step on a meaningful roadmap towards rate design adjustments required within the next several years, and to clearly show the key differences in this regard between Option C as recommended by Yukon Energy and Option B as proposed by Yukon Electrical.

Yukon Energy's recommended retail rate design is addressed in more detail below, including review of related issues raised by YECL and other parties. First, however, Yukon Energy's role and interest in retail rate design has been at times downplayed in this proceeding – and therefore this specific matter is addressed briefly below.

2.3.1 Role of Yukon Energy in COS and Retail Rate Design

Yukon Electrical, and other intervenors (see cross-examination of CW at transcript pages 299 -302), have suggested from time to time that Yukon Energy should play a lesser role than Yukon Electrical in rate design issues since YEC is not the main distributor, and does not directly serve the vast majority of retail customers in the Yukon.

Yukon Energy fundamentally takes issue with this assertion.

The rate issues that Yukon is grappling with (and will continue to need to grapple with in the years to come) are fundamentally bulk power issues that relate directly to generation and transmission issues in the cost of service and resulting rate design implications. The rationale for ensuring runoff rates that reflect incremental costs (economy and efficiency price signals) fundamentally relates to bulk power and system planning issues and not to distribution.

While YECL is responsible for directly serving 90% of retail customers in Yukon, Yukon Energy is responsible for directly supplying more than 90% of bulk power generation and transmission in Yukon, i.e., Yukon Energy is responsible for ensuring the bulk power system is planned appropriately over the long term to meet the needs of all retail customers in Yukon (including YECL customers). This responsibility for bulk power planning fundamentally includes ensuring that all Yukon ratepayers receive appropriate price signals that reflect the material generation and transmission costs being incurred on the system. [See discussion at T pages 300-301]. As noted in discussion on the transcript, Yukon Energy has had "*a fundamental longstanding interest in cost of service and rate-design matters with respect to that, and in the interest of the territory, from our perspective, it's important that Yukon Energy plays a role in the rate design as it has throughout the history*".

Further, as a Crown Corporation, Yukon Energy has a unique role and responsibility, on behalf of Yukoners, to consider ongoing generation and transmission developments in the best interests of all Yukoners – further [T page 301], "*the rate system that's in place by Order-in-Council, ensures that all Yukoners will benefit from the assets that Yukon Energy holds, in terms of getting a lower rate for the first rate block, to be blunt, because of the lower cost hydro assets that Yukon Energy [has] responsibility for*".

2.3.2 Yukon Energy's Recommended Retail Rate Design – Modified Option C

Leading Edge in responses to interrogatories identified the fact that "between YECL's Option B and YEC's Option A there is a vast middle ground which went, apparently, unexplored." As noted in Exhibit B14, aside from different Residential 2nd block use limits, Options A and B differed primarily as regards the extent at this time of runoff rate increase towards incremental costs. Leading Edge proposed a slight modification on the Option A runoff rate (at 20 cents versus the Option A 22.39 cents).

Yukon Energy noted in Exhibit B14 that its review of the hearing record and further discussions with YECL prior to the oral hearing led to further refinement of its position on rates and the advancement of Option C, which adopted the Option B demand charge and 2nd block rate and included the following key provisions:

- A minimum initial runoff rate at 20 cents for all zones other than Old Crow (per LE's proposal, or 71.5% of 2009 incremental costs), with the longer term proposal to move the runoff rate up to 100% of short term incremental costs as soon as is reasonable; and

- Adjustment of initial rate blocks to be the same as Option B for residential as well as general service classes, with a first priority for future residential rate adjustments to move the residential 3rd block starting point down from 2,501 kW.h/month towards 2,000 kW.h/month or lower.

Yukon Energy noted that given the rate issues Yukon was faced with it wanted to focus on ensuring material progress towards implementing appropriate price signals in the runoff block while at the same time putting in place a rate structure that over time could be adjusted to address rate issues in a staged manner (i.e., by lowering the cut off point for 2nd block rates and raising the runoff rate further to reflect full incremental costs).

At the hearing YEC testified [T page 297-98] that it would continue to listen to discussion and positions advanced by parties to the proceeding and provide the Board in argument with its views and recommendations on rate design. YEC noted there may be "tweaks and variations" that emerge and that it may modify its final recommendations accordingly. As noted in discussion at transcript page 301, YEC's position in this process has been to encourage discussion and dialogue and minimize the degree to which conflict and disagreement frustrate those objectives. In this respect, Option C filed October 1, 2010 was an attempt to provide a proposal that satisfied objectives and issues raised by parties to the proceeding to date. Further adjustments to this proposal included in the recommended revised Option C as set out in this Argument are an attempt to respond to ongoing discussion and issues raised during the oral hearing process.

Attachment A provides updated bill comparison tables (residential and general service non-government), with and without the IER, that include the modified Option C as now recommended by Yukon Energy in this Argument. The recommended Option C is the same as Option C presented in the hearing (Exhibits B12, B14, B21) except as modified for residential customer classes (where the block 2 rate is reduced from 13.75 cents per kW.h to 13.00 cents per kW.h)[26]. The modification included in the recommended Option C **ensures no residential rate increase impacts relative to current bills for any monthly**

[26] As a result, the 1st block rate must be increased from 11.77 cents to 11.93 cents per kW.h; further, the gap between the 1st and 2nd block rates is reduced from 1.98 cents to 1.07 cents per kW.h.

use up to 2,500 kW.h/month (i.e., the start of the interim residential runoff rate block)[27]; in this one respect, the recommended Option C is similar to Option B. In other key respects, the recommended Option C differs from Option B for residential and general service customers as follows:

- Option C provides a higher runoff rate today than Option B (at 20 cents vs 13.99 cents per kW.h in all zones other than Old Crow);
- Option C as recommended ensures that non-government 2nd block rates today in the hydro/large diesel zones show at least some increase over effective current rates (this is not the case for Option B for residential non-government);
- Option C as recommended reduces non-government customer rates today for all users in the 1st and 2nd rate blocks (in contrast, Option B provides rate reductions only for residential non-government users in the 2nd rate block); and
- Option C as recommended provides a road map for future changes to both rate blocks and runoff rates (which will also affect 2nd and 1st block rates) to move towards specified objectives (no similar road map has been provided for Option B).

Requested Decisions

In summary, Yukon Energy's priority focus is reflected in the following requested decisions by the Board today related to the initial rate design for residential and general service customer classes:

1. **Runoff energy rates for residential and general service retail classes -** A minimum initial runoff rate to be approved at this time at 71.5% of 2009 incremental cost of diesel, with a longer-term commitment to move the runoff rate up to 100% of the incremental cost of diesel as soon as is reasonable, resulting in the following energy rates to be approved at this time:
    a) 20 cents per kW.h for the third energy block for all residential and general service rate schedules, other than the Old Crow third block runoff energy residential rate; and
    b) 43.98 cents per kW.h for the Old Crow third block runoff energy residential rate (the general service third block rate in Old Crow is 20 cents per kW.h, as the third block for general service is not technically a runoff block and therefore must be equalized with the other rate zones).
2. **First and second block residential energy rates** – To reflect Yukon Energy's priority focus throughout its 2008-2009 GRA filing on the need today for an adjusted runoff rate of at least 20 cents per kW.h, an adjusted Option C residential **second block energy rate** is recommended at 13.00 cents per kW.h for non-government and government residential classes in all rate zones so as to provide no adverse rate changes today for any residential customer use up to 2,500 kW.h per month; as a result, the adjusted residential **first block energy rate** is 11.93 cents per kW.h for non-government and 17.54 cents per kW.h for government.

[27] The earlier Option C had minimal (less than 1%) residential rate increases starting at about 1,800 kW.h/month use, with these rate increases rising to 3.2% at 2,500 kW.h/month.

3. **First block general service energy rates** – As set out in Exhibit B12 for Option C, an adjusted first block general service energy rate in all rate zones of 9.41 cents per kW.h for non-government and 18.88 cents per kW.h for government.

4. **Future residential rate block adjustments** - At the next GRA by either Company, a first priority for future rate adjustments for residential class rates be to move the third rate block starting point downwards from 2,501 kW.h per month.

5. **Wholesale Rate Schedule 42 ERA** – In the event that the non-government residential runoff rate in the hydro zone is now set at less than 80% of the approved incremental cost of diesel generation for that zone[28], the Wholesale Rate Schedule 42 ERA incremental charge to be set at 100% of the approved incremental cost of diesel generation adopted to assess runoff rates for that zone (e.g., 27.67 ¢/kW.h based on the Application, which proposed that one runoff rate be set for the hydro, large diesel and small diesel zones based on the weighted average of the incremental diesel generation costs for these zones).

Overall, as noted in the hearing (T p295), the recommended retail rate design Option C "*is more than a set of numbers. It is very much a set of numbers along with a set of priorities and a roadmap for how those numbers would then unfold over time*." [29]

Recommended roadmap for future rate adjustments

Yukon Energy's recommended retail rate design includes more than setting out initial rates for Board approval today.

YEC noted in its Opening Comments (Ex. B14) and in discussion on the transcript at pages 394-5 that the key focus for Yukon Energy for this hearing was "*to put in place a roadmap, to put in place a set of updated principles and updated methods for looking at how rate could be set, and to put in place a trajectory for where rates are going*." In this respect, YEC is not focused on "a numbers game or bidding war" over block sizes and runoff rates, and is more focused on ensuring that key issues and concerns related to bulk power planning requirements and changes on the system (raised by YEC since the 2008/2009 GRA) begin to be addressed in a meaningful manner. Yukon Energy has noted it is less concerned at this time with defining exact rate levels or block sizes, than with ensuring a well understood and accepted plan is in place to ensure progress towards addressing the material issues facing Yukon today.

In response to questions about existing versus new runoff rates complying with OIC 1995/90, YEC has noted [T pages 307-10] that the Board normally has discretion "as to how they address a problem that requires a transition so it can be done in an orderly manner", subject to the need (in the current case) to

[28] The ERA rate under Wholesale Rate Schedule 42 is currently set (per the 1996/97 GRA) to equal "the approved run out rate for non-government residential service in the hydro zone", based on the premise that this approved runoff rate was to be set to equal 100% of the term incremental cost of diesel generation for that zone.

[29] See also response to YUB-YEC/YECL-1-12(a) which notes YEC concerns with rate design at this time are primarily related to the pricing within the blocks rather than the blocking structure per se; and CW-YEC/YECL-1-19(a) which notes YEC primarily preferred Option A over Option B due to the fact that a runoff rate at 80% diesel "restores a process for rate design adjustments (after a 12 year period when no rate adjustments could take place) rather than retaining a status quo that no longer reflects current system conditions or near term trends."

"reflect the diesel price in some meaningful way in this hearing and what ends up being the runoff rate." This response presumes, when discretion is used as suggested, that the problem and the roadmap for ongoing adjustments are addressed along with the initial decisions.

The modified Option C as recommended addresses the following key "roadmap" issues of concern consistently identified by Yukon Energy in Tab 4YEC and in Interrogatory responses:

- **Need for plan to move runoff rate price signal back to reflect incremental diesel generation costs -** It was noted that at this time, given the length of time since the last runoff rate adjustment and the reality that the runoff rate today is less than 50% of incremental diesel generation costs in the hydro/large diesel zone, the runoff block rate did not need to move immediately to 100% of incremental costs, but should make notable progress today in this direction. In the 2008/2009 GRA YEC identified a range of 20-22 cents/kWh as a reasonable step towards reflecting full incremental costs at the time; Option A identified in Tab4 YEC provided a rate of 22 cents per kWh.h (reflecting 80% of incremental cost) and YEC Option C filed on October 1 provided a runoff rate of 20 cents/kWh (at 71.5% of incremental cost). Yukon Energy's recommended roadmap is that a decision be made today that this initial runoff rate will be moved as soon as is reasonable back up to reflect 100% of incremental short term supply costs in each rate zone. It was noted in the hearing that moving the runoff rate within a reasonable period of time to 100% of incremental supply costs will enhance customer conservation incentives and enhance their own long term purchase decisions.

- **Need to ensure that runoff price signal is ultimately provided to a meaningful share of customers and purchases** – Although ensuring that material diesel costs were reflected in runoff rates was seen as the first priority at this time under Option C, YEC noted in Exhibit B14 that the next priority would need to be adjusting third block runoff rate blocks starting points downwards to ensure that over time more ratepayers begin to receive this economy and efficiency price signal at a more appropriate level of consumption.

One key difference between the Companies relates to the timing when customers consuming in runoff rate blocks should begin to receive material price signals based on incremental costs. This disagreement is currently focused on the degree to which the runoff rate should today reflect the incremental cost of diesel; however, by inference this disagreement also affects any roadmap directing the path of future runoff rate increases. Yukon Energy has noted throughout its testimony that taking steps today to establish a clear and coherent plan or framework to over time move runoff rates to 100% of incremental costs is a key rate design challenge facing Yukon now and for the foreseeable future. In this respect, Yukon Energy has noted that setting the runoff rate today under Option C at 71.5% of incremental cost of diesel (while not fully reflecting incremental costs as ultimately required by OIC and past Yukon practice) takes a material step towards this requirement. As noted [T pages 307-10], Yukon Energy understands that this first step is consistent with OIC 1995/90 and past precedents in Yukon and elsewhere provided that it is stated to be an initial step on a clear roadmap to set the runoff rate once again at 100% of incremental cost as soon as is reasonable.

Yukon Energy noted in cross examination by the CW that to defer taking this step would only exacerbate the identified rate issues and create a more acute problem to be addressed in the future. Taking this

notable step towards full incremental diesel costs would also promote rate stability, and provide ratepayers with a predicable path for further rate adjustments. It was noted by Mr. Bowman [T page 368] that "rate stability is not about not changing rates", but about "getting some predictability on a path that you're on towards where you need to go. It's about looking forward[30]".

A second key difference between the Companies, as evidenced in the original Application Options A vs. B as applied to residential customers, relates to share of customer bills ultimately to be affected by runoff rates. In the previously approved rate design, with only two rate blocks, all customers using more than the first rate block were impacted by the runoff rate (i.e, about 30% of non-government residential class monthly bills in Yukon over the year exceed the 1,000 kW.h first block cut off and are currently affected by the runoff rate). With the introduction of a new equalized second block, the share of customer bills affected by the runoff rate declines sharply – under Option A (with the second block cut off at 1,500 kW.h/month), only 10% of non-government residential class bills would be affected by the runoff rate, while under Options B and C (with the second block cut off at 2,500 kW.h/month) less than 2% of these residential bills would be affected by the runoff rate. In response to YUB-YEC/YECL-12(a), YEC stated in this regard that Option A was preferable to Option B in that 10% of customers "is a reasonable proportion of the population so as to make this provision effective."

During the hearing a related "roadmap" concern was noted regarding impacts of the proposed rate design changes on Yukon diesel served communities such as Watson Lake as well as Old Crow. In these communities, diesel is obviously "on the margin" for every kW.h supplied – and normal rate design principles in Canada for such communities, as well OIC 1995/90 directions and past Board decisions, clearly endorse a two block rate structure where the runoff rate reflects the full cost of incremental diesel generation[31]. In contrast, under all of the options under discussion, full diesel costs will not be charged in runoff rates at this time and in addition the new equalized second block will likely permanently reduce bills for customers in these diesel-served communities who consume over the first rate block. As noted regarding the new second block proposed in the Application, the Companies have no choice – this new block must be equalized throughout Yukon [T 419-20].

Based on all of the above considerations, there is a clear need for a transition period plan to re-establish an effective runoff price signal and Option C as recommended is designed to meet this need.

The implications of further delay on the above effective price signal matters in terms of customer response and elasticity was noted in the evidence provided by LE as well as testimony provided by the YEC panel during cross examination (see also CW-YEC/YECL-1-16). Mr. Osler and Mr. Bowman noted in cross examination that while larger industrials are slightly more elastic in terms of their ability to respond to price signals, smaller retail and general service customers are considerably inelastic over the short term (see discussion on transcript at page 317-19); "*Yukon at this time is dominated by residential and general service customers that tend to be inelastic*". However, (at page 320) "*over the longer term,*

[30] At transcript 367-8, it was noted that the Mayo B hearing highlighted the resource planning issues facing Yukon related to reduced available hydro surplus and anticipated future loads coming on the system, "looking forward two years, five years, a decade, there is a need for a plan. And that plan doesn't stop with Option A or Option C. Those are steps towards where that plan needs to go." It was also noted that rate stability would not be provided by "locking in today's rates or putting off this issue longer" – delay would ultimately exacerbate the problem.

[31] Evidence during the hearing confirmed this Canadian practice for remote diesel served communities in several jurisdictions, e.g., NWT as well as northern Manitoba, Saskatchewan and Quebec as well as Newfoundland (T pages 327, 332 (with correction), 480).

somebody may buy a more energy efficient fridge the next time they're swapping out their fridge, but most people don't go out tomorrow and buy a new fridge just because the price of electricity went up a bit. That happens over time." It was noted that proper price signals need to be in place now to help inform the types of decisions with longer term impacts as, "*you don't get to change the situation – after these people have put this heat in their apartments or done other things – on a dime tomorrow morning*".

A third key difference between the Companies relates to the reductions in block one retail rates under YEC's Option C versus no such reduction (at least for non-government residential customers) under Option B. In summary, Yukon Energy understands that normal rate design principles applicable in Canada for similar utilities as well as OIC 1995/90 directions and past YUB decisions all support allowing first block retail rates to reflect the benefits of the lower cost heritage resources. Further, in the current Yukon context where the IER subsidy to first block non-government residential customer use is currently set to expire at the end of next March, these customers in particular may well face a major bill increase within the next six months. Any option (such as Option C with the roadmap as proposed) that facilitates reduction in burden placed on first block rates will help the vast majority of Yukon customers weather the impact of future IER reduction or removal as well as the impact of future general rate increases [T page 350; 361; 373-74; 388-89; 437-38]. These points remain relevant in future with or without any future rebalancing of overall residential rates in the event that the restrictions in OIC 2008/149 in fact end after 2012.

2.3.3 Rate Design Issues Raised by YECL and Others

Yukon Electrical has requested the Board to approve Option B – a retail rate option which introduces a new equalized rate blocks, but does not seek to materially change any bills at this time. Yukon Electrical proposes Option B on the grounds that a runoff rate at 50% of incremental costs is appropriate today, that the runoff blocks in Option B are appropriate in the longer-term as well as today, and that no rate reductions should be provided today to first block residential non-government customer rates. As such, YECL's recommended option directly raises questions about Yukon Energy's recommended approach. YECL notes that Option B's runoff rate is more reasonable due to [see YUB-YEC/YECL-1-24(a)]:

- Limits related to inter-class rate balancing (i.e., OIC 2008/149);
- Reducing rate shock impact across customer classes;
- Avoidance of undue discrimination; and
- Allowing further adjustments to rates when more accurate signals showing how costs move with usage is identified.

YECL in its evidence, and other parties through IRs and cross examination, have also directly raised issues regarding Yukon Energy's proposed retail rate design. Aside from questions about the need to move forward today on these matters, these major issues with Option C can be summarized as follows:

- **Runoff rates as proposed are excessive** - The runoff rates (includes 3rd block general service rates) as proposed by YEC are argued to be "excessive" and "inequitable", resulting in unnecessary rate shock [T504; 612-14].

- **Rates as proposed are unduly discriminatory** – YEC's proposal is argued to not treat fairly all customers within a class (relates to rate reductions for some and rate increases for others) [T 503-06;510-12; 516; 536-7; 613; 62].

- **Unacceptable revenue variability** - YECL is concerned that YEC's proposed increases in rates as between rate blocks will result in unacceptable revenue variability or instability for YECL, noting that it is a "fixed cost" utility [T 507; 513; 541; 607].

- **Rate reductions today for residential first block send wrong price signal** – This YECL issue is apparently related to the OIC that prevents inter-class rebalancing to bring residential R/C ratios closer to unity [T 506; 508; 517-8].

- **Delay rate changes until later** – YECL has argued that, beyond what is proposed in Option B, rate changes are not required until diesel generation is forecast on the hydro grid for a significant duration within the forecast period (such that utility diesel-based generation costs would change with usage) [T 506; 617; 626-7].

Yukon Energy notes at the outset that the fourteen year period the fourteen year period that has passed since the last time the Board addressed rate design matters. As a result, Yukoners collectively face today the need to deal with a multitude of major changes that have already occurred (including the "material disconnect" between incremental costs incurred and average rates charged based on heritage costs) as well as the major changes that are known to be coming by 2012. [YECL T610-11;YEC Exhibit B14,page1]

In 1997-98, the Board and parties did not anticipate this extended hiatus from rate design deliberations – there was a reasonable expectation that these matters would be addressed again as soon as 1999 [T322]. Now that the first full Phase II hearing has been held in Yukon, it is time to address in a material way the major issues and changes that confront electric rates in Yukon today. It would not be prudent to propose that these matters now be deferred for resolution to some future GRA hearing.

In proposing its Rider D Application, Yukon Electrical argues for action today to change what is in place based on the relevance of the "material disconnect" since the last GRA noted above between incremental costs and average costs charged based on heritage costs. Yukon Energy's comments on Rider D are addressed separately – but with regard to retail rate design, in YEC's view the "material disconnect" noted by Yukon Electrical in that matter underlines the need to make measureable progress towards addressing retail rate design issues today.

As noted in cross-examination of the YEC panel, this disconnect is not restricted to the hydro zone but exists in Watson Lake and each of the other diesel served communities in Yukon (where every kWh generated as supplied comes from diesel at high incremental costs [ranging from 27.23 cents/kWh in Watson Lake to 61.54 cents/kW.h in Old Crow]. Currently these communities are served at rates well below the cost of diesel and the incremental revenue for every kW.h sold under the current or proposed rates (and especially under Option B) remains substantially less than the full incremental cost of diesel. The YEC panel noted that disconnect results in material rate design concerns that cannot be addressed in one Application at this time – however, this Application is an opportunity to take initial first steps towards addressing the issue.

Yukon Energy comments as follows with regard to the specific positions advanced by YECL as noted above:

1. **Limits related to inter-class rebalancing – rate reductions today for residential first block send wrong price signal**

This concern apparently relates to the low R/C ratio for the residential non-government class (it has been approximately 80% since 1996/97), and the idea that any rate reduction to these first block customers today is sending the wrong price signal by failing to warn that (when revenue rebalancing among classes can occur) these rates will all need to go up materially to result in an acceptable R/C ratio [T506].

Yukon Energy sees no merit in the argument that residential R/C ratio issues that have been longstanding (i.e., this is one of the few issues where no material change has occurred since 1996/97) should have any bearing on the rate design changes to be addressed today. If and when the Board can address the residential R/C ratio matter, the Companies will may need to address a long-term plan to deal with this matter as it affects rates throughout the residential class. This matter is not being addressed in the current hearing by any party. Indeed, the issue of IER subsidy removal by the end of March 2011 is far more timely an issue which, if it occurs in whole or in part as announced, will have a major impact on increasing the bills of all non-government residential customers (and particularly those in the first rate block).

On the specifics of rate rebalancing among retail classes, apportionment of total costs of service to ratepayers cannot be satisfied at this time due to the effects of OIC 2008/149 which prohibits rate rebalancing that would result in differing percentage rate changes for retail customer classes. Rebalancing between retail classes cannot currently be undertaken until after the OIC expires on December 31, 2012. As noted in the hearing by both the YEC and YECL panels, neither the Companies nor the YUB can predict at this time with certainty when OIC directions will allow for rebalancing between residential non-government and general service government classes.

2. **Rate shock (runoff rates as proposed are excessive) and Revenue Variability**

YECL argues that the runoff rates (includes 3rd block general service rates) as proposed by YEC are "excessive" and "inequitable", resulting in unnecessary rate shock [T504; 612-14]; in this regard, YECL says that anything in excess of 10% change would be considered rate shock [T574]. YECL further argues that YEC's proposed increases in rates as between rate blocks will result in unacceptable revenue variability or instability for YECL, noting that it is a "fixed cost" utility [T 507; 513; 541; 607].

The evidence shows that runoff rate increases under Option C as modified in YEC's recommendation will not have bill impacts in excess of 10%, as compared with current bills (see Attachment A):

- For any residential non-government customer using less than 3,000 kW.h per month (accounts for over 99% of annual customer bills in hydro zone and for essentially 100% of large diesel zone bills).

- For general service non-government customers using slightly less than or slightly more than 20,000 kW.h per month although a precise number of affected customer bills has not been determined, it is likely well below 2% of the annual total bills for this class).

Given the adoption of minimal second block rate increases in YEC's Option C (these increases are either the same or similar to Option B), Yukon Energy cannot see any apparent basis for any reasonable concern about revenue instability as between first and second block rate levels. As for the gap between second block and runoff rates, given the very small share of customers and use currently covered in the runoff block Yukon Energy cannot see any reasonable basis for revenue stability concern.

In summary, Yukon Energy sees no merit in the concerns about rate shock or revenue variability as regards Option C.

Yukon Energy notes that the following significant steps have already been adopted in the rate proposals being advanced to address concerns related to rate shock and the need to take a stepped approach towards meeting rate objectives required by OIC and normal rate design principles.

- **Runoff Rates based on percentage of incremental cost – not full incremental cost** - While it is recognized that current runoff rates based on 1996/97 fuel prices no longer practically provide for economy and efficiency as required by OIC 1995/90, runoff rates based on 100% incremental diesel costs cannot be practically achieved at this time without raising severe rate and bill impact concerns. As noted in cross-examination, YEC's objective since filing the 2008/2009 GRA has been to make material required progress towards addressing the disparity between current approved runoff rates (based on 1996/97 diesel prices) and runoff rates based on materially higher incremental diesel costs. No rate design option proposed today moves the runoff rate to 100% incremental diesel costs.

- **Blocking structure ensures that rate impacts based on incremental costs are only applied to very high levels of usage on the system at this time** - The premise for providing an additional equalized rate block (a provision included in every rate proposal advanced for review in this process) is to address rate stability/rate shock considerations related to the material increase in incremental costs compared to current rates. As noted, setting the second block cut off at 2,500 kW.h for residential customers meets the objectives of ensuring that material diesel costs to be incurred on the system are recognized in today's rate structure. This blocking structure may be contrasted with the current two-block structure that would see incremental price signals start at 1000 kW.h for residential, and with Option A (and LE's Preferred Option) which would see incremental price signals start at 1,500 kW.h.

In addressing rate design, Yukon Energy recognizes the concerns raised regarding rate shock, but has noted that if no material progress is made at this time to move runoff rates directionally towards better reflecting incremental costs on the system the problem will only be more pronounced the next time the Board reviews this issue.

Further, as discussed during the hearing process, the concerns regarding rate impacts noted by YECL must be considered in the context of rates in effect over the past few years and rates implemented in other jurisdictions:

- **September 2008 Monthly bills comparison** – The September 2008 monthly bill comparison was provided in Exhibit B-11 and B-12 and is included in Attachment A. This provides a useful benchmark and illustrates the rates in place and recently paid by ratepayers prior to YEC filing in

2008/2009 GRA. One important consideration is that the YEC 2008/2009 GRA resulted in an across the board rate decrease of 2.47%. Thus, as shown in Attachment A, for this and other reasons monthly bills are currently lower than was experienced in September 2008; however, under Option C as modified and recommended herein, residential non-government customer bills would be lower than in September 2008 for almost all customers (i.e., a saving is shown for all bills up to at least 3,000 kW.h/month).

Contrasting proposed rates with rates in place in September 30, 2008 raises concerns with the runoff rate proposed by YECL in its Application. As noted by Mr. Maissan in cross-examination, in the 2008/2009 Application the runoff rate for residential customers in Hydro and Large Diesel rate zone communities (including all riders) was 14.39 cents/kW.h. The runoff rate proposed in YECL Option B is 13.99 cents/kWh. Given the overriding requirement to begin to restore economy and efficiency price signals after 14 years without adjustment, to set a runoff rate that effectively reduces the price signal (when the reality is that diesel prices are considerably increased and material baseload diesel is expected to be incurred on the system in the next few years) sends a perverse price signal to ratepayers in these zones.

- **Runoff rates implemented in other jurisdiction** – As noted in discussion during the oral hearing, stepped rate structures are in place in a number of jurisdictions to promote both efficient price signal for higher levels of use and to address revenue stability concerns. In these other jurisdictions with diesel-served communities, runoff blocks are routinely set to reflect even higher incremental costs (between 30-40 cents/kWh) than proposed in any of the options before the Board in this process (T332).

3. Under Discrimination and Inconsistent Price Signals

YECL argues that YEC's proposal does not treat fairly all customers within a class (relates to rate reductions for some and rate increases for others) [T 503-06;510-12; 516; 536-7; 613; 62]. In this regard, YECL raised concerns that applying runoff rates based on 70-80% of incremental costs may be considered discriminatory towards high consumption users while rewarding or encouraging inefficient use in the first block. YECL notes high volume users (in the 3000 kWh/month range) may in fact be more efficient than customers in the 1000 kWh/month ranges and asserts it is unfair to penalize these customers while crediting smaller inefficient customers.

Yukon Energy sees no merit or basis for this concern. Retail rate design in Yukon and elsewhere has long recognized that it is not unfair or unduly discriminatory (or of concern regarding sending inconsistent price signal) to charge, within a rate class, lower first block rates to reflect heritage cost savings and higher subsequent block rates for increased levels of use (with runoff rates in diesel served areas, and now often in hydro served areas, reflecting current incremental costs [in terms of generation costs or revenue foregone]). Further, in Yukon this matter is settled under policy direction to the Board (OIC 1995/90, which does not have any expiry date).

Added comments are provided below:

- **Economy and Efficiency in Yukon Rate Design** – YECL in response to YUB-YEC/YECL-1-22(a) notes it "has been unable to determine from past Yukon proceedings the definition of "economy and efficiency". [See also T 607-8; 617-8].

  Appendix 7.1 of the Application, Attachment C, provides the 1992 Report on Cost of Service and Rates Charged to Customers in Yukon. This report sets out the definition adopted by the YUB in 1992, that has subsequently been reviewed in Board Orders (1993-8 and 1996-7). The Board defined economy and efficiency as the optimal use of electricity over time where consumers are making rational decisions regarding the future and current use of electricity (at page 37). The Board recommended that runout rates for all zones be adjusted to reflect short run incremental costs. Economy and efficiency has not historically been related to cost of service or cost causation principles.

- **A stepped rate structure with a higher runoff block based on incremental diesel costs and lower heritage block rates has been in place in Yukon since the early 1990's** – At no point in this period has this form of rate been considered discriminatory or to provide unfair price signals to small energy users at the expense of larger users. Further, as noted above, this type of rate structure has been adopted in jurisdictions throughout Canada – and in most of those jurisdictions the disparity between the first block rate and the runoff block is more exaggerated than any option before the Board today. YEC's panel in discussion in cross examination [T 329-33] noted two distinct philosophies regarding how diesel communities were treated in northern Canada: (1) view that each community should pay the cost to serve that that community; (2) as part of broader public policy, the view that rates in a jurisdiction should be equalized to a certain level, beyond which there should be price incentives (to reflect economy and efficiency).

- **The premise for the blocked rate structure with a higher runout block and lower heritage block rates is based on long standing government policy direction in Yukon** - The current blocking structure in Yukon reflects government policy in place since the late 1980's and adopted via OICs (OIC 1988-150; OIC 1991/62 and current rate policy OIC 1995/90). In essence, rate policy OIC's historically and today require that non-government residential and general service customers in Yukon receive a specified level of energy (up to at least 1000 kWh for Residential and 2000 kWh for general service) at an equalized lower cost heritage rates, with a runout or runoff rate for higher levels of use (that may vary by zone) based on incremental costs of diesel to provide economy and efficiency (required to be set above 1000 kWh and 2000 kWh respectively).

  The broader policy rationale underlying this rate structure was discussed by Mr. Bowman [T330]:

  > "The key element of Order-in-Council 1995-90, the same as you'd find in most jurisdictions that have heritage hydro assets is to say we're going to take the benefit of these lower cost resources and share those throughout the territory. Manitoba does that with its levelized rates. Newfoundland does that this with its hydro system, even for people who are not connected to the hydro system, and we're going to do it for a reasonable level of consumption. It's not unlimited, we're not averaging everything

together. We're taking a group of core hydro assets and we're allocating the benefits of those lower-cost resources to everyone for a reasonable level of consumption. Above that, they're going to reflect economy [and] efficiency. So that's where the premise comes in; that it is the residual after the point that you've got a first block of an allocation that gives everyone a reasonable share of the hydro, whether they're in Old Crow or here."

- **This Stepped rate structure also reflects the cost environment in a jurisdiction with two tiers of generation** - The Yukon power system is fundamentally comprised of two "tiers" of generation [see discussion in CW-YEC/YECL-1-13]:

    - Low cost renewable heritage generation, which has a limited quantity available, and is being effectively fully consumed at the load levels existing or forecast in the near future.
    - High cost, GHG emitting diesel generation which will become an increasingly prominent portion of grid supply. New renewable developments, such as new hydro and wind, may become available to offset portions of this diesel generation, but are likely to be significantly higher cost sources of supply than heritage generation and will not all forecast baseload diesel generation.

  The framework reflected in OIC 1995/90 is found throughout Canada (T 332): "*in Saskatchewan, if you were in – if you were [not] in a interconnected system, you get 650 kilowatt hours at about 10 cents, and beyond that, you're paying 40 cents a kilowatt hour for your supply. If you're in Quebec, you get about 900 kilowatt hours at 5.4 cents, and beyond that, you're paying 31 1/2. And I can go through more examples, Manitoba, Northwest Territories. But they're designed around the premise that there's a reasonable allocation of hydro, and beyond that, you're paying something that reflects the incremental supply and the overall incremental cost drive. Not tied to utilities revenues requirement, not tied to average supply; but what happens when you turn the switch on and off? What is the cost you're driving?"*

  Beyond policy considerations, there are also underlying cost rationales and basis for the lower first block energy rate. Since 1997, the cost of incremental supply has increased; however, at the same time, the costs of the heritage supply have gone down (as assets have depreciated). Until recently there has not been material investment in generation-related assets (with some recent investment in transmission assets helping to supply a larger, non-industrial load as well as recent new industrial connections).

4. **Delay rate changes - Further Adjustments Can Be Made When Diesel Use is Being Incurred**

YECL has argued that, beyond what is proposed in Option B, rate changes are not required until diesel generation is forecast on the hydro grid for a significant duration within the forecast period (such that utility diesel-based generation costs would change with usage) [T 506; 617; 626-7]. YECL asserts that at this time only a modest change to the residential blocking structure and the prices customers pay per energy block should be made, and any material changes should wait until such time short term diesel generation becomes more prominent. YECL notes (in response to YUB-YEC/YECL-1-24) that "the intention of charging an incremental runoff rate as contemplated in the Application is to properly reflect

the incremental costs for new generation that are required to meet today's demands" and "YECL does not consider it appropriate to be providing phantom price signals to customers when the short-run incremental costs are not forecast to change". YECL noted in interrogatories (and in discussion on the transcript at page 562) that diesel on the margin is not forecast to occur for some time – consequently, today's ratepayers should not be required to incur costs that are not presently being incurred or expected to be incurred on the system. YECL's views on the timing of when material diesel will be on the system is inconsistent (at transcript pages 603-4, YECL notes that this could occur anywhere between two months or many years; at page 618, YECL guessed that diesel generation on the margin may occur within two years).

Yukon Energy does not agree with YECL on this matter, and considers that YECL's position fails to properly consider the developed rate policy in Yukon relating to the underlying rationale and basis for the runoff rate block structure adopted and the current and anticipated cost environment on the system.

- As noted in cross-examination of YECL, material diesel is already being incurred in the system – at transcript page 555 it was noted that YECL's approved diesel fuel cost is approximately $5.397 million out of a total YEC/YECL rate revenue requirement of $50.833 million (it was further noted that YEC's approved diesel fuel expense was $443,000). In sum, approximately 10% of the approved consolidated rate revenue requirement is made up of diesel fuel costs. As Mr. Maissan pointed out, these costs are not "seldom incurred" but "are occurring right now" in diesel communities.

- Further, in response to YUB-YEC/YECL-1-15: It is noted that Board's May 17, 2010 Report to the Minister on the Mayo B Part 3 Application recommended that the Mayo B Project proceed as proposed for in-service by 2012, and that this project is premised on Mayo B being able to displace diesel generation, yielding cost savings and other benefits from displacing diesel. This IR response also noted that, during the Mayo B proceeding, further analysis of possible flow conditions indicates that at the 2009 GRA approved load levels (approximately 325 GW.h YEC WAF hydro generation), no diesel would be required in 90% of cases (the wetter years on record), while in the remaining 10% of cases between 25 and 50 GW.h of diesel could be required (i.e., in the driest years that would be expected to arise). Over a long-term average, a load that required 325 GW.h of YEC baseload dispatchable generation (i.e., net of Fish Lake and wind generation) would be supplied by an average of approximately 321 GW.h of hydro and 4 GW.h of diesel." In this sense, diesel costs related to the 4 GWh of diesel in low flow conditions should have been included as a component of YEC's costs in 2009 and similarly will need to be considered a component of future revenue requirements.

- YEC updated the status of Mayo B, Carmacks-Stewart and the Alexco PPA, as well as the continued expected need for diesel on the margin on the hydro grid by 2012, at transcript pages 470-73].

For the smaller retail classes, the acute problems related to the gap between diesel prices and average rates make it difficult to implement any adjustments to incremental rates when diesel is on the margin without adverse rate impacts and bill impacts for customers. By contrast, to mitigate concerns related to rate shock retail rate adjustments must be addressed over time. Since diesel is

forecast to be on the margin in the 2012 timeframe for the hydro zone (as well as being on the margin already for all other zones), in order to make the required progress for residential and general service classes, a material step towards incremental costs must begin today[32].

[32] In discussion in cross examination [T pages 305-306] the stepped rate structure for industrials was contrasted with the retail runoff rate. It was noted that the blocked rate structure for industrials does not present the same type of timing issues for implementation present for smaller retail classes. In essence, the industrial rate includes a provision for a runoff block for industrials that can be triggered when diesel is on the margin. “The only difference between the smaller classes and the larger classes is that when you're dealing with these small number of very large customers, your rate -- your approach is somewhat more fine-tuned and customized and refined so that rather than having this triggered today, you can leave to a more sophisticated customer a better opportunity to have this implemented, as we have now, an opportunity to come back to the Board and have this implemented, closer to when diesel is being used. With their smaller customers, it's somewhat of a different trajectory. You need to focus on the fact you're dealing with an overall class, a large number of customers, and the fact that the power bill is not something that people spend a lot of time thinking about on a typical basis. If you're going to start to move the rate structure towards a certain direction, you have to not wait till you have diesel being burned and all of a sudden trying to turn things on a dime. You work your way towards that, as proposals in this GRA set out. But both -- I don't want any misstatement on the record that in some economy efficiency doesn't matter for the larger customers. It's there in exactly the same provision.

3.0 YECL'S SEPARATE RIDER D APPLICATION

3.1 OVERVIEW OF YUKON ENERGY ARGUMENT

Yukon Energy's Argument on this matter is directed to Yukon Electrical's Rider D Application which requests [Ex. 20, page 3, lines 19 to 23] "...approval to implement the new Diesel Generation Energy Cost Recovery Rider as a placeholder to flow through the actual cost of purchase power for the hydro zone during the period when diesel generation is on the margin that has not been forecasted..."

For the reasons summarized below and elaborated on in the subsequent Argument, Yukon Energy recommends that the Board not approve the Rider D Application or any modified version of the Rider D Application:

- **Placeholder Rider D that YECL has filed should not be approved** – The Rider D Application as filed is only a "placeholder" and as such;
    - Provides nothing useful or meaningful for the Board to review or approve at this time;
    - There is no need for the Board to consider this matter today; and
    - Any approval of the Rider D Application may only serve to fetter the Board in its review of these matters if and when so required in future proceedings.
- **Broader issues need to be addressed before any such implementation mechanism is considered** – Given the material disconnect between the cost of diesel and the revenue both utilities collect when diesel is on the margin -- whether that be in the hydro zones or diesel served communities -- the Board should direct the Companies, prior to any future GRA by either Company, to work together diligently to address diesel costs variances related solely to unforecast load growth variance in Yukon, focusing on identifying when and how it would be appropriate to adopt deferral account or rider mechanisms that would avoid or defer the need for new phase I GRAs.

Yukon Energy has addressed separately in Section 2 of this Argument, as a matter of joint agreement, any amendments to the ERA provisions in Rate Schedule 42 that were proposed by Yukon Electrical in the Rider D Application.

Placeholder Rider D that YECL has filed should not be approved

Unlike Rider F charges or refunds applicable to diesel fuel price variances (where the Companies can proceed, based on OIC 1995/90, to adjust the rider without seeking Board approval), the creation of any specific Rider D as well as any specific charge or refund pursuant to such a new rider will require a specific future Rider D application to, and approval by the Board before it can be implemented.

In this context, no specific Rider D charge or refund rate has been filed by YECL in this proceeding for the Board to approve. Further, no specific mechanism to assist implementation of a future Rider D application has been filed by YECL. All such matters have been deferred until YECL needs to file an application to approve a specific charge or refund rate.

Accordingly, YECL's Rider D Application provides nothing useful or meaningful for the Board to review or approve at this time, there is no urgency for the Board to consider this matter today, and any approval of any such Rider D Application may only serve to fetter the Board in its review of the matters that are underpinning the deferral account in future proceedings.

Relevant evidence and argument in support of these points are reviewed below:

- **No forecast basis to consider Rider D (or any other such mechanism) today –** Rider D as proposed by YECL will only arise for meaningful consideration at such time as the YEC wholesale Rate 42 ERA mechanism results in a material charge or refund to YECL related to a variance in YECL's actual wholesale purchases relative to an approved GRA forecast when diesel is on the margin[33] (which wholesale purchase variance could potentially arise from either a variance in YECL's loads generally or a variance in its self generation forecast[34]). Based on the evidence, there is no forecast basis to consider today Rider D or any other mechanism to dispose of any potential future deferral account balance related to YEC Rate 42 ERA charges or refunds to YECL:

    - With regard to the hydro zone, diesel is not forecast to be on the margin in any month during the 2010 test year. YEC's evidence in the hearing, based on its evidence in the recent Mayo B Part 3 hearing, is that diesel is expected to be on the margin in the hydro zone by 2012 [Transcript vol 2B, page 398 line 4 to 16].
    - Accordingly, there is no forecast basis or need to consider today Rider D or any other mechanism to dispose of any potential future deferral account balance related to YEC Rate 42 ERA charges or refunds to YECL.

- **No attempt to address Rider D mechanics prior to end of oral hearing** – YECL confirmed at the hearing that, prior to the end of the oral hearing, there has been no attempt to address the mechanics of Rider D. The evidence is that YECL expects that the mechanics of Rider D would be developed for approval in a subsequent Rider D application when specific balances to charge or refund exist [Transcript, vol 3A, page 594, lines 3 to 16; page 602 line 24 to Page 603 line 8]. In Exhibit B26 response regarding Undertakings No. 5 and 6 (page 6) to Mr. Landry seeking clarification of the mechanics, YECL further confirmed that the details of the Rider D mechanism and the calculation of the rider amount "will be explained in detail in a [future] Rider D application." Absent a proposed rate or any related proposed mechanics to determine such a rate, there is nothing meaningful or useful to consider today, and therefore the relevant matters are best deferred until such time as YECL brings forward a more detailed and complete application.

- **Issues related to Information Filed after the Oral Hearing** – After the oral hearing, in its Exhibit B26 response regarding Undertakings No. 5 and 6 to Mr. Landry in Volume 3A of the Transcript, YECL provided further information on the rate adjustment formula (with examples)

[33] This variance must occur during months when diesel generation is on the margin in the hydro zone at normal long-term average water flows (i.e., diesel generation must be required to serve incremental energy loads on this system during a month, aside from peaking capacity requirements or requirements related to variability in water flows).

[34] If diesel is on the margin, variances related to YECL's hydro generation at Fish Lake may also be addressed separately by the DCF (compensating YECL for related diesel generation impacts on either its own WAF diesel generators or ERA related impacts related to power purchased from YEC.

that it would propose to apply at the time of a future Rider D application to take into account YEC's approved ERA incremental diesel generation cost or rebate as well as "YECL retail customers incremental base rate revenue associated with recovery the production function, which occurred during the ERA period" (which YECL's example assumes is equal to only the approved base wholesale energy rate). After review of this response, Yukon Energy notes the following:

- The so called "Rate Adjustment" mechanism and related example provided in this Undertaking attempt to address methods as to how amounts should be determined for any potential deferral account rather than the mechanics for any future Rider D, i.e., the Rider should be to recover or rebate amounts in an approved deferral account and should not involve adjustments to such amounts, and the formula and examples all go solely to determination of such amounts. On this basis, the information goes beyond the scope of the matters under review in the current proceeding.
- The proposed deferral account calculation as described in this Exhibit B26 response would lock in YECL's profit on each kW.h of added load when actual hydro zone loads exceed YECL forecasts, i.e., the revenue offset proposed ignores all YECL revenues from such added sales other than an amount equal to its then average base energy wholesale rate. No such mechanism ever applied in the past dealings with the ERA (where all of the relevant generation costs related to a retail load forecast variance continued to flow through only to the utility serving that retail load and not to Yukon retail customers), and no such mechanism was suggested or addressed in any way in YECL's proposal in its 2008-2009 GRA request "to continue utilizing" a Purchase Power deferral account [Exhibit B20, page 11 copy of page 1-4 of YECL GRA], which deferral account YECL has acknowledged in the current hearing did not exist prior to Order 2009-2 [Transcript vol 3A, page 578 line 3 to line 10; page 583, lines 11 to 15; page 585, lines 13 to 20].
- The information provided in Exhibit B26 deals for the first time with key and fundamental issues relevant to the deferral account and YECL's Rider D Application It was provided only after close of the oral hearing, and thus was not subject to any cross examination or review. Therefore, not only does this information highlight the need to review in a much more substantive and thorough manner this whole issue, it must be given no material weight by the Board as to what the appropriate mechanics should be for either any potential deferral account or Rider D in the future.

Accordingly, this proposed mechanism as set out in Exhibit B26 should not be approved by the Board.

- **Rider D as applied for "Placeholder" should not be Approved** - Yukon Electrical's Rider D Application request [Ex. 20, page 3, lines 19 to 23] is only for "...approval to implement the new Diesel Generation Energy Cost Recovery Rider as a placeholder to flow through the actual cost of purchase power for the hydro zone during the period when diesel generation is on the margin that has not been forecasted..."

  The Rider D Application attaches only a "placeholder" Rider D rate schedule. It does not propose a specific rate or mechanics for the Board to approve beyond stating that any such rider when approved would be a "surcharge/(refund) to collect wholesale purchase costs incurred when diesel generation on the margin for the Hydro zone is greater or less than the forecast as billed from YEC per the Energy Reconciliation Adjustment set out under Rate 42", and would apply "to

all classes of service" throughout Yukon for both Companies excepting only Rate Schedule 32 Secondary Energy and Rate Schedule 40 Maintenance Energy.

As previously noted, not only does the placeholder Rider D not provide a rate mechanism to determine a rate YECL now seeks approval utilizing new key details that would have been relevant in the Board's review of YECL's 2008-2009 GRA application "to continue utilizing" a "Purchased Power deferral account":

- YECL's 2008-2009 GRA application and evidence referenced only "the continuation of a deferral account to flow through increases or decreases to purchased power rates" [Exhibit B20, page 20 as reviewed at Transcript vol 3A, Page 581 line 18 to page 582 line 13; this is consistent with the YECL GRA application at pages 1-4 and 3-2 as reviewed in Exhibit B20, pages 11 and 16].
- Now, in this Rider D Application, YECL is somewhat more specific stating that the proposed rider would "collect wholesale purchase power costs incurred when diesel generation is on the margin in the Hydro zone is greater or less than the forecast as billed from YEC per the Energy Reconciliation Adjustment set out under Rate 42".
- The reference to "diesel generation" as such being greater than forecast does not accord with either the wording set out in the ERA or in the earlier 2008-2009 YECL GRA. Further, this new wording makes no reference to a "deferral account to flow through increases or decreases to purchased power rates" (what YECL stated in its prior application), nor does it reflect the reality that any such deferral account determination would need to consider matters beyond merely a change in "rates". The ERA essentially relies on a fixed Board approved "rate" and, when diesel is on the margin, simply addresses a variance in YECL's actual purchase load requirements from what was in the approved GRA forecast used to determine the wholesale base energy rate for Rate 42. Further, as reviewed in Exhibit B26, the deferral account determination would also need to address matters beyond any YEC's ERA flow though, i.e., YECL revenue offsets related to the load variance from forecast ***must also be addressed*** (this point is simply not appropriately undertaken in the description provided in Exhibit B 26). In short, the wording on this matter in the placeholder Rider D Application does not adequately address the amounts to be determined for flow through to customers.
- The placeholder Rider D Application also presumes, without discussion of any options, that the existence of a Purchase Power deferral must in fact lead to the approval of the automatic establishment of a Rider mechanism that charges or rebates a fixed amount per kW.h to all retail and industrial customers in Yukon. By taking this approach, the Rider D Application will ensure that YECL can avoid the need to address load forecast variance derived ERA cost changes through a normal Phase I GRA process [YECL notes that without a deferral account, YECL would ultimately need to go into a Phase I application to recover these costs in some fashion –Transcript vol 3A, page 553 line 15 to page 554 line 8]. YEC's experience has shown that there need be no such automatic connection between a deferral account (e.g., the Faro Mine Dewatering deferral account) and the need for a new rider mechanism, and confirms the benefit of keeping available other options to address the amounts in such accounts (including the need for Phase I applications to address major changes in forecast conditions related to loads and system generation costs).

- The Application is also not consistent with the Companies' initial proposal to establish the ERA, as set out in the joint 1993/1994 GRA filed March 1993 which stated at page 3-9 that "the new wholesale rate will cause adjustments in transfers between YECL and YEC that balance the changes in revenues and costs caused by sales fluctuations and will have no effect on retail rates" [Exhibit B20, page 26]. Further, such a rider to address YECL cost changes due to sales load forecast variances is not appropriate based on the principles as reviewed by YECL in its 2008-2009 GRA hearing [Exhibit B20 at page 29 includes transcript from page 368 of that hearing where YECL explained, at lines 7 to 19, why a deferral account would not be appropriate for sales forecast variances, i.e., YECL's evidence at the hearing was that a sales forecast is 'reasonably forecastable' and therefore the effects of such variances are not appropriate for a deferral account]. YEC testified that, under conventional thinking a deferral account related to YECL cost impacts from its sales load forecast variance (as would occur in this instance) would be part of the utility risk that they take on to get a return [Transcript vol 2B, page 417 lines 6 to 9]; YEC also noted that all variances in diesel generation cost due to load forecast variance are already fully born by the supplying utility in each diesel served community and further YEC continues to fully bear risk of variance in costs related to all of its retail and industrial loads [Transcript vol 2B, page 449 line 22 to page 451 line 6; page 454 line 22 to page 455 line 1].
- Finally, the specific proposal to charge all customers other than secondary energy customers is not consistent with OIC 2007/94 in that no such rider can be charged to Industrial Rate 39 customers at this time.

In consideration of all of the above, the applied for placeholder Rider D should not be approved by the Board.

Broader issues need to be addressed before any such implementation mechanism is considered

YECL has argued that it requires a new Rider D today because, unlike the earlier 1990s period when the ERA applied when diesel was on the margin and "there was a small difference between the cost and the revenue", there is today a "significant and material disconnect between the amount of revenue that we see or we get from our customers and the amount of costs that we would incur as a result of this incremental cost of diesel". More specifically, "The problem that we have right now is that the incremental cost of diesel is sitting at 27 cents per kilowatt hour, but our incremental revenue is substantially lower than 27 cents per kilowatt hour." [Transcript vol 3A, page 610 line 1 to page 611 line 6].

Yukon Energy recognizes the "material disconnect" referenced by YECL, and has stated in this regard (as part of the broader issues before the Board today) that the key challenge faced today in addressing retail rate design is that over the 14 years since the Board last addressed retail rate design issues the gap between incremental costs per kW.h and heritage costs per kW.h has greatly increased [YEC Rate Design Panel Opening Comments, Exhibit B14, bottom of page 1].

The reality remains, however, that this "material disconnect" exists in full force for YECL today in Watson Lake and each of its other diesel served communities, i.e., **every** kW.h supplied in these communities comes from diesel at the high incremental costs per kW.h noted (from 27.23 cents in Watson Lake to 61.54 cents in Old Crow), while the amount of incremental revenue that YECL gets from its customers

under the rates proposed in this hearing (and especially the rates under Option B as proposed by YECL) for **every** kW.h sold remain substantially less than full incremental cost of diesel. And it is apparently well understood that there is no reasonable basis to resolve this "material disconnect" in the today's diesel served communities by establishing any form of new deferral account or rider to shift sales forecast risk from the YECL to the customers throughout Yukon.

Similarly, a new deferral account or rider is simply not an appropriate solution to the "material disconnect" issue when it emerges in the hydro zone. There is no reasonable basis to implement a deferral account or rider solely to protect one Company in one rate zone. If such a concept is to be pursued, it should only be pursued as one element of an overall rate and revenue requirement strategy to address new Yukon realities in relation to both load growth and the need for diesel generation. The Companies must look beyond the issues facing one Company in one rate zone to the issues and options in the broader context of all rate zones and both Companies [Transcript vol 2B, page 416 line 22 to 24].

In this context, a deferral account and rider mechanism as proposed in the YECL application would implement a new set of rate principles in Yukon that would provide that load risk on WAF will be borne by all Yukon customers (and not the utility); as reviewed earlier [35], this is a major shift in risk from utilities to customers beyond what normally exists, and such a shift requires further consideration and deliberation to ensure that both matters Companies and all Yukon customers, whether served on WAF or not, are treated fairly.

Given the realities of future load growth and diesel generation it is indeed relevant to examine options whereby load variations lead to flow through to customers as opposed to leading to a need for expensive new GRAs [Transcript vol 2B, page 415 line 13 to line 25]. If parties want to avoid expensive hearings, these issues and options should be considered in a much broader context to see if and when a deferral account related to specific load variance risks may have merit [Transcript page 416 line 18 to line 25].

Accordingly, based on the above and in the event that the Board sees merit in addressing these issues, Yukon Energy recommends that the Board direct the Companies, prior to any future GRA by either Company, to work together diligently to develop an efficient and effective joint proposal to address diesel costs variances related solely to unforecast load growth variance in Yukon, focusing on identifying when and how it would be appropriate to adopt deferral account or rider mechanisms that would avoid or defer the need for new phase 1 GRAs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

October 22, 2010

P. John Landry
Counsel for Yukon Energy Corporation

[35] Earlier review of what the Companies stated in initial joint filing to establish ERA; review of YECL evidence at 2008-2009 YECL GRA hearing as to why a deferral account would not be appropriate for sales forecast variances.

ATTACHMENT A – OPTION COMPARISON WITH MODIFIED OPTION C

Table 1 – Comparison of Options (Residential Non-Government) with IER – Hydro/Lg Diesel

Table 2 - Comparison of Options (Residential Non-Government) with IER – Small Diesel

Table 3 - Comparison of Options (Residential Non-Government) with IER – Old Crow

Table 4 - Comparison of Options (Residential Non-Government) without IER – Hydro/Lg Diesel

Table 5 - Comparison of Options (General Service Non-Government) – Hydro/Lg Diesel

Notes:

- Tables 1, 2 and 3 same as provided in Exhibit B-21, except for modification of Option C block 2 rate (reduced from 13.75 cents to 13.00 cents per kW.h).
- Table 4 same bills as provided in Exhibit B-14, Table 2, except for modification of Option C block 2 rate (reduced from 13.75 cents to 13.00 cents per kW.h).
- Table 5 same bills as provided in Exhibit B-14, Table 3 (modified Option C has no chane to Option C general service rates).

Table 1 - Comparison of Options (Residential Non-Government) with IER

Hydro/Lg Diesel

	12519 bills (2007) Hydro Zone	671 bills (2007) Large Diesel Zone	present monthly bill	Sep-08 monthly bill	change		Option A monthly bill	change		Option B monthly bill	change		Option C-Modified monthly bill	change		LE Preferred Option monthly bill	change	
100			$25.10	$26.17	$1.07	4.3%	$23.80	($1.29)	-5.2%	$25.10	$0.00	0.0%	$24.89	($0.21)	-0.8%	$23.92	($1.17)	-4.7%
200			$34.89	$38.66	$3.77	10.8%	$32.30	($2.59)	-7.4%	$34.90	$0.01	0.0%	$34.47	($0.42)	-1.2%	$32.54	($2.35)	-6.7%
300	8717	501	$44.69	$51.15	$6.47	14.5%	$40.80	($3.88)	-8.7%	$44.69	$0.01	0.0%	$44.05	($0.64)	-1.4%	$41.16	($3.52)	-7.9%
400	bills	bills	$54.48	$63.64	$9.17	16.8%	$49.30	($5.18)	-9.5%	$54.49	$0.01	0.0%	$53.63	($0.85)	-1.6%	$49.78	($4.70)	-8.6%
500	cum 70%	cum 75%	$64.27	$76.14	$11.86	18.5%	$57.80	($6.47)	-10.1%	$64.28	$0.01	0.0%	$63.21	($1.06)	-1.7%	$58.40	($5.87)	-9.1%
600			$74.07	$88.63	$14.56	19.7%	$66.30	($7.77)	-10.5%	$74.08	$0.01	0.0%	$72.79	($1.28)	-1.7%	$67.02	($7.04)	-9.5%
700			$83.86	$101.12	$17.26	20.6%	$74.79	($9.06)	-10.8%	$83.88	$0.02	0.0%	$82.37	($1.49)	-1.8%	$75.64	($8.22)	-9.8%
800			$93.65	$113.61	$19.96	21.3%	$83.29	($10.36)	-11.1%	$93.67	$0.02	0.0%	$91.95	($1.70)	-1.8%	$84.26	($9.39)	-10.0%
900			$103.45	$126.11	$22.66	21.9%	$91.79	($11.65)	-11.3%	$103.47	$0.02	0.0%	$101.53	($1.91)	-1.9%	$92.88	($10.57)	-10.2%
1000			$113.24	$138.60	$25.36	22.4%	$100.29	($12.95)	-11.4%	$113.26	$0.02	0.0%	$111.11	($2.13)	-1.9%	$101.50	($11.74)	-10.4%
1100	2476	126	$126.58	$153.66	$27.07	21.4%	$116.10	($10.49)	-8.3%	$126.56	($0.02)	0.0%	$124.60	($1.99)	-1.6%	$118.12	($8.46)	-6.7%
1200	bills	bills	$139.93	$168.72	$28.79	20.6%	$131.90	($8.03)	-5.7%	$139.86	($0.07)	0.0%	$138.09	($1.84)	-1.3%	$134.74	($5.19)	-3.7%
1300	cum 89%	cum 93%	$153.28	$183.77	$30.50	19.9%	$147.71	($5.57)	-3.6%	$153.16	($0.12)	-0.1%	$151.57	($1.70)	-1.1%	$151.36	($1.91)	-1.2%
1400			$166.62	$198.83	$32.21	19.3%	$163.52	($3.10)	-1.9%	$166.46	($0.16)	-0.1%	$165.06	($1.56)	-0.9%	$167.99	$1.36	0.8%
1500	516	21	$179.97	$213.89	$33.92	18.8%	$179.32	($0.64)	-0.4%	$179.76	($0.21)	-0.1%	$178.55	($1.42)	-0.8%	$184.61	$4.64	2.6%
1600	cum 94%	cum 97%	$193.31	$228.94	$35.63	18.4%	$202.62	$9.31	4.8%	$193.06	($0.25)	-0.1%	$192.04	($1.28)	-0.7%	$205.41	$12.10	6.3%
1700	298	11	$206.66	$244.00	$37.35	18.1%	$225.92	$19.26	9.3%	$206.36	($0.30)	-0.1%	$205.52	($1.13)	-0.5%	$226.21	$19.55	9.5%
1800	bills	bills	$220.00	$259.06	$39.06	17.8%	$249.22	$29.21	13.3%	$219.66	($0.35)	-0.2%	$219.01	($0.99)	-0.5%	$247.01	$27.01	12.3%
1900	cum 96%	cum 98%	$233.35	$274.12	$40.77	17.5%	$272.51	$39.17	16.8%	$232.95	($0.39)	-0.2%	$232.50	($0.85)	-0.4%	$267.81	$34.46	14.8%
2000			$246.69	$289.17	$42.48	17.2%	$295.81	$49.12	19.9%	$246.25	($0.44)	-0.2%	$245.98	($0.71)	-0.3%	$288.61	$41.92	17.0%
2100	288	8	$260.04	$304.23	$44.19	17.0%	$319.11	$59.07	22.7%	$259.55	($0.48)	-0.2%	$259.47	($0.57)	-0.2%	$309.41	$49.37	19.0%
2200	bills	bills	$273.38	$319.29	$45.91	16.8%	$342.41	$69.02	25.2%	$272.85	($0.53)	-0.2%	$272.96	($0.42)	-0.2%	$330.21	$56.83	20.8%
2300	cum 98%	cum 99%	$286.73	$334.35	$47.62	16.6%	$365.70	$78.98	27.5%	$286.15	($0.58)	-0.2%	$286.45	($0.28)	-0.1%	$351.01	$64.28	22.4%
2400			$300.07	$349.40	$49.33	16.4%	$389.00	$88.93	29.6%	$299.45	($0.62)	-0.2%	$299.93	($0.14)	0.0%	$371.81	$71.74	23.9%
2500			$313.42	$364.46	$51.04	16.3%	$412.30	$98.88	31.5%	$312.75	($0.67)	-0.2%	$313.42	$0.00	0.0%	$392.61	$79.19	25.3%
2600	108	4	$326.76	$379.52	$52.76	16.1%	$435.60	$108.83	33.3%	$327.27	$0.51	0.2%	$334.22	$7.46	2.3%	$413.41	$86.65	26.5%
2700	bills	bill	$340.11	$394.58	$54.47	16.0%	$458.89	$118.78	34.9%	$341.79	$1.68	0.5%	$355.02	$14.91	4.4%	$434.21	$94.10	27.7%
2800	cum 99%	cum 100%	$353.45	$409.63	$56.18	15.9%	$482.19	$128.74	36.4%	$356.31	$2.86	0.8%	$375.82	$22.37	6.3%	$455.01	$101.56	28.7%
2900			$366.80	$424.69	$57.89	15.8%	$505.49	$138.69	37.8%	$370.84	$4.04	1.1%	$396.62	$29.82	8.1%	$475.81	$109.01	29.7%
3000	116	1	$380.14	$439.75	$59.60	15.7%	$528.79	$148.64	39.1%	$385.36	$5.21	1.4%	$417.42	$37.28	9.8%	$496.61	$116.47	30.6%
5000	bills	bill	$647.05	$740.90	$93.85	14.5%	$994.74	$347.69	53.7%	$675.79	$28.74	4.4%	$833.43	$186.38	28.8%	$912.62	$265.57	41.0%
	over 3000 kW.h	over 3000 kW.h	**Effective without Rider F:**				**Effective with Rider F:**			**Runoff 1500 at 80% of diesel**			**Runoff 2500 at 50% of diesel**			**Runoff 2500 at 71.5% of diesel**			**Runoff 1500 at 71.5% of diese**
			Block 1 rate	**12.13**			**Block 1 rate**		**13.69**	**Block 1 rate**		**10.90**	**Block 1 rate**		**12.14**	**Block 1 rate**		**11.93**	**Block 1 rate**		**11.01**
			Block 2 rate	**12.85**			**Block 2 rate**		**14.39**	**Block 2 rate**		**15.22**	**Block 2 rate**		**12.82**	**Block 2 rate**		**13.00**	**Block 2 rate**		**16.00**
										Block 3 rate		**22.39**	**Block 3 rate**		**13.99**	**Block 3 rate**		**20.00**	**Block 3 rate**		**20.00**

Table 2 - Comparison of Options (Residential Non-Government) with IER cont.

Small Diesel

		present monthly bill	Sep-08 monthly bill	change		Option A monthly bill	change		Option B monthly bill	change		Option C-Modified monthly bill	change		LE Preferred Option monthly bill	change	
100	258 bills (2007)	$25.10	$26.17	$1.07	4.3%	$23.80	($1.29)	-5.2%	$25.10	$0.00	0.0%	$24.89	($0.21)	-0.8%	$23.92	($1.17)	-4.7%
200		$34.89	$38.66	$3.77	10.8%	$32.30	($2.59)	-7.4%	$34.90	$0.01	0.0%	$34.47	($0.42)	-1.2%	$32.54	($2.35)	-6.7%
300	205	$44.69	$51.15	$6.47	14.5%	$40.80	($3.88)	-8.7%	$44.69	$0.01	0.0%	$44.05	($0.64)	-1.4%	$41.16	($3.52)	-7.9%
400	bills	$54.48	$63.64	$9.17	16.8%	$49.30	($5.18)	-9.5%	$54.49	$0.01	0.0%	$53.63	($0.85)	-1.6%	$49.78	($4.70)	-8.6%
500	cum 80%	$64.27	$76.14	$11.86	18.5%	$57.80	($6.47)	-10.1%	$64.28	$0.01	0.0%	$63.21	($1.06)	-1.7%	$58.40	($5.87)	-9.1%
600		$74.07	$88.63	$14.56	19.7%	$66.30	($7.77)	-10.5%	$74.08	$0.01	0.0%	$72.79	($1.28)	-1.7%	$67.02	($7.04)	-9.5%
700		$83.86	$101.12	$17.26	20.6%	$74.79	($9.06)	-10.8%	$83.88	$0.02	0.0%	$82.37	($1.49)	-1.8%	$75.64	($8.22)	-9.8%
800		$93.65	$113.61	$19.96	21.3%	$83.29	($10.36)	-11.1%	$93.67	$0.02	0.0%	$91.95	($1.70)	-1.8%	$84.26	($9.39)	-10.0%
900		$103.45	$126.11	$22.66	21.9%	$91.79	($11.65)	-11.3%	$103.47	$0.02	0.0%	$101.53	($1.91)	-1.9%	$92.88	($10.57)	-10.2%
1000		$113.24	$138.60	$25.36	22.4%	$100.29	($12.95)	-11.4%	$113.26	$0.02	0.0%	$111.11	($2.13)	-1.9%	$101.50	($11.74)	-10.4%
1100	39	$129.04	$156.05	$27.01	20.9%	$116.10	($12.94)	-10.0%	$126.56	($2.48)	-1.9%	$124.60	($4.44)	-3.4%	$118.12	($10.92)	-8.5%
1200	bills	$144.84	$173.51	$28.66	19.8%	$131.90	($12.94)	-8.9%	$139.86	($4.98)	-3.4%	$138.09	($6.76)	-4.7%	$134.74	($10.10)	-7.0%
1300	cum 94%	$160.64	$190.96	$30.31	18.9%	$147.71	($12.94)	-8.1%	$153.16	($7.49)	-4.7%	$151.57	($9.07)	-5.6%	$151.36	($9.28)	-5.8%
1400		$176.45	$208.41	$31.96	18.1%	$163.52	($12.93)	-7.3%	$166.46	($9.99)	-5.7%	$165.06	($11.39)	-6.5%	$167.99	($8.46)	-4.8%
1500	7	$192.25	$225.86	$33.62	17.5%	$179.32	($12.93)	-6.7%	$179.76	($12.49)	-6.5%	$178.55	($13.70)	-7.1%	$184.61	($7.64)	-4.0%
1600	cum 97%	$208.05	$243.32	$35.27	17.0%	$202.62	($5.43)	-2.6%	$193.06	($14.99)	-7.2%	$192.04	($16.01)	-7.7%	$205.41	($2.64)	-1.3%
1700	3	$223.85	$260.77	$36.92	16.5%	$225.92	$2.07	0.9%	$206.36	($17.50)	-7.8%	$205.52	($18.33)	-8.2%	$226.21	$2.36	1.1%
1800	bills	$239.65	$278.22	$38.57	16.1%	$249.22	$9.56	4.0%	$219.66	($20.00)	-8.3%	$219.01	($20.64)	-8.6%	$247.01	$7.35	3.1%
1900	cum 98%	$255.45	$295.67	$40.22	15.7%	$272.51	$17.06	6.7%	$232.95	($22.50)	-8.8%	$232.50	($22.96)	-9.0%	$267.81	$12.35	4.8%
2000		$271.26	$313.13	$41.87	15.4%	$295.81	$24.55	9.1%	$246.25	($25.00)	-9.2%	$245.98	($25.27)	-9.3%	$288.61	$17.35	6.4%
2100	2	$287.06	$330.58	$43.52	15.2%	$319.11	$32.05	11.2%	$259.55	($27.51)	-9.6%	$259.47	($27.59)	-9.6%	$309.41	$22.35	7.8%
2200	bills	$302.86	$348.03	$45.17	14.9%	$342.41	$39.55	13.1%	$272.85	($30.01)	-9.9%	$272.96	($29.90)	-9.9%	$330.21	$27.35	9.0%
2300	cum 99%	$318.66	$365.48	$46.82	14.7%	$365.70	$47.04	14.8%	$286.15	($32.51)	-10.2%	$286.45	($32.22)	-10.1%	$351.01	$32.35	10.2%
2400		$334.46	$382.94	$48.47	14.5%	$389.00	$54.54	16.3%	$299.45	($35.01)	-10.5%	$299.93	($34.53)	-10.3%	$371.81	$37.35	11.2%
2500		$350.27	$400.39	$50.12	14.3%	$412.30	$62.03	17.7%	$312.75	($37.52)	-10.7%	$313.42	($36.84)	-10.5%	$392.61	$42.35	12.1%
2600	1	$366.07	$417.84	$51.78	14.1%	$435.60	$69.53	19.0%	$327.27	($38.80)	-10.6%	$334.22	($31.85)	-8.7%	$413.41	$47.35	12.9%
2700	bills	$381.87	$435.29	$53.43	14.0%	$458.89	$77.02	20.2%	$341.79	($40.07)	-10.5%	$355.02	($26.85)	-7.0%	$434.21	$52.34	13.7%
2800	cum 100%	$397.67	$452.75	$55.08	13.8%	$482.19	$84.52	21.3%	$356.32	($41.35)	-10.4%	$375.82	($21.85)	-5.5%	$455.01	$57.34	14.4%
2900		$413.47	$470.20	$56.73	13.7%	$505.49	$92.02	22.3%	$370.84	($42.63)	-10.3%	$396.62	($16.85)	-4.1%	$475.81	$62.34	15.1%
3000	1	$429.27	$487.65	$58.38	13.6%	$528.79	$99.51	23.2%	$385.36	($43.91)	-10.2%	$417.42	($11.85)	-2.8%	$496.61	$67.34	15.7%

Table 3 - Comparison of Options (Residential Non-Government) with IER cont.

Old Crow

	121 bills (2007)	present monthly bill	Sep-08 monthly bill	change		Option A monthly bill	change		Option B monthly bill	change		Option C-Modified monthly bill	change		LE Preferred Option monthly bill	change	
100		$25.10	$26.17	$1.07	4.3%	$23.80	($1.29)	-5.2%	$25.10	$0.00	0.0%	$24.89	($0.21)	-0.8%	$23.92	($1.17)	-4.7%
200		$34.89	$38.66	$3.77	10.8%	$32.30	($2.59)	-7.4%	$34.90	$0.01	0.0%	$34.47	($0.42)	-1.2%	$32.54	($2.35)	-6.7%
300	110	$44.69	$51.15	$6.47	14.5%	$40.80	($3.88)	-8.7%	$44.69	$0.01	0.0%	$44.05	($0.64)	-1.4%	$41.16	($3.52)	-7.9%
400	bills	$54.48	$63.64	$9.17	16.8%	$49.30	($5.18)	-9.5%	$54.49	$0.01	0.0%	$53.63	($0.85)	-1.6%	$49.78	($4.70)	-8.6%
500	cum 91%	$64.27	$76.14	$11.86	18.5%	$57.80	($6.47)	-10.1%	$64.28	$0.01	0.0%	$63.21	($1.06)	-1.7%	$58.40	($5.87)	-9.1%
600		$74.07	$88.63	$14.56	19.7%	$66.30	($7.77)	-10.5%	$74.08	$0.01	0.0%	$72.79	($1.28)	-1.7%	$67.02	($7.04)	-9.5%
700		$83.86	$101.12	$17.26	20.6%	$74.79	($9.06)	-10.8%	$83.88	$0.02	0.0%	$82.37	($1.49)	-1.8%	$75.64	($8.22)	-9.8%
800		$93.65	$113.61	$19.96	21.3%	$83.29	($10.36)	-11.1%	$93.67	$0.02	0.0%	$91.95	($1.70)	-1.8%	$84.26	($9.39)	-10.0%
900		$103.45	$126.11	$22.66	21.9%	$91.79	($11.65)	-11.3%	$103.47	$0.02	0.0%	$101.53	($1.91)	-1.9%	$92.88	($10.57)	-10.2%
1000		$113.24	$138.60	$25.36	22.4%	$100.29	($12.95)	-11.4%	$113.26	$0.02	0.0%	$111.11	($2.13)	-1.9%	$101.50	($11.74)	-10.4%
1100	10	$146.29	$172.87	$26.58	18.2%	$116.10	($30.19)	-20.6%	$126.56	($19.73)	-13.5%	$124.60	($21.69)	-14.8%	$118.12	($28.17)	-19.3%
1200	bills	$179.34	$207.14	$27.80	15.5%	$131.90	($47.43)	-26.4%	$139.86	($39.48)	-22.0%	$138.09	($41.25)	-23.0%	$134.74	($44.59)	-24.9%
1300	cum 99%	$212.38	$241.41	$29.02	13.7%	$147.71	($64.68)	-30.5%	$153.16	($59.22)	-27.9%	$151.57	($60.81)	-28.6%	$151.36	($61.02)	-28.7%
1400		$245.43	$275.68	$30.24	12.3%	$163.52	($81.92)	-33.4%	$166.46	($78.97)	-32.2%	$165.06	($80.37)	-32.7%	$167.99	($77.45)	-31.6%
1500	1	$278.48	$309.94	$31.46	11.3%	$179.32	($99.16)	-35.6%	$179.76	($98.72)	-35.5%	$178.55	($99.93)	-35.9%	$184.61	($93.87)	-33.7%
1600	cum 100%	$311.53	$344.21	$32.68	10.5%	$230.66	($80.87)	-26.0%	$193.06	($118.47)	-38.0%	$192.04	($119.49)	-38.4%	$230.48	($81.05)	-26.0%
1700	0	$344.58	$378.48	$33.90	9.8%	$282.00	($62.57)	-18.2%	$206.36	($138.22)	-40.1%	$205.52	($139.06)	-40.4%	$276.36	($68.22)	-19.8%
1800	bills	$377.63	$412.75	$35.13	9.3%	$333.35	($44.28)	-11.7%	$219.66	($157.97)	-41.8%	$219.01	($158.62)	-42.0%	$322.23	($55.40)	-14.7%
1900		$410.67	$447.02	$36.35	8.9%	$384.69	($25.99)	-6.3%	$232.95	($177.72)	-43.3%	$232.50	($178.18)	-43.4%	$368.10	($42.57)	-10.4%
2000		$443.72	$481.29	$37.57	8.5%	$436.03	($7.70)	-1.7%	$246.25	($197.47)	-44.5%	$245.98	($197.74)	-44.6%	$413.98	($29.74)	-6.7%
2100	0	$476.77	$515.56	$38.79	8.1%	$487.37	$10.60	2.2%	$259.55	($217.22)	-45.6%	$259.47	($217.30)	-45.6%	$459.85	($16.92)	-3.5%
2200	bills	$509.82	$549.83	$40.01	7.8%	$538.71	$28.89	5.7%	$272.85	($236.97)	-46.5%	$272.96	($236.86)	-46.5%	$505.73	($4.09)	-0.8%
2300		$542.87	$584.10	$41.23	7.6%	$590.05	$47.18	8.7%	$286.15	($256.72)	-47.3%	$286.45	($256.42)	-47.2%	$551.60	$8.73	1.6%
2400		$575.92	$618.37	$42.45	7.4%	$641.39	$65.48	11.4%	$299.45	($276.47)	-48.0%	$299.93	($275.98)	-47.9%	$597.48	$21.56	3.7%
2500		$608.96	$652.63	$43.67	7.2%	$692.73	$83.77	13.8%	$312.75	($296.22)	-48.6%	$313.42	($295.54)	-48.5%	$643.35	$34.39	5.6%
2600	0	$642.01	$686.90	$44.89	7.0%	$744.07	$102.06	15.9%	$344.80	($297.21)	-46.3%	$359.30	($282.72)	-44.0%	$689.23	$47.21	7.4%
2700	bills	$675.06	$721.17	$46.11	6.8%	$795.42	$120.35	17.8%	$376.85	($298.21)	-44.2%	$405.17	($269.89)	-40.0%	$735.10	$60.04	8.9%
2800		$708.11	$755.44	$47.33	6.7%	$846.76	$138.65	19.6%	$408.91	($299.20)	-42.3%	$451.04	($257.07)	-36.3%	$780.98	$72.87	10.3%
2900		$741.16	$789.71	$48.55	6.6%	$898.10	$156.94	21.2%	$440.96	($300.20)	-40.5%	$496.92	($244.24)	-33.0%	$826.85	$85.69	11.6%
3000	0	$774.21	$823.98	$49.77	6.4%	$949.44	$175.23	22.6%	$473.01	($301.19)	-38.9%	$542.79	($231.41)	-29.9%	$872.72	$98.52	12.7%

Table 4 - Comparison of Options (Residential Non-Government) without IER

Hydro/Lg Diesel

	12519 bills (2007) Hydro Zone	671 bills (2007) Large Diesel Zone	present monthly bill	Sep-08 monthly bill	change		Option A monthly bill	change		Option B monthly bill	change		Option C-Modified monthly bill	change		LE Preferred Option monthly bill	change	
100			$25.10	$26.17	$1.07	4.3%	$26.60	$1.50	6.0%	$27.89	$2.80	11.1%	$27.68	$2.58	10.3%	$26.72	$1.62	6.5%
200			$34.89	$38.66	$3.77	10.8%	$37.89	$3.00	8.6%	$40.48	$5.59	16.0%	$40.05	$5.16	14.8%	$38.13	$3.24	9.3%
300	8717	501	$44.69	$51.15	$6.47	14.5%	$49.18	$4.49	10.1%	$53.07	$8.39	18.8%	$52.43	$7.74	17.3%	$49.54	$4.86	10.9%
400	bills	bills	$54.48	$63.64	$9.17	16.8%	$60.47	$5.99	11.0%	$65.66	$11.18	20.5%	$64.80	$10.32	18.9%	$60.96	$6.48	11.9%
500	cum 70%	cum 75%	$64.27	$76.14	$11.86	18.5%	$71.76	$7.49	11.7%	$78.25	$13.98	21.7%	$77.17	$12.90	20.1%	$72.37	$8.10	12.6%
600			$74.07	$88.63	$14.56	19.7%	$83.05	$8.99	12.1%	$90.84	$16.77	22.6%	$89.55	$15.48	20.9%	$83.78	$9.71	13.1%
700			$83.86	$101.12	$17.26	20.6%	$94.35	$10.49	12.5%	$103.43	$19.57	23.3%	$101.92	$18.06	21.5%	$95.19	$11.33	13.5%
800			$93.65	$113.61	$19.96	21.3%	$105.64	$11.98	12.8%	$116.01	$22.36	23.9%	$114.29	$20.64	22.0%	$106.60	$12.95	13.8%
900			$103.45	$126.11	$22.66	21.9%	$116.93	$13.48	13.0%	$128.60	$25.16	24.3%	$126.67	$23.22	22.4%	$118.02	$14.57	14.1%
1000			$113.24	$138.60	$25.36	22.4%	$128.22	$14.98	13.2%	$141.19	$27.95	24.7%	$139.04	$25.80	22.8%	$129.43	$16.19	14.3%
1100	2476	126	$126.58	$153.66	$27.07	21.4%	$144.03	$17.44	13.8%	$154.49	$27.91	22.0%	$152.53	$25.94	20.5%	$146.05	$19.47	15.4%
1200	bills	bills	$139.93	$168.72	$28.79	20.6%	$159.83	$19.90	14.2%	$167.79	$27.86	19.9%	$166.02	$26.09	18.6%	$162.67	$22.74	16.3%
1300	cum 89%	cum 93%	$153.28	$183.77	$30.50	19.9%	$175.64	$22.36	14.6%	$181.09	$27.81	18.1%	$179.50	$26.23	17.1%	$179.29	$26.02	17.0%
1400			$166.62	$198.83	$32.21	19.3%	$191.45	$24.83	14.9%	$194.39	$27.77	16.7%	$192.99	$26.37	15.8%	$195.92	$29.29	17.6%
1500	516	21	$179.97	$213.89	$33.92	18.8%	$207.25	$27.29	15.2%	$207.69	$27.72	15.4%	$206.48	$26.51	14.7%	$212.54	$32.57	18.1%
1600	cum 94%	cum 97%	$193.31	$228.94	$35.63	18.4%	$230.55	$37.24	19.3%	$220.99	$27.68	14.3%	$219.97	$26.65	13.8%	$233.34	$40.03	20.7%
1700	298	11	$206.66	$244.00	$37.35	18.1%	$253.85	$47.19	22.8%	$234.29	$27.63	13.4%	$233.45	$26.80	13.0%	$254.14	$47.48	23.0%
1800	bills	bills	$220.00	$259.06	$39.06	17.8%	$277.15	$57.14	26.0%	$247.59	$27.58	12.5%	$246.94	$26.94	12.2%	$274.94	$54.94	25.0%
1900	cum 96%	cum 98%	$233.35	$274.12	$40.77	17.5%	$300.44	$67.10	28.8%	$260.88	$27.54	11.8%	$260.43	$27.08	11.6%	$295.74	$62.39	26.7%
2000			$246.69	$289.17	$42.48	17.2%	$323.74	$77.05	31.2%	$274.18	$27.49	11.1%	$273.91	$27.22	11.0%	$316.54	$69.85	28.3%
2100	288	8	$260.04	$304.23	$44.19	17.0%	$347.04	$87.00	33.5%	$287.48	$27.45	10.6%	$287.40	$27.36	10.5%	$337.34	$77.30	29.7%
2200	bills	bills	$273.38	$319.29	$45.91	16.8%	$370.34	$96.95	35.5%	$300.78	$27.40	10.0%	$300.89	$27.51	10.1%	$358.14	$84.76	31.0%
2300	cum 98%	cum 99%	$286.73	$334.35	$47.62	16.6%	$393.63	$106.91	37.3%	$314.08	$27.35	9.5%	$314.38	$27.65	9.6%	$378.94	$92.21	32.2%
2400			$300.07	$349.40	$49.33	16.4%	$416.93	$116.86	38.9%	$327.38	$27.31	9.1%	$327.86	$27.79	9.3%	$399.74	$99.67	33.2%
2500			$313.42	$364.46	$51.04	16.3%	$440.23	$126.81	40.5%	$340.68	$27.26	8.7%	$341.35	$27.93	8.9%	$420.54	$107.12	34.2%
2600	108	4	$326.76	$379.52	$52.76	16.1%	$463.53	$136.76	41.9%	$355.20	$28.44	8.7%	$362.15	$35.39	10.8%	$441.34	$114.58	35.1%
2700	bills	bill	$340.11	$394.58	$54.47	16.0%	$486.82	$146.71	43.1%	$369.72	$29.61	8.7%	$382.95	$42.84	12.6%	$462.14	$122.03	35.9%
2800	cum 99%	cum 100%	$353.45	$409.63	$56.18	15.9%	$510.12	$156.67	44.3%	$384.24	$30.79	8.7%	$403.75	$50.30	14.2%	$482.94	$129.49	36.6%
2900			$366.80	$424.69	$57.89	15.8%	$533.42	$166.62	45.4%	$398.77	$31.97	8.7%	$424.55	$57.75	15.7%	$503.74	$136.94	37.3%
3000	116	1	$380.14	$439.75	$59.60	15.7%	$556.72	$176.57	46.4%	$413.29	$33.14	8.7%	$445.35	$65.21	17.2%	$524.54	$144.40	38.0%
5000	bills	bill	$647.05	$740.90	$93.85	14.5%	$1,022.67	$375.62	58.1%	$703.72	$56.67	8.8%	$861.36	$214.31	33.1%	$940.55	$293.50	45.4%
	over 3000 kW.h	over 3000 kW.h	Effective without Rider F:				Effective with Rider F:			Runoff 1500 at 80% of diesel			Runoff 2500 at 50% of diesel			Runoff 2500 at 71.5% of diesel		
			Block 1 rate	12.13			Block 1 rate	13.69		Block 1 rate	10.90		Block 1 rate	12.14		Block 1 rate	11.93	
			Block 2 rate	12.85			Block 2 rate	14.39		Block 2 rate	15.22		Block 2 rate	12.82		Block 2 rate	13.00	
										Block 3 rate	22.39		Block 3 rate	13.99		Block 3 rate	20.00	

Runoff 2500 at 71.5% of diesel	
Block 1 rate	11.01
Block 2 rate	16.00
Block 3 rate	20.00

Table 5 - Comparison of Options (General Service Non-Government)

Hydro/Lg Diesel

KWh	KV	present monthly bill	Sep-08 monthly bill	change		Option A monthly bill	change		Option B monthly bill	change		Option C monthly bill	change	
200	5	$59.77	$60.69	$0.92	1.5%	$48.52	($11.25)	-18.8%	$59.78	$0.01	0.0%	$58.06	($1.71)	-2.9%
400	5	$80.96	$83.76	$2.81	3.5%	$65.69	($15.27)	-18.9%	$80.95	($0.00)	0.0%	$77.52	($3.44)	-4.2%
600	5	$102.14	$106.84	$4.70	4.6%	$82.86	($19.28)	-18.9%	$102.12	($0.02)	0.0%	$96.97	($5.17)	-5.1%
800	5	$123.33	$129.91	$6.58	5.3%	$100.03	($23.29)	-18.9%	$123.30	($0.03)	0.0%	$116.43	($6.90)	-5.6%
1000	5	$144.51	$152.98	$8.47	5.9%	$117.21	($27.31)	-18.9%	$144.47	($0.04)	0.0%	$135.89	($8.63)	-6.0%
1200	5	$165.70	$176.05	$10.35	6.2%	$134.38	($31.32)	-18.9%	$165.64	($0.05)	0.0%	$155.35	($10.35)	-6.2%
1400	5	$186.89	$199.12	$12.24	6.5%	$151.55	($35.33)	-18.9%	$186.82	($0.07)	0.0%	$174.80	($12.08)	-6.5%
1600	5	$208.07	$222.20	$14.12	6.8%	$168.73	($39.35)	-18.9%	$207.99	($0.08)	0.0%	$194.26	($13.81)	-6.6%
1800	5	$229.26	$245.27	$16.01	7.0%	$185.90	($43.36)	-18.9%	$229.17	($0.09)	0.0%	$213.72	($15.54)	-6.8%
2000	5	$250.44	$268.34	$17.90	7.1%	$203.07	($47.37)	-18.9%	$250.34	($0.10)	0.0%	$233.17	($17.27)	-6.9%
2500	7	$332.60	$358.68	$26.07	7.8%	$292.97	($39.63)	-11.9%	$332.59	($0.01)	0.0%	$315.42	($17.18)	-5.2%
3000	8	$407.05	$441.49	$34.44	8.5%	$376.60	($30.45)	-7.5%	$407.12	$0.07	0.0%	$389.95	($17.09)	-4.2%
3500	10	$489.21	$531.82	$42.62	8.7%	$466.50	($22.71)	-4.6%	$489.37	$0.16	0.0%	$472.20	($17.00)	-3.5%
4000	11	$563.65	$614.63	$50.98	9.0%	$550.13	($13.52)	-2.4%	$563.90	$0.25	0.0%	$546.73	($16.91)	-3.0%
4500	12	$638.09	$697.44	$59.35	9.3%	$633.76	($4.33)	-0.7%	$638.43	$0.34	0.1%	$621.26	($16.83)	-2.6%
5000	14	$720.25	$787.78	$67.53	9.4%	$723.66	$3.41	0.5%	$720.68	$0.43	0.1%	$703.52	($16.74)	-2.3%
6000	16	$869.14	$953.40	$84.27	9.7%	$890.92	$21.78	2.5%	$869.74	$0.60	0.1%	$852.58	($16.56)	-1.9%
7000	19	$1,025.74	$1,126.55	$100.81	9.8%	$1,064.44	$38.70	3.8%	$1,026.52	$0.78	0.1%	$1,009.36	($16.38)	-1.6%
8000	22	$1,182.34	$1,299.70	$117.35	9.9%	$1,237.97	$55.63	4.7%	$1,183.30	$0.96	0.1%	$1,166.14	($16.20)	-1.4%
9000	25	$1,338.95	$1,472.84	$133.90	10.0%	$1,411.50	$72.56	5.4%	$1,340.08	$1.14	0.1%	$1,322.92	($16.03)	-1.2%
10000	27	$1,487.83	$1,638.47	$150.64	10.1%	$1,578.76	$90.93	6.1%	$1,489.14	$1.31	0.1%	$1,471.98	($15.85)	-1.1%
15000	41	$2,263.13	$2,496.68	$233.55	10.3%	$2,440.13	$177.01	7.8%	$2,265.33	$2.20	0.1%	$2,248.16	($14.97)	-0.7%
20000	55	$3,038.42	$3,354.89	$316.46	10.4%	$3,692.77	$654.34	21.5%	$3,099.50	$61.07	2.0%	$3,396.28	$357.85	11.8%
25000	68	$3,806.00	$4,205.57	$399.57	10.5%	$4,441.30	$635.30	16.7%	$3,866.91	$60.91	1.6%	$4,163.70	$357.69	9.4%
30000	82	$4,581.30	$5,063.78	$482.48	10.5%	$5,196.11	$614.81	13.4%	$4,642.05	$60.75	1.3%	$4,938.83	$357.53	7.8%
40000	110	$6,131.89	$6,780.20	$648.31	10.6%	$6,705.73	$573.84	9.4%	$6,192.33	$60.44	1.0%	$6,489.11	$357.22	5.8%
50000	137	$7,674.77	$8,489.10	$814.33	10.6%	$8,209.08	$534.31	7.0%	$7,734.89	$60.12	0.8%	$8,031.67	$356.90	4.7%
75000	205	$11,535.82	$12,765.10	$1,229.28	10.7%	$11,970.58	$434.76	3.8%	$11,595.14	$59.32	0.5%	$11,891.92	$356.11	3.1%
100000	274	$15,404.58	$17,048.63	$1,644.04	10.7%	$15,738.35	$333.77	2.2%	$15,463.12	$58.53	0.4%	$15,759.90	$355.31	2.3%
125000	342	$19,265.63	$21,324.63	$2,059.00	10.7%	$19,499.86	$234.23	1.2%	$19,323.37	$57.74	0.3%	$19,620.15	$354.52	1.8%
		Effective without Rider F:	**Effective with Rider F:**											
		Block 1 rate **10.22**	**Block 1 rate**		**11.83**	**Block 1 rate**		**8.31**	**Block 1 rate**		**10.22**	**Block 1 rate**		**9.40**
		Blokc 2 rate **12.85**	**Blokc 2 rate**		**14.39**	**Block 2 rate**		**14.90**	**Block 2 rate**		**12.88**	**Block 2 rate**		**12.88**
						Block 3 rate		**22.39**	**Block 3 rate**		**13.99**	**Block 3 rate**		**20.00**
		Demand Charge **7.38**	**Demand Charge**		**7.20**	**Demand Charge**		**6.00**	**Demand Charge**		**7.39**	**Demand Charge**		**7.39**