

**YUKON ENERGY CORPORATION
2008/2009 GENERAL RATE APPLICATION**

**APPLICATION AND SUPPORTING DOCUMENTS
SEPTEMBER 2008**

Stringing line on the Carmacks-Stewart Transmission Line Project
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**YUKON
ENERGY**



2008/2009 GENERAL RATE APPLICATION
TO THE YUKON UTILITIES BOARD (BOARD)
YUKON ENERGY CORPORATION

INTRODUCTION TO APPLICATION

Yukon Energy's 2008 and 2009 General Rate Application (the "GRA" or "Application") addresses adjustments to Yukon Energy's approved revenue requirement and other matters as required to:

- Recover the costs to supply customers in 2008 and 2009 (the two "test years");
- Implement overall rate reductions proposed for the test years, reflecting benefits secured from timely completion of Stage One of the Carmacks-Stewart Transmission Project ("CSTP") and connection of the Minto mine to the grid through the approved Purchase Power Agreement ("PPA") with Minto Explorations Ltd. ("Minto Explorations");
- Adjust runoff rates to begin restoring efficient price signals to each customer class as soon as is practicable, with immediate adjustments to begin increasing the level of residential runoff rates which presently serve to encourage residential electric heating; and
- Implement specific other timely rate schedule adjustments as set out in the Application.

All proposed rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers, and therefore prevent rate revenue rebalancing among retail customer classes. Matters pertaining to further rate design and/or cost of service studies, which typically require joint work by Yukon Energy and the Yukon Electrical Company Limited ("YECL"), are not addressed in the Application.

The Application includes the following:

- Overview
- Summary of Requested Orders
- Key Factors Considered in the Application
- Overview of Supporting Documents.

OVERVIEW

Background

Yukon Energy is the main generator and transmitter of electrical energy in Yukon, accounting for over 90% of annual Yukon power generation and the Whitehorse-Aishihik-Faro ("WAF") and Mayo-Dawson ("MD") grid systems. Yukon Energy directly serves 1900 retail customers, mostly in Dawson City, Mayo and Keno, as well as the Minto Mine, and supplies wholesales to YECL.

Yukon Energy revenue requirements were last reviewed and approved by the Board in 2005 during Yukon Energy's 2005 Required Revenues and Related Matters application (Board Order 2005-12), which deferred the need for Yukon Energy to request any increase in firm rates through, among other measures, access from 2005 until the end of 2007 to \$0.292 million per year from deferred funds (the Faro Dewatering Account) held by Yukon Energy for ratepayer benefit.

Since the 2005 Required Revenues and Related Matters hearing, the Board has reviewed three major Yukon Energy submissions or applications related to system bulk power (generation and transmission) supplies for Yukon power loads, including new industrial loads: Yukon Energy's 20-Year Resource Plan: 2006-2025 (hearing in 2006 with report to the Commissioner in Executive Council, January 15, 2007); the Minto PPA application (2007 proceedings, Orders 2007-5 and 2007-6); and the Part 3 Energy Certification review regarding the CSTP (2007 proceeding, Report and Recommendations to Yukon Minister of Justice, May 31, 2007).

Rate Policy Directive (OIC 1995/90) was amended prior to the filing of this Application to direct that, prior to January 1, 2013, the Board must ensure that rate adjustments for retail customers (as defined in OIC 1995/90) apply equally, when measured as percentages, to all classes of retail customers. Accordingly, given the latest Directive to the Board, Yukon Energy is not, as part of the current GRA submissions, addressing cost of service and rate design work related to any rate shift program or rate rebalancing as between customer classes. The Application, however, addresses rate design issues within each retail customer class related to OIC 1995/90 directives regarding runoff rates.

Proposed First Block Retail Rate Reductions and Runoff Rate Changes

Yukon Energy today remains on track to complete the Stage One CSTP and initiate service to the Minto mine in about mid to late October 2008 in accordance with the Minto PPA and the rate schedule approved by Board Order 2008-13. The additional major new firm sales of surplus WAF hydro generation are forecast, as previously expected, to provide material net revenue benefits to ratepayers. Accordingly, as previously

committed, Yukon Energy seeks approval in the Application, on an interim refundable basis, for retail rate reductions (Rider U) effective November 1, 2008 and continuing at the same level through the 2009 test year. The proposed interim rate changes are identical to the final 2009 rates proposed in the Application.

By reducing the surplus hydro generation, new industrial loads also advance the timing for potential renewed diesel generation in Yukon. To promote economy and efficiency as directed by OIC 1995/90, Rider U rate reductions are therefore proposed (where feasible) only for first block rates. In addition, residential runoff rates are increased to start restoring efficient runoff rate signals, with the resulting added revenues being used within each residential class to further reduce first block residential rates. As noted, these rate adjustment proposals are designed to prevent rate revenue rebalancing among retail customer classes.

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

- No change to the monthly customer charges or demand charges.
- A reduction in the first block (first 1,000 kW.h per month for Residential, first 2,000 kW.h per month for General Service) retail rate energy charge as follows (on average over a year, about 70% of non-government residential customer monthly bills, and 67% of non-government general service customer monthly bills, show only first block energy level use):

Class	Cents/kW.h Change			Overall Percentage
	Rider U + Base Rate = Total			Change
Residential Non-Government	(0.496) + (1.624) = (2.12)			(17.8%)
Residential Government	(0.715) + (1.991) = (2.71)			(14.2%)
GS Non-Gov	(1.50)	+ 0	= (1.50)	(13.7%)
GS Municipal Gov	(1.50)	+ 0	= (1.50)	(13.5%)
GS Fed and Terr. Gov	(3.96)	+ 0	= (3.96)	(17.4%)

- An increase in the second block energy charge to all residential non-government customers of 6.70 cents/kW.h (varying percentage depending on zone, from 46.7% in Hydro and Large Diesel zones to 20.5% in Old Crow) and to all residential government customers of 6.73 cents/kW.h (percentages similarly vary by zone from 46.8% to 20.5%). Forecast additional second block revenue is applied to reduce residential first block base rates in each class as noted above.
- Overall impacts on non-government residential customer monthly bills before GST will depend on average monthly use levels (overall savings occur for all customers with use of up to slightly

more than 1,300 kW.h per month – in 2007, 84% of non-government residential monthly bills used no more than 1,300 kW.h):

- At 500 kW.h/month: Saving of \$10.60/month (14.6% of current overall bill)
- At 1,000 kW.h/month: Saving of \$21.20/month (16.1% of current overall bill)
- At 1,300 kW.h/month: Saving of \$1.10/month (0.6% of current overall bill)
- At 1,500 kW.h/month: Increase of \$12.30/month (4.2% to 6.0% of current bill)
- At 2,000 kW.h/month: Increase of \$45.80/month (10.0% to 16.6% of current bill)
- At 3,000 kW.h/month: Increase of \$112.80/month (14.4% to 26.9% of current bill).

SUMMARY OF REQUESTED ORDERS

In summary, approval of the Board is requested for the following Orders:

1. **2008 and 2009 Revenue Requirement:** Approval of the forecast revenue requirement of \$29.217 million for 2008 and \$31.599 million for 2009, and including approval as required of the following costs, revenues and other related provisions:
 - a. **Fuel and Purchased Power Costs** of \$0.487 million and \$0.582 million in 2008 and 2009 respectively, including approval to adjust diesel prices used in setting fuel costs to reflect current forecast conditions.
 - b. **Non-Fuel Operating and Maintenance Costs** of \$12.362 million and \$13.228 million in 2008 and 2009 respectively, including approval:
 - i. To apply \$0.463 million of the remaining Faro Dewatering Account deferred regulatory liability amounts (related to earlier “de-watering sales” to the Faro mine site) against the current outstanding balance in the Yukon Energy Reserve for Injuries and Damages; and
 - ii. To increase the annual appropriation to the Reserve for Injuries and Damages to \$150,000 from the current \$50,000 level starting in 2009.
 - c. **Depreciation and Amortization Expenses** of \$6.403 million for 2008 and \$6.930 million for 2009 including approval to amortize the following regulatory costs:
 - i. An estimated “placeholder” expense of \$0.800 million related to costs for the current GRA (Phase I) Application, anticipated to be incurred over 2008 and 2009 for preparation and review of the Application and reimbursement of related intervenor and YUB costs, to be amortized over the 2 test years (2008 and 2009). The intensity and duration of the regulatory process cannot be determined at this time.

Accordingly, Yukon Energy seeks approval to adjust the above amount to reflect the full actual amounts incurred or Ordered to be reimbursed at the time of the final refiling in the current GRA process, following receipt of all final Orders from the Board. No amounts have been estimated for any future Phase II GRA activities related to further rate design and/or cost of service study matters.

- ii. A total incurred cost of \$0.643 million related to the regulatory review of Yukon Energy's 2006-2025 Resource Plan, as required by the Minister of Justice, to be amortized over 10 years consistent with the anticipated frequency of full Resource Plan updates.
- iii. A total incurred cost of \$0.243 million related to the regulatory review of the Minto Explorations Power Purchase Agreement, to be amortized over 12 years which is the currently anticipated economic life of the substantial terms of the PPA.
- iv. A total incurred cost of \$0.185 million related to the regulatory review of the Carmacks-Stewart Transmission Project ("CSTP") under Part 3 of the Public Utilities Act, as required by the Minister of Justice, to be amortized over 45 years consistent with the approximate average life for the project assets.

- d. **Mid-Year 2008 and 2009 Forecast Rate Base** costs of \$145.212 million and \$151.416 million for 2008 and 2009 respectively, including costs for capital works projects brought into service (or forecast to be brought into service) since the 2005 Required Revenues and Related Matters application as well as deferred costs (including deferred costs related to this Application) and working capital forecast to be included in rate base. Relevant major projects (i.e., costs over \$1 million) include capital works for the Stage One CSTP, acquisition of the Minto Diesel Units, Whitehorse Mirrlees Diesel (WD3) Rebuild, Faro Mirrlees Diesel (FD1) Recommissioning, and Aishihik Third Turbine. Major projects involving deferred costs include work in progress for planning, engineering, permitting and potential tendering activities regarding Mayo B hydro generation enhancement, other generation feasibility assessments, Western Copper (Carmacks Copper mine) connection, and CSTP Stage Two.

- e. **Return on Rate Base** of \$9.965 million in 2008 and a placeholder estimate of \$10.860 million in 2009, including an allowed rate of return on equity ("ROE") of 8.64% for 2008, and a 2009 placeholder ROE of 8.64%, to be adjusted to the final requested level based on the British Columbia Utilities Commission ROE determination for 2009 expected in November 2008.

- 2. **2009 Rates:** Approval of rate adjustments, by class for all related customers of Yukon Energy and YECL, all proposed initially effective November 1, 2008 on an interim refundable basis:

- a. **Retail Rates:** for each retail rate class, rate adjustments consisting of a combination of residential base rate adjustments to promote economy and efficiency within this class as well as a new Rider U “Yukon Energy Rate Reduction Rider” that varies by customer class and is applied to first block rates (and lighting rates) without any rebalancing of overall rate revenues as between customer classes.
- i. **Residential Non-Government (Rate Schedules 1160, 1260, 1360, 1460):** A base rate decrease of 1.36 cents/kW.h for the first 1000 kW.h in any one billing month (“residential first block”), an offsetting base rate increase of 5.61 cents/kW.h for all energy over 1000 kW.h in any one billing month (“residential runoff block”), and a Rider U of negative 0.496 cents/kW.h for all first block energy.
 - ii. **Residential Government (Rate Schedules 1180, 1280, 1380, 1480):** A base rate decrease of 1.66 cents/kW.h for residential first block energy, an offsetting base rate increase of 5.61 cents/kW.h for residential runoff block energy, and a Rider U of negative 0.715 cents/kW.h for all residential first block energy.
 - iii. **General Service Non-Government and Municipal Government (Rate Schedules 2160, 2170, 2260, 2270, 2360, 2370, 2460, 2470):** A Rider U of negative 1.50 cents/kW.h for the first 2000 kW.h in any one billing month (“GS first block”).
 - iv. **General Service Federal and Territorial Government (Rate Schedules 2180, 2280, 2380, 2480):** A Rider U of negative 3.96 cents/kW.h for GS first block energy.
 - v. **Lighting (Rate Schedules 61/66, 67, 75/76):** A Rider U of negative 3.48% to all base rates.
 - vi. **Pelly Crossing:** provision in retail rate schedules, as required as soon as the Stage One CSTP connection occurs at Pelly Crossing, for Pelly Crossing to be included in the Hydro rate zone rate schedules and to be removed from the Small Diesel rate zone rate schedules.
- b. **Wholesale Rates (Rate Schedule 42):** Approval to increase the Wholesale Rate (Rate Schedule 42) charged to YECL throughout Yukon by 0.011 cents/kW.h (from 6.840 cents/kW.h to 6.851 cents/kW.h), commencing concurrent with the above residential base rate changes, so as to maintain revenue neutrality to YECL with respect to base rate revisions. Also approval to adjust, starting in 2009, the rate established for the Energy Reconciliation Adjustment (ERA) provisions of Rate Schedule 42 to 37.37 cents/kW.h using the same principles established in the 1996/1997 GRA to reflect the current forecast incremental cost of diesel generation in WAF.

- c. **Major Industrial Rates (Rate Schedule 39) and related Rider F:** Approval to implement Rate Schedule 39 as mandated by OIC 2007/94 (and approved by Board Order 2008-13) to give effect to the Rider F provisions on a basis consistent with this GRA, by way of;
- i. A “fixed Rider F” charged by Yukon Energy to the Minto mine, and recorded by Yukon Energy as revenue in the period received, of 0.585 cents/kW.h, to reflect required rate adjustments for fuel price variances between November 20, 2006 and the Application’s oil-price forecasts for 2009; and
 - ii. Additional variable Rider F amounts, recorded as payments towards Yukon Energy’s Deferred Fuel Price Adjustment balance, equal to;
 - 1. 0.086 cents/ kW.h so long as the Rider F charge to all other customers in Yukon remains at 1.86 cents/kW.h, and adjusted accordingly if the Rider F charge to these other customers is adjusted prior to final orders of the Board on this Yukon Energy GRA and the YECL GRA; and thereafter
 - 2. The same cents/kW.h rate applied to all other customers in Yukon, and recorded as payments towards Yukon Energy’s and YECL’s consolidated Deferred Fuel Price Adjustment balance the same as all other variable Rider F collections.
- d. **Secondary Energy Rates (Rate Schedule 32):** Approval to adjust the terms of Rate Schedule 32 interruptions, such that future diesel requirements are to be reviewed based on five day weather and load forecasts rather than the current seven day forecasts. Also approval to establish Yukon Energy secondary energy revenue amounts for the GRA Application at a new baseline of: 6.5 cents/kW.h for the retail rate for all sales starting January 1, 2008, 7.2 cents/kW.h for sales starting April 1, 2008, 8.3 cents/kW.h for sales starting July 1, 2008 and 9.3 cents/kW.h for sales starting October 1, 2008 and thereafter at 9.3 cents per kW.h through all of 2009, consistent with approved rates charged in each period (corresponding wholesale secondary rates equal 1.1 cents/kW.h less than these amounts pursuant to Rate Schedule 43). No changes are proposed in the rates to be paid by secondary customers or the approach to setting those rates on a quarterly basis.
3. **Interim Refundable Rates effective November 1, 2008:** Approval to implement the above noted 2009 retail rate changes and decreases effective on an interim refundable basis at November 1, 2008, along with other rate schedule changes as set out above. Following receipt of final orders in this proceeding, including a final 2008 revenue requirement, Yukon Energy can determine any residual shortfall or surplus for each test year and address this amount pursuant to direction of the Board.

4. **Faro Dewatering Account:** In addition to applying \$0.463 million of the Faro Dewatering Account balance against the Reserve for Injuries and Damages (as noted in item 1(b)(i) above), approval, after review and approval of the Board, to address (if and as required) specified income forecast contingencies related to final 2008 retail rate revenue requirements (i.e., offsetting, to the extent required to enable final approved forecast 2008 retail rate revenues, any net revenue losses due to delays in the final connection timing of Minto mine and Pelly Crossing loads to the CSTP from the October 1, 2008 connection date assumed in the Application) and secondary sales revenue losses, if any, arising due to below average water flows in any year after 2008.

KEY FACTORS CONSIDERED IN THE APPLICATION

The Application sets out the major factors affecting Yukon Energy's revenue requirements for each test year, the proposed rates, and other issues. The following key factors are reviewed below:

- CSTP Connection of Minto Mine and Pelly Crossing Loads
- Oil Price Forecasts and Yukon Energy Retail Rate Revenue Requirements
- System Bulk Power Supplies
- Other Factors

CSTP Connection of Minto Mine and Pelly Crossing Loads

The Application has been prepared on the assumption that the Stage One CSTP connection of the Minto mine and Pelly Crossing loads would occur as targeted on October 1, 2008. This approach maximizes the rate reductions available to retail customer classes, and allowed Yukon Energy to proceed over the past several months to complete the Application's detailed schedules required for filing with the Board at the earliest feasible date without consideration of delays and potential adjustments related to the actual final CSTP and mine spur commissioning and final full service connection dates for these two new grid loads. The Application protects the proposed retail rate reductions by proposing to utilize the Faro Dewatering Account to the extent required to offset any net revenue losses due to delays in the final connection timing of these loads to the CSTP from the assumed October 1, 2008 connection date. By way of example, a delay of a full month in connecting these loads (from October 1 to November 1) would reduce Yukon Energy 2008 net revenues by approximately \$197,000 after considering revenue losses and offsetting reductions in CSTP depreciation and related return costs (including reduced Flexible Term Note interest); however, the Application proposes to

offset any such net revenue loss through access to the Faro Dewatering Account to the extent required to enable final approved forecast 2008 retail rate revenue requirements.

As of mid-September, completion of Stage One CSTP and full service connection of the Minto mine and Pelly Crossing loads is currently expected to occur in mid to late October 2008.

Oil Price Forecasts and Yukon Energy Retail Rate Revenue Requirements

As demonstrated since the 1996/97 GRA, both Yukon Energy and YECL are protected against actual fuel price variances from GRA forecasts (as such variances affect diesel fuel generation costs) through the Deferral Fuel Price Account (Rider F), and as a result all customer classes in Yukon today are subject to material Rider F charges (e.g., 1.86 cents per kW.h for all energy used by each retail rate class). Secondary sales price variances from the last Yukon Energy GRA forecast (2005) also currently go the Rider F deferral account rather than to Yukon Energy's income.

The Application assumes that Yukon Energy Rider F account balances for 2008, and the portion of such balances for 2009 prior to final Board GRA approvals, will be adjusted as required to reflect final 2008 and 2009 Yukon Energy GRA fuel and secondary price forecasts as approved by the Board, and that ongoing Rider F accounting thereafter (until the next Yukon Energy GRA) will address variances from the 2009 Yukon Energy fuel and secondary price forecasts as approved by the Board for Yukon Energy's 2009 forecast retail rate revenue requirement.

Oil price forecasts adopted for the GRA test years affect Yukon Energy forecast retail rate revenue requirements through the following three separate paths (today the biggest impact for Yukon Energy tends to be related to secondary sales revenue forecasts):

- Forecast diesel fuel prices used to forecast generation costs directly affect each test year Yukon Energy forecast revenue requirement, with a rise in GRA oil price forecasts acting to increase GRA revenue requirements;
- Forecast Furnace Oil prices adopted in the GRA test years to forecast secondary sales revenues directly affect each test year Yukon Energy forecast retail rate revenue requirement, with a rise in these GRA oil price forecasts acting to reduce GRA retail rate revenue requirements; and
- The 2009 oil price-related forecasts, as well as YECL fuel price forecasts at whatever level ultimately approved by the Board for the YECL 2009 GRA revenue requirement, directly affect Minto mine Fixed Rider F revenues used to determine forecast 2009 the Yukon Energy forecast

retail rate revenue requirement; overall, a rise in these GRA oil price forecasts tends to reduce Yukon Energy GRA retail revenue requirements.

Notwithstanding protections provided by Rider F, experience since the 1996/97 GRA demonstrates how material variances between GRA approved oil price forecasts (as reflected in approved base rates) and current oil prices can lead to inadequate runoff rate price signals that adversely affect economy and efficiency rate requirements. Accordingly, Yukon Energy has sought to adopt realistic oil-related price forecasts for the 2008 and 2009 test years.

There has been considerable volatility, however, in oil prices during 2008 to date, and this situation may well continue during the coming months. The Application assumes Furnace Oil prices through 2008 as actually applied to quarterly adjusted secondary sales rates, with an assumed continuation of the final quarter 2008 rate through 2009. Other oil price forecasts were generally adopted as of late August, reflecting the last Rider F adjustments enacted by YEC/YECL as of August 1, 2008 with some consideration for Yukon Energy forecasts of some moderation in oil prices thereafter.

System Bulk Power Supplies

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

1. **Implications on Customer Use Beginning in the Test Years:** Reduction in the availability of surplus hydro power, and anticipated future requirements to use diesel power (or new renewable generation) for baseload generation on both the WAF and Mayo-Dawson ("MD") systems, will have varying implications for different types of loads:
 - a. **Secondary Sales:** With the increased utilization of surplus hydro generation in coming years, the existing opportunity to sell secondary energy on an interruptible basis will be basically eliminated. There may remain for a few years a small amount of secondary energy available in summer months, during off-peak hours, but the quantities will be limited. In the test years, Yukon Energy forecasts an ability to maintain secondary sales through most hours

of the year, but during cold winter periods there is increased anticipated use of diesel generation for firm load peaking requirements, and consequently much greater forecast interruptions of secondary sales than in recent years (with consequent reductions in secondary sales revenues in the test years).

- b. **Firm Electric Heating:** Affecting primarily the residential class, future system requirements indicate that within a few years, in the absence of new renewable generation, material baseload diesel will be required on the grid systems. In this situation, it is imperative that customers today do not receive price signals that encourage the installation of inefficient baseboard electric heating in new home construction which cannot be easily replaced by a switch to another fuel at a later date. These price signals are concentrated in the second block or “runoff” rates which apply to all residential consumption over 1000 kW.h in a billing month. At today’s rates (which reflect oil prices forecast for the 1996/97 General Rate Application), residential customers are receiving inefficient price signals such that electricity is presently cheaper for heating than oil – a situation that the Application proposes to begin correcting as soon as interim rates come into effect in 2008.
2. **Future Rate Pressures:** Similar to Canada’s other hydro-based jurisdictions, Yukon’s power system includes material assets with embedded costs well below the cost to bring on new generation today. In short, once the existing surplus hydro is fully utilized, ongoing increases in load will serve to be an upward rate driver for all customers. In this type of cost environment, it is important to develop rate structures for all customers that reflect appropriate efficiency signals based on incremental costs, while still ensuring a fair sharing of the benefits of the past resources. OIC 1995/90 provides directions in this regard which the Board implemented through runoff rates approved in the 1996/97 General Rate Application of Yukon Energy and YECL. Full implementation of these principles will be required for all rate classes. While initial efforts towards efficient price signals are incorporated into this Application’s residential and wholesale rates, future rate adjustments will require continued attention in the Residential classes, as well as in the General Service class. Extension of efficient price signals to the General Service rate classes, however, will require future review as soon as feasible with YECL to assess rate re-design options that cannot be addressed in this Yukon Energy Application.
3. **Planning Costs:** With anticipated load increases, both cost and environmental reasons provide strong incentives for Yukon Energy to expand the available complement of renewable generation, as well as transmission interconnections. Developing either enhancements to existing hydro projects, or new renewable generation, is very costly and requires long planning times. The test year planning cost budgets begin to include material expenditures for this next generation of

power projects, but they remain in Work-in-Progress through the test years so do not affect GRA amortization or rate base costs.

Other Items

The Supporting Documents set out detail in respect of a number of other items that are relevant to the requested orders and Yukon Energy's revenue requirement in the test years. Highlights include:

- **WAF Capacity, including Mirrlees Refurbishment and Minto Diesels:** As reviewed in detail at the 2006-2025 Resource Plan proceeding, as of 2006 Yukon Energy faced significant pending capacity shortfalls on WAF related to YEC's new capacity planning criteria as well as planned retirement of a number of major diesel generation units ("Mirrlees") and ongoing load growth. Consistent with the recommendations of the Board in their January 15, 2007 Report to the Commissioner in Executive Council in respect of the Resource Plan, Yukon Energy has initiated a series of activities to address these potential future shortfalls. Under the present planning sequence, Yukon Energy has secured cost effective options for up to 25.4 MW of WAF capacity in a staged and flexible manner, comprised of recommissioning a 5 MW Mirrlees unit at Faro, acquisition of 6.4 MW of diesel units at Minto, plus staged refurbishment of up to three Mirrlees units at Whitehorse (totalling 14 MW) over the period to 2012. While present plans are to proceed with the full 25.4 MW, in the event this full complement of capacity is not determined to be required, or required in the same time frame as presently assumed, options exist to adapt the sequence and timing so as to ensure only the required level of capacity is made available.
- **Faro Dewatering Account "regulatory liability":** In Order 2005-12, the Board directed that Yukon Energy address its 2005 revenue requirement shortfall of \$0.292 million by way of an annual withdrawal from the Faro Dewatering Account regulatory liability that Yukon Energy maintained on behalf of ratepayers. That annual withdrawal was approved for a maximum of 3 years - 2005, 2006 and 2007. Yukon Energy has received approval for the withdrawal for the three years noted; however, no provision was made by the Board for such a withdrawal in 2008 or beyond, and the Application does not seek to extend these annual withdrawals for the test years. The balance in the regulatory liability provision remained at \$1.191 million as of year-end 2007. In this Application, as noted above, Yukon Energy seeks approval to apply \$0.463 million of this provision against the Reserve for Injuries and Damages. The Application also proposes that the forecast Faro Dewatering Account balance of \$0.728 million be available, after review and approval of the Board, to address specified income forecast contingencies related to final 2008 retail rate revenue requirements (offsetting, to the extent required to enable final approved forecast 2008 retail rate revenues, any net revenue losses due to delays in the final connection

timing of the Minto mine and Pelly Crossing loads to the CSTP from the October 1, 2008 connection date assumed in the Application) and secondary sales revenue losses, if any, arising due to below average water flows (see below).

- **Reserve for Future Removal and Site Restoration:** In the 2005 proceeding (Order 2005-12), the YUB directed that Yukon Energy cease the annual appropriations to its Reserve for Future Removal and Site Restoration (or “salvage” account), then at a balance of \$5.618 million, but to continue to use the reserve for its intended purpose. The Board directed that Yukon Energy inform the Board and interested parties when the account reached \$2.0 million. As of 2008, the account has not reached \$2.0 million (it remains in excess of \$5.0 million). Accordingly, Yukon Energy is not seeking any new salvage amounts or appropriations to this Reserve in its 2008 and 2009 test year revenue requirement.
- **Risks related to Low Water:** During recent years, effectively since the closure of the Faro Mine, Yukon Energy’s WAF system has been at load levels that present very little risks of low water resulting in hydro generation shortfalls and costly requirements for diesel generation. When the Faro Mine was operating, a regulatory provision was adopted to address the financial risk to Yukon Energy of using more diesel than forecast to meet firm loads (now called the Diesel Contingency Fund, or “DCF”). Starting 2009, Yukon Energy’s loads once again are reaching levels where very low flow conditions could cause financial impacts for the utility. While the DCF still operates as needed to address the risks of higher than forecast diesel generation being required to serve firm loads, there is no provision in the DCF to address the possible financial implications on Yukon Energy of sustained interruption of secondary sales (and consequently secondary sales revenues) arising from low water conditions. As this situation is likely only potentially relevant for a few more years and is highly unlikely within the 2009 test year, given present water conditions and anticipated loads, no formal new mechanism is proposed to address this risk in the test years. However, in the event this situation affecting secondary sales reductions due to low water does arise prior to Yukon Energy’s next revenue requirement application, Yukon Energy proposes to come back to the Board to seek relief from the financial impacts of this uncontrollable factor (the Faro Dewatering Account will be the preferred source for such relief).
- **Future Joint YEC/YECL Applications re: Rate Design and Cost of Service Matters:** Yukon Energy proposes that, as a first priority, future joint YEC/YECL attention be directed as soon as practicable at identifying and assessing rate design options for General Service rate classes as required to promote economy and efficiency in accordance with OIC 1995/90, taking into consideration current and near term forecast incremental system costs in Yukon in the same manner as such costs were considered by the Board and YEC/YECL in the 1996/97 General Rate

Application. Yukon Energy further proposes that joint YEC/YECL action to prepare a Cost of Service Study be assigned a lower priority, with delayed timing as appropriate, to reflect the timely need to address the above near term rate design priorities that are not tied to Cost of Service Study assessments as well as the fact that OIC 2007/94 and the latest Rate Policy Directive in effect defer until after 2012 any cost-of-service based rate rebalancing adjustments or other rate shift programs affecting the percentage of overall rate revenues allocated to major industrial customers or to any retail customer class.

OVERVIEW OF SUPPORTING DOCUMENTS

Detailed schedules, analysis and documentation in support of the Application are presented in the attached supporting documents.

The supporting documents included with the Application provide detailed information on Yukon Energy's operations and activities, focusing on actual results for 2005 to 2007, and forecasts for 2008 and 2009 that generally reflect actual results to mid-year 2008, and forecasts for the remainder of 2008 and 2009.

The supporting documents also provide other background information relevant to the Application, including review of past Board Orders and directives since the 2005 Required Revenues and Related Matters application, details on specific elements of the Application (e.g., specific proposals relating to rates, return on equity determination), and copies of relevant Orders-in-Council.

The following is an outline of the specific supporting documents included with the Application:

- **Tab 1 Introduction:** provides an introduction to the supporting documents, addressing YUB review of Yukon Energy matters since the 1996/97 GRA, bulk power system resource planning and development challenges, Yukon Energy cost and financial performance, and Yukon Energy rates and bills.
- **Tab 2 Yukon Energy System Sales and Generation:** provides detail on the power system operated by Yukon Energy and its forecast sales and generation for 2008 and 2009.
- **Tab 3 Revenue Requirement:** provides detailed information on Yukon Energy's total forecast cost of providing service in 2008 and 2009 including operating and maintenance expenses, rate base, depreciation and amortization, return on rate base (including a fair return on equity).
- **Tab 4 Rates:** reviews Yukon Energy's rates and provides an explanation of Yukon Energy's proposed rate adjustments and Riders.

- **Tab 5 Capital Projects:** provides an overview of Yukon Energy's capital spending for the period 2005 to 2007, including review of the Carmacks-Stewart Transmission Project and the purchase of the Minto Diesels as well as and forecast capital spending for 2008 and 2009.
- **Tab 6 Board Directives:** provides a review of past Board Orders and responses to outstanding directives since the 2005 Required Revenues and Related Matters Application.
- **Tab 7 Financial Schedules:** provides detailed regulatory schedules for Yukon Energy supporting the Application.
- **Tab 8 Return on Equity:** provides details with respect to Yukon Energy's fair rate of return for 2008 and 2009.
- **Tab 9 2007 Audited Financial Statements:** provides a copy of Yukon Energy's latest audited financial statements.
- **Tab 10 Orders in Council:** provides the relevant Order in Council documents which direct the Board regarding certain aspects of Yukon Energy's revenue requirement and rate design.

SUPPORTING DOCUMENTS – TABLE OF CONTENTS

1.0	INTRODUCTION.....	1-1
1.1	YUB REVIEW OF YUKON ENERGY MATTERS SINCE 1996/97 GRA	1-1
1.1.1	REVENUE REQUIREMENT AND RATE REVIEWS.....	1-1
1.1.2	RESOURCE PLAN, MINTO PPA AND CSTP PART 3 HEARINGS SINCE 2005	1-3
1.1.3	BOARD RECOMMENDATIONS AND DIRECTIVES REGARDING CURRENT YEC AND YECL GRA'S	1-4
1.1.4	CORRESPONDENCE LEADING TO CURRENT GRAS	1-4
1.2	BULK POWER SYSTEM RESOURCe PLANNING AND DEVELOPMENT CHALLENGES	1-6
1.3	YUKON ENERGY COSTS AND FINANCIAL PERFORMANCE	1-9
1.4	YUKON ENERGY RATES AND BILLS.....	1-10
2.0	YUKON ENERGY SYSTEM SALES AND GENERATION.....	2-1
2.1	OVERVIEW	2-1
2.2	SALES FORECAST	2-2
2.2.1	WHOLESALE SALES TO YECL	2-2
2.2.2	MAJOR INDUSTRIAL.....	2-5
2.2.3	YUKON ENERGY FIRM RETAIL SALES.....	2-7
2.2.4	SECONDARY SALES	2-9
2.3	POWER GENERATION.....	2-11
2.3.1	WAF HYDRO GENERATION	2-11
2.3.2	MAYO DAWSON HYDRO	2-12
2.3.3	DIESEL GENERATION	2-12
2.4	PEAK DEMAND FORECAST	2-13
3.0	REVENUE REQUIREMENT	3-1
3.1	OVERVIEW	3-1
3.2	FUEL AND PURCHASED POWER.....	3-4

3.3	NON-FUEL OPERATING AND MAINTENANCE EXPENSES	3-5
3.3.1	PRODUCTION	3-7
3.3.2	TRANSMISSION	3-8
3.3.3	DISTRIBUTION	3-8
3.3.4	GENERAL OPERATION AND MAINTENANCE.....	3-9
3.3.5	ADMINISTRATION.....	3-10
3.3.6	INSURANCE AND RESERVE FOR INJURY AND DAMAGES	3-12
3.3.7	PROPERTY TAXES	3-15
3.4	RATE BASE, DEPRECIATION AND AMORTIZATION.....	3-15
3.5	RETURN ON RATE BASE (INTEREST COSTS AND ROE).....	3-18
3.5.1	COSTS OF DEBT.....	3-19
3.5.2	RETURN ON COMMON EQUITY	3-20
3.6	STABILIZATION MECHANISMS	3-21
4.0	RATES.....	4-1
4.1	OVERVIEW	4-2
4.2	SECONDARY ENERGY RATE DESIGN.....	4-4
4.2.1	RETAIL SECONDARY SALES RATES (RATE SCHEDULE 32)	4-4
4.2.2	LOW GRADE ORE PROCESSING.....	4-6
4.3	MAJOR INDUSTRIAL FIRM RATES.....	4-6
4.4	NON-INDUSTRIAL FIRM RETAIL DESIGN	4-9
4.4.1	YUKON-WIDE RETAIL NON INDUSTRIAL RATES	4-9
4.4.2	OVERVIEW OF RUNOFF (OR “SECOND BLOCK”) RATE LEVELS.....	4-10
4.4.3	YUKON ENERGY RATE REDUCTION	4-14
4.4.4	RATE PROPOSAL.....	4-15
4.5	WHOLESALE RATES.....	4-17
5.0	CAPITAL PROJECTS.....	5-1
5.1	OVERVIEW OF CAPITAL SPENDING	5-1
5.2	CAPITAL WORKS.....	5-2
5.2.1	MAJOR PROJECTS OVER \$1 MILLION.....	5-3

5.2.2	PROJECTS \$100,000 TO \$1 MILLION	5-13
5.3	DEFERRED COSTS.....	5-19
5.3.1	MAJOR PROJECTS OVER \$1 MILLION.....	5-20
5.3.2	PROJECTS BETWEEN \$100,000 AND \$1 MILLION	5-21
6.0	BOARD DIRECTIVES.....	6-1
6.1	ORDER 2005-12	6-1
6.2	ORDER 2007-5 – MINTO POWER PURCHASE AGREEMENT.....	6-3
6.3	BOARD ORDERS 2007-7, 2007-8, 2007-9 AND 2008-1.....	6-7
7.0	FINANCIAL SCHEDULES.....	7-1
8.0	RETURN ON EQUITY	8-1
8.1	BACKGROUND	8-1
8.2	YUKON ENERGY ALLOWED ROE FOR 2008 AND 2009	8-2
9.0	2007 AUDITED FINANCIAL STATEMENTS.....	9-1
10.0	ORDERS IN COUNCIL	10-1

LIST OF TABLES

TAB 2

TABLE 2.1	DIFFERENCE IN ONGOING FORECAST OF PRIMARY SALES OF YEC AND YECL
TABLE 2.2	SUMMARY OF CUSTOMERS, ENERGY SALES AND REVENUES (EXCLUDING RIDERS) – COMPANY
TABLE 2.3	SUMMARY OF CUSTOMERS, ENERGY SALES AND REVENUES (EXCLUDING RIDERS) – MAYO DAWSON
TABLE 2.4	SUMMARY OF CUSTOMERS, ENERGY SALES, AND REVENUES (EXCLUDING RIDERS) – WAF
TABLE 2.5	SUMMARY OF ENERGY BALANCE, LOSSES, PEAK AND LOAD FACTOR

TAB 3

TABLE 3.1	YUKON ENERGY REVENUE REQUIREMENT
TABLE 3.2	FUEL AND PURCHASED POWER
TABLE 3.3	NON-FUEL OPERATING, MAINTENANCE AND ADMINISTRATIVE EXPENSES
TABLE 3.4	EMPLOYEE COMPLEMENT HISTORY
TABLE 3.5	PRODUCTION COSTS
TABLE 3.6	TRANSMISSION COSTS
TABLE 3.7	DISTRIBUTION COSTS
TABLE 3.8	GENERAL OPERATING AND MAINTENANCE
TABLE 3.9	ADMINISTRATION
TABLE 3.10	INSURANCE AND RESERVE FOR INJURY AND DAMAGES
TABLE 3.11	CONTINUITY SCHEDULE FOR THE RFID 1997-2007
TABLE 3.12	PROPERTY TAXES
TABLE 3.13	DEPRECIATION AND AMORTIZATION
TABLE 3.14	COST OF CAPITAL

TAB 4

TABLE 4.1	YUKON ENERGY REVENUE REQUIRED FROM RATES
TABLE 4.2	CALCULATION OF MINTO “FIXED” RIDER F COMPONENT
TABLE 4.3	EXISTING “BASE” FIRM RATES (BEFORE RIDERS AND TAXES) IN \$/KW.H
TABLE 4.4	EQUIVALENT PRICE OF ELECTRICITY FOR HEATING – AUGUST 13, 2008 OIL PRICES
TABLE 4.5	EFFECTIVE RESIDENTIAL 2 ND BLOCK RATE (HYDRO AND LARGE DIESEL ZONES) – EXISTING RATES
TABLE 4.6	REVENUE REDUCTION BY CLASS
TABLE 4.7	RESIDENTIAL EFFECTIVE RATE INCLUDING ALL RIDERS, REBATES, SUBSIDIES AND GST
TABLE 4.8	GENERAL SERVICE EFFECTIVE RATE INCLUDING ALL RIDERS, REBATES, SUBSIDIES AND GST
TABLE 4.9	PRIMARY SALES BY YEC/YECL RATE CLASS & BILLING DETERMINANTS – 2009 EXISTING RATES
TABLE 4.10	PRIMARY SALES BY YEC/YECL RATE CLASS & BILLING DETERMINANTS – 2009 WITH PROPOSED RATE REBALANCING
TABLE 4.11	BILL COMPARISONS: 2009 PROPOSED RATES VS EXISTING – RESIDENTIAL NON GOVERNMENT
TABLE 4.12	BILL COMPARISONS: 2009 PROPOSED RATES VS EXISTING – RESIDENTIAL NON GOVERNMENT (ABSENT RSF)
TABLE 4.13	BILL COMPARISONS: 2009 PROPOSED RATES VS EXISTING – RESIDENTIAL GOVERNMENT
TABLE 4.14	BILL COMPARISONS: 2009 PROPOSED RATES VS EXISTING – GENERAL SERVICE NON GOVERNMENT
TABLE 4.15	BILL COMPARISONS: 2009 PROPOSED RATES VS EXISTING – GENERAL SERVICE NON GOVERNMENT (ABSENT RSF)
TABLE 4.16	BILL COMPARISONS: 2009 PROPOSED RATES VS EXISTING – GENERAL SERVICE MUNICIPAL GOVERNMENT

TABLE 4.17 BILL COMPARISONS: 2009 PROPOSED RATES VS EXISTING – GENERAL
SERVICE MUNICIPAL GOVERNMENT (ABSENT RSF)

TABLE 4.18 BILL COMPARISONS: 2009 PROPOSED RATES VS EXISTING – GENERAL
SERVICE FEDERAL AND TERRITORIAL GOVERNMENT

TAB 5

TABLE 5.1 EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT – SUMMARY

TABLE 5.2 EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT

TABLE 5.3 CONTINUITY SCHEDULE OF PLANNING AND STUDY COSTS (2005)

TABLE 5.4 CONTINUITY SCHEDULE OF PLANNING AND STUDY COSTS (2006)

TABLE 5.5 CONTINUITY SCHEDULE OF PLANNING AND STUDY COSTS (2007)

TABLE 5.6 CONTINUITY SCHEDULE OF PLANNING AND STUDY COSTS (2008)

TABLE 5.7 CONTINUITY SCHEDULE OF PLANNING AND STUDY COSTS (2009)

TAB 6

TABLE 6.1 COST AWARDS 2007-7, 2007-8, 2007-9 AND 2008-1

TAB 7

FILING SCHEDULES

TAB 1
INTRODUCTION

1.0 INTRODUCTION

Yukon Energy's 2008 and 2009 General Rate Application (the "GRA" or "Application") to the Yukon Utilities Board ("YUB" or "Board") includes 10 tabs of supporting documents reviewing information related to Yukon Energy's operations and the requested Board Orders.

Tab 1 provides an introduction to the supporting documents under the following headings:

- YUB Review of Yukon Energy Matters since 1996/97 GRA
- Bulk Power System Resource Planning and Development Challenges
- Yukon Energy Costs and Financial Performance
- Yukon Energy Rates and Bills

1.1 YUB REVIEW OF YUKON ENERGY MATTERS SINCE 1996/97 GRA

The following are reviewed below:

- Revenue Requirement and Rate Reviews
- Resource Plan, Minto PPA and CSTP Part 3 Hearings since 2005
- Board Recommendations and Directives regarding current Yukon Energy and YECL GRAs
- Correspondence Leading to Current GRAs

1.1.1 Revenue Requirement and Rate Reviews

Yukon Energy was last before the Board in 2005 for a general review of its revenue requirements as well as requested approvals for changes to the Secondary Energy Rate Schedules for interruptible surplus hydro generation. Board Order 2005-12 approved Yukon Energy's 2005 revenue requirement, including major capital project costs affecting 2005 revenue requirements, and deferred the need for Yukon Energy

1 to request any increase or change to firm rates through, among other measures, access from 2005
2 through the end of 2007 to \$0.292 million per year from deferred funds (the Faro Dewatering Account)
3 held by Yukon Energy for ratepayer benefit. As required, Yukon Energy filed updates with the Board to
4 secure approval for the 2006 and 2007 use of the \$0.292 million from deferred funds.

5
6 Prior to the 2005 Required Revenues and Related Matters hearing, Yukon Energy had not been before
7 the Board for a general review of its revenue requirements since the 1996/97 General Rate Application
8 ("1996/97 GRA"), which was necessitated by the 1995 re-opening of the Faro mine. The 1996/97 GRA
9 involved a joint application by Yukon Energy and Yukon Electrical Company Limited ("YECL") for each
10 company's separate revenue requirements in 1996 and 1997 as well as for revised rates based on the
11 consolidated rate revenues of these companies and consistent with the rate directives in OIC 1995/90.

12
13 Between the 1996/97 GRA and the 2005 Required Revenues and Related Matters hearing, the Board
14 conducted a limited scope implementation and subsequent adjustments to Rider J to respond to the
15 closure of the Faro mine in 1997 and 1998, affecting about 40% of Yukon utility sales. As reviewed in
16 detail in the Board's 1998 hearing, that rider was set only to recover specific identifiable and major
17 adverse impacts on Yukon Energy from the Faro mine closing. Rider J was not designed to address other
18 ancillary impacts from the closure, such as reductions in retail electricity sales in the town of Faro or
19 other communities, or to address any other cost pressures affecting Yukon Energy since the Board's 1996
20 hearing on the 1996/97 GRA. The Faro mine continues to be closed today. The current reduced 14.93%
21 Rider J rate as approved by the Board in Order 2003-2 was calculated to recover Yukon Energy's annual
22 net revenue shortfall resulting from the loss of this major industrial customer, based on Yukon Energy's
23 revenue requirements and rates for the 1996/97 GRA.

24
25 At the outset of the 2005 Required Revenues and Related Matters hearing, in response to a motion that
26 the Board require both Yukon Energy and YECL to file a general rate application (and a separate motion
27 that the Board require YECL to file a rate application as soon as possible to be heard in conjunction with
28 Yukon Energy's application), the Board issued Order 2005-1 directing Yukon Energy and YECL to jointly
29 file a report with the Board by September 1, 2005 that provides information on the revenue to cost ratios
30 by customer class for both companies using the most recent cost of service allocation study. Yukon
31 Energy and YECL filed the required report with the Board on August 24, 2005, including comments on the
32 implementation of rate shift program over 10 years in response to Board Order 1996-7 from the 1996/97

GRA.¹ Intervenors provided comments to the Board on this report, and on October 27, 2005 Yukon Energy and YECL jointly responded to the Board on these comments.

1.1.2 Resource Plan, Minto PPA and CSTP Part 3 Hearings Since 2005

Since the 2005 Required Revenues and Related Matters hearing, Yukon Energy has been before the YUB on a number of occasions related to the planning for and acquisition of new loads and major bulk power infrastructure (generation and transmission) for Yukon. These include:

- First, a review of **Yukon Energy's 20-Year Resource Plan: 2006-2025** pursuant to a request from the Minister of Justice² focusing on proposed near term major projects of \$3 million or more capital cost, leading to a January 15, 2007 Report to the Minister with Recommendations;
- Second, a hearing to review and approve the **Power Purchase Agreement** (the "PPA") with Minto Explorations Ltd. ("Minto Explorations"),³ which resulted in Order 2007-5 April 30, 2007 rejecting the PPA as filed, and subsequently Order 2007-6 approving the amended May 14, 2007 PPA;
- Third, a hearing under Part 3 of the Public Utilities Act related to the **Carmacks-Stewart Transmission Project** (the "CSTP")⁴ leading to a YUB Report to the Minister of Justice regarding Yukon Energy Corporation's Application for Energy Project and Energy Operation Certificates regarding the Proposed Carmacks-Stewart Transmission Project on May 31, 2007.

¹ Order 1996-7 directed the companies to "design a rate shift program that would target revenue/cost ratios in the range of 90% to 110% over a 10-year period."

² On June 5, 2006, the Minister of Justice of the Government of Yukon requested that the Yukon Utilities Board hold a hearing to review the Yukon Energy Resource Plan and forward a report on its findings to the Commissioner in Executive Council. A hearing was held on this submission in 2006. The Board provided its recommendations to the Commissioner in Executive Council related to the 20-Year Resource Plan on January 15, 2007.

³ The Board's recommendations relating to the 20-Year Resource Plan recommended that the final PPA should be submitted for Board approval. On February 9, 2007, Yukon Energy filed the finalized PPA for review and approval by the Board.

⁴ The CSTP was designated on March 16, 2007, by OIC 2007/51, as a regulated project under Part 3 of the Public Utilities Act. On April 2, 2007, Yukon Energy applied to the Minister for an energy project certificate and an energy operation certificate under Part 3 of the Public Utilities Act for the CSTP, providing information for such an application as prescribed under OIC 2007/50. The Minister of Justice of the Government of Yukon directed, by letter and Terms of Reference dated April 2, 2007, that the Board review the application for the certificates and conduct an oral hearing as part of its review. The Board was ordered to consider the implications to the project of the findings of the Board in its current review and adjudication of the PPA application. The Minister directed the YUB to report and make recommendations regarding the necessity for the CSTP and its timing and design and to submit its report and recommendations to the Minister of Justice by April 30, 2007 and no later than May 31, 2007. The Board submitted its Report and Recommendations to the Minister of Justice on May 31, 2007.

Subsequent to the PPA hearing and the two Board Orders related to the PPA, OIC 2007/94 was issued which fixed Industrial Rate Schedule 39 as required by the amended PPA. This OIC amended the earlier OIC 1995/90,⁵ to “ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary” attached as Schedule A to OIC 2007/94. On August 25, 2008, Yukon Energy filed an application with the YUB to approve as final the Rate Schedule 39 attached to OIC 2007/94; this approval was provided in Board Order 2008-13.

1.1.3 Board Recommendations and Directives regarding current YEC and YECL GRA's

In its January 2007 Report to the Commissioner in Executive Council on the Yukon Utility Board review of Yukon Energy's 20-Year Resource Plan: 2006-2025, the YUB recommended the following:

Now is an appropriate time for YEC and YECL to have a complete review of all GRA Phase I and Phase II matters. The Board recommends that YEC and YECL file a full GRA application before October 31, 2007. The application should include a full cost of service, rate design and an update of the Electric Service Regulations. The Board also suggests that YEC and YECL consider a performance-based regulation mechanism. As well, the Board recommends that evidence be provided as to what other utilities provide for Maximum Company Investment and model theirs accordingly (Report to the Commissioner in Executive Council, page 53).

The Board re-iterated the recommendation for a complete cost of service (“COS”) study in Order 2007-5 on the PPA, setting out specific elements to be included in such a COS study.

1.1.4 Correspondence leading to current GRAs

On July 20, 2007 the YUB sent a letter to both Yukon Energy and YECL asking for a reply by August 22, 2007 as to whether they will be in a position to comply with the Board's January 2007 recommendation to file a GRA by October 31, 2007, and if not, to indicate when they would be in a position to bring the GRA before the Board. The two utilities met and discussed this matter, and then replied separately to the Board on August 17, 2007.

⁵ To add subsection 6(3) immediately after subsection 6(2) of OIC 1995/90.

- **YECL:** YECL indicated that it was working towards filing a Phase I General Rate Application by March 31, 2008 (after upcoming regulatory filings with its sister companies in NWT) and a Phase II General Rate Application shortly thereafter.

- **YEC:** Yukon Energy indicated: "Although YEC is currently planning towards filing a Phase I [revenue requirement] application in February 2008 this timing is subject to having the required information regarding the factors that could materially affect YEC revenue requirements, including clarity as to the timing and expected costs for the completion of the Stage One Carmacks-Stewart Transmission Project and connection of the Minto Mine to the WAF grid". YEC also indicated that a joint YEC/YECL cost of service and rate design filing (Phase II filing), which must flow from the Phase I revenue requirements as separately filed by YEC and YECL, would be the most effective way to comply with OIC 1995/90 directives, and that this Phase II filing would likely occur a few months after both Phase I filings have occurred.

YEC sent a letter to the YUB on December 17 informing the Board that YEC now planned to file its next revenue requirement application in August/September 2008 and, based on this timing, that YEC and YECL have committed to work together to file a consolidated YEC/YECL Phase II cost of service and rate design filing concurrent with YEC's revenue requirement filing so that these matters can be reviewed at the same hearing. YEC's letter noted that its timing in this regard reflected the need to consider:

- Expected in-service timing for Minto mine connection to grid (this timing is subject to weather-related delays regarding winter work and spring timing enabling substation work to proceed, and by May/June YEC expected to be in a better position to determine if the targeted connection by September 30, 2008 is obtainable);
- Minto mine power loads and life (YEC will work with Minto to confirm projected power loads for 2008 and 2009, as well as updated mine life); and
- Prospects for connecting other mines, diesel generation requirements and planning for other major new resource projects.

On April 30, 2008 YECL filed a Phase I General Rate Application requesting approval for its revenue requirements for the 2008 and 2009 test years, and noting that YECL expects a joint YEC/YECL Phase II GRA (cost of service and rates for 2009) to be filed within three months after Yukon Energy files its Phase I GRA.

As committed, Yukon Energy's current Application has been filed following confirmation of CSTP connection timing for the Minto mine. Rate Policy Directive (OIC 1995/90) was also amended prior to the filing of this Application to direct that, prior to January 1, 2013, the Board must ensure that rate adjustments for retail customers (as defined in OIC 1995/90) apply equally, when measured as percentages, to all classes of retail customers. Accordingly, given the latest Directive to the Board, Yukon Energy is not, as part of the current GRA submissions, addressing COS and rate design work related to any rate shift program or rate rebalancing as between customer classes. The Application, however, addresses rate design issues within each retail customer class related to OIC 1995/90 directives regarding runoff rates.

1.2 BULK POWER SYSTEM RESOURCE PLANNING AND DEVELOPMENT CHALLENGES

Since the 2005 Required Revenues and Related Matters hearing, resource planning and development requirements for Yukon's bulk power system (i.e., grid generation and transmission) have become a key focus for Yukon Energy activities.

As evidenced by Yukon Energy's several hearings before the YUB since 2005, as well as the company's recent and ongoing major capital spending projects, bulk power system resource planning and development challenges are being addressed in several key areas, including:

- **Winter Peak Generating Capacity Planning Shortfalls on WAF** – Winter peak generation interruption related to a single major system risk event (Aishihik transmission interruption) was underlined by the January 29, 2006 Whitehorse-Aishihik-Faro ("WAF") grid outage.⁶ Yukon Energy's 20-Year Resource Plan proposed new generation capacity planning criteria, and forecast significant WAF generating capacity shortfalls based on these criteria as early as 2007 and 2008. To address these winter peak generating capacity shortfalls Yukon Energy has initiated a series of cost effective capital spending activities which will enable 25.4

⁶ On April 11, 2006 Yukon Energy provided a response to the Board regarding three questions related to this outage.

MW of WAF diesel capacity to be added, restored, or extended as required in the near term.
(See Sections 2.4, 5.2.1.2, 5.2.1.3, and 5.2.1.4 for more detailed information).

- **WAF Hydro Energy Surplus, Minto Industrial Load Opportunity and CSTP Development** – In 2005, surplus hydro generation on WAF prior to secondary (interruptible) sales approximated 90 GWh/yr at normal flows; absent new industrial loads, some surplus hydro was forecast to remain at normal flows on both the WAF and Mayo Dawson (“MD”) grids until at least around 2020. The 2007 PPA with Minto Explorations and 2008 Stage One CSTP development is resulting in new firm sales of surplus WAF hydro generation to displace diesel generation at the Minto Mine as well as at Pelly Crossing. Customer and government capital cost contributions towards this new transmission extension, along with the new firm Industrial Primary Rate Schedule 39 rates, are resulting in substantial near term net revenue benefits to offset other Yukon Energy costs and provide the basis for rate revenue requirement reductions in this Application. Yukon is also securing cost effective major new transmission infrastructure development which is a major step toward future connection of the WAF and MD grids; Stage Two CSTP development has been licensed to proceed on a timely basis to connect these grids in response to additional industrial loads. (See Sections 2.2.2.1, 2.3, 4.3 and 5.2.1.1 for more detailed information).
- **Aishihik Third Turbine Development** – Installation of the 7 MW turbine at the existing Aishihik generation station in 2010, as reviewed by the Board in the recent Resource Plan and CSTP Part 3 hearings, will help to reduce future diesel generation through both more efficient use of water at this facility, as well as better ability to use the plant to meet short-term peak loads (as an alternative to diesel generation). The approximate \$8.5 million capital cost is being offset by \$5.0 million Yukon Government capital cost contributions. (See Section 5.2.1.5 for more detailed information).
- **Additional Near Term Potential Industrial Load Requirements** - Over the 2010-2011 period commercial mining developments on both the WAF⁷ and MD⁸ systems may require

⁷ Western Copper Corporation has recently completed its YESAB review process for the Carmacks Copper mine project and this mine is expected to require grid service commencing sometime after 2010 with an expected annual requirement of 4 GWh per month (48 GWh per year) for at least six years.

⁸ On the MD grid, Alexco Resource Corp is expected to commence mining and milling activities on the Keno Hill property in early 2010, requiring 21-25 GWh/year of load for at least a 5 year period.

grid service, and necessitate the licencing and construction of a spur line (in the case of the Carmacks Copper mine), as well as the negotiation and Board approval of new power purchase agreements. Yukon Energy is also aware of other possible commercial mining developments (over the next 4 to 7 year horizon) that may materialize near the MD and WAF grids. (See Section 2.2.2.2 for more detailed information).

- **Near Term End of Hydro Energy Surpluses, Potential Resumption of Baseload Diesel Generation, and New Renewable Resource Generation Planning** - After CSTP Stage One development and the Minto Mine connection (and before allowing any secondary sales), hydro generation surpluses at long term average flows will likely now be fully utilized by firm sales on WAF sometime between 2011 and 2014. Connection of additional new industrial loads could fully utilize existing hydro generation surplus energy on the WAF and MD grids sooner, to the point where, absent new renewable sources of generation, material near term baseload diesel generation (e.g., 50 to 100 GW.h/yr) could be required during the 2010 to 2015 period even after allowing for CSTP Stage Two and Aishihik Third Turbine developments. Major deferred project costs (totaling \$2.5 million in 2008 and \$15.3 million in 2009) are forecast to plan and develop renewable resource projects, such as Mayo B, that would meet new system load requirements and displace near term baseload diesel requirements. (See Sections 5.3 and 5.3.1 for more detailed information).
- **Higher Oil Prices** - Forecast oil prices for 2009 are materially above levels approved for the 2005 Yukon Energy revenue requirement.⁹ Higher oil prices increase test year overall Yukon power system costs to the extent that diesel generation is required in 2009, and highlight the potential importance of timely new renewable resource generation development to minimize any renewed requirements for baseload diesel generation on the WAF and MD grids.
- **Implications for Secondary Sales** - Surplus hydro generation is forecast to supply secondary sales in the test years, and higher Furnace Oil prices than in 2005 result in higher Yukon Energy secondary sales revenues to offset other revenue requirement costs.¹⁰ While the amount of available surplus energy is lower over the test period than in previous years,

⁹ Yukon Energy diesel fuel prices for 2009 are forecast to average 117 cents per litre (comparable 2005 forecast as approved averaged almost 60 cents per litre, e.g., 56.4 c/l at Whitehorse in 2005, versus almost 115 c/l in 2009).

¹⁰ Forecast YEC secondary sales revenues average 6.7 cents/kWh for 2008 and 8.2 cents/kWh for 2009, as compared with approximately 4.1 cents/kWh as approved for 2005.

the maximum reasonable amount of hydraulic generation is forecast to be made available for secondary sales over the test period to ensure that both secondary sales customers and firm customers continue to receive the benefits provided from the sale of available surplus generation. Beyond 2009, however, new industrial loads would lead to curtailment of secondary sales and these related revenues.

- **Inefficient Price Signals for Firm Electric Heating and other Power Loads –**

Inefficient price signals currently exist with regard to firm (non-interruptible) electric heating as well as other power loads, reflecting runoff second block rates unchanged from the 1996/97 GRA (when such rates were set to reflect Yukon Energy's then forecast diesel fuel generation costs based on a fuel price averaging about 30 cents per litre). Bulk power system planning requirements include a need to correct this situation as soon as possible. (See Section 4.4 for more detailed information and Yukon Energy's proposed initial residential runoff rate adjustments. Section 4.5 addresses related adjustments to the firm wholesale rate).

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

1.3 YUKON ENERGY COSTS AND FINANCIAL PERFORMANCE

Notwithstanding ongoing cost pressures, robust sales have allowed the Return on Equity ("ROE") earned in recent years by Yukon Energy to exceed the 9.05% level approved by the Board in 2005, permitting Yukon Energy to operate without any requirement for rate adjustments in the interim.¹¹

Yukon Energy has experienced increasing cost pressures since 2005 owing to the feasibility and planning requirements necessary to bring on the next generation of bulk power infrastructure, as well as increased

¹¹ See Tab 7, Schedule 4. ROE was 9.48% in 2005, 10.59% in 2006 and 9.45% in 2007.

operations costs. These cost pressures in particular include higher fuel costs, increased labour costs and employee requirements (mostly incurred by 2007), other non-fuel operating and maintenance cost increases, amortization cost increases related to deferred costs (including planning studies, regulatory activities and licensing costs, and hearing costs), and increased average costs of debt (as a component of rate base return). In contrast, the forecast ROE for the test years (which continues to be proposed by reference to British Columbia Utilities Commission formulas as approved by the Board in 2005 and other earlier Yukon Energy applications) is reduced to 8.64% for 2008. (See Tabs 3 and 8 for more detailed information).

Notwithstanding increasing cost pressures, additional Yukon Energy revenues arising from service to the Minto mine after commissioning of the CSTP in October 2008 combined with continuing revenues from secondary sales enable a general rate reduction for ratepayers over the forecast test years.¹²

For the past decade, Yukon Energy has maintained two mechanisms as accounts approved by the Board to stabilize rates and revenues:

- The Deferral Fuel Price Account (Rider F) captures variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA-approved fuel price. Since Board Order 2005-12, issuing from the 2005 Required Revenues and Related Matters hearing, Yukon Energy has also credited this account with all variations in the ongoing quarterly adjustment to the prices of secondary sales.
- The Diesel Contingency Fund (DCF) serves to stabilize Yukon Energy's costs to serve firm loads on WAF due to variances in water flows and consequent variations in hydro generation. When diesel is on the margin the account stabilizes diesel costs related to water flow variations.

1.4 YUKON ENERGY RATES AND BILLS

Since Yukon Energy was established in 1987, rate matters related to Yukon Energy and YECL have been typically dealt with on a joint basis. This arrangement reflected YECL management of Yukon Energy prior

¹² Between 2005 to 2007 Yukon Energy had access to \$0.292 million per year from deferred "funds" (regulatory liability) held by Yukon Energy for ratepayer benefit. This annual provision was approved for the three years from 2005 and 2007 only with no provision for a further withdrawal after that time. As of year-end 2007 the balance in this account was \$1.191 million.

to 1998 as well as the rate policy directive to the YUB set out since 1987 in various OIC's establishing equalized rates in Yukon (Tab 10 provides copies of the current OIC's directing the Board on rate determinations).

The Board directly determines rates (other than Rider F which is adjusted by the utilities in accordance with Board and OIC directives). The Yukon Government separately determines two other key factors directly affecting bills paid by most ratepayers (namely, the Income Tax Rebate and the Rate Stabilization Fund).

The following are the major changes affecting firm rates and bills generally paid by Yukon Energy's customers since 2005:

1. Rider F (Diesel Fuel Price Changes): Yukon Energy and YECL have jointly required Rider F collections from all retail customers since December 2000. Routine updates are provided to the Board. The current Rider F for all retail customers as at August 2008 is 1.86 cents per kW.h, reflecting variances in fuel prices for YECL since 1997 (from the 1996/97 GRA) and for Yukon Energy since 2005 (from the approved 2005 revenue requirement).

2. Retail Secondary Sales Rates: With Order 2005-12, the Board approved an automatic adjustment mechanism that adjusts the rate on a quarterly basis based on the lowest of the three most recent Yukon Bureau of Statistics bi-weekly furnace oil prices for Whitehorse. To address fuel price related variance in income, the Rider F Deferred fuel price mechanism was used to normalize secondary sales revenues and act as a natural hedge to the Rider F account, reducing variability.

3. Rate Stabilization Fund: The Yukon Government's Rate Stabilization Fund (RSF) began providing non-government residential customers with additional bill relief starting December 1, 1998, providing a maximum monthly rebate on the 1st block of energy used by each non-government and municipal retail customer class. The Yukon Government determined in 2007 to phase out the RSF. OIC 2007/58 repealed OIC 2005/49 and extended a reduced RSF from July 1 2007 until June 30, 2008. OIC 2008/70 provides for the RSF to continue from July 1 2008 until June 30, 2009.

1 **4. Industrial Rate 39:** When the amended PPA was filed Yukon Energy advised that the
2 Yukon Government would fix Rate Schedule 39 as required by the amended PPA. In Board
3 Order 2007-6 (dated May 25, 2007) the Board approved the PPA as amended on May 14,
4 2007 and noted that it had “reviewed the filing and agrees that it meets the intent of Board
5 Order 2007-5.” On August 25, 2008 Yukon Energy filed an amended Rate Schedule 39 with
6 the Board for approval noting that the Board had yet to approve a final rate schedule 39 that
7 conforms to the Rate Schedule 39 attached to OIC 2007/94. Board Order 2008-13 approved
8 a final Rate Schedule 39.

9
10 As reviewed in Tab 4 of this Application, specific rate adjustments by class, proposed in this Application
11 consist of a combination of base rate adjustments as well as a new Rider U “Yukon Energy Rate
12 Reduction Rider” which together provide for a reduction in retail rates.

TAB 2
YUKON ENERGY SYSTEM SALES AND GENERATION

2.0 YUKON ENERGY SYSTEM SALES AND GENERATION

Yukon Energy's rates are based on recovering the costs of owning, operating and maintaining the assets required to provide service to its customers. Tab 2 provides an overview of the Yukon Energy system forecast sales and generation for 2008 and 2009.

The following items are reviewed in this Tab:

- Overview
- Sales Forecast
- Power Generation
- Peak Demand Forecast

2.1 OVERVIEW

Yukon Energy is the main generator and transmitter of electrical energy in Yukon, accounting for over 90% of annual Yukon power generation and providing 138 kV and 69 kV transmission facilities for the Whitehorse/Aishihik/Faro ("WAF") and Mayo-Dawson ("MD") grid systems respectively.

Yukon Energy directly serves about 1900 customers at the distribution (retail) level (about 11% of all electrical retail customers in Yukon), most of whom live in and around Dawson City, Mayo and Faro. Indirectly, Yukon Energy also provides power to Yukon retail customers served on the WAF system (including those located in Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and Teslin, and, starting fall 2008, Pelly Crossing) and MD system (Keno, Stewart Crossing) through its wholesale sales to the Yukon Electrical Company Limited ("YECL"). Sales to the Minto Mine ("Minto") (under Primary Industrial Rate Schedule 39) are forecast to commence in October 2008 with completion of the Minto Spur line and Stage One of the Carmacks-Stewart Transmission Project ("CSTP") between Carmacks (WAF) and Pelly Crossing. No other Major Industrial customer sales (i.e., 1000 kW load or greater with activities as defined in Order-in-Council 1995/90) are forecast for the test period.

Yukon Energy hydro generation capability materially exceeded firm sales on both the WAF and Mayo systems after the Faro mine closure in 1998 on WAF and the 1989 closure of the United Keno Hill Mine (“UKHM”) on the Mayo system. However, given continued load growth on the WAF system, including new industrial load once grid service to Minto commences in October 2008, WAF surplus generation will have declined markedly by 2009. The forecast for the test years is based on continued ability to supply nearly the entire test year generation forecast on both the WAF and MD grids from hydraulic generation (other than for limited “peaking” requirements). Anticipated connection of other industrial customers beyond the test years, as well as ongoing wholesale load growth and completion of Stage Two of CSTP to connect the two grids, are expected within the next five years to result in WAF and MD loads both increasing to levels that exceed the long-term average capability of the installed hydraulic generation, driving the need for either renewed baseload diesel generation or, preferably, new or enhanced hydraulic or other renewable generation resources.

2.2 SALES FORECAST

Yukon Energy actual sales from 2005-2007 and forecast sales for 2008 and 2009 are summarized in Tables 2.2 to 2.4 at the end of this tab. Sales forecasts include actual sales through June 2008.

Total forecast sales are 316,031 MW.h for the 2008 test year and 343,581 MW.h for the 2009 test year. Total forecast sales for 2008 include 258,989 MW.h of primary (firm) wholesale sales, 6,845 MW.h of primary Major Industrial sales, 29,640 MW.h of firm Retail sales (i.e., all firm sales other than wholesale or Major Industrial), and 20,557 MW.h of secondary sales (most sold on a wholesale basis to YECL), while total forecast sales for 2009 include 266,926 MW.h primary wholesale sales, 29,023 MW.h Major Industrial sales, 31,019 MW.h firm Retail sales, and 16,613 MW.h of wholesale and retail secondary sales. Tables 2.3 and 2.4 summarize sales information for each of MD and WAF respectively.

2.2.1 Wholesale Sales to YECL

Yukon Energy's sales are primarily made up of firm wholesale sales on the WAF system to YECL, combined with a small amount of wholesale sales to YECL on the Mayo Dawson system. Each year YECL provides Yukon Energy with an updated WAF firm wholesale purchase power forecast for the following year reflecting its forecast WAF system firm retail sales less its forecast generation from its small Fish

Lake hydro plant.¹ Yukon Electrical also provides its forecast firm wholesale purchased power on the Mayo-Dawson system.

Over the forecast period, wholesale sales are expected to grow by approximately 1.6% over the 2007 to 2008 period and approximately 3.1% over the 2008 to 2009 period. Yukon Energy forecasts an approximate 2,300 MW.h increase in annual wholesale sales to YECL due to the completion of the CSTP and the provision of grid service to Pelly Crossing. Grid sales to Pelly Crossing are forecast at 550 MW.h in 2008 (sales are forecast for the months of October, November and December of 2008) and 2,300 MW.h in 2009.² Absent Pelly Crossing, wholesale sales are forecast at 258,439 MW.h in 2008 and 264,626 MW.h in 2009, with percentage growth rates of approximately 1.38% in 2008 over 2007 actuals, and 2.39% in 2009 over forecast 2008.

Yukon Energy's forecast wholesale loads for 2008 and 2009 vary from the forecasts prepared by YECL and filed with their 2008/2009 General Rate Application ("GRA"). There are three reasons for this:

1. **Secondary Sales Losses:** When 2008 and 2009 load forecasts for secondary sales were initially developed by Yukon Energy (in consultation with YECL), issues related to secondary sales availability following connection of the Minto Mine had not been fully considered. Due to higher firm system loads, Yukon Energy at that time adopted a conservative set of assumptions that no secondary sales were to be included in Yukon Energy's initial 2009 load forecast outside of a very limited amount of sales in summer months from excess flows at Whitehorse. This earlier Yukon Energy forecast appears to form the basis for the forecast used by YECL in its 2008/2009 GRA which reflected only 16,853 MW.h of YECL retail secondary sales in 2008, and 6,954 MWh of YECL retail secondary sales in 2009. This is 3,052 MW.h and 9,029 MW.h below Yukon Energy's current forecasts for YECL secondary sales in 2008 and 2009 respectively. As YECL only purchases an equal quantity of secondary wholesale energy from Yukon Energy as it sells at the retail level, in effect all losses on YECL's system associated with secondary sales are supplied by Yukon Energy at wholesale

¹ The YECL 2008/2009 General Rate Application notes that in their forecasts, Fish Lake hydro generation is based on average generation over the last 10 years adjusted for estimated downtime for required rebuilds during the test period. Variations in the annual generation at Fish Lake can have an impact on Yukon Energy's revenues from purchased power. Yukon Electrical forecasts 6.2 GW.h of generation at Fish Lake for the 2008 and 2009 test years, a 3.8 GW.h reduction from the approximately 10 GW.h hours of generation available at the time of the 1996/97 GRA. This is also a material reduction from the actual numbers reported from 2006 and 2007 (8.2 GW.h and 9.0 GW.h respectively).

² YECL's 2008/2009 General Rate Application at Schedule 4.2 provides a forecast Pelly diesel generation load of 2,272 MW.h in 2007, 22 MW.h higher than 2006 actuals. The forecast diesel generation drops to 1,746 MW.h in 2008 for an estimated 550 MW.h of grid wholesale sales (comprised of a diesel generation reduction of 527 MW.h from 2007, plus growth from 2007 to 2008) and to 11 MW.h in 2009 for an estimated 2,300 MW.h of grid wholesales.

primary service (Rate Schedule 42). Assuming system average 6.2% distribution losses on YECL's system,³ this factor accounts for 189 MW.h and 560 MW.h of additional forecast wholesale primary sales in 2008 and 2009 respectively compared to YECL's forecasts.

2. **2008 Actuals Year-to-Date:** Yukon Energy's load forecasts for 2008 incorporate actual sales through June 2008, which were not available to YECL as of their filing date of April 30, 2008.

3. **2009 Forecast Load Growth:** Yukon Energy's 2009 load forecasts are markedly higher than the YECL forecasts in their GRA reflecting Yukon Energy's analysis of wholesale load growth, including the WAF load growth analysis for the 2001-2004 period (averaging 2.2% per year), as reviewed in the Yukon Energy 20-Year Resource Plan 2006-2025 ("Resource Plan") and the more recent experienced growth rate in WAF wholesales from 2004 to 2007 actuals, at 2.5% per year. Yukon Energy has utilized a growth rate in this range (2.39%) as the basis for estimating load increases from 2008 to 2009 based on this evidence of the experienced longer-term load trends.

³ Consistent with Schedule 3.2 of the YECL 2008/2009 GRA.

The net result of the Yukon Energy versus YECL forecasts for wholesale load is set out in Table 2.1 below:

Table 2.1

Difference in Ongoing Forecast of Primary Sales of YEC and YECL

Yukon Energy - GRA forecast of primary sales to YECL

MW.h

	2007 actual	2008 forecast	2009 forecast
Total	254,914	258,989	266,926
less: Pelly Crossing		(550)	(2,300)
Ongoing WAF and MD sales (excl Pelly)	254,914	258,439	264,626
<i>growth</i>		1.38%	2.39%

YECL - GRA forecast of primary purchases from YEC

MW.h

	2007 actual	2008 forecast	2009 forecast
Total	254,914	260,093	263,202
addback: add'l secondary losses		189	560
less: Pelly Crossing (est)		(550)	(2,300)
Ongoing WAF and MD sales (excl Pelly)	254,914	259,732	261,462
<i>growth</i>		1.89%	0.67%

difference in "ongoing sales" forecast (MW.h)
between YEC and YECL

-1,293 3,164

2.2.2 Major Industrial

Between 2005 and 2007 there were no Major Industrial customers on the system. With the completion of the Stage One CSTP (expected by October 2008), service to Minto under Industrial Primary Rate Schedule 39 is expected to commence. No other Major Industrial Power customer load is forecast for the test years.

2.2.2.1 Minto Mine

Forecast industrial sales as provided in July 2008 by Minto Explorations Ltd. for the last three months of 2008 are 6,845 MW.h and forecast industrial sales for 2009 are 29,023 MW.h. This is slightly lower than the 32.5 GWh per year load assumed in the Power Purchase Agreement ("PPA") application for Minto

1 filed in February 2007, and reflects the fact that several loads included in the original assumptions
2 provided by Minto Explorations were not ultimately required.

3
4 As the 2009 forecast revenues are only slightly above the minimum take-or-pay amounts as set out in the
5 PPA (\$3 million in total sales per Payment Year),⁴ it is noted that in the event of any further material
6 reductions in revenues from Minto for 2009, the minimum take-or-pay provision will be triggered, thus
7 mitigating any further downside risk associated with the 2009 Minto revenue forecast.

8
9 No sales are forecast to Minto under Rate Schedule 35 Low Grade Ore Processing Secondary Energy
10 Rate. This rate cannot be utilized by the mine until audit and control measures and reporting
11 requirements have been developed between Yukon Energy and Minto Explorations, and filed with, and
12 approved by, the Board.⁵ This has not yet occurred, nor has Minto Explorations to date provided any
13 specific forecasts for such loads. Further, as noted below with respect to secondary sales, there is little
14 surplus generation available on the WAF system to service any further non-firm loads beyond reduced
15 Rate Schedule 32 Secondary Sales. As provided for in the rate schedule, any Rate Schedule 35 Low Grade
16 Ore Processing Secondary Energy loads would only be served as a lower priority service than Rate
17 Schedule 32 Secondary Sales.

18
19 The GRA forecast does not include any potential reduction in revenues related to use of the peak shaving
20 rate option for Minto, as provided for in Rate Schedule 39. To date, Minto Explorations has not indicated
21 that they would expect to make use of this initiative. Electing to take service under this provision requires
22 at least 6 months advance notice from the customer.

23 **2.2.2.2 Update on Other Mines**

24 The Carmacks Copper mine being developed by Western Copper Corporation is not expected to be
25 operational or to require grid service over the test period. The mine is currently completing the YESAB
26 review process, which will be followed by the issuance of the necessary Quartz Mining Licence and a
27 water licencing process before the Yukon Water Board. Yukon Environmental and Socio-economic
28 Assessment Board ("YESAB") Recommendations for this project pursuant to section 58(1) of the Yukon

⁴ Based on Industrial Primary Rate Schedule 39 as provided for in OIC 2007/94, the forecast loads will pay an average of 10.36 cents per kWh in 2008 (\$0.709 million) and 10.83 cents per kWh in 2009 (\$3.142 million), excluding Rider F charges proposed to be set at 0.671 cents/kW.h in the August 25, 2008 Rate Schedule 39 filing with the Yukon Utilities Board.

⁵ See Board Order 2007-5, Board Directive #5 which notes, "Should Minto pursue Rate 35, proposed audit and control measures and reporting requirements must be established between YEC and Minto, and then YEC is to file these with the Board. YEC is not to implement Rate Schedule 35 until such approval has been granted." This directive was reflected in the PPA as amended May 14, 2007 and approved by Board Order 2007-6.

Environmental and Socio-economic Assessment Act (“YESAA”) were filed on July 18, 2008, and on September 12, 2008 the Yukon Government issued a decision document accepting the YESAB Recommendations. Carmacks Copper has yet to apply for its water licence. Based on forecasts provided to Yukon Energy by Western Copper, the Carmacks Copper mine will not commence commercial operation in the test years. The projected in service date at this time is 2011, with an expected annual requirement averaging approximately 4 GW.h per month (48 GW.h per year) and a mine life of at least six years. In order to connect the Carmacks Copper Mine to WAF, a new spur line connecting the mine with the Stage One CSTP will need to be licenced and constructed, and Yukon Energy will need to have concluded a power purchase agreement with Western Copper that is then reviewed and approved by the YUB. Discussions between Yukon Energy and Western Copper with regard to such a power purchase agreement are expected to commence later this year after the Carmacks Copper project YESAB review process is completed.

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

Other WAF near-term mine developments are also under consideration for potential commercial operation beginning within the next 4 to 7 years at locations close to the WAF and MD grids, including the Dublin Gulch project near the MD grid and the Casino mine project near the WAF grid.

2.2.3 Yukon Energy Firm Retail Sales

After experiencing a 3.1% decline in firm retail sales (i.e., residential, general service, street and space lights combined) between actual 2005 and actual 2006, Yukon Energy's retail sales grew by 2.6% in actual 2007, and are forecast to grow by 3.2% in 2008 and by a further 4.6% in 2009. The test year increases over the forecast period, compared to actual 2005 to actual 2007 results, are mainly attributed to the growth in general service sales.

2.2.3.1 Residential Sales

Firm residential retail sales have grown from 10,169 MW.h in actual 2005 to 11,155 MW.h in forecast 2008 and 11,183 MW.h in forecast 2009. This reflects ongoing modest growth in the number of customers, and basically consistent use per customer over the period.

2.2.3.2 General Service Sales

Firm general service retail sales were 18,438 MW.h, in actual 2005, and are forecast at 18,193 MW.h in 2008 and 19,543 MW.h in 2009. Lower general service sales starting in 2006 and 2007 compared to 2005 can be attributed to a decline in total Faro load, related to the varying load for dewatering activities at the Faro mine site. Total Faro general service load dropped from 7,091 MW.h in 2005 to 5,488 MW.h in 2006 and 5,398 MW.h in 2007. This change in load is fundamentally due to changes at the Faro Mine site.

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

The Faro mine site load is forecast at approximately 3.3 GW.h for 2008 and 2.7 GW.h for 2009. Current forecasts have reclamation efforts at the Faro mine site increasing significantly beyond the test years, approximately in 2012.

2.2.3.3 Lighting

Firm retail sales for streetlights have grown from 257 MW.h actual in 2005 to 278 MW.h for both forecast 2008 and forecast 2009, an 8.2% increase over the 4 year period. Firm retail sales for space lights have remained steady since actual 2005 and are forecast to remain at approximately this same level for 2008 and 2009.

2.2.4 Secondary Sales

After the Faro mine closure in 1998, Yukon Energy took significant efforts to market surplus hydro available from Yukon Energy's facilities, with net revenues derived from sales going towards lowering rates compared to what would otherwise be required for firm customers throughout the Yukon.

Yukon Energy total secondary sales⁶ (i.e., sales sold at special rates on condition that these sales can be interrupted at any time that surplus hydro generation is not available) increased substantially leading up to the 2005 Required Revenues and Related Matters hearing, to a forecast level of 20,613 MW.h in 2005. As reviewed at that time, further increases in secondary sales quantities were not being aggressively targeted as the remaining surplus on the system was diminishing. Since the 2005 Required Revenues and Related Matters hearing, only two new secondary customers have been added, and total secondary sales increased at a slower pace, increasing to 22,185 MW.h in 2006 and to 24,225 MW.h in 2007.

For test year 2008, forecast sales decline to 20,557 MWh, primarily due to equipment outages at a small number of the largest secondary customers through the early part of the year.

In test year 2009, the availability of surplus power is expected to decrease with increased firm loads (including grid service to Minto Mine). Yukon Energy has rules in place, as approved by the Board pursuant to Rate Schedule 32 that interrupt secondary sales as required to ensure these sales are not served by high-cost diesel generation but only by surplus hydro.⁷ This can lead to interruptions for one of two reasons:

1. **Peaking Diesel Operation:** In very cold weather, at certain times of day, Yukon Energy's test year forecast peak loads (including secondary) exceed the current peak winter hydro generation capability of the WAF system.⁸ When this occurs, interruptions of secondary

⁶ The majority of Yukon Energy's secondary sales occur at the wholesale level (to YECL, for ultimate distribution to customers) with only a small amount of secondary sales by Yukon Energy directly to retail customers (exclusively on the Mayo-Dawson system).

⁷ Pursuant to Rate Schedule 32, customers can opt for installing SCADA-controlled service that allows Yukon Energy to initiate interruptions on 15 minutes notice, as and when required only for actual real-time diesel generation being required on the respective system or for system emergencies or outages; alternatively, customers can have a standard metered service. Under the latter option, customers' supply will be interrupted after 24 hours notice at any time that Yukon Energy forecasts a need to run diesel units for more than 10% of the hours in the subsequent seven day period, or that Yukon Energy begins running diesels for unforeseen reasons and expects the diesel operation to continue for more than 48 hours. As noted in Tab 4, for practical reasons Yukon Energy is proposing to reduce the seven day forecast period to 5 days.

⁸ With existing loads, Mayo-Dawson peak capacity does not routinely exceed the installed hydro generation capability of that system, and consequently no interruption of Mayo-Dawson secondary sales are built into the forecast. Interruptions will begin to occur in the event that loads are higher than forecast, or for actual diesel generation for either planned or unplanned unavailability of hydro. With the anticipated future development of new industrial loads on the MD system (e.g., Alexco), the Mayo-Dawson secondary sales loads are also anticipated to be interrupted over the long-term for energy related reasons.

energy availability will occur,⁹ which will reduce the quantity of secondary sales compared to lower load periods. It is anticipated that increased secondary sales interruptions will begin to occur during cold winter months of 2009 as a result of materially higher firm WAF loads following connection of Minto.¹⁰ This is the primary factor driving secondary sales down to the 16,613 MW.h level forecast for the 2009 test year compared to 20,557 MW.h in 2008.¹¹

2. **Water Availability:** In contrast to peaking diesel operation, which is a real-time hydro generation capacity-related constraint on secondary sales, past history has also provided occasions where lengthy secondary sales interruptions were required due to inadequate long-term water on the system to support the sales (an inherently energy-related constraint). For example, this was forecast in the 1996/97 GRA to occur for WAF throughout the year when the Faro mine was operating. For the test years 2008 and 2009, interruptions for this reason are not anticipated on either a seasonal or annual basis. Under normal long-term average flows, there is sufficient water to support the forecast level of firm and secondary sales indicated. In future beyond the test years, with ongoing load growth and potential additional mine loads, long-term interruptions of secondary energy are expected. Although not able to be forecast for GRA purposes, interruptions can also occur as required when water flow conditions are materially below long term average flows.

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

⁹ Short-term surplus hydro forecasts are regularly developed by YEC using a forecast model which combines the most current weather forecast against load curve data from the prior week. The process of determining surplus hydro versus the potential need for diesel generation is based on the following variables: Environment Canada weather forecasts; system peak and load curve; average water flows; hydro unit availability and maintenance; hydro and diesel operational constraints; 10% of hours criteria; avoiding premature disconnect of secondary sales; timing of disconnect notice to YECL; provision of notice from YEC to YECL. Separate consideration goes into determining interruptions of SCADA connected customers, given the approved rules in Rate Schedule 32.

¹⁰ The assumed hours of interruption total 1740 hours, concentrated in January, February and December of 2009.

¹¹ Absent short-term interruptions, the maximum potential secondary sales in 2009 is forecast to be 22.0 GW.h reflecting the sum of all connected loads, less an unavailability factor related to customer equipment.

2.3 POWER GENERATION

Yukon Energy produces power on two independent systems – the Whitehorse – Aishihik – Faro (“WAF”) system and the Mayo-Dawson (“MD”) system. For both systems the predominant source of generation forecast for the test period is hydro, supplemented as necessary by a small amount of diesel for peaking or maintenance purposes. There is also a small amount of wind generation on the WAF system. While the amount of surplus hydro energy available for secondary sales is lower than previous years, some level of surplus hydro generation is forecast for most hours of the year on each of Yukon Energy’s systems over the test period.

2.3.1 WAF Hydro Generation

Yukon Energy’s long-term average hydro generation capability from its Whitehorse and Aishihik plants on the WAF system, as estimated in the 1996/1997 General Rate Application when the Faro mine was assumed to be fully operational and all available hydro generation was expected to be fully utilized, approximates 351 GW.h per year.¹² By contrast, forecast WAF Yukon Energy hydro generation is 314 GW.h in 2008 and 340 GW.h in 2009 (including 20 GW.h of secondary sales forecast in 2008 and 16 GW.h of secondary sales forecast in 2009). The remaining surplus hydro generation on the WAF system is approximately 37 GW.h in 2008 and 11 GW.h in 2009 (a material reduction from the 72 GW.h of surplus hydro remaining after secondary sales as noted in 2005). Since the secondary sales consume much of the normal surplus winter hydro generation, further surplus hydro generation is predominantly available in summer and fall.

The WAF system typically operates with Whitehorse Hydro as first-on generation (outside of wind and Fish Lake) as a largely run-of-river plant. Aishihik is used to supplement this run-of-river generation to achieve the required output. When peak loads exceed the combined Whitehorse and Aishihik Hydro capacity of between 54-58 MW in winter, diesel generation is dispatched to serve firm loads. When diesel is forecast to be used or required to be used, secondary sales are interrupted pursuant to the rules of Rate Schedule 32.

Yukon Energy is committed to providing the maximum reasonable amount of hydraulic generation, and maximizing the surplus secondary energy for sale that is available in any year in order to secure benefits for both secondary customers and firm power customers (from the offsetting effect of secondary

¹² Yukon Energy is in the process of updating this value, in support of current resource planning activities. The earlier Resource Plan Submission (2006) addressed integrated WAF hydro capability including YECL’s Fish Lake plant.

revenues on firm power rates). At long-term average water levels, basically all firm loads and forecast secondary loads set out for the test years can be met by hydraulic generation. This requires that significant stored water from Aishihik be used over the course of the winters for the two test years. In the event of an extreme drought occurring, it is possible that secondary sales may need to be curtailed by about late 2009 to ensure Aishihik stored water is prioritized for future firm load service and offsetting any high risk of future diesel generation beyond 2009. While such a drought event is not anticipated, in the event it arises over the test years, the practical impact on secondary sales volumes is most likely to arise in the latter part of test year 2009, and into 2010.¹³ In the event this arises, Yukon Energy would likely be required to return to the Board for 2010 to address the cost and revenue shortfall implications of such an event.

2.3.2 Mayo Dawson Hydro

Hydro generation from the Mayo Generating Station currently supplies the Town of Mayo, the City of Dawson, Keno and Stewart Crossing (wholesales to YECL) as well as a number of new loads along the Mayo-Dawson transmission line route. Hydro generation for 2009 is forecast at 31 GW.h compared to a long-term average from this facility approximating 40 GW.h. Similar to the WAF system, there is less winter surplus capacity available than summer and fall surplus capacity.

2.3.3 Diesel Generation

Yukon Energy's forecast generation for the test period is made up of 99.5% hydro. For the required diesel generation, comprising 0.3% - 0.4% of total system generation (1,206 MW.h in 2008 and 1,262 MW.h in 2009), fuel prices have increased substantially since the last review in Yukon Energy's Required Revenues and Related Matters application for 2005 (from an average of approximately 60 cents per litre to a forecast of diesel prices in 2009 of \$1.164/litre in Dawson, \$1.181/ litre in Faro,¹⁴ \$1.156/litre in Mayo and \$1.149/litre in Whitehorse as reviewed in Tab 3). In 2009 this diesel generation is forecast to supply the system during times of peak loads as well as certain maintenance activities. Yukon Energy forecasts average efficiency on this diesel generation of 3.64 kW.h/litre in Whitehorse, 3.55 kW.h/litre in Faro and 3.71 kW.h/litre in Dawson, based on recent 12 month averages. This efficiency is an increase from the 2005 application, where the approved forecast average efficiency was 3.48 kW.h/litre. Average

¹³ Going into the winter of 2008/2009, the Aishihik Lake reservoir will be full making it unlikely that a drought event in 2009 would affect secondary sales until at most the very end of 2009.

¹⁴ While Yukon Energy does not have a fuel supply arrangement for the Minto diesel units, it is assumed that fuel prices would be in the range of prices at Faro, given transportation requirements.

fuel efficiencies remain low compared to the mid-1990s when these same plants were used for sustained baseload generation, as opposed to the lower efficiency of peaking use.

With respect to WAF diesel, it is not possible under most situations to forecast the precise diesel units that will be dispatched to serve firm loads when needed for peaking. For 2009, Table 4.5 indicates all diesel power generation occurring at Faro as proxy for diesel generation anywhere on the WAF system (e.g., generation could occur at Whitehorse, Minto). Similarly, Mayo-Dawson diesel generation requirements are assumed at Dawson.

2.4 PEAK DEMAND FORECAST

Yukon Energy developed the peak demand forecast for 2008 and 2009 based on long term planning assumptions. As indicated in Table 2.5, the peak demand for the WAF system is forecast to be 58 MW in 2008 and 62 MW in 2009. At these peak levels (which exceed typical WAF winter hydro generating capacity), secondary sales are assumed to be interrupted for the peak hours. For the Mayo-Dawson system, the peak demand is forecast to be in the range of 5 MW in 2009.¹⁵

At the 2005 Required Revenues and Related Matters application, Yukon Energy noted concerns about the ongoing application of its then current WAF generation planning criteria. This issue was addressed in some detail at the hearing to review Yukon Energy's 20-Year Resource Plan: 2006-2025, where expert evidence indicated that continued use of this criteria would allow maximum peak loads to reach a level well beyond the reasonable capability of the system before the criteria would indicate new generation was required. In its Resource Plan Submission, Yukon Energy proposed a new two-part capacity planning criteria. In the January 15, 2007 report to the Minister, the YUB recommended the adoption of a new two-part planning criteria, with some differences compared to the version adopted by Yukon Energy in respect of one of the criteria (the LOLE approach):

- **LOLE:** With respect to the Loss of Load Expectation ("LOLE") criteria, variations in the potential approaches to applying this criteria remain between the Yukon Energy Resource Plan approach and the approach recommended by the Board in their January 15, 2007 report to the Commissioner in Executive Council. However, under either approach, this criteria is not the driving factor on the WAF system today.

¹⁵ This is dependant in part on the load characteristics of the Alexco bulk sampling load, which may also be coincident with other system loads.

- **N-1:** The N-1 criteria remains the key requirement in respect of additions to capacity on the WAF system. Yukon Energy has incorporated the N-1 planning criteria into its planning activities for the test years. Generation additions in the test years (focused on Minto diesels and Whitehorse Mirrlees) are required by the N-1 criteria and are reviewed in Tab 5.

As reviewed in the 2006 Resource Plan proceeding, for 2007 and into 2008 Yukon Energy was forecast to be faced with capacity constraints even absent industrial loads, leading the Board to recommend, at page 34 of its Report to the Minister, that “new capacity should be added to the WAF system as soon as possible”. In order to address this situation, Yukon Energy committed to complete a full recommissioning of a 5 MW Mirrlees unit that had previously been retired at Faro, to which the Board concurred. That unit is scheduled to be fully in-service in 2008.

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

With the addition of these two new capacity sources, Yukon Energy has initiated an orderly refurbishment of the Whitehorse Mirrlees units, as recommended in the 2006 Resource Plan.

The N-1 analysis (which is the driving criteria at this point in time) indicates the capability to take each respective Whitehorse Mirrlees off-line for refurbishment as needed, without driving system shortfalls during the refurbishment period, even if it occurs over a winter. This is a substantial reduction in system risk compared to the situation expected to be required at the outset of the Resource Planning exercise in 2005 (where each respective Mirrlees refurbishment would have to be completed within one summer season; otherwise capacity shortfalls would arise the following winter should the unit remain offline for any technical reasons or late parts delivery, etc.). The Whitehorse Mirrlees refurbishment process is now scheduled for the first unit in 2008 (WD3 for 5 MW),¹⁶ and the second in 2010 (WD2 for 5 MW). For the

¹⁶ The generator rewind for this unit is not scheduled until 2010, to allow for more efficient coordination of the necessary work on WD2 and WD3. The unit will be operational from 2008-2010 with the current winding.

1 third unit, options exist following 2010 with respect to refurbishment, or “mothballing”¹⁷ that unit for a
2 number of years pending a future full refurbishment, as under certain load growth scenarios sufficient
3 capacity would exist to permit this refurbishment spending to potentially be deferred for some period.
4 Complementary common systems and general plant work is scheduled for 2008 (e.g., electrical upgrades
5 and cooling system enhancements). At the present time, the unit is scheduled to be refurbished in 2012.

6
7 One capacity-related matter was noted in the Resource Plan in respect of the hydro systems. At that
8 time, Yukon Energy established a reliable firm output for its Whitehorse Hydro plant at 24 MW in winter,
9 but noted that investigations were required to determine if further revisions were needed, or possible,
10 based on ice conditions on the Yukon River. Further investigation into Yukon River icing indicate that the
11 24 MW value remains valid for planning the system as a reliable winter peak output for this plant.

¹⁷ While the unit would not remain on an active supply duty, it would not be salvaged or removed from the building, so that a future refurbishment process could be conducted on the unit to bring it back to full service.

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues (excluding Riders) - Company

Table 2.2
September 2008

Line No.	Description	Approved				Forecast Existing	Forecast Existing
		2005	Actual 2005	Actual 2006	Actual 2007	2008	2009
1	Residential						
2	Customers	1,302	1,336	1,365	1,390	1,416	1,432
3	Sales in MWh	10,201	10,169	10,665	10,908	11,155	11,183
4	MWh sales per customer	7.8	7.6	7.8	7.8	7.9	7.8
5	Revenue (\$000s)	1,208	1,215	1,267	1,313	1,319	1,335
6	Cents per KWh	11.84	11.95	11.88	12.04	11.83	11.94
7	General Service						
8	Customers	447	450	447	450	450	457
9	Sales in MWh	16,808	18,438	17,037	17,507	18,193	19,543
10	MWh sales per customer	37.6	41.0	38.1	38.9	40.4	42.8
11	Revenue (\$000s)	2,305	2,470	2,301	2,376	2,442	2,637
12	Cents per KWh	13.71	13.40	13.51	13.57	13.42	13.49
13	Industrial						
14	Sales in MWh	0	0	0	0	6,845	29,023
15	Revenue (\$000s)	0	0	0	0	709	3,142
16	Cents per KWh	7.00	7.00	7.00	7.00	10.36	10.83
17	Street lights						
18	Sales in MWh	252	257	270	275	278	278
19	Revenue (\$000s)	65	66	69	71	71	71
20	Cents per KWh	25.75	25.64	25.64	25.62	25.64	25.63
21	Space lights						
22	Sales in MWh	13	14	14	14	14	15
23	Revenue (\$000s)	2	3	3	3	3	3
24	Cents per KWh	19.76	21.89	21.48	22.00	21.82	21.54
25	<u>Total Company - Firm Retail & Ind.</u>						
26	Customers	1,749	1,786	1,812	1,840	1,866	1,889
27	Sales in MWh	27,274	28,878	27,987	28,705	36,485	60,042
28	Revenue (\$000s)	3,580	3,754	3,641	3,763	4,545	7,188
29	Cents per KWh	13.13	13.00	13.01	13.11	12.46	11.97
30	Wholesale sales						
31	Sales in MWh	234,542	237,419	251,861	254,914	258,989	266,926
32	Revenue (\$000s)	16,043	16,239	17,227	17,436	17,715	18,258
33	Cents per KWh	6.84	6.84	6.84	6.84	6.84	6.84
34	<u>Total Company - Firm</u>						
35	Sales in MWh	261,816	266,296	279,847	283,619	295,474	326,968
36	Revenue (\$000s)	19,623	19,993	20,868	21,199	22,259	25,446
37	Cents per KWh	7.49	7.51	7.46	7.47	7.53	7.78
38	Secondary						
39	Sales in MWh	20,613	18,933	22,185	24,225	20,557	16,613
40	Revenue (\$000s)	854	767	917	1,000	850	688
41	Cents per KWh	4.14	4.05	4.13	4.13	4.13	4.14
42	Total Company						
43	Sales in MWh	282,428	285,229	302,032	307,844	316,031	343,581
44	Revenue (\$000s)	20,477	20,760	21,785	22,200	23,109	26,134
45	Cents per KWh	7.25	7.28	7.21	7.21	7.31	7.61

Note:

Excludes revenues from Rider J, Industrial Rider F, and offsets in new Revenue Reduction Rider as set out in Tab 4

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues (excluding Riders) - Mayo Dawson

Table 2.3
September 2008

Line No.	Description	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast Existing 2008	Forecast Existing 2009
1	Residential						
2	Customers	1,015	1,031	1,056	1,073	1,095	1,108
3	Sales in MWh	8,112	7,982	8,346	8,510	8,739	8,759
4	MWh sales per customer	8.0	7.7	7.9	7.9	8.0	7.9
5	Revenue (\$000s)	960	954	992	1,025	1,033	1,046
6	Cents per KWh	11.84	11.95	11.88	12.04	11.83	11.94
7	General Service						
8	Customers	370	370	366	370	372	378
9	Sales in MWh	10,786	11,139	11,289	11,808	11,937	13,976
10	MWh sales per customer	29.2	30.1	30.8	31.9	32.1	37.0
11	Revenue (\$000s)	1,493	1,492	1,525	1,603	1,602	1,886
12	Cents per KWh	13.84	13.40	13.51	13.57	13.42	13.49
13	Industrial						
14	Sales in MWh	0	0	0	0	0	0
15	Revenue (\$000s)	0	0	0	0	0	0
16	Cents per KWh	N/A	N/A	N/A	N/A	N/A	N/A
17	Street lights						
18	Sales in MWh	154	159	173	177	181	180
19	Revenue (\$000s)	40	41	44	45	46	46
20	Cents per KWh	25.75	25.64	25.64	25.62	25.64	25.63
21	Space lights						
22	Sales in MWh	10	12	13	13	13	13
23	Revenue (\$000s)	2	3	3	3	3	3
24	Cents per KWh	19.76	21.89	21.48	22.00	21.82	21.54
25	<u>Total - Firm Retail and Industrial</u>						
26	Customers	1,385	1,401	1,423	1,443	1,467	1,486
27	Sales in MWh	19,063	19,293	19,821	20,508	20,870	22,928
28	Revenue (\$000s)	2,495	2,490	2,564	2,675	2,685	2,980
29	Cents per KWh	13.09	12.90	12.93	13.05	12.86	13.00
30	Wholesale sales						
31	Sales in MWh	581	390	854	855	891	916
32	Revenue (\$000s)	40	27	58	58	61	63
33	Cents per KWh	6.84	6.84	6.84	6.84	6.84	6.84
34	<u>Total - Firm</u>						
35	Sales in MWh	19,644	19,684	20,675	21,363	21,761	23,844
36	Revenue (\$000s)	2,535	2,516	2,622	2,734	2,746	3,043
37	Cents per KWh	12.90	12.78	12.68	12.80	12.62	12.76
38	Secondary						
39	Sales in MWh	800	570	630	659	652	630
40	Revenue (\$000s)	42	30	33	34	34	33
41	Cents per KWh	5.20	5.20	5.20	5.20	5.20	5.20
42	<u>Total</u>						
43	Sales in KWh	20,444	20,254	21,305	22,022	22,412	24,474
44	Revenue (\$000s)	2,576	2,546	2,655	2,768	2,780	3,076
45	Cents per KWh	12.60	12.57	12.46	12.57	12.40	12.57

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues (excluding Riders) - WAF

Table 2.4
September 2008

Line No.	Description	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast Existing 2008	Forecast Existing 2009
1	Residential						
2	Customers	288	305	309	317	322	324
3	Sales in MWh	2,089	2,186	2,320	2,398	2,416	2,424
4	MWh sales per customer	7.3	7.2	7.5	7.6	7.5	7.5
5	Revenue (\$000s)	247	261	276	289	286	289
6	Cents per KWh	11.84	11.95	11.88	12.04	11.83	11.94
7	General Service						
8	Customers	77	80	80	80	78	79
9	Sales in MWh	6,022	7,299	5,747	5,699	6,256	5,568
10	MWh sales per customer	78.2	91.5	71.5	71.2	80.2	70.5
11	Revenue (\$000s)	811	978	776	774	840	751
12	Cents per KWh	13.47	13.40	13.51	13.57	13.42	13.49
13	Industrial						
14	Sales in MWh	0	0	0	0	6,845	29,023
15	Revenue (\$000s)	0	0	0	0	709	3,142
16	Cents per KWh	N/A	N/A	N/A	N/A	10.36	10.83
17	Street lights						
18	Sales in MWh	97	97	97	97	97	97
19	Revenue (\$000s)	25	25	25	25	25	25
20	Cents per KWh	25.75	25.64	25.64	25.62	25.64	25.63
21	Space lights						
22	Sales in MWh	2	1	2	1	1	1
23	Revenue (\$000s)	0.5	0.3	0.4	0.3	0.3	0.3
24	Cents per KWh	19.76	21.89	21.48	22.00	21.82	21.54
25	<u>Total - Firm Retail and Industrial</u>						
26	Customers	365	385	389	397	400	403
27	Sales in MWh	8,211	9,584	8,166	8,196	15,615	37,113
28	Revenue (\$000s)	1,084	1,264	1,077	1,087	1,860	4,208
29	Cents per KWh	13.21	13.19	13.19	13.27	11.91	11.34
30	Wholesale sales						
31	Sales in MWh	233,961	237,028	251,007	254,059	258,098	266,011
32	Revenue (\$000s)	16,003	16,212	17,169	17,378	17,654	18,195
33	Cents per KWh	6.84	6.84	6.84	6.84	6.84	6.84
34	<u>Total - Firm</u>						
35	Sales in MWh	242,172	246,612	259,173	262,254	273,713	303,124
36	Revenue (\$000s)	17,087	17,477	18,246	18,465	19,514	22,403
37	Cents per KWh	7.06	7.09	7.04	7.04	7.13	7.39
38	Secondary						
39	Sales in MWh	19,813	18,363	21,555	23,566	19,905	15,983
40	Revenue (\$000s)	812	737	884	966	816	655
41	Cents per KWh	4.10	4.02	4.10	4.10	4.10	4.10
42	<u>Total</u>						
43	Sales in KWh	261,985	264,975	280,728	285,820	293,618	319,107
44	Revenue (\$000s)	17,900	18,214	19,130	19,431	20,330	23,058
45	Cents per KWh	6.83	6.87	6.81	6.80	6.92	7.23

Yukon Energy Corporation
Summary of Energy Balance, Losses, Peak and Load Factor

Table 2.5
September 2008

Line No.	Description	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast 2008	Forecast 2009
Sales and Losses							
1	Total Energy Sales	282,428	285,229	302,032	307,844	316,031	343,581
2	Losses - MWh	21,841	23,957	24,884	25,031	27,355	28,945
3	Losses - %	7.73%	8.40%	8.24%	8.13%	8.66%	8.42%
4	Total Generation	304,270	309,186	326,916	332,875	343,386	372,526
Source - MWh							
Hydro Generation							
WAF System							
5	Whitehorse	179,469	201,990	216,766	206,389	206,145	237,294
6	Aishihik	99,480	80,650	80,690	98,142	108,060	102,794
7	Total	278,949	282,640	297,456	304,531	314,206	340,088
8	Mayo	22,946	25,077	27,166	26,735	27,476	30,686
9	Total Hydro	301,895	307,717	324,622	331,266	341,681	370,774
10	Wind Turbine	1,125	890	600	362	618	491
Diesel Generation							
11	Whitehorse	200	80	690	363	284	0
12	Faro	50	34	729	106	546	866
13	Dawson	1,000	461	271	757	377	396
14	Mayo	0	4	4	21	0	0
15	Total Diesel	1,250	580	1,694	1,247	1,206	1,262
Source - %							
16	Hydro Generation	99.2%	99.5%	99.3%	99.5%	99.5%	99.5%
17	Diesel Generation	0.4%	0.2%	0.5%	0.4%	0.4%	0.3%
18	Wind Generation	0.4%	0.3%	0.2%	0.1%	0.2%	0.1%
Peak - MW							
WAF System							
19	firm (excl sec - note 1)	55	n/a	n/a	n/a	58	62
20	firm plus secondary	59	56	60	58	58	62
21	Mayo System (note 1)	5	4	4	4	5	5

Notes:

- Yukon Energy does not track actual secondary peak usage, as these customer are not metered in a way to permit this monitoring. For forecast years, loads are estimated separately for firm versus secondary.

TAB 3
REVENUE REQUIREMENT

3.0 REVENUE REQUIREMENT

Yukon Energy's forecast revenue requirement is the total forecast cost of providing service in a given year, including a fair return on equity. As set out in Tab 4, this revenue requirement is recovered from the proposed firm and secondary rates charged to Yukon Energy's retail customers and wholesale customer, as well as other Yukon Energy revenues.

The following items are reviewed in this Tab:

- Overview
- Fuel and Purchased Power
- Non-Fuel Operating and Maintenance Expenses
- Rate Base, Depreciation and Amortization
- Return on Rate Base (Interest Costs and ROE)
- Stabilization Mechanisms

3.1 OVERVIEW

This Tab summarizes the revenue requirement for Yukon Energy for test years 2008 and 2009, as well as comparative figures for 2005 to 2007 (actual). Yukon Energy's operations were last reviewed in detail during the 2005 hearing on Required Revenues and Related Matters.

There are three major components to Yukon Energy's 2008 and 2009 revenue requirement:

- Operating and maintenance expenses, including fuel costs, labour and costs for administering the utility;

- Depreciation and amortization of assets and deferred costs included in rate base; and
- Return on rate base to cover the costs of the utility's various sources of capital (long-term debt issuances and equity) required to finance the rate base.

Yukon Energy's forecast 2008 and 2009 revenue requirement reflects proposed adjustments to diesel fuel prices, as well as changes to labour and non-labour costs relative to 2005, the last test year reviewed by the Board during the 2005 Required Revenues and Related Matters hearing. Table 3.1 compares Yukon Energy's forecast 2008 and 2009 revenue requirement to the requirements for 2005 to 2007. The forecast revenue requirement for 2008 of \$29.217 million is \$2.801 million higher than actual costs in 2005, while the revenue requirement for 2009 of \$31.599 million is \$5.183 million higher than the actual costs of running the utility in 2005. Completion of the Stage One CSTP, which contributes to these increased revenue requirements, is the key factor leading to an overall 2009 rate reduction (see Tab 4) due to additional revenues and cost savings derived from commencement of grid service to the Minto mine and Pelly Crossing.

Table 3.1
Yukon Energy Revenue Requirement
(\$000)

				Forecast		Forecast	
	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Fuel and Purchased Power	\$ 185	\$ 178	\$ 271	\$ 280	\$ 487	\$ 324	\$ 582
Non-Fuel Operating and Maintenance	11,233	11,293	12,116	12,362	12,362	13,128	13,228
Depreciation and Amortization	5,379	5,611	5,779	5,913	6,403	6,441	6,930
Return on Rate Base	9,619	10,609	10,024	10,435	9,965	12,189	10,860
Revenue Requirement	\$ 26,416	\$ 27,690	\$ 28,191	\$ 28,991	\$ 29,217	\$ 32,082	\$ 31,599

The forecast diesel fuel cost increases reflect the biggest percentage growth from 2005 to 2009 (215%) in the four cost categories set out in Table 3.1. Approximately \$0.302 million of the revenue requirement change from 2005 to 2008, and \$0.397 million of the change from 2005 to 2009, is due to fuel and purchased power costs for generation (approximately 11% of the 2005-2008 increase, and 8% of the 2005-2009 increase), including incorporating recent fuel price increases in forecast costs of diesel fuel consumed. Prior to the 2008 test year, extra costs for generation due to diesel fuel prices in excess of

2005 Required Revenues and Related Matters hearing forecasts were not included in Yukon Energy's revenue requirement, but collected from customers directly through the Rider F Deferred Fuel Price Adjustment mechanism. The 2005 revenue requirement was based on fuel prices forecast in the 60 cent per litre range (the 2005 forecast prices) rather than the more recent forecast price of approximately \$1.11 per litre in 2008 and \$1.15 per litre in 2009.

The forecast Non-Fuel Operating and Maintenance cost increase from 2005 to 2009 of \$1.995 million (18% increase) accounts for the largest share (about 38%) of the overall revenue requirement change from 2005 to 2009. As noted in Table 3.3, over 60% of this Non-Fuel Operating and Maintenance cost increase is related to increased Labour costs and requirements for administration and other company operations, with 80% of this increase occurring by 2007.

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

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

These changes to revenue requirement components are reviewed in more detail below.

3.2 FUEL AND PURCHASED POWER

Fuel and Purchased Power costs have increased substantially since 2005, from \$0.185 million in 2005 to \$0.487 million in 2008 and to \$0.582 million in 2009 as set out in Table 3.2. In 2009, approximately 65% of this increase is due to diesel fuel price increases.

Table 3.2
Fuel and Purchased Power
(\$000)

				Forecast		Forecast	
	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Fuel	\$ 137	\$ 126	\$ 218	\$ 227	\$ 434	\$ 270	\$ 528
Purchased Power	48	52	53	53	53	54	54
TOTAL Fuel and Purchased Power	\$ 185	\$ 178	\$ 271	\$ 280	\$ 487	\$ 324	\$ 582

The quantity of fuel required on Yukon Energy's system reflects the standby nature of YEC's generation. The quantity of diesel generation (and therefore diesel fuel consumption) has remained relatively constant in the 0.6 GW.h to 1.7 GW.h range since 2005 (compared to the 1990s when over 100 GW.h of diesel generation was used when the Faro mine was operating and Dawson was served with diesel generation). The 2008 and 2009 diesel generation forecasts are in the 1.2 to 1.3 GW.h range and reflect only forecast peaking and unplanned outage requirements, as well as mechanical maintenance and electrical (i.e. transmission planned outage) requirements.

Forecast fuel prices for the 2008/2009 test years are approximately \$1.108 per litre for 2008¹ and \$1.149 per litre for 2009 for Whitehorse. For other Yukon Energy locations, additional costs of 3.2 cents/litre (Faro),² 1.5 cents/litre (Dawson) and 0.7 cents/litre (Mayo) apply. This is considerably higher than the fuel price forecast at the 2005 Required Revenues and Related Matters hearing averaging approximately \$0.60 per litre.

¹ As per normal test year practice, Yukon Energy has set the fuel prices in the revenue requirement to reflect the full 12 month period in 2008. Given the present timing, the Deferred Fuel Price adjustment account (Rider F) has been operating since January 1, 2008 based on prices last approved by the YUB. As of the date of a final Board Order in this application, Yukon Energy will adjust the Deferred Fuel Price adjustment account for all periods of 2008 to reflect the approved 2008 test year fuel prices, and adjust the go-forward Rider F amount at that time accordingly.

² Fuel prices for Minto generation are assumed to equal Faro levels, given transportation requirements.

Forecast fuel efficiencies based on recent 12 month averages total 3.64 kW.h/litre for Whitehorse, 3.55 kW.h/litre for Faro, and 3.71 kW.h/litre for Dawson and Mayo, for an average Yukon Energy efficiency of 3.62 kW.h/litre in 2008 and 3.60 kW.h/litre in 2009. This is an improved efficiency compared to 3.48 kW.h/litre forecast average efficiency at the 2005 proceeding.

For 2008, total forecast diesel generation is 1.206 GW.h. Of this amount, 0.175 GW.h occurred in the first part of the year and relates to insurable or uninsured incidents (charged to insurance claims or the Reserve for Injuries and Damages). The remaining 1.031 GW.h will require 285,100 litres of diesel fuel. In addition, 100,700 litres of diesel fuel is forecast to be required for maintenance activities (such as test runs) that are not related to energy generation. Total forecast fuel consumption for 2008 is 385,800 litres, for an average price of \$1.125/litre.

For 2009, total forecast diesel generation is 1.262 GW.h, which is forecast to require 350,600 litres of diesel fuel. In addition, 100,700 litres of diesel fuel are forecast for mechanical maintenance purposes. Total forecast fuel consumption for 2009 is 451,300 litres, at an average price of \$1.170/litre.

Purchased power costs relate to power received by Yukon Energy at Johnson's Crossing from YECL at a rate of 20 cents/kWh. Purchase power costs remain relatively consistent with actual costs experienced in 2005, 2006 and 2007.

3.3 NON-FUEL OPERATING AND MAINTENANCE EXPENSES

The total actual non-fuel operating and maintenance expense for 2005 was \$11.233 million as set out in Table 3.3. Total operating and maintenance costs are forecast to increase to \$12.362 for 2008 and \$13.228 million for 2009. This is a \$1.995 million increase over the period 2005-2009, as shown in Table 3.3 below.

Table 3.3
Non-Fuel Operating, Maintenance and Administration Expenses
(\$000)

	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
				Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	\$ 5,636	\$ 6,084	\$ 6,632	\$ 6,676	\$ 6,676	\$ 6,880	\$ 6,880
Production	797	761	793	657	657	798	798
Transmission	340	354	470	507	507	612	612
Distribution	163	310	97	148	148	178	178
General O&M	592	644	732	807	807	858	858
Administration	2,450	1,978	2,223	2,347	2,347	2,544	2,544
Insurance and Reserve for Injuries/Damages	1,009	913	914	964	964	1,002	1,102
Property Taxes	246	249	256	256	256	256	256
Total OM&A	\$ 11,233	\$ 11,293	\$ 12,116	\$ 12,362	\$ 12,362	\$ 13,128	\$ 13,228

Of the \$1.995 million increase, increases in non-labour expenses make up \$0.751 million, or 38%. This is an average annual increase since 2005 of only 3.2% a year on overall non-labour O&M costs, which is in the range of experienced inflation over the period.³

Increases in labour expense make up the remainder of the increase totalling \$1.244 million, or 62%. Most of this increase occurred between 2005 and 2007 (\$0.996 million). This reflects additional positions, as well as negotiated and step increases. A further \$0.248 million is the forecast increase in labour expenses over 2007-2009 (about 1.9% per year). Detailed information on the labour increases by function is provided in the following sections. The Yukon Energy employee complement (FTE) is shown in Table 3.4.

³ For example, the most recent available CPI statistics from the Yukon Bureau of Statistics indicates the 12 months CPI from July 2007 to July 2008 at 4.2%, and from July 2006 to July 2007 at 3.0%. Annual figures for 2005 were 2.2%.

Table 3.4
Employee Complement History

	Actual 2005	Actual 2006	Actual 2007	GRA 2008	GRA 2009
President	1.60	1.50	2.50	2.50	2.50
Communications	1.00	1.00	1.00	1.00	1.00
Human Resources & Info. Mgmt.	6.06	6.01	6.00	7.00	7.00
Business Development	1.08	1.00	1.00	1.00	1.00
Finance, Cust. Acctg. & Purchasing	11.05	11.49	11.63	12.81	12.81
Operations	34.82	39.43	38.60	40.20	40.10
Engineering Services	13.21	13.58	14.00	12.67	12.00
Health, Safety & Environment	1.00	1.00	3.00	3.33	3.33
Total	69.82	75.01	77.73	80.51	79.74

3.3.1 Production

Costs for production consist of labour and non-labour components, excluding fuel and purchased power costs. As set out in Table 3.5, total production costs in 2008 are forecast to be lower than actual 2005 costs by \$0.186 million, and in 2009 are forecast to be higher than 2005 levels by \$0.019 million.

Table 3.5
Production Costs
(\$000)

	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
				Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	\$ 2,161	\$ 2,418	\$ 2,488	\$ 2,114	\$ 2,114	\$ 2,179	\$ 2,179
Diesel	173	189	147	191	191	194	194
Hydro	602	551	602	423	423	560	560
Wind	22	5	21	8	8	8	8
Operation Supervision	0	16	23	35	35	36	36
Total Production	\$ 2,958	\$ 3,179	\$ 3,281	\$ 2,771	\$ 2,771	\$ 2,977	\$ 2,977

Proposed costs for 2008 and 2009 remain consistent with, or below, actual levels of cost experienced between 2005 and 2007.

3.3.2 Transmission

Transmission costs have increased since 2005 as indicated in Table 3.6.

Table 3.6
Transmission Costs
(\$000)

	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
				Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	\$ 295	\$ 307	\$ 293	\$ 466	\$ 466	\$ 482	\$ 482
Brushing	158	117	239	257	257	377	377
Other Non-Labour	182	237	231	250	250	235	235
Total Transmission	\$ 635	\$ 661	\$ 763	\$ 973	\$ 973	\$ 1,094	\$ 1,094

Non-labour costs are forecast at \$0.507 million in 2008 (\$0.167 million above actual 2005 levels) and \$0.612 million in 2009 (\$0.272 million above 2005). These increases are dominated by a required staged increase in brushing activity, which is a periodic cyclical requirement in Yukon.

Transmission labour costs for 2008 and 2009 are well above the actual 2005-2007 levels due to having a full complement of line crew in 2008 and 2009.

3.3.3 Distribution

Changes to the costs of operating and maintaining the distribution system since 2005 are set out in Table 3.7.

Table 3.7
Distribution Costs
(\$000)

	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
				Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	\$ 354	\$ 372	\$ 446	\$ 505	\$ 505	\$ 521	\$ 521
Brushing	14	72	1	40	40	46	46
Other Non-Labour	149	238	96	108	108	132	132
Total Distribution	\$ 517	\$ 682	\$ 543	\$ 653	\$ 653	\$ 699	\$ 699

Distribution costs for brushing vary by year, and for 2008 and 2009 reflect approximately the midpoint of the range of costs experienced in the 2005-2007 period.

Other non-labour costs for 2008 are well below the typical levels experienced in the 2005-2007 period. Higher costs experienced in 2006 were due to one-time project costs being written off in that year. For 2009, the costs are forecast to increase due to a metering audit of approximately \$0.025 million.

Distribution labour costs for 2008 and 2009 are well above the actual 2005-2007 levels due to having a full complement of line crew in 2008 and 2009.

3.3.4 General Operation and Maintenance

Yukon Energy incurs expenses categorized as General in respect of transportation, communications, SCADA communications, and maintenance of company owned properties, as set out in Table 3.8.

Table 3.8
General Operating and Maintenance
(\$000)

				Forecast		Forecast	
	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	\$ 135	\$ 139	\$ 116	\$ 92	\$ 92	\$ 94	\$ 94
Transportation	291	321	370	386	386	394	394
Maintenance of Company Owned Properties	230	242	290	342	342	384	384
SCADA Communication and Special Projects	71	81	72	79	79	80	80
Total General O&M	\$ 727	\$ 783	\$ 848	\$ 899	\$ 899	\$ 952	\$ 952

Total cost increases in the General O&M categories relate largely to fuel for vehicles (as shown under transportation in Table 3.8) and maintenance on company owned properties. Cost increases due to maintenance on company owned buildings relate to increased janitorial costs, the need to rent space for file storage, required renovations and costs required to paint the trim on the Whitehorse office building. Labour costs in the test years are forecast to be lower than the 2005-2007 levels. The purchase of new vehicles will result in less time spent on maintenance of the fleet over the test years. Cost decreases are also attributed to the completion of renovations on Yukon Energy's headquarters.

3.3.5 Administration

The costs of administration in forecast 2008 and 2009 are approximately \$0.704 million and \$1.007 million respectively greater than 2005 actual expenses, as shown in Table 3.9.

Table 3.9
Administration
(\$000)

	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
				Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Labour	\$ 2,691	\$ 2,846	\$ 3,288	\$ 3,498	\$ 3,498	\$ 3,605	\$ 3,605
Resource Planning	1	6	21	17	17	17	17
Communications	72	87	118	87	87	105	105
Customer Accounting	164	170	189	201	201	206	206
Environmental Mgmt	46	7	30	35	35	52	52
General	873	805	597	745	745	734	734
Information Systems	213	265	341	351	351	425	425
Fish Hatchery	126	106	132	130	130	136	136
Fish Ladder	18	33	11	25	25	26	26
Safety	38	54	133	59	59	162	162
Training	177	139	142	201	201	211	211
Recruitment	170	19	181	165	165	169	169
Board of Directors	156	91	166	145	145	148	148
Union	54	27	32	25	25	26	26
Regulatory Affairs	0	6	106	93	93	57	57
Material Management	300	155	14	42	42	43	43
Contracting	26	8	6	11	11	11	11
Professional Development	16	0	4	15	15	15	15
Total Administration	\$ 5,141	\$ 4,824	\$ 5,511	\$ 5,845	\$ 5,845	\$ 6,148	\$ 6,148

Non-labour amounts in total remain approximately equal to the actual spending in 2005 (\$0.103 million below for 2008, \$0.094 million above for 2009), although notable increases have occurred in information systems and safety, largely offset by reductions in general administration and materials management:

- **Information Systems** (forecast increase of \$0.212 million by 2009 over 2005 actuals): In 2005, Yukon Energy prepared an IT Strategic Plan and developed an IT Security Policy. In 2006, a Business Impact Assessment was also prepared. Subsequently, funds have been allocated towards implementing the recommendations that issued from the IT Strategic Plan and Business Impact Assessment in order to put in place the procedures necessary to support the IT Security Policy. In 2007, Yukon Energy also paid to YTG \$15,000 for data circuit charges and this cost is expected to be incurred on an ongoing basis. Since 2005, there has also been a significant increase in annual software licence fees⁴ (from \$12,000 in 2005 to \$30,000 in 2006 to \$82,000 in 2007, \$104,000 in 2008 and \$162,000 in 2009). Annual licences are required to be purchased on an ongoing basis as more IT hardware and software is required (some of these requirements are due to IT Strategic Plan, IT Security Policy and Business Impact Assessment recommendations).
- **Safety** (forecast increase of \$0.124 million by 2009 over 2005 actuals): Safety costs have fluctuated from 2005-2007 (from as low as \$38,000 in 2006 to as high as \$133,000 in 2007). For test year 2008, base costs of safety activities remain in the historical range, at \$0.059 million. In 2009, there is an added \$0.100 million for a process to document YEC's safety procedures, which is a periodic requirement of the Yukon Occupational Health and Safety Act⁵ and the Yukon Worker's Compensation Health and Safety Board.⁶
- **Materials Management** (forecast decrease of \$0.257 million by 2009 compared to 2005): The materials management amounts in 2005 included a number of inventory adjustments and write-downs as well as implementation of an accounting change that are not anticipated to re-occur in the test years.

⁴ There is a legal requirement to purchase annual software license.

⁵ Section 7(d), Section 3(1)(b) and section 3(1)(c).

⁶ Requires that safe work procedures be followed and workers receive adequate job training, and that workers be instructed on how to perform jobs safely.

- **General Administration** (forecast 2009 is \$0.139 million below 2005 actual levels): Costs for General Administration have decreased from 2005 actual levels due to a large number of small adjustments. Among these are lower expenses for contributions to project partners, and the scheduled termination of the lease on Yukon Energy's financial information system.

Administration labour increased between 2005 and 2007 due to both wage increases (negotiated and step increases) and increases in staff positions. This includes allocations of some or all of the following changed positions since 2005:

- Document Specialist (added in 2007)
- Manager, Environmental Assessment and Licencing (added in 2007)
- Records Management Analyst (added in 2008)
- 2 Year Term Financial Administrator (added in 2008)
- Office Administrators increased by .20 FTE from .60 FTE due to CIS System Conversion (increased in 2008)
- As well as the administration components of the following positions:
 - Manager Operations (added in 2006)
 - Vice President Operations and Engineering (added in 2007)
 - Coordinator Capital Projects (added in 2008)
 - Maintenance Mechanic (added 2006)
 - Apprentice Powerline Tech (1 added in 2005 and 2 added in 2006)
 - Engineer-in-Training (2 year term added late 2006 and scheduled to end August 2008)

3.3.6 Insurance and Reserve for Injury and Damages

Yukon Energy's costs related to insurance are set out in Table 3.10.

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

	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
				Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Insurance	\$ 909	\$ 813	\$ 814	\$ 914	\$ 914	\$ 952	\$ 952
Reserve Appropriation	100	100	100	50	50	50	150
One-time Transfer	744				463		
Less: Application of fire gain funds	(744)				(463)		
Total RFID	\$ 1,009	\$ 913	\$ 914	\$ 964	\$ 964	\$ 1,002	\$ 1,102

Yukon Energy's costs for insurance remain within 5% of 2005 levels through the test years.

The Reserve for Injuries and Damages ("RFID") is an account maintained as approved by the Board, in order to address uninsured and uninsurable losses as well as the deductible portion of insured losses.⁷ The reserve serves two purposes: (1) it allows for a balance to be struck between purchasing additional insurance vs. using a self-insurance type approach via the reserve; and (2) it allows the costs of unforeseen events to be smoothed out over a number of years to avoid rate instability for ratepayers.

Since 2005, Yukon Energy's Reserve for Injuries and Damages balance has grown from approximately \$0 (after the 2005 YUB approvals to transfer \$744,000 of one-time funds against this balance)⁸ to negative \$463,000 at year-end 2007 (negative amounts represent an excess of charges to the reserve compared to appropriations to the reserve). Pursuant to Board Order 2005-12,⁹ the appropriation against the reserve was set at \$100,000 per year over this 2005-2007 period. Absent further direction from the Board, this appropriation is to revert to \$50,000 per year starting 2008.¹⁰

⁷ Yukon Energy noted during the 2005 rate review process that it applies the following corporate accounting practice with respect to the Reserve for Injuries and Damages (RFID):

- It is a contingency reserve set up to address the cost of uninsured/uninsurable losses.
- Uninsured losses are defined as losses that could be covered by insurance but which Yukon Energy has chosen not to insure because the probability, frequency and/or dollar value of losses do not justify the premium.
- Uninsurable losses are those losses for which coverage is not available in the conventional insurance market.
- The RFID is also used to pay the insurance policy deductible in the event of a claimed loss.

⁸ See Appendix A of Order 2005-12 at page 29-30.

⁹ See Appendix A of Order 2005-12 at page 30.

¹⁰ See Appendix A of Order 2005-12 at page 29-30. At page 30 the board approves an increase to the annual appropriation to \$100,000 for 2005, 2006 and 2007.

Given the current balance in the reserve, and the desire to avoid similar issues in future, Yukon Energy is seeking approval of a two-part solution to the Reserve account:

1. **Increase the annual appropriation to the Reserve, starting 2009, to \$150,000 per year:** In 2005, Yukon Energy requested that appropriations to the Reserve for Injuries and Damages be increased to \$150,000. Order 2005-12 noted that in the Board's view there was not sufficient detail as to actual uninsured losses in 2005, and that the previous four years demonstrated considerable variability in the annual losses, ranging from \$25,000 to nearly \$400,000. Given the lack of information on 2005 actual losses, the Board indicated that the \$150,000 requested increase was considered to be too high; however, the annual appropriation to the reserve was increased to \$100,000 for each of 2005, 2006 and 2007 by Board Order 2005-12.

Since the 2005 hearing, Yukon Energy has accumulated three more years of data that demonstrate \$150,000 per year in appropriations to the reserve to be reasonable. As noted in the Table below, the average annual charges to the reserve over the last 11 years were approximately \$181,000. This clearly demonstrates the justification to increase annual appropriations to the reserve to at least \$150,000 at this time, with a potential measured increase to a higher level in future applications.

Table 3.11
Continuity Schedule for the RFID 1997-2007
(\$000)

	Actual 1997	Actual 1998	Actual 1999	Actual 2000	Actual 2001	Actual 2002	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Total	11 Year Average
Annual Changes	\$ 200	\$ 613	\$ 175	\$ 123	\$ 25	\$ 105	\$ 383	\$ 167	\$ 14	\$ 633	\$ 63	\$2,501	
Fire Insurance Claims Settlements	(100)	(367)		(36)								(503)	
Annual Changes net of Insurance Claims	\$ 100	\$ 246	\$ 175	\$ 87	\$ 25	\$ 105	\$ 383	\$ 167	\$ 14	\$ 633	\$ 63	\$1,998	\$ 181

2. **Apply \$463,000 of the remaining one-time regulatory liability amounts to address the current (year-end 2007) balance:** The current balance in the Reserve is well into negative range (\$463,000 at year-end 2007). In order to address this balance, it is recommended that Yukon Energy seek to apply the one-time "funds" remaining from the Faro mine dewatering (\$1.191 million) against this balance as a first priority use of these funds. This is consistent with the approach adopted in the 2005 hearing, where other available one-time funds (related to an insurance settlement) were used to discharge a similar one-time balance being held in reserves.

In order to permit an orderly progression to the new rate level starting November 1, 2008, as set out in Tab 4, Yukon Energy proposes to retain \$50,000 in appropriations for 2008.

3.3.7 Property Taxes

Yukon Energy's property tax costs reflect payments in lieu made to the municipalities where it operates. Property taxes have remained relatively constant since 2005, increasing from \$246,000 in that year to \$256,000 in 2009.

Table 3.12
Property Taxes
(\$000)

	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
				Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Property Taxes	\$ 246	\$ 249	\$ 256	\$ 256	\$ 256	\$ 256	\$ 256

3.4 RATE BASE, DEPRECIATION AND AMORTIZATION

Yukon Energy's rate base includes all investment providing service to ratepayers, as well as components of necessary working capital. It comprises property, plant and equipment (net of depreciation), deferred study and other costs, reserves set aside for various purposes and working capital as indicated in Schedule 1 of Tab 7 of this submission.

Yukon Energy's 2009 mid-year forecast rate base is \$151.416 million, an increase of \$11.865 million from 2005 mid-year actual. Mid-year net plant in service, which includes unamortized costs (other than rate case expenses), as well as physical plant net of depreciation, is forecast to increase to \$193.312 million (a \$46.054 million increase over 2005 actuals), primarily reflecting the Carmacks-Stewart Transmission Project which is forecast to come into service October 2008. Increases in net plant in service since 2005 were offset largely by increased mid-year contributions for extensions of \$34.906 million. The balance of the increase in net rate base from mid-year 2005 actuals to mid-year 2009 reflects increased working capital (\$52,000) and unamortized rate case expense (\$664,000). A detailed summary of the spending undertaken by Yukon Energy since 2005, as well a forecast capital spending for 2008 and 2009, is provided in Tab 5 of this submission.

Yukon Energy's rate base is calculated net of "regulatory liabilities" or funds held by Yukon Energy for the future benefit of ratepayers. The notable amounts held in this regard for the 2008 and 2009 test years relate to funds earned from the sales of "dewatering" energy to the Faro mine site from 1998 to 2004. There remains \$1.191 million in this regulatory liability at the start of 2008. As noted above, Yukon Energy seeks Board approval to transfer \$0.463 million as a one-time amount to the Reserve for Injuries and Damages. The remaining \$0.728 million is not reduced further in this Application and the residual is applied as an offset to rate base (effectively equivalent to application of these amounts as a form of no-cost capital). The Application proposes that these funds be applied in future to the benefit of ratepayers, including to address specified income forecast contingencies (see Section 4.1 of this Application).

Yukon Energy's 2008 and 2009 expense related to depreciation of capital assets and amortizing other deferred charges is \$6.403 million and \$6.930 million respectively as shown in Table 3.13.

Table 3.13
Depreciation and Amortization
(\$000)

	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
				Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
Fixed Asset Depreciation	\$ 5,079	\$ 5,128	\$ 5,298	\$ 5,743	\$ 5,743	\$ 6,583	\$ 6,583
Less: Customer contribution	(319)	(345)	(357)	(538)	(538)	(1,091)	(1,091)
Less: Amortization of fire insurance recoveries	(270)	(270)	(270)	(270)	(270)	(270)	(270)
Plus: Amortization of deferred charges	889	1,098	1,108	977	1,467	1,219	1,707
Total Depreciation & Amortization	\$ 5,379	\$ 5,611	\$ 5,779	\$ 5,913	\$ 6,403	\$ 6,441	\$ 6,930

Yukon Energy's depreciation costs continue to be based on depreciation rates approved by the YUB in Order 2005-12. The 2005 review of Yukon Energy's depreciation rates made significant changes to the Corporation's service lives, salvage rates, and group procedure. In particular, depreciation rates were updated to reflect the Average Service Life ("ASL") group procedure (as opposed to the Equal Life Group ("ELG") procedure that had previously been in place). When compared with existing methods, the change led to an approximate \$1.17 million reduction in depreciation expense in 2005 (net of customer contributions and amortization of fire insurance recoveries).¹¹ As well, the Board directed a termination of

¹¹ In the 2005 Required Revenues and Related Matters hearing it was noted that the reduction in depreciation was related to two factors: (1) Yukon Energy's assets have a longer service life than had been calculated in earlier depreciation studies (i.e., prior to the 1996/1997 GRA) and the change from ELG to ASL procedures (which accounted for an estimated 57% of the reduction) in depreciation for 2005.

any further appropriations to Yukon Energy's Reserve for Future Removal and Site Restoration ("Salvage") which Yukon Energy had forecast at \$0.533 million for 2005, until such time as the "balance of the site removal liability account reaches \$2.0 million".¹² The account is not forecast to reach this level in the test years.

As a component of net depreciation costs, the revenue requirement includes substantial credits related to amortization of contributions (customer contributions, and other no-cost capital such as grants from Yukon Development Corporation). This offset has grown from \$0.319 million in 2005 to \$1.091 million in 2007. The largest growth in credits relates to the Carmacks-Stewart transmission line, which is the source of substantial contributions from the Yukon Government, Yukon Development Corporation, and Minto Explorations, as set out in Tab 5.

The largest component of deferred charges relates to planning and study costs, regulatory hearing costs and licencing costs related to maintaining licences of YEC's hydro facilities and air emission permits. The cost for amortization of deferred charges has increased \$0.818 million, from \$0.889 million in actual 2005 to \$1.707 million forecast in 2009 as set out in Tab 5.¹³ The largest component of this increase since 2005 (\$0.547 million) relates to planning and study costs, which is primarily studies of the existing system and options for expanding the quantity of renewable generation,¹⁴ as well as studies related to the safety and reliability of the system, the Minto Mine PPA negotiations, and other small projects, offset by the termination of amortization since 2005 on old study amounts as they become fully amortized. Yukon Energy has experienced considerable requirements to re-initiate activities aimed at expanding the availability of renewable and local generation as loads continue to approach the limits of the existing hydro generation and the price of diesel increases to unprecedented levels. Since the closure of the Faro mine in 1998 such resource planning activities had been maintained at only a very low level given the surplus hydro that existed for the past decade.

Outside of planning and study costs, amortization of deferred costs has also increased due to amortization of:

- **Regulatory costs (\$0.178 million increase in annual costs by 2009 compared to 2005)**, including the impacts of amortizing the current GRA over 2 years, the Resource Plan proceeding over 10 years (the anticipated period of time until another Resource Plan will be

¹² Appendix A Board Order 2005-12, page 48.

¹³ See Tab 5 Table 5.3 and Table 5.7

¹⁴ As set out in Tab 5.

prepared), the PPA proceeding over 12 years (the anticipated primary accounting life of the PPA), and the Carmacks-Stewart Part 3 proceeding over 45 years (the approximate life of the assets as per Yukon Energy's most recent depreciation study) offset by the termination of the amortization of the costs of the 2005 proceeding (which are now fully amortized).

- **Relicensing Costs (\$0.163 million increase in annual costs by 2009 compared to 2005)**, dominated by the ongoing costs imposed by the terms of the Aishihik Water Licence and Fish Act Authorization (\$0.136 million), as well as an Air Emissions Permit (\$0.025 million).

These increases are offset by reductions in amortizing dam safety reviews (\$0.020 million) and deferred downsizing costs (which were \$0.048 million/year in 2005, and are now fully amortized).

3.5 RETURN ON RATE BASE (INTEREST COSTS AND ROE)

The total forecast return on Yukon Energy's rate base for 2008 is \$9.965 million and for 2009 is \$10.860 million. This is comprised of average interest costs related to the Corporation's debt, as well as a fair return on shareholder equity as directed under Order-in-Council 1998/32.

Yukon Energy seeks approval of a forecast average cost of capital is 6.86% for 2008 and 7.17% for 2009, as set out in Table 3.14. This reflects changes to both the average interest rate on debt, and the level of fair return on equity, each reviewed below. There has been no change in the relative weighting of debt and equity in Yukon Energy's capital structure since the 2005 proceeding (since 1992, Yukon Energy has maintained a balance of 60% long-term debt and 40% equity).¹⁵

¹⁵ Yukon Energy's practice with respect to dividends and issuances of long-term debt is to declare dividends out of equity and issue long-term debt annually, as required in order to maintain a 60% debt: 40% equity capital structure at year end, while retaining a minimum of cash in the utility outside of amounts required to finance the ongoing capital programs.

Table 3.14
Cost of Capital

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

Yukon Energy's forecast capital structure at December 31, 2008 is comprised of \$92.970 million in long-term debt and \$61.979 million in common equity. The December 31, 2009 forecast balances are \$94.069 million and \$62.713 million respectively.

3.5.1 Costs of Debt

Yukon Energy's long-term debt consists of the following components (see schedule 13 of Tab 7):

- **Unsecured Advances from Yukon Development Corporation:** Yukon Development has provided long-term advances totalling \$40.032 million as at December 31, 2007, with interest rates ranging from 5.28% to 6.03%. Additional advances of \$3.515 million from Yukon Development are forecast at December 31, 2008 and a further \$5.043 million at December 31, 2009, with forecast interest rates of 5.28%¹⁶ to maintain the 60% debt and 40% equity balance.
- **Minto Mine obligation re: Diesels:** As set out in Tab 5, Yukon Energy has agreed to purchase the diesel units currently installed at the Minto mine (the "Minto Diesels") and finance the \$2.24 million purchase price of these units with Minto over 7 years. The rate on this financing is 7.5%, equal to all interest rates on advances contained in the Minto Power Purchase Agreement ("PPA") as reviewed by the YUB in early 2007, and payments are equal blended principal and interest monthly. The outstanding balances on this advance total \$2.179 million at year-end 2008 and \$1.921 million in 2009, with interest costs of \$0.042 million (partial year 2008) and \$0.155 million (full year 2009) respectively.

¹⁶ Debt issued between Yukon Development and Yukon Energy is priced based on a "spread" over long Canada bonds of 120 basis points. The long Canada bond yield during the preparation of this filing was 4.08%, supporting a rate for new long term debt of 5.28%.

- **Yukon Development Flexible Promissory Note (for Mayo-Dawson Project):** In order to provide the 60% long-term debt component of the Mayo-Dawson project capital costs, and to ensure ratepayers would not be worse off in any year as a result of the Mayo-Dawson project than they would have been had Dawson remained on diesel fuel generation, Yukon Development provided an \$18 million advance with flexible terms with respect to interest payable ("Mayo Dawson Note"). The forecast balance on the Mayo-Dawson Note is \$15.607 million as at year-end 2008 and \$15.157 million at year-end 2009. The face interest rate on the note is 6.55% and, due to the present substantial benefits to ratepayers arising from the Mayo-Dawson line given current and forecast diesel fuel prices, the full 6.55% face interest rate is forecast to be paid in 2008 and 2009.
- **7 % Flexible Term Note:** The Flexible Term Note is a flexible debt provision which forgives interest and defers principal payments when the level of Yukon Energy sales on the Whitehorse-Aishihik-Faro (WAF) grid is less than 310 GW.h per year. The forecast balance outstanding at December 31, 2008 is \$26.081 million. The level of forecast firm sales in 2008 and 2009 remain below the 310 GW.h level, so the full face interest rate of 7% is not forecast to be paid. However, as the rate to be applied in any given year is a linear function linked to WAF firm sales (from 0% at 200 GW.h and 7% at 310 GW.h), each increase in the volume of sales brings added interest payments on the Flexible Term Note. As a result, the interest costs in respect of the Flexible Term Note are forecast to increase reflecting the increased WAF sales to Minto and other customers, i.e., this average interest rate increases from 4.1% in 2005, to 4.7% in 2008 and 6.6% in 2009. Forecast WAF firm sales are set out in Table 2.4.
- **TD Canada Trust Note:** The outstanding balance on the TD Canada Trust term note at year-end 2008 is \$7.163 million and \$6.471 million at year-end 2009. This note has an effective interest rate of 7.81% with equal blended monthly principal and interest payments, and is due in 2011.

3.5.2 Return on Common Equity

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

In both Yukon Energy's 1998 proceeding¹⁷ and 2005 proceeding¹⁸, efforts were made to permit a cost effective and simple means to set the fair level of ROE. In particular, in the 2005 proceeding, the fair ROE for test year 2005 was proposed by Yukon Energy to be set by reference to the British Columbia Utilities Commission ("BCUC") formulaic ROE approach, based on Yukon Energy receiving a 52 basis points premium due to its risk compared to low risk utility. This was accepted by the Board in Order 2005-12. As set out in Tab 8, Yukon Energy has maintained this same approach to set the proposed ROE for 2008, at 8.64%. For 2009, Yukon Energy proposes that the ROE be set using the same approach, based on the BCUC calculations to be completed approximately at the end of November, 2008, and that this ROE be incorporated in the requested approvals for 2009 at that time. For the purposes of this filing document, a 2009 "placeholder" ROE of 8.64% has been utilized, to be consistent with 2008.

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

3.6 STABILIZATION MECHANISMS

For more than a decade, Yukon Energy has maintained two mechanisms or accounts designed to stabilize rates and revenues. These are:

- **The Deferred Fuel Price Account (or "Rider F") established pursuant to Order in Council 1995/90 section 8.** This account captures all variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA-approved fuel prices. Pursuant to Board Order 2005-12, Yukon Energy also credits this account with all variations (positive or negative) in the ongoing quarterly adjustment to the prices of secondary sales, compared to the most recent GRA-approved price. As with the typical situation where final rates are put in place following the start of the test year, once final approvals are received for new test year fuel prices, Yukon Energy recalculates the balances in these accounts to ensure that all charges to the accounts are precisely equal to what would have occurred had the ultimate YUB approvals been known at the start of the first test year.
- **The Diesel Contingency Fund ("DCF") established in the 1996/97 GRA Negotiated Settlement.** This account serves to stabilize Yukon Energy's costs to serve firm loads on

¹⁷ Revised 1997 and 1998 Rate Application to the Yukon Utilities Board Related to Board Order 1997-6 and Related to the 1998 Closure of the Faro Mine.

¹⁸ 2005 Required Revenues and Related Matters Application.

WAF, due to variances in water flows (and resulting hydro generation variances). The account, in effect, can be either credited or debited each month for one of two reasons:

- When diesel is in “on the margin” (defined as being used to meet long-term firm energy requirements of the system, not just periodic peaking requirements), the account stabilizes the diesel costs related to water flow variations. The premise of the account in these situations is that, when hydro varies positive or negative from forecast, that variance is met effectively 1 for 1 with changes in diesel generation compared to what would have occurred had the hydro variance not occurred.
- When diesel is not on the margin, the account can in certain circumstances be used to pay for the costs of generation using diesel (when monthly diesel generation exceeds 250 MW.h notwithstanding that it is not required to meet base loads under normal flows, i.e., in the case of a drought that requires diesel generation even though hydro should be able to fully satisfy the system outside of limited peaking use).

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

There is no comparable DCF fund for the Mayo-Dawson system. Yukon Energy does not at this time anticipate a requirement for such a fund during 2008 and 2009.

TAB 4
RATES

4.0 RATES

This Tab reviews Yukon Energy's existing rates and sets out the changes applied for with regard to firm retail, industrial, wholesale, and secondary rates and riders.

This Tab consists of the following items:

- Overview
- Secondary Sales Rate Design
- Major Industrial Firm Rates
- Non-Industrial Firm Retail Rate Design
- Wholesale Rates

Changes are sought in this Application for the following rate schedules, provided in blacklined form in Appendix 4.1:

- Rate Schedule 32 Secondary Energy
- Rate Schedule 39 (re: fixed Rider F component applicable to Rate Schedule 39 Major Industrial customers)
- New Rider U – Yukon Energy Revenue Reduction Rider
- Rate Schedules for Residential Non-Government (1160, 1260, 1360, 1460) and Residential Government (1180, 1280, 1380, 1480)
- Rate Schedule 42 re: Energy Reconciliation Adjustment provision, and a small adjustment to the base energy rate.

The Application also requests provision in rate schedules, as required when Stage One CSTP connection occurs, to include Pelly Crossing in the Hydro rate zone rate schedules.

The rates arising from the final order in this GRA will not be in place until into 2009 given current timing estimates. Interim rates are sought effective November 1, 2008 to implement rate changes proposed for final 2009 rates, on the understanding that any required “true-up” will occur following the final order setting the approved 2008 and 2009 Revenue Requirements. As a result, this tab addresses primarily the level of firm rates to be in place for 2009, based on the Application.

4.1 OVERVIEW

The rates charged to Yukon Energy’s customers are designed to yield the revenue requirements set out in Tab 3, net of a small amount of non-rate revenues (\$125,000 in each test year) received by Yukon Energy related to items such as pole rentals, connection charges, and other facility rentals. In 2008 the revenue requirement is \$29.217 million, and in 2009 is \$31.599 million. Yukon Energy’s forecast revenue requirement from electrical rates is \$29.092 million in 2008 and \$31.474 million in 2009.

Yukon Energy’s revenue earned from rates is collected from charges for firm power and for secondary (interruptible or surplus) power. All revenues from secondary power, as an opportunity use of hydro power that would otherwise be wasted, go to lower the required level of retail rates for firm power.

As set out in Table 4.1, assuming the sales forecasts set out in Tab 2 (e.g., assuming Minto mine and Pelly Crossing CSTP connection October 1, 2008), the current level of existing firm rates (including Rider J and the Fixed component of industrial Rider F, as reviewed in Section 4.3) provides \$0.359 million excess revenue in 2008 and \$1.334 million excess revenue in 2009 compared to revenue requirements set out in Tab 3. These amounts are the basis for the rate reductions proposed in this Application.

Table 4.1

Yukon Energy Revenue Required from Rates (\$000s)

	2008	2009
Revenue Requirement (from Table 3.1)	\$29,217	\$31,599
Less: Non-rate Revenues	\$125	\$125
Less: Secondary rate revenues (section 4.2)	<u>\$1,396</u>	<u>\$1,369</u>
Revenue Required from Firm Rates	\$27,696	\$30,105
Less: Revenues from Firm Sales at Existing Rates (including Rider J and "Fixed" component of industrial Rider F) (section 4.3)	<u>\$28,055</u>	<u>\$31,439</u>
Firm Rate Reduction Proposed	(\$359)	(\$1,334)

Prior to 2008, in the period 2005-2007, Yukon Energy also had access to \$0.292 million per year from deferred "funds" (Faro Dewatering Account regulatory liability) held by Yukon Energy for ratepayer benefit.¹ This annual allocation was approved in Order 2005-12 for only 3 years, and is consequently terminated starting 2008. There remains \$1.191 million in the regulatory liability at the start of 2008.

In this Application (Tab 3) Yukon Energy seeks Board approval to transfer \$0.463 million from the Faro Dewatering Account as a one-time amount to the Reserve for Injuries and Damages. Yukon Energy proposes that the remaining \$0.728 million in the Faro Dewatering Account be available for use, on approval of the Board after application by Yukon Energy, to address (if and as required) specified income forecast contingencies related to:

1. Final 2008 retail rate revenue requirements affected by delays in CTSP connection of the Minto mine and Pelly Crossing loads, i.e., offsetting, to the extent required to enable final approved forecast 2008 retail rate revenue revenues, any net revenue losses due to delays in the final connection timing of the Minto mine and Pelly Crossing loads to the CSTP from the October 1, 2008 date assumed in the Application's Tab 2 sales forecasts);² and

¹ These amounts were established out of rates charged to the Faro mine site for dewatering activities in 1998-2004 and deferred and not recorded as Yukon Energy income pursuant to Board Order 1998-5. No further amounts are being accrued to this account. The funds are not held in cash, but are accounted for as an offset to ratebase, similar to customer contributions.

² By way of example, delay of one month in connecting these loads (from October 1 to November 1) is forecast to reduce YEC 2008 net revenues by approximately \$197,000 (reflects \$252,000 loss of industrial sales revenues plus \$11,000 loss of Pelly Crossing wholesale revenues, less saving of about \$66,000 in depreciation and related costs (lower mid-year rate base and reduced Flexible Term Note interest).

2. Offsetting any net revenue losses of Yukon Energy after 2008 due to low water risks not covered by the DCF, i.e., loss of secondary revenues due to below normal water flows in any year after 2008.

Beyond these specific contingencies, the Faro Dewatering Account is proposed to be retained for future use, as directed by the Board, to be applied to the benefit of ratepayers.

4.2 SECONDARY ENERGY RATE DESIGN

Yukon Energy's secondary rate offering provides interruptible power to customers of Yukon Energy or YECL who qualify under Rate Schedule 32. In order to qualify, the power must be "in excess of normal consumption and represent incremental electric usage displacing an alternative fuel source in order to provide space or process heating." The customer must have a viable alternative fuel source available to provide backup in the event of power interruptions.

The bulk of secondary sales in Yukon are made by YECL as retailer, with Yukon Energy selling the equivalent quantity of power on a wholesale secondary basis to YECL at the then current retail secondary power rate less 1.1 cents/kW.h (per approved Wholesale Secondary Rate Schedule 43). Yukon Energy does not propose to change this relationship between wholesale and retail secondary energy rates.

4.2.1 Retail Secondary Sales Rates (Rate Schedule 32)

In 2005, the YUB approved an increase in the secondary sales rate and established an ongoing adjustment mechanism to maintain a reasonable correlation between the secondary sales rate and fuel oil prices. The secondary sales rate was set effective January 1, 2005 at 66.7% of the equivalent costs of heating with oil.³ Yukon Energy also proposed, and the Board approved in Order 2005-12, an automatic adjustment mechanism that would adjust the rate on a quarterly basis, based on the lowest of the three most recent Yukon Bureau of Statics bi-weekly furnace oil prices for Whitehorse. In order to address fuel price related variance in income, the Rider F Deferred Fuel Price mechanism was used to normalize the secondary sales revenues and act as a natural hedge to the Rider F account, reducing variability that would otherwise be charged through the joint Yukon Energy/YECL rate rider.

³ For measuring the costs of heating with oil, the calculation uses the price for oil based on the lowest of the three values cited in the biweekly Yukon bureau of Statistics measurement for Furnace Oil in Whitehorse. The efficiency assumed for the alternate heating source was 90%.

Based on then current oil prices, the secondary sales rate to retail customers has been set as follows for 2008:

- Quarter beginning January 1, 2008: 6.5 cents/kW.h
- Quarter beginning April 1, 2008: 7.2 cents/kW.h
- Quarter beginning July 1, 2008: 8.3 cents/kW.h
- Quarter beginning October 1, 2008: 9.3 cents/kW.h

For determining test year secondary revenues for 2008, Yukon Energy has used the above rates to determine revenues in this GRA. For 2009 forecast revenues, Yukon Energy has applied the October 1, 2008 rate of 9.3 cents/kW.h at the retail level throughout the year (8.2 cents/kW.h for wholesale secondary sales).

For all of 2008, Yukon Energy's test year rates are based on including the above noted rates in income as an offset to the level of firm rates, including adjustments to the Deferred Fuel Price (Rider F) account balance to the beginning of the 2008 test year. This reconciliation will be initiated upon completion of the GRA process.

Only one term of the secondary energy service (Rate Schedule 32) is proposed to be changed in this Application. In the 2005 proceeding, Yukon Energy received approval for a procedure related to determining the timing of scheduled secondary sales interruptions based on forecasting the quantity (hours) of diesel generation expected to be required over the coming seven day period in winter (i.e., interruptions were to be initiated if YEC forecast a requirement to dispatch diesel generation for more than 10% of the hours over the coming seven day period). It has become apparent that a seven day forecast period is not practical, given the Environment Canada long-range forecasts are focused on the coming five days. Accordingly, Yukon Energy is seeking approval to adjust the rate schedule provision to reflect interruptions being initiated for any forecast requirement to use diesel for more than 10% of the hours over the subsequent five day period. No material effect is expected on the amount of time secondary energy is expected to be made available. A blacklined copy of Rate Schedule 32 is provided in Attachment A to this Tab for Board approval.

4.2.2 Low Grade Ore Processing Secondary Energy (Rate Schedule 35)

The PPA with Minto Explorations includes as Schedule D, Rate Schedule 35, and entitled Low Grade Ore Processing Secondary Energy Rate. As discussed during the PPA hearing process this was a negotiated rate specific to the circumstances of the Minto mine (i.e., it may only be used for processing low grade copper ore as defined under Rate Schedule 35), interruptible and available only from surplus hydroelectricity not otherwise required by Rate Schedule 32 customers.

This rate was reviewed by the YUB and intervenors during the PPA hearing process, and the YUB approved the rate on an interim basis. The Board also noted that audit and control measures and reporting requirements must be developed between YEC and Minto, and once developed these are to be filed with the Board for approval. This requirement was included in the PPA as amended May 14, 2007, which was approved by Board Order 2007-6. Accordingly, YEC cannot implement this rate until such audit and control measures and reporting requirements have been proposed by Minto, reviewed and agreed upon by Yukon Energy, and approved by the Board.

As of the date of filing Minto Explorations has yet to provide further information to YEC regarding specific proposed auditable reporting and control mechanisms. In the event this service was requested by Minto Explorations and there was anticipated power to be made available, YEC and Minto Explorations intend to work together to determine acceptable auditable reporting and controls.

Accordingly, because the YUB prerequisites for this rate have not been met, and the forecast quantities of power available for such service are very limited,⁴ Yukon Energy forecasts do not include any Rate Schedule 35 sales in the test years.

4.3 MAJOR INDUSTRIAL FIRM RATES

Major Industrial customers are defined in OIC 1995/90 as being those customers “engaged in manufacturing, processing, or mining and whose peak demand for electricity exceeds 1 MW”. In the forecast test years, this classification only applies to the Minto mine.

⁴ This rate is to be served at a lower priority than Rate Schedule 32 secondary sales. In this Application, Rate Schedule 32 sales are forecast to be constrained and to be approaching the limits of the system. Accordingly, no material energy is expected to be further “surplus” to Rate Schedule 32 needs for service under Rate Schedule 35, except possibly for a few years during summer.

On June 4, 2007, the Yukon Government enacted OIC 2007/94 amending OIC 1995/90 to add subsection 6(3) immediately after subsection 6(2). Subsection 6(3) provides that “despite subsection (1), the Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary” attached as Schedule A to the OIC. On August 25, 2008, Yukon Energy applied to have this firm Rate Schedule 39 per OIC 2007/94 approved by the Board. Rates for industrial customers in the forecast test years are based on this OIC prescribed rate schedule, and the rate as now approved by Board Order 2008-13.

Consistent with the YUB’s directive in Order 2007-5 and the PPA as amended May 14, 2007 (and approved by Board Order 2007-6) the OIC mandated Rate Schedule 39 includes a provision that Rider F applies to these industrial customers such that the rider is “set to \$0.0 for fuel price forecast filed November 20, 2006”. The November 20, 2006 forecast was premised on a YECL average fuel price of 83.56 cents/litre, a Yukon Energy average fuel price of 78.68 cents/litre and a retail secondary sales rate of 6.3 cents/kW.h and a wholesale secondary rate of 5.2 cents/kW.h.

Implementation of Rider F for Major Industrial customers therefore requires a different “baseline” regime than for all other customers.

Yukon Energy’s filing on August 25, 2008 (regarding the amended Rate Schedule 39) notified the Board that Rider F of 0.671 cents per kW.h is applicable to Minto at time of connection, in accordance with Rate Schedule 39 and the current Rider F of 1.86 cents per kW.h charged to all retail customers as implemented August 1, 2008. Yukon Energy noted that Rider F application to Rate Schedule 39 beyond the current GRAs would be addressed further in Yukon Energy’s GRA Application for 2008 and 2009.

As explained below, in order to implement Rate Schedule 39 in this Application using November 20, 2006 as the Rider F baseline, a “fixed” Rider F amount of 0.585 cents/kW.h is required to bring Industrial customers to a level basis with the Rider F rate established following the current GRAs for all other customers on the system⁵ plus a variable Rider F amount which will vary exactly the same as applies to other customers at any given point in time until the next Yukon Energy or YECL GRA. Similar to all other amounts paid by customers towards the baseline GRA fuel prices, the fixed component of the industrial

⁵ Following implementation of the 2009 GRA decisions for Yukon Energy and YECL, the rates for all of these other customers will be based on the higher current fuel prices as approved for the 2009 GRA revenue requirements, offset by the higher current secondary sales rate as approved for Yukon Energy’s 2009 GRA revenue requirement.

Rider F will be recorded by Yukon Energy as revenue. All collections from the variable portion of industrial Rider F will be credited against the Deferred Fuel Price Variance Account balances.

The applied for Fixed Rider F of 0.585 cents per kW.h assumes that the Board approves the latest forward fuel price forecasts now filed as GRA or Rider F fuel price forecasts for 2009.⁶ Based on these latest fuel price forecasts, the forecast system-wide variance relevant to determining Minto's Rider F charges under this provision in 2009 is \$1.961 million,⁷ or 0.585 cents/kWh for all firm sales, as set out in Table 4.2.⁸

Table 4.2
Calculation of Minto "Fixed" Rider F Component

	Fuel price forecast (\$/litre)		GRA 2009 litres	Variance
	2009 Nov 20/06			
YECL	1.25	0.8356	5,516,000	2,285,830
YEC	1.17	0.7868	451,380	173,095
				<u>2,458,926</u>
			kW.h	
Sec sales	0.082	0.052	16,613,000	(498,390)
				<u>1,960,536</u>
Sales				
firm retail	YEC		31,019,000	
	YECL		275,091,304	
industrial			<u>29,023,000</u>	
			335,133,304	
Fixed Rider F rate (cents/kW.h)				0.585

⁶YECL's forecast average at 125 cents/litre for August 2008 through July 2009 per the July 10, 2008 Rider F filing; YEC's forecast average for 2009 at 117 cents/litre per this Application; secondary sales at 9.3 cents/kW.h at the retail level for 2009 per this Application.

⁷ The YECL price variance equals 125 cents/litre currently (August 2008) compared to 83.56 cents/litre in the Nov 20, 2006 filing, or 41.44 cents/litre variance, times an estimated 2009 fuel consumption of 5.516 million litres or a total variance of \$2.286 million. The YEC price variance equals 117 cents/litre compared to 78.68 cents/litre in the Nov 20, 2006 filing, or a variance of 38.32 cents/litre, times a 2009 fuel consumption forecast of 0.451 million litres, or a total variance of \$0.173 million. This is offset by a secondary sales variance of 3.0 cents/kW.h (9.3 cents/kW.h as 2009 retail level forecast compared to 6.3 cents/kW.h for November 20, 2006 filing, 1.1 cents/kW.h lower for wholesale) times 16,613 MW.h totals \$0.498 million. Accordingly, the net annualized variance is \$1.961 million.

⁸ Table 4.2 includes YECL load per CW-YECL-19 with the exception that 2009 Hydro zone and lighting loads are increased by 1.2%, per YEC's higher forecast for 2009 YECL loads as set out in Tab 2.

For 2008, the forecast revenue to YEC under this fixed Rider F component is \$0.040 million (assuming Minto connection to the grid October 1, 2008 as forecast in Tab 2) and for 2009 totals \$0.170 million.

The revised Rate Schedule 39 to implement the OIC 2007/94 with the above fixed Rider F provisions is set out in Appendix A to this Tab in blacklined form for Board approval.

4.4 NON-INDUSTRIAL FIRM RETAIL RATE DESIGN

Yukon Energy's firm retail non-industrial rates are required by OIC 1995/90 to be equal throughout Yukon for both Yukon Energy and YECL customers. Concurrent with the rate reduction sought by Yukon Energy in this Application and the need to promote economy and efficiency as regards retail runoff rates the present structure of these rates in Yukon highlights certain issues that must be addressed.

4.4.1 Yukon-Wide Retail Non-Industrial Rates

Firm retail *rates* in Yukon for each customer class comprise "base" rates, riders in effect from time to time and (for non-government customers) an income tax rebate. Pursuant to OIC 2008/70 customer *bills* also include, in the case of non-government and municipal government customers, Yukon Government Rate Stabilization Fund ("RSF") subsidies as well as GST.

As a result of the YEC/YECL 1996/97 GRA, the current levels of base energy rates were established in 1997 as shown in Table 4.3:

Table 4.3
Existing "Base" Firm Rates (before riders and taxes) in \$/kW.h

Rate Zone	First Block [Res=1,000 kWh/m; GS= 2,000 kWh/m]				Second Block (run-out rates)			
	NG & Mun res	GS	Govt res	GS	NG & Mun res	GS	Govt res	GS
hydro (WAF, MD)	0.0986	0.0831	0.1434	0.1745	0.1045	0.1045	0.1045	0.1045
large diesel (Watson)	0.0986	0.0831	0.1434	0.1745	0.1045	0.1045	0.1045	0.1045
small diesel (YECL)	0.0986	0.0831	0.1434	0.1745	0.1236	0.1236	0.1236	0.1236
Old Crow (YECL)	0.0986	0.0831	0.1434	0.1745	0.2577	0.2577	0.2577	0.2577

In addition to the base energy rates shown in Table 4.3, residential customers currently pay a monthly fixed charge of \$11.90 for non-government customers and \$15.00 for government customers. General Service customers pay a demand charge of \$6.00 per kW for non-government or municipal government customers, and \$10.00 per kW for federal and territorial government customers, in each case with a minimum monthly bill equal to 5 kW of the relevant demand charge.

Base rates in the 1997 GRA reflected an approach to rate design taking into account the systems at that time, as well as the OIC 1995/90 requirements. In particular, the rates were designed by setting runoff rate levels (second block rates by rate zone) first and then, based on these rates, first block rate levels were set to achieve the remaining revenue requirement not recovered from runoff rates.

4.4.2 Overview of Runoff (or “Second Block”) Rate Levels: 1996/97 GRA

Review of runoff rate levels as established in the 1996/97 GRA, and retained since that time, highlights the extent to which current runoff rates no longer have any reasonable relationship to oil prices. It is therefore timely today to address runoff rates in Yukon to restore efficient runoff rate price signals to each customer class as soon as is practicable.

Runoff rates as established in 1996/97 GRA – Comparison to oil costs for home heating

The following principles guided rate design of the second block rates in the 1996/97 GRA:

- **Requirements under OIC 1995/90:** OIC 1995/90 specifies that the Board must set rates for each non-government retail customer class so as to include a “runoff rate block” for all consumption in excess of a specified level, (set at no less than 1000 kW.h per month for residential and 2000 kW.h per month for GS). The Board is mandated to set run out rates for all non-government customers in order to “promote economy and efficiency”. Further, although first block rates within each customer class must be the same throughout Yukon, separate runoff rates are allowed in different communities or rate zones as long as the same rate design principles are used throughout Yukon.
- **System Conditions:** As of the 1996/97 GRA, the WAF system (included in the Hydro rate zone) as well as the large diesel rate zone systems (Watson Lake and, at that time, Dawson), the small diesel rate zone systems and the Old Crow system were all operating with diesel being the total or incremental source of generation. The only exception was the Mayo system which, as part of the Hydro rate zone, had surplus hydro generation available at that time. Consequently, in order to meet the OIC requirement of “economy and efficiency”, runoff rates were set at levels which approximated the incremental short term cost of generating an extra kW.h using diesel generation.⁹

⁹ For example, the runoff rate in all hydro and large diesel rate zone communities (10.45 cents/kW.h) were set based on averages of approximately 30 cent/litre diesel, engine efficiency in the range of 3.7 to 3.8 kW.h\litre, approximately 10% losses and variable O&M costs of 1.6 cents/kW.h. The same effective mathematics was applied to all small diesel rate zone communities (with a slightly higher fuel price of approximately 33 cents/litre and lower efficiency of 3.5 kW.h per litre, to yield 12.36 cents/kW.h runoff rate) and Old Crow (substantially higher fuel price of 77 cents/litre and 3.49 efficiency, to yield 25.77 cents/kW.h runoff rate). (Set out in Table 3.3 from the 1996/97 GRA filing).

In reflecting short term incremental diesel generation costs, the 1996/97 GRA runoff rate design approach provided a strong economic disincentive to customers from using electricity for space heating at that time (as opposed to oil or other alternatives). The net result was that electric heating costs were more than double (rather than even close to parity) the cost for oil home heating. For example, with the 1996/97 GRA run off rates in place, the cost of operating electric heating in Whitehorse at that time was approximately 120% higher than the cost of heating with fuel oil, i.e., oil prices on a per kW.h basis, for a home with 80% oil heating efficiency, were only 45% of the cost for electric heating.¹⁰

Current runoff rates relative to oil prices for home heating

Since 1997, fuel oil prices and diesel prices have increased dramatically. In contrast, base electricity runoff rates have not changed and electricity costs (with all riders) applicable to electric heating have also not risen to any degree similar to the increases in oil prices.

At current (August 13, 2008) oil prices as reported by Yukon Bureau of Statistics, the cost of oil in various Yukon Hydro and large diesel rate zone communities is such that runoff rates need to be in the range of 18 cents/kW.h before taxes just to ensure electricity space heating is close to parity with oil space heating in Mayo and only marginally (16%) higher than oil space heating in Whitehorse, based solely on fuel costs. This is set out below in Table 4.4:

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

	Whitehorse	Faro	Mayo	Dawson
Price of Furnace Oil August 13, 2008 (\$/litre)	1.39	1.51	1.61	1.49
Oil price excluding GST	1.32	1.43	1.53	1.42
Equivalent Price of Electricity (cents/kW.h)				
at 80% efficiency furnace (excl GST)	0.1544	0.1671	0.1784	0.1653

To appreciate the magnitude of the issue, applying the same rate design approach for 2009 as was approved in the 1996/97 GRA would yield target runoff rates for hydro zone communities of

¹⁰ Yukon Housing Corporation historic graphs show Furnace Oil fuel costs in 1998 in Whitehorse at about \$50 per 1,000 kW.h with GST for a home with 80% heating efficiency (implies oil price of approximately 43 cents per litre, assuming approximately 10.722 kW.h per litre). In contrast, Hydro zone residential runoff rates in 1997 approximated 10.21 cents/kW.h, after income tax rebates (2%), excluding GST.

approximately 37.37 cents/kW.h,¹¹ and would result in runoff rates about 140% higher than oil home heating costs (at 80% efficiency) in Whitehorse.

However, the runoff rate today for residential customers in Hydro and Large Diesel rate zone communities (including all riders) is only 14.39 cents/kW.h¹² (see Table 4.5).

Table 4.5

Effective Residential 2nd Block Rate (Hydro and Large Diesel Zones) – Existing Rates

	Residential Effective 2nd Block Rate Hydro and Large Diesel
2nd Block Base Rate Charge (\$/kW.h)	0.1045
Rider F (\$/kW.h)	0.0186
Rider J % applied to base rates	14.93%
Rider R % applied to base rates	5.00%
Total (\$/kW.h) excluding Income Tax Rebate and GST	0.1439

Effective runoff rates for other classes and zones are shown in Tables 4.7 and 4.8. In summary, runoff rates no longer conform with the 1996/97 GRA principles and OIC 1995/90, and as a result it is now actually cheaper to heat with electricity at current runoff rates (even including all riders) than it is with oil,¹³ which has the effect of encouraging inefficient and inappropriate use of electric heating in Yukon homes.

Given the Yukon Hydro zone electrical systems are now approaching the point where diesel generation will be required for more peaking occasions, and ultimately for near-term baseload generation (absent the development of added new renewable generation), current run out rates in all rate zones simply are not in keeping with the conservation principles of OIC 1995/90 nor are such rates consistent with the overriding principles outlined in the YTG's climate change policy.¹⁴

It is also important to note that without proper economic signals there may be a tendency in new construction for electric heating to be preferable to customers due to the lower capital cost of electric

¹¹ Average 2009 YEC fuel price for hydro systems of \$1.170/litre, average efficiency of 3.60 kW.h/litre, 10% system-wide losses and assuming retention of the 1.6 cents/kW.h variable O&M estimates from 1996/97.

¹² For non-government customers, net of income tax rebate of 0.5% this effective rate is 14.34 cents/kW.h - no RSF applies to these rates.

¹³ Based on August heating oil prices as reported by Yukon Bureau of Statistics.

¹⁴ http://www.environmentyukon.gov.yk.ca/pdf/yg_env_climate_change_final.pdf

heating (baseboards) compared to oil (furnaces). This combined with the fact that electricity prices in Yukon are more stable and predictable than oil prices (in part due to YUB regulation) realistically suggests that electricity prices today should at least be in the 20-22 cents/kW.h range (i.e., at least 25 to 40% higher than oil heating costs) to promote in the short term “economy and efficiency” by once again starting to discourage electric heating. Further, given the system realities these rates should be planned now to be set in the near term at even higher levels (e.g., in excess of 30 to 35 cents per kW.h based on the current GRA diesel fuel price forecasts), if the rate design principles adopted by the Board in the 1996/97 GRA are to be followed in the future.

In summary, it is timely and necessary to address runoff rates in Yukon for all customer classes.

Considerations affecting runoff rate changes today vary for each rate class

In addressing runoff rates for both residential and general service customers, the considerations affecting immediate action for each class are markedly different:

- **Residential:** In the residential class, by far the minority of sales are made at the second block rates. As shown in Table 4.9, less than 20% of the residential energy sold in Yukon at second block rates for the non-government class, and only slightly higher (approximately 23%) for the government class. The residential class is clearly where price signals can lead to inefficient choices, such as deciding to install electric baseboard heating in new construction, a decision which is very difficult to reverse. Given the small share of energy sales in the second block, it is practical to increase the second block rate in order to begin to correct the current price signal issue. This can be done by establishing an offsetting decrease to first block rates so as to ensure the residential share of overall electricity charges remain the same.
- **General Service:** In contrast, the General Service class is dominated by sales at second block rates (approximately 71% of sales in the non-government class, and 87% of sales in the government class). Although these sales reflect a relatively small number of very large users (such as very large stores, hotels, hospitals, etc.), they also include numerous customers whose usage varies widely. Accordingly, when dealing with a large and relatively non-homogenous group, rate structures that impose a notable inverted structure require careful attention given the range of impacts on the different profiles of customers in the class. For example, in order to provide fair price signals it may require establishing multiple general service rate subclasses, or further rate blocks. Yukon Energy does not believe that it

is practical to properly analyze and implement an appropriate rate design package in a Yukon Energy Revenue Requirement proceeding.

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

As noted above, any meaningful runoff rate change for general service customers is simply not practical until further study is conducted by Yukon Energy and YECL to assess rate design options – and it is proposed that such joint study proceed in order to provide specific proposals to the Board as soon as practicable.

4.4.3 Yukon Energy Rate Reduction

With the completion of the Carmacks-Stewart Transmission Project and the connection of the Minto mine, Yukon Energy is able to implement substantial rate reductions for all retail customer classes throughout Yukon. For 2009, this reduction totals \$1.334 million, or 3.48% of total Yukon-wide base rate revenues as forecast by Yukon Energy. Table 4.6 sets out the distribution of the rate reduction by retail customer classes, based on total base rate revenues:

Table 4.6
Revenue Reduction by Class (\$000s)

\$000s	Total Estimated 2009 Revenue before reduction YEC and YECL	Revenue Reduction
Residential Non-Government	15,592.1	542.2
Residential Government	338.9	11.8
General Service Non-Government	13,994.4	486.7
General Service Government	7,488.4	260.4
Lighting	945.3	32.9
Total	38,359.1	1,334.0

Allocation of the rate decrease amount to each class based on total base rate revenue is consistent with all other rate adjustment riders applied to firm rates in Yukon since 1998, including Rider J at various

percentage levels, as well as interim Rider R, pending a future full review of joint YEC/YECL cost of service and revenue: cost ratios and other factors affecting overall rate design for each customer class.

Given that adoption of another fixed rider applicable to all base rates to implement this rate reduction would result in reduction of runoff rates as well as first block rates, Yukon Energy has devised a rate proposal that not only ensures the rate reduction is allocated appropriately to all rate classes, it ensures that the residential runoff rate issue described above is also dealt with.

4.4.4 Rate Proposal

Given the above considerations, Yukon Energy proposes to implement a rate revision in this Application consisting of the following:

- A **rate reduction rider** to implement Yukon Energy's 2009 revenue requirement reduction, focused solely on the first block consumption for each rate class (with the exception of lighting classes which do not have separate first and second blocks) consisting of the following adjustments by way of Rider:
 - Residential Non-government: negative 0.496 cents/kW.h on first block energy (5.03% of the present first block energy rate of 9.86 cents/kW.h)
 - Residential Government: negative 0.715 cents/kW.h on first block energy (5.01% of the present first block energy rate of 14.29 cents/kW.h)
 - General Service Non-government and Municipal Government: negative 1.50 cents/kW.h on first block energy (18.04% of the present first block energy rate of 8.31 cents/kW.h)
 - General Service Government: negative 3.96 cents/kW.h on first block energy (22.71% of the present first block energy rate of 17.45 cents/kW.h).
 - Street lighting and Private lighting: negative 3.48% of total base rate revenues.
- A **revenue-neutral base rate revision** for residential classes to take the first step in raising runoff rates without rebalancing overall rate revenues collected from each class, applicable to all residential consumption throughout Yukon (in both Yukon Energy and YECL served areas), consisting of the following (as shown in Tables 4.9 and 4.10):
 - Residential Non-government: A revenue-neutral increase of 5.61 cents/kW.h in the second block base rates, offset by a decrease of 1.36 cents/kW.h in the first block base rates. The same cents/kW.h adjustment applies to all zones.
 - Residential Government: A revenue-neutral increase of 5.61 cents/kW.h in the second block base rates, offset by a decrease of 1.66 cents/kW.h in the first block base rates. The same cents/kW.h adjustment applies to all zones.

After all current riders, rebates and subsidies, but prior to GST, the net effects are as follows on retail residential and general service customers (as shown in detail in Tables 4.7 and 4.8):

- No change to the monthly customer charges or demand charges.
- A reduction in the first block energy charge as follows affecting first 1,000 kwh/month for Residential, and the first 2,000 kW.h/month for General Service (on average over a year, about 70% of non-government residential customer monthly bills, and 67% of non-government general service customer monthly bills, show only first block energy level use):

Class	Cents/kW.h	Percentage
Change	Change	Change
Residential Non-Government	(2.12)	(17.8%)
Residential Government	(2.71)	(14.2%)
GS Non-Gov and Municipal Gov	(1.50)	(13.7%)
GS Municipal Gov.	(1.5)	(13.5%)
GS Fed and Terr. Gov	(3.96)	(17.4%)

- An increase in the second block energy charge to all residential non-government customers of 6.70 cents/kW.h (varying percentage depending on zone, from 46.7% in Hydro and Large Diesel zones to 20.5% in Old Crow) and to all residential government customers of 6.73 cents/kW.h (percentages similarly vary by zone from 46.8% to 20.5%). Forecast additional second block revenue is applied to reduce residential first block rates in each class as noted above.
- Overall impacts on non-government residential customer monthly bills before GST will depend on average monthly use levels (overall savings occur for all customers with use of up to slightly more than 1,300 kW.h per month - in 2007, 84% of non-government residential monthly bills used no more than 1,300 kW.h):
 - Saving of \$10.60/month at 500 kW.h/month
 - Saving of \$21.20/month at 1,000 kw.h/month
 - Saving of \$4.45/month at 1,250 kW.h/month
 - Saving of \$1.10/month at 1,300 kW.h/month
 - Increase of \$12.30/month at 1,500 kW.h/month
 - Increase of \$45.80/month at 2,000 kW.h/month
 - Increase of \$112.80/month at 3,000 kW.h/month.

The ultimate impact on the overall levels of bill by class, by rate zone and by usage tier are shown in the detailed bill impacts Tables 4.11 through 4.18.

4.5 WHOLESALE RATES

Yukon Energy's firm rate revenues today primarily arise from the wholesale rate charged to Yukon Electrical.

The structure of the wholesale rate to Yukon Electrical must meet the criteria of OIC 1995/90. Specifically, that OIC sets out two key requirements:

- The wholesale rate must "be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers"; and
- The wholesale rate "shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein."

The approved Rate Schedule 42 Primary Wholesale is an energy-only rate with two rate levels. First, when the WAF system does not have diesel "on the margin" as is the case in the test years, the rate for all primary power supplied to YECL is at a single rate (currently 6.84 cents/kW.h). Second, when diesel is on the margin for the WAF system, an additional provision, the Energy Reconciliation Adjustment ("ERA"), is triggered to, in effect, result in a two-block inverted wholesale rate.¹⁵

Two changes to the wholesale rate are required at this time:

- **Base rates:** The present base rates to YECL are set at 6.840 cents/kW.h, for a total revenue at existing rates of \$18.258 million in 2009, on a sales volume of 266.926 GW.h. As noted above, Yukon Energy proposes to implement a system-wide revenue-neutral adjustment to firm residential non-government and residential government rates for both Yukon and YECL retail customers. As shown in Table 4.9 and 4.10, this proposed rate change will not alter the consolidated YEC/YECL revenues from these two classes (totalling \$15.592 million for residential non-government, and \$0.339 million for residential government), but will alter the net revenues of each utility once implemented. In particular, Yukon Energy's total residential

¹⁵ See Order 1999-4.

revenues will decrease from \$1.335 million to \$1.305 million, a decrease of \$0.030 million, while YECL's residential revenues will increase from \$14.596 million to \$14.626 million, an increase of \$0.030 million. In order to address this imbalance, it is necessary to implement an adjustment to the firm wholesale rate of 0.011 cents/kW.h, from 6.840 cents/kW.h to 6.851 cents/kW.h to balance this \$0.030 million offset. The net effect of this adjustment, combined with the residential rate adjustments, is revenue neutrality for each class as well as each utility.

- **Energy Reconciliation Adjustment (ERA):** The structure of the ERA is designed to ensure both that YECL receives a full pass through of the incremental costs of diesel generation (when diesel is on the margin) driven by increases in the volume of wholesale sales, and second to ensure that Yukon Energy is able to recover its costs (as required by OIC 1995/90 section 7(b)) when diesel generation is on the margin. As noted above, in the 1996/97 GRA, the residential runoff rates were intended to be proxies for the short term incremental cost of diesel generation (taking into account fuel price as forecast in each rate zone, forecast heat rates, diesel generation operating and maintenance costs, and normal line losses). In keeping with the underlying principles used to establish the ERA, the level of ERA needs to be changed to reflect the cost of WAF diesel generation (37.37 cents/kW.h) as forecast for 2009 in the Application. The ERA adjusts charges to YECL periodically to reconcile actual wholesale purchases to test year forecast purchases, and therefore no Wholesale ERA revenues would ever be forecast for any test year. The ERA is also not anticipated to have any impact during the test year because diesel is not forecast to be on the margin; however, it is prudent to adjust Rate Schedule 42 to provide for such contingencies.

Table 4.7: Residential Effective Rate including all Riders, Rebates, Subsidies and GST

**Table 4.7
September 2008**

		Proposed						Existing					
		Residential Non-Government						Residential Non-Government					
		Customer Charge	First Block Energy	Second Block Energy				Customer Charge	First Block Energy	Second Block Energy			
		all zones \$/month	all zones c/kW.h	Hydro c/kW.h	Lg Diesel c/kW.h	Sm Diesel c/kW.h	Old Crow c/kW.h	all zones \$/month	all zones c/kW.h	Hydro c/kW.h	Lg Diesel c/kW.h	Sm Diesel c/kW.h	Old Crow c/kW.h
Base Rate		\$11.90	\$0.0850	\$0.1606	\$0.1606	\$0.1797	\$0.3138	\$11.90	\$0.0986	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider F (kW.h)	\$0.0186		\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186		\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186
Rider J (%)	14.93%	\$1.78	\$0.0127	\$0.0240	\$0.0240	\$0.0268	\$0.0469	\$1.78	\$0.0147	\$0.0156	\$0.0156	\$0.0185	\$0.0385
Interim Rider R (%)	5.00%	\$0.60	\$0.0043	\$0.0080	\$0.0080	\$0.0090	\$0.0157	\$0.60	\$0.0049	\$0.0052	\$0.0052	\$0.0062	\$0.0129
Proposed Rider U (1st block kW.h)	-\$0.00496		-\$0.00496										
Effective rate before Tax rebate, RSF and GST		\$14.27	\$0.1156	\$0.2112	\$0.2112	\$0.2341	\$0.3949	\$14.27	\$0.1369	\$0.1439	\$0.1439	\$0.1668	\$0.3277
Income Tax Rebate (%)	-0.50%	-\$0.06	-\$0.0004	-\$0.0008	-\$0.0008	-\$0.0009	-\$0.0016	-\$0.06	-\$0.0005	-\$0.0005	-\$0.0005	-\$0.0006	-\$0.0013
RSF Cust Charge (\$/month)	-\$1.19	-\$1.19						-\$1.19					
RSF Energy (1st block kW.h)	-\$0.0174		-\$0.0174						-\$0.0174				
Total before GST		\$13.02	\$0.0978	\$0.2104	\$0.2104	\$0.2332	\$0.3934	\$13.02	\$0.1190	\$0.1434	\$0.1434	\$0.1662	\$0.3264
Change		\$0.00	-\$0.0212	\$0.0670	\$0.0670	\$0.0670	\$0.0670						
		0.00%	-17.82%	46.72%	46.72%	40.31%	20.53%						

		Proposed						Existing					
		Residential Government						Residential Government					
		Customer Charge	First Block Energy	Second Block Energy				Customer Charge	First Block Energy	Second Block Energy			
		all zones \$/month	all zones c/kW.h	Hydro c/kW.h	Lg Diesel c/kW.h	Sm Diesel c/kW.h	Old Crow c/kW.h	all zones \$/month	all zones c/kW.h	Hydro c/kW.h	Lg Diesel c/kW.h	Sm Diesel c/kW.h	Old Crow c/kW.h
Base Rate		\$15.00	\$0.1268	\$0.1606	\$0.1606	\$0.1797	\$0.3138	\$15.00	\$0.1434	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider F (kW.h)	\$0.0186		\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186		\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186
Rider J (%)	14.93%	\$2.24	\$0.0189	\$0.0240	\$0.0240	\$0.0268	\$0.0469	\$2.24	\$0.0214	\$0.0156	\$0.0156	\$0.0185	\$0.0385
Interim Rider R (%)	5.00%	\$0.75	\$0.0063	\$0.0080	\$0.0080	\$0.0090	\$0.0157	\$0.75	\$0.0072	\$0.0052	\$0.0052	\$0.0062	\$0.0129
Proposed Rider U (1st block kW.h)	-\$0.00715		-\$0.00715										
Total before GST		\$17.99	\$0.1635	\$0.2112	\$0.2112	\$0.2341	\$0.3949	\$17.99	\$0.1906	\$0.1439	\$0.1439	\$0.1668	\$0.3277
Change		\$0.00	-\$0.0271	\$0.0673	\$0.0673	\$0.0673	\$0.0673						
		0.00%	-14.20%	46.75%	46.75%	40.33%	20.53%						

Table 4.8: General Service Effective Rate including all Riders, Rebates, Subsidies and GST

**Table 4.8
September 2008**

		Proposed								Existing					
		GS Non-Government								GS Non-Government					
		Demand Charge	First Block Energy	Second Block Energy						Customer Charge	First Block Energy	Second Block Energy			
		all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow			all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow
		\$/kW	c/kW.h	c/kW.h	c/kW.h	c/kW.h	c/kW.h			\$/month	c/kW.h	c/kW.h	c/kW.h	c/kW.h	c/kW.h
Base Rate		\$6.00	\$0.0831	\$0.1045	\$0.1045	\$0.1236	\$0.2577			\$6.00	\$0.0831	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider F (kW.h)	\$0.0186		\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186				\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186
Rider J (%)	14.93%	\$0.90	\$0.0124	\$0.0156	\$0.0156	\$0.0185	\$0.0385			\$0.90	\$0.0124	\$0.0156	\$0.0156	\$0.0185	\$0.0385
Interim Rider R (%)	5.00%	\$0.30	\$0.0042	\$0.0052	\$0.0052	\$0.0062	\$0.0129			\$0.30	\$0.0042	\$0.0052	\$0.0052	\$0.0062	\$0.0129
Proposed Rider U (1st block kW.h)	-\$0.01500		-\$0.01500												
Effective rate before Tax rebate, RSF and GST		\$7.20	\$0.1033	\$0.1439	\$0.1439	\$0.1668	\$0.3277			\$7.20	\$0.1183	\$0.1439	\$0.1439	\$0.1668	\$0.3277
Income Tax Rebate (%)	-0.50%	-\$0.03	-\$0.0004	-\$0.0005	-\$0.0005	-\$0.0006	-\$0.0013			-\$0.03	-\$0.0004	-\$0.0005	-\$0.0005	-\$0.0006	-\$0.0013
RSF Energy (1st block kW.h)	-\$0.00798		-\$0.00798								-\$0.00798				
Total before GST		\$7.17	\$0.0949	\$0.1434	\$0.1434	\$0.1662	\$0.3264			\$7.17	\$0.1099	\$0.1434	\$0.1434	\$0.1662	\$0.3264
Change		\$0.00	-\$0.0150	\$0.0000	\$0.0000	\$0.0000	\$0.0000								
		0.00%	-13.65%	0.00%	0.00%	0.00%	0.00%								

		Proposed								Existing					
		GS Municipal Government								GS Municipal Government					
		Demand Charge	First Block Energy	Second Block Energy						Customer Charge	First Block Energy	Second Block Energy			
		all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow			all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow
		\$/kW	c/kW.h	c/kW.h	c/kW.h	c/kW.h	c/kW.h			\$/month	c/kW.h	c/kW.h	c/kW.h	c/kW.h	c/kW.h
Base Rate		\$6.00	\$0.0831	\$0.1045	\$0.1045	\$0.1236	\$0.2577			\$6.00	\$0.0831	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider F (kW.h)	\$0.0186		\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186				\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186
Rider J (%)	14.93%	\$0.90	\$0.0124	\$0.0156	\$0.0156	\$0.0185	\$0.0385			\$0.90	\$0.0124	\$0.0156	\$0.0156	\$0.0185	\$0.0385
Interim Rider R (%)	5.00%	\$0.30	\$0.0042	\$0.0052	\$0.0052	\$0.0062	\$0.0129			\$0.30	\$0.0042	\$0.0052	\$0.0052	\$0.0062	\$0.0129
Proposed Rider U (1st block kW.h)	-\$0.01500		-\$0.01500												
Effective rate before RSF and GST		\$7.20	\$0.1033	\$0.1439	\$0.1439	\$0.1668	\$0.3277			\$7.20	\$0.1183	\$0.1439	\$0.1439	\$0.1668	\$0.3277
RSF Energy (1st block kW.h)	-\$0.00728		-\$0.00728								-\$0.00728				
Total before GST		\$7.20	\$0.0960	\$0.1439	\$0.1439	\$0.1668	\$0.3277			\$7.20	\$0.1110	\$0.1439	\$0.1439	\$0.1668	\$0.3277
Change		\$0.00	-\$0.0150	\$0.0000	\$0.0000	\$0.0000	\$0.0000								
		0.00%	-13.52%	0.00%	0.00%	0.00%	0.00%								

		Proposed								Existing					
		GS Government								GS Government					
		Demand Charge	First Block Energy	Second Block Energy						Customer Charge	First Block Energy	Second Block Energy			
		all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow			all zones	all zones	Hydro	Lg Diesel	Sm Diesel	Old Crow
		\$/kW	c/kW.h	c/kW.h	c/kW.h	c/kW.h	c/kW.h			\$/month	c/kW.h	c/kW.h	c/kW.h	c/kW.h	c/kW.h
Base Rate		\$10.00	\$0.1745	\$0.1045	\$0.1045	\$0.1236	\$0.2577			\$10.00	\$0.1745	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider F (kW.h)	\$0.0186		\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186				\$0.0186	\$0.0186	\$0.0186	\$0.0186	\$0.0186
Rider J (%)	14.93%	\$1.49	\$0.0261	\$0.0156	\$0.0156	\$0.0185	\$0.0385			\$1.49	\$0.0261	\$0.0156	\$0.0156	\$0.0185	\$0.0385
Interim Rider R (%)	5.00%	\$0.50	\$0.0087	\$0.0052	\$0.0052	\$0.0062	\$0.0129			\$0.50	\$0.0087	\$0.0052	\$0.0052	\$0.0062	\$0.0129
Proposed Rider U (1st block kW.h)	-\$0.03960		-\$0.03960												
Total before GST		\$11.99	\$0.1883	\$0.1439	\$0.1439	\$0.1668	\$0.3277			\$11.99	\$0.2279	\$0.1439	\$0.1439	\$0.1668	\$0.3277
Change		\$0.00	-\$0.0396	\$0.0000	\$0.0000	\$0.0000	\$0.0000								
		0.00%	-17.38%	0.00%	0.00%	0.00%	0.00%								

Table 4.9

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

September 2008

YEC sales per YEC GRA forecast - YECL sales per YECL GRA forecast (CW-YECL-19) plus 1.2% escalation in hydro zones (per YEC forecast)

Rate Class / Billing Determinants	Sales Volumes (MWh)				Base Rate Average Rate (\$/kWh)			Base Rate Billing (Sales) Values (\$000)		
	YEC	YECL	Total		YEC	YECL	Total	YEC	YECL	Total
(variance mainly reflects rate zones)										
Residential-Non Government*										
1st block energy	9180	100,086	109,266	80.47%	0.0986	0.0986	0.0986	905	9,868	10,774
2nd block energy	1724	24,799	26,523	19.53%	0.1045	0.1053	0.1052	180	2,611	2,791
Customer Charge**								206	1,821	2,027
Total class	10,904	124,885	135,789	100.00%				1,291	14,301	15,592
Residential- Government										
1st block energy	234	1,414	1,648	77.22%	0.1434	0.1434	0.1434	34	203	236
2nd block energy	46	440	486	22.78%	0.1045	0.1195	0.1181	5	53	57
Customer Charge**								5	40	45
Total class	280	1,854	2,134	100.00%				44	295	339
All Residential	11,184	126,739	137,923					1,335	14,596	15,931
General Service-Non Government*										
1st block energy	2,812	29,656	32,468	28.84%	0.0831	0.0831	0.0831	234	2,464	2,698
2nd block energy	9,569	70,528	80,097	71.16%	0.1045	0.1051	0.1050	1,000	7,413	8,413
Demand Charge***								378	2,506	2,883
Total class	12,381	100,184	112,565	100.00%				1,611	12,383	13,994
General Service-Government										
1st block energy	837	5,733	6,570	12.85%	0.1745	0.1745	0.1745	146	1,000	1,147
2nd block energy	6,327	38,232	44,559	87.15%	0.1045	0.1055	0.1053	661	4,033	4,694
Demand Charge***								219	1,429	1,648
Total class	7,164	43,965	51,129	100.00%				1,026	6,463	7,488
All General Service	19,545	144,149	163,694					2,637	18,846	21,483
Street & Space lights	293	4,203	4,496					74	871	945
Total Primary Sales	31,022	275,091	306,113					4,046	34,313	38,359

*includes municipal re: rates

**Overall customer charge [\$211k for YEC] allocated between government and non-government classes based on share of energy sales.[Charge =\$11.90/customer month NG, \$15/customer month Govt.]

***Overall demand charge [\$596k for YEC] allocated between government and non-government classes based on share of energy sales. [Charge=\$6.00/kW/month NG, \$10.00/kW/month Govt.]

Table 4.10
September 2008

Table 4.10: Primary Sales by YEC/YECL Rate Class & Billing Determinants - 2009 With Proposed Rate Rebalancing

YEC sales per YEC GRA forecast - YECL sales per YECL GRA forecast (CW-YECL-19) plus 1.2% escalation in hydro zones (per YEC forecast)

Rate Class / Billing Determinants	Sales Volumes (MWh)				Base Rate Average Rate (\$/kWh)			Base Rate Billing (Sales) Values (\$000)			Change from Existing	
	YEC	YECL	Total		YEC	YECL	Total	YEC	YECL	Total		
	(variance mainly reflects rate zones)											
Residential-Non Government*												
1st block energy		9180	100,086	109,266	80.47%	0.0850	0.0850	0.0850	780	8,506	9,286	(1,488)
2nd block energy		1724	24,799	26,523	19.53%	0.1606	0.1614	0.1613	277	4,002	4,279	1,488
Customer Charge**									206	1,821	2,027	-
Total class	10,904	124,885	135,789	100.00%				1,263	14,329	15,592	-	
Residential- Government												
1st block energy		234	1,414	1,648	77.22%	0.1268	0.1268	0.1268	30	179	209	(27)
2nd block energy		46	440	486	22.78%	0.1606	0.1756	0.1742	7	77	85	27
Customer Charge**									5	40	45	-
Total class	280	1,854	2,134	100.00%				42	297	339	-	
All Residential	11,184	126,739	137,923					1,305	14,626	15,931	-	
General Service-Non Government*												
1st block energy		2,812	29,656	32,468	28.84%	0.0831	0.0831	0.0831	234	2,464	2,698	-
2nd block energy		9,569	70,528	80,097	71.16%	0.1045	0.1051	0.1050	1,000	7,413	8,413	-
Demand Charge***									378	2,506	2,883	-
Total class	12,381	100,184	112,565	100.00%				1,611	12,383	13,994	-	
General Service-Government												
1st block energy		837	5,733	6,570	12.85%	0.1745	0.1745	0.1745	146	1,000	1,147	-
2nd block energy		6,327	38,232	44,559	87.15%	0.1045	0.1055	0.1053	661	4,033	4,694	-
Demand Charge***									219	1,429	1,648	-
Total class	7,164	43,965	51,129	100.00%				1,026	6,463	7,488	-	
All General Service	19,545	144,149	163,694					2,637	18,846	21,483	-	
Street & Space lights	293	4,203	4,496					74	871	945	-	
Total Primary Sales	31,022	275,091	306,113					4,016	34,343	38,359	-	

*includes municipal re: rates

**Overall customer charge [\$211k for YEC] allocated between government and non-government classes based on share of energy sales.[Charge =\$11.90/customer month NG, \$15/customer month Govt.]

***Overall demand charge [\$596k for YEC] allocated between government and non-government classes based on share of energy sales. [Charge=\$6.00/kW/month NG, \$10.00/kW/month Govt.]

Table 4.11
September 2008

Bill Comparisons: 2009 Proposed Rates Vs. Existing											Income Tax Rebate GST	-0.50% 5.00%	
CUSTOMER CLASS:		RESIDENTIAL - NON GOVERNMENT											
Zone		Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro	Proposed Bill	\$34.21	\$44.47	\$54.74	\$65.01	\$75.27	\$90.67	\$116.34	\$171.57	\$226.80	\$337.26	\$447.72	\$558.19
	Existing Bill	\$38.66	\$51.15	\$63.64	\$76.14	\$88.63	\$107.37	\$138.60	\$176.24	\$213.89	\$289.17	\$364.46	\$439.75
	Var. (\$)	-\$4.45	-\$6.68	-\$8.91	-\$11.13	-\$13.36	-\$16.70	-\$22.26	-\$4.68	\$12.91	\$48.09	\$83.26	\$118.44
	Var. (%)	-11.52%	-13.06%	-13.99%	-14.62%	-15.07%	-15.55%	-16.06%	-2.65%	6.04%	16.63%	22.85%	26.93%
Large Diesel	Proposed Bill	\$34.21	\$44.47	\$54.74	\$65.01	\$75.27	\$90.67	\$116.34	\$171.57	\$226.80	\$337.26	\$447.72	\$558.19
	Existing Bill	\$38.66	\$51.15	\$63.64	\$76.14	\$88.63	\$107.37	\$138.60	\$176.24	\$213.89	\$289.17	\$364.46	\$439.75
	Var. (\$)	-\$4.45	-\$6.68	-\$8.91	-\$11.13	-\$13.36	-\$16.70	-\$22.26	-\$4.68	\$12.91	\$48.09	\$83.26	\$118.44
	Var. (%)	-11.52%	-13.06%	-13.99%	-14.62%	-15.07%	-15.55%	-16.06%	-2.65%	6.04%	16.63%	22.85%	26.93%
Small Diesel	Proposed Bill	\$34.21	\$44.47	\$54.74	\$65.01	\$75.27	\$90.67	\$116.34	\$177.56	\$238.78	\$361.21	\$483.65	\$606.09
	Existing Bill	\$38.66	\$51.15	\$63.64	\$76.14	\$88.63	\$107.37	\$138.60	\$182.23	\$225.86	\$313.13	\$400.39	\$487.65
	Var. (\$)	-\$4.45	-\$6.68	-\$8.91	-\$11.13	-\$13.36	-\$16.70	-\$22.26	-\$4.68	\$12.91	\$48.09	\$83.26	\$118.44
	Var. (%)	-11.52%	-13.06%	-13.99%	-14.62%	-15.07%	-15.55%	-16.06%	-2.57%	5.72%	15.36%	20.80%	24.29%
Old Crow	Proposed Bill	\$34.21	\$44.47	\$54.74	\$65.01	\$75.27	\$90.67	\$116.34	\$219.60	\$322.86	\$529.38	\$735.90	\$942.42
	Existing Bill	\$38.66	\$51.15	\$63.64	\$76.14	\$88.63	\$107.37	\$138.60	\$224.27	\$309.94	\$481.29	\$652.63	\$823.98
	Var. (\$)	-\$4.45	-\$6.68	-\$8.91	-\$11.13	-\$13.36	-\$16.70	-\$22.26	-\$4.68	\$12.91	\$48.09	\$83.26	\$118.44
	Var. (%)	-11.52%	-13.06%	-13.99%	-14.62%	-15.07%	-15.55%	-16.06%	-2.08%	4.17%	9.99%	12.76%	14.37%
Cumulative percentage of customers		0-200 13.8%	200-300 19.2%	300-400 25.2%	400-500 32.2%	500-600 40.2%	600-800 56.4%	800-1000 70.1%	1000-1300 84.3%	1300-1500 89.7%	1500-2000 96.1%	2000-2500 98.3%	2500-3000 99.1%
Existing Rates		Proposed Rates											
		Hydro	L. Diesel	S. Diesel	Old Crow					Hydro	L. Diesel	S. Diesel	Old Crow
	Customer Charge	\$11.90	\$11.90	\$11.90	\$11.90					\$11.90	\$11.90	\$11.90	\$11.90
	1st. Block Energy	\$0.0986	\$0.0986	\$0.0986	\$0.0986					\$0.0850	\$0.0850	\$0.0850	\$0.0850
	2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577					\$0.1606	\$0.1606	\$0.1797	\$0.3138
	Rider J	14.93%	14.93%	14.93%	14.93%					14.93%	14.93%	14.93%	14.93%
	Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186					\$0.0186	\$0.0186	\$0.0186	\$0.0186
	YECL Interim Rider R	5.00%	5.00%	5.00%	5.00%					5.00%	5.00%	5.00%	5.00%
	Rate Stabilization Fund (Cust. Chrg	-\$1.1900	-\$1.1900	-\$1.1900	-\$1.1900					-\$1.1900	-\$1.1900	-\$1.1900	-\$1.1900
	Rate Stabilization Fund (1st block)	-\$0.0174	-\$0.0174	-\$0.0174	-\$0.0174					-\$0.0174	-\$0.0174	-\$0.0174	-\$0.0174
										Proposed Rider U	-\$0.0050	-\$0.0050	-\$0.0050

Note: "Percentage of Customers" = Average number of bills per month using the specified amount or less, the number of customers are based on 2007 actual number of bills.

Table 4.12
September 2008

Bill Comparisons: 2009 Proposed Rates Vs. Existing											Income Tax Rebate GST	-0.50% 5.00%	
CUSTOMER CLASS:		RESIDENTIAL - NON GOVERNMENT (ABSENT RSF)											
Zone		Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro	Proposed Bill	\$39.11	\$51.20	\$63.29	\$75.38	\$87.47	\$105.61	\$135.84	\$191.07	\$246.30	\$356.76	\$467.22	\$577.69
	Existing Bill	\$43.56	\$57.88	\$72.19	\$86.51	\$100.83	\$122.30	\$158.10	\$195.74	\$233.39	\$308.67	\$383.96	\$459.25
	Var. (\$)	-\$4.45	-\$6.68	-\$8.91	-\$11.13	-\$13.36	-\$16.70	-\$22.26	-\$4.68	\$12.91	\$48.09	\$83.26	\$118.44
	Var. (%)	-10.22%	-11.54%	-12.34%	-12.87%	-13.25%	-13.65%	-14.08%	-2.39%	5.53%	15.58%	21.69%	25.79%
Large Diesel	Proposed Bill	\$39.11	\$51.20	\$63.29	\$75.38	\$87.47	\$105.61	\$135.84	\$191.07	\$246.30	\$356.76	\$467.22	\$577.69
	Existing Bill	\$43.56	\$57.88	\$72.19	\$86.51	\$100.83	\$122.30	\$158.10	\$195.74	\$233.39	\$308.67	\$383.96	\$459.25
	Var. (\$)	-\$4.45	-\$6.68	-\$8.91	-\$11.13	-\$13.36	-\$16.70	-\$22.26	-\$4.68	\$12.91	\$48.09	\$83.26	\$118.44
	Var. (%)	-10.22%	-11.54%	-12.34%	-12.87%	-13.25%	-13.65%	-14.08%	-2.39%	5.53%	15.58%	21.69%	25.79%
Small Diesel	Proposed Bill	\$39.11	\$51.20	\$63.29	\$75.38	\$87.47	\$105.61	\$135.84	\$197.06	\$258.27	\$380.71	\$503.15	\$625.59
	Existing Bill	\$43.56	\$57.88	\$72.19	\$86.51	\$100.83	\$122.30	\$158.10	\$201.73	\$245.36	\$332.62	\$419.89	\$507.15
	Var. (\$)	-\$4.45	-\$6.68	-\$8.91	-\$11.13	-\$13.36	-\$16.70	-\$22.26	-\$4.68	\$12.91	\$48.09	\$83.26	\$118.44
	Var. (%)	-10.22%	-11.54%	-12.34%	-12.87%	-13.25%	-13.65%	-14.08%	-2.32%	5.26%	14.46%	19.83%	23.35%
Old Crow	Proposed Bill	\$39.11	\$51.20	\$63.29	\$75.38	\$87.47	\$105.61	\$135.84	\$239.10	\$342.36	\$548.88	\$755.40	\$961.92
	Existing Bill	\$43.56	\$57.88	\$72.19	\$86.51	\$100.83	\$122.30	\$158.10	\$243.77	\$329.44	\$500.79	\$672.13	\$843.48
	Var. (\$)	-\$4.45	-\$6.68	-\$8.91	-\$11.13	-\$13.36	-\$16.70	-\$22.26	-\$4.68	\$12.91	\$48.09	\$83.26	\$118.44
	Var. (%)	-10.22%	-11.54%	-12.34%	-12.87%	-13.25%	-13.65%	-14.08%	-1.92%	3.92%	9.60%	12.39%	14.04%
Cumulative percentage of customers		0-200 13.8%	200-300 19.2%	300-400 25.2%	400-500 32.2%	500-600 40.2%	600-800 56.4%	800-1000 70.1%	1000-1300 84.3%	1300-1500 89.7%	1500-2000 96.1%	2000-2500 98.3%	2500-3000 99.1%
Existing Rates		Proposed Rates											
	Hydro	L. Diesel	S. Diesel	Old Crow						Hydro	L. Diesel	S. Diesel	Old Crow
	Customer Charge	\$11.90	\$11.90	\$11.90	\$11.90					Customer Charge	\$11.90	\$11.90	\$11.90
	1st. Block Energy	\$0.0986	\$0.0986	\$0.0986	\$0.0986					1st. Block Energy (-0.0136)	\$0.0850	\$0.0850	\$0.0850
	2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577					2nd. Block Energy (+0.0561)	\$0.1606	\$0.1606	\$0.1797
	Rider J	14.93%	14.93%	14.93%	14.93%					Rider J	14.93%	14.93%	14.93%
	Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186					Rider F	\$0.0186	\$0.0186	\$0.0186
	YECL Interim Rider R	5.00%	5.00%	5.00%	5.00%					YECL Interim Rider R (Aug 2008)	5.00%	5.00%	5.00%
	Rate Stabilization Fund (Cust. Chrg)									Rate Stabilization Fund (Cust. Chrg)			
	Rate Stabilization Fund (1st block)									Rate Stabilization Fund (1st block)			
										Proposed Rider U	-\$0.0050	-\$0.0050	-\$0.0050

Note: "Percentage of Customers" = Average number of bills per month using the specified amount or less, the number of customers are based on 2007 actual number of bills.

Table 4.13
September 2008

Bill Comparisons: 2009 Proposed Rates Vs. Existing											Income Tax Rebate	0.00%	
											GST	5.00%	
CUSTOMER CLASS:		RESIDENTIAL - GOVERNMENT											
Zone		Monthly Consump. (kW.h) 200	Monthly Consump. (kW.h) 300	Monthly Consump. (kW.h) 400	Monthly Consump. (kW.h) 500	Monthly Consump. (kW.h) 600	Monthly Consump. (kW.h) 750	Monthly Consump. (kW.h) 1000	Monthly Consump. (kW.h) 1250	Monthly Consump. (kW.h) 1500	Monthly Consump. (kW.h) 2000	Monthly Consump. (kW.h) 2500	Monthly Consump. (kW.h) 3000
Hydro	Proposed Bill	\$53.23	\$70.40	\$87.57	\$104.74	\$121.91	\$147.66	\$190.59	\$246.03	\$301.47	\$412.35	\$523.24	\$634.12
	Existing Bill	\$58.91	\$78.92	\$98.93	\$118.94	\$138.95	\$168.97	\$219.00	\$256.78	\$294.56	\$370.12	\$445.68	\$521.24
	Var. (\$)	-\$5.68	-\$8.52	-\$11.36	-\$14.21	-\$17.05	-\$21.31	-\$28.41	-\$10.75	\$6.91	\$42.23	\$77.56	\$112.88
	Var. (%)	-9.65%	-10.80%	-11.49%	-11.94%	-12.27%	-12.61%	-12.97%	-4.19%	2.35%	11.41%	17.40%	21.66%
Large Diesel	Proposed Bill	\$53.23	\$70.40	\$87.57	\$104.74	\$121.91	\$147.66	\$190.59	\$246.03	\$301.47	\$412.35	\$523.24	\$634.12
	Existing Bill	\$58.91	\$78.92	\$98.93	\$118.94	\$138.95	\$168.97	\$219.00	\$256.78	\$294.56	\$370.12	\$445.68	\$521.24
	Var. (\$)	-\$5.68	-\$8.52	-\$11.36	-\$14.21	-\$17.05	-\$21.31	-\$28.41	-\$10.75	\$6.91	\$42.23	\$77.56	\$112.88
	Var. (%)	-9.65%	-10.80%	-11.49%	-11.94%	-12.27%	-12.61%	-12.97%	-4.19%	2.35%	11.41%	17.40%	21.66%
Small Diesel	Proposed Bill	\$53.23	\$70.40	\$87.57	\$104.74	\$121.91	\$147.66	\$190.59	\$252.04	\$313.50	\$436.41	\$559.32	\$682.23
	Existing Bill	\$58.91	\$78.92	\$98.93	\$118.94	\$138.95	\$168.97	\$219.00	\$262.79	\$306.59	\$394.17	\$481.76	\$569.35
	Var. (\$)	-\$5.68	-\$8.52	-\$11.36	-\$14.21	-\$17.05	-\$21.31	-\$28.41	-\$10.75	\$6.91	\$42.23	\$77.56	\$112.88
	Var. (%)	-9.65%	-10.80%	-11.49%	-11.94%	-12.27%	-12.61%	-12.97%	-4.09%	2.25%	10.71%	16.10%	19.83%
Old Crow	Proposed Bill	\$53.23	\$70.40	\$87.57	\$104.74	\$121.91	\$147.66	\$190.59	\$294.26	\$397.93	\$605.27	\$812.62	\$1,019.96
	Existing Bill	\$58.91	\$78.92	\$98.93	\$118.94	\$138.95	\$168.97	\$219.00	\$305.01	\$391.02	\$563.04	\$735.06	\$907.08
	Var. (\$)	-\$5.68	-\$8.52	-\$11.36	-\$14.21	-\$17.05	-\$21.31	-\$28.41	-\$10.75	\$6.91	\$42.23	\$77.56	\$112.88
	Var. (%)	-9.65%	-10.80%	-11.49%	-11.94%	-12.27%	-12.61%	-12.97%	-3.52%	1.77%	7.50%	10.55%	12.44%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	\$15.00	\$15.00	\$15.00	\$15.00
1st. Block Energy	\$0.1434	\$0.1434	\$0.1434	\$0.1434
2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider J	14.93%	14.93%	14.93%	14.93%
Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186
YECL Interim Rider R	5.00%	5.00%	5.00%	5.00%
Rate Stabilization Fund (Cust. Chrg)				
Rate Stabilization Fund (1st block)				

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Customer Charge	\$15.00	\$15.00	\$15.00	\$15.00
1st. Block Energy (-0.0166)	\$0.1268	\$0.1268	\$0.1268	\$0.1268
2nd. Block Energy (+0.0561)	\$0.1606	\$0.1606	\$0.1797	\$0.3138
Rider J	14.93%	14.93%	14.93%	14.93%
Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186
YECL Interim Rider R (Aug 2008)	5.00%	5.00%	5.00%	5.00%
Rate Stabilization Fund (Cust. Chrg)				
Rate Stabilization Fund (1st block)				
Proposed Rider U	-\$0.0072	-\$0.0072	-\$0.0072	-\$0.0072

Table 4.14
September 2008

Bill Comparisons: 2009 Proposed Rates Vs. Existing										Income Tax Rebate GST		-0.50% 5.00%		
CUSTOMER CLASS:		GENERAL SERVICE - NON GOVERNMENT												
Zone		Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)
		400	700	1000	1500	2000	2500	3000	3500	4000	5000	6000	7500	10000
		5.00	5.00	5.00	5.00	5.00	7.00	8.00	10.00	11.00	14.00	16.00	21.00	27.00
Hydro	Proposed Bill	\$77.46	\$107.35	\$137.23	\$187.03	\$236.84	\$327.18	\$409.99	\$500.32	\$583.13	\$756.28	\$921.90	\$1,185.39	\$1,606.97
	Existing Bill	\$83.76	\$118.37	\$152.98	\$210.66	\$268.34	\$358.68	\$441.49	\$531.82	\$614.63	\$787.78	\$953.40	\$1,216.89	\$1,638.47
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.52%	-9.31%	-10.30%	-11.21%	-11.74%	-8.78%	-7.13%	-5.92%	-5.13%	-4.00%	-3.30%	-2.59%	-1.92%
Large Diesel	Proposed Bill	\$77.46	\$107.35	\$137.23	\$187.03	\$236.84	\$327.18	\$409.99	\$500.32	\$583.13	\$756.28	\$921.90	\$1,185.39	\$1,606.97
	Existing Bill	\$83.76	\$118.37	\$152.98	\$210.66	\$268.34	\$358.68	\$441.49	\$531.82	\$614.63	\$787.78	\$953.40	\$1,216.89	\$1,638.47
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.52%	-9.31%	-10.30%	-11.21%	-11.74%	-8.78%	-7.13%	-5.92%	-5.13%	-4.00%	-3.30%	-2.59%	-1.92%
Small Diesel	Proposed Bill	\$77.46	\$107.35	\$137.23	\$187.03	\$236.84	\$339.15	\$433.94	\$536.25	\$631.04	\$828.14	\$1,017.71	\$1,317.12	\$1,798.58
	Existing Bill	\$83.76	\$118.37	\$152.98	\$210.66	\$268.34	\$370.65	\$465.44	\$567.75	\$662.54	\$859.64	\$1,049.21	\$1,348.62	\$1,830.08
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.52%	-9.31%	-10.30%	-11.21%	-11.74%	-8.50%	-6.77%	-5.55%	-4.75%	-3.66%	-3.00%	-2.34%	-1.72%
Old Crow	Proposed Bill	\$77.46	\$107.35	\$137.23	\$187.03	\$236.84	\$423.23	\$602.10	\$788.49	\$967.36	\$1,332.63	\$1,690.36	\$2,242.02	\$3,143.89
	Existing Bill	\$83.76	\$118.37	\$152.98	\$210.66	\$268.34	\$454.73	\$633.60	\$819.99	\$998.86	\$1,364.13	\$1,721.86	\$2,273.52	\$3,175.39
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.52%	-9.31%	-10.30%	-11.21%	-11.74%	-6.93%	-4.97%	-3.84%	-3.15%	-2.31%	-1.83%	-1.39%	-0.99%
Cumulative percentage of customers		0-400 28.5%	400-700 39.2%	700-1000 47.8%	1000-1500 58.7%	1500-2000 66.6%	2000-2500 72.3%	2500-3000 76.5%	3000-5000 86.0%		5000-10000 94.0%		10000+ 100%	
Existing Rates		Proposed Rates												
		Hydro	L. Diesel	S. Diesel	Old Crow						Hydro	L. Diesel	S. Diesel	Old Crow
	Demand Charge	\$6.00	\$6.00	\$6.00	\$6.00						\$6.00	\$6.00	\$6.00	\$6.00
	1st. Block Energy	\$0.0831	\$0.0831	\$0.0831	\$0.0831						\$0.0831	\$0.0831	\$0.0831	\$0.0831
	2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577						\$0.1045	\$0.1045	\$0.1236	\$0.2577
	Rider J	14.93%	14.93%	14.93%	14.93%						14.93%	14.93%	14.93%	14.93%
	Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186						\$0.0186	\$0.0186	\$0.0186	\$0.0186
	YECL Interim Rider R	5.00%	5.00%	5.00%	5.00%						5.00%	5.00%	5.00%	5.00%
	Rate Stabilization Fund (1st block)	-\$0.0080	-\$0.0080	-\$0.0080	-\$0.0080						-\$0.0080	-\$0.0080	-\$0.0080	-\$0.0080
											Proposed Rider U	-\$0.0150	-\$0.0150	-\$0.0150

Table 4.15
September 2008

Bill Comparisons: 2009 Proposed Rates Vs. Existing											Income Tax Rebate GST		-0.50% 5.00%		
CUSTOMER CLASS:		GENERAL SERVICE - NON GOVERNMENT (ABSENT RSF)													
Zone		Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	Monthly Consump.	
		(kW.h)	(kW.h)	(kW.h)	(kW.h)	(kW.h)	(kW.h)	(kW.h)	(kW.h)	(kW.h)	(kW.h)	(kW.h)	(kW.h)	(kW.h)	
		400	700	1000	1500	2000	2500	3000	3500	4000	5000	6000	7500	10000	
		5.00	5.00	5.00	5.00	5.00	7.00	8.00	10.00	11.00	14.00	16.00	21.00	27.00	
Hydro	Proposed Bill	\$80.82	\$113.21	\$145.61	\$199.60	\$253.60	\$343.93	\$426.74	\$517.08	\$599.89	\$773.04	\$938.66	\$1,202.14	\$1,623.72	
	Existing Bill	\$87.12	\$124.24	\$161.36	\$223.23	\$285.10	\$375.43	\$458.24	\$548.58	\$631.39	\$804.54	\$970.16	\$1,233.64	\$1,655.22	
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	
	Var. (%)	-7.23%	-8.87%	-9.76%	-10.58%	-11.05%	-8.39%	-6.87%	-5.74%	-4.99%	-3.92%	-3.25%	-2.55%	-1.90%	
Large Diesel	Proposed Bill	\$80.82	\$113.21	\$145.61	\$199.60	\$253.60	\$343.93	\$426.74	\$517.08	\$599.89	\$773.04	\$938.66	\$1,202.14	\$1,623.72	
	Existing Bill	\$87.12	\$124.24	\$161.36	\$223.23	\$285.10	\$375.43	\$458.24	\$548.58	\$631.39	\$804.54	\$970.16	\$1,233.64	\$1,655.22	
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	
	Var. (%)	-7.23%	-8.87%	-9.76%	-10.58%	-11.05%	-8.39%	-6.87%	-5.74%	-4.99%	-3.92%	-3.25%	-2.55%	-1.90%	
Small Diesel	Proposed Bill	\$80.82	\$113.21	\$145.61	\$199.60	\$253.60	\$355.91	\$450.70	\$553.01	\$647.79	\$844.89	\$1,034.47	\$1,333.88	\$1,815.34	
	Existing Bill	\$87.12	\$124.24	\$161.36	\$223.23	\$285.10	\$387.41	\$482.20	\$584.51	\$679.29	\$876.39	\$1,065.97	\$1,365.38	\$1,846.84	
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	
	Var. (%)	-7.23%	-8.87%	-9.76%	-10.58%	-11.05%	-8.13%	-6.53%	-5.39%	-4.64%	-3.59%	-2.96%	-2.31%	-1.71%	
Old Crow	Proposed Bill	\$80.82	\$113.21	\$145.61	\$199.60	\$253.60	\$439.99	\$618.86	\$805.25	\$984.12	\$1,349.38	\$1,707.12	\$2,258.78	\$3,160.65	
	Existing Bill	\$87.12	\$124.24	\$161.36	\$223.23	\$285.10	\$471.49	\$650.36	\$836.75	\$1,015.62	\$1,380.88	\$1,738.62	\$2,290.28	\$3,192.15	
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	
	Var. (%)	-7.23%	-8.87%	-9.76%	-10.58%	-11.05%	-6.68%	-4.84%	-3.76%	-3.10%	-2.28%	-1.81%	-1.38%	-0.99%	
Cumulative percentage of customers		0-400	400-700	700-1000	1000-1500	1500-2000	2000-2500	2500-3000	3000-5000			5000-10000			
		28.5%	39.2%	47.8%	58.7%	66.6%	72.3%	76.5%	86.0%			94.0%			
Existing Rates		Proposed Rates													
		Hydro	L. Diesel	S. Diesel	Old Crow						Hydro	L. Diesel	S. Diesel	Old Crow	
	Demand Charge	\$6.00	\$6.00	\$6.00	\$6.00						\$6.00	\$6.00	\$6.00	\$6.00	
	1st. Block Energy	\$0.0831	\$0.0831	\$0.0831	\$0.0831						\$0.0831	\$0.0831	\$0.0831	\$0.0831	
	2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577						\$0.1045	\$0.1045	\$0.1236	\$0.2577	
	Rider J	14.93%	14.93%	14.93%	14.93%						14.93%	14.93%	14.93%	14.93%	
	Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186						\$0.0186	\$0.0186	\$0.0186	\$0.0186	
	YECL Interim Rider R	5.00%	5.00%	5.00%	5.00%						5.00%	5.00%	5.00%	5.00%	
	Rate Stabilization Fund (1st block)						Rate Stabilization Fund (1st block)								
							Proposed Rider U					-\$0.0150	-\$0.0150	-\$0.0150	-\$0.0150

Table 4.16
September 2008

Bill Comparisons: 2009 Proposed Rates Vs. Existing												Income Tax Rebate	0.00%
												GST	5.00%
CUSTOMER CLASS: GENERAL SERVICE - MUNICIPAL GOVERNMENT													
Zone		Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)
		400	700	1000	1500	2000	2500	3000	3500	4000	5000	6000	7500
		5.00	5.00	5.00	5.00	5.00	7.00	8.00	10.00	11.00	14.00	16.00	21.00
Hydro	Proposed Bill	\$78.09	\$108.32	\$138.56	\$188.94	\$239.33	\$330.01	\$413.12	\$503.80	\$586.91	\$760.70	\$926.94	\$1,191.40
	Existing Bill	\$84.39	\$119.35	\$154.31	\$212.57	\$270.83	\$361.51	\$444.62	\$535.30	\$618.41	\$792.20	\$958.44	\$1,222.90
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.47%	-9.24%	-10.21%	-11.11%	-11.63%	-8.71%	-7.08%	-5.88%	-5.09%	-3.98%	-3.29%	-2.58%
Large Diesel	Proposed Bill	\$78.09	\$108.32	\$138.56	\$188.94	\$239.33	\$330.01	\$413.12	\$503.80	\$586.91	\$760.70	\$926.94	\$1,191.40
	Existing Bill	\$84.39	\$119.35	\$154.31	\$212.57	\$270.83	\$361.51	\$444.62	\$535.30	\$618.41	\$792.20	\$958.44	\$1,222.90
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.47%	-9.24%	-10.21%	-11.11%	-11.63%	-8.71%	-7.08%	-5.88%	-5.09%	-3.98%	-3.29%	-2.58%
Small Diesel	Proposed Bill	\$78.09	\$108.32	\$138.56	\$188.94	\$239.33	\$342.03	\$437.18	\$539.87	\$635.02	\$832.86	\$1,023.15	\$1,323.69
	Existing Bill	\$84.39	\$119.35	\$154.31	\$212.57	\$270.83	\$373.53	\$468.68	\$571.37	\$666.52	\$864.36	\$1,054.65	\$1,355.19
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.47%	-9.24%	-10.21%	-11.11%	-11.63%	-8.43%	-6.72%	-5.51%	-4.73%	-3.64%	-2.99%	-2.32%
Old Crow	Proposed Bill	\$78.09	\$108.32	\$138.56	\$188.94	\$239.33	\$426.47	\$606.04	\$793.18	\$972.75	\$1,339.46	\$1,698.62	\$2,252.46
	Existing Bill	\$84.39	\$119.35	\$154.31	\$212.57	\$270.83	\$457.97	\$637.54	\$824.68	\$1,004.25	\$1,370.96	\$1,730.12	\$2,283.96
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.47%	-9.24%	-10.21%	-11.11%	-11.63%	-6.88%	-4.94%	-3.82%	-3.14%	-2.30%	-1.82%	-1.38%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	\$6.00	\$6.00	\$6.00	\$6.00
1st. Block Energy	\$0.0831	\$0.0831	\$0.0831	\$0.0831
2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider J	14.93%	14.93%	14.93%	14.93%
Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186
YECL Interim Rider R	5.00%	5.00%	5.00%	5.00%
Rate Stabilization Fund (1st block)	-\$0.0073	-\$0.0073	-\$0.0073	-\$0.0073

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	\$6.00	\$6.00	\$6.00	\$6.00
1st. Block Energy	\$0.0831	\$0.0831	\$0.0831	\$0.0831
2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider J	14.93%	14.93%	14.93%	14.93%
Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186
YECL Interim Rider R (Aug 2008)	5.00%	5.00%	5.00%	5.00%
Rate Stabilization Fund (1st block)	-\$0.0073	-\$0.0073	-\$0.0073	-\$0.0073
Proposed Rider U	-\$0.0150	-\$0.0150	-\$0.0150	-\$0.0150

Table 4.17
September 2008

Bill Comparisons: 2009 Proposed Rates Vs. Existing												Income Tax Rebate	0.00%
												GST	5.00%
CUSTOMER CLASS: GENERAL SERVICE - MUNICIPAL GOVERNMENT (ABSENT RSF)													
Zone		Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)
		400	700	1000	1500	2000	2500	3000	3500	4000	5000	6000	7500
		5.00	5.00	5.00	5.00	5.00	7.00	8.00	10.00	11.00	14.00	16.00	21.00
Hydro	Proposed Bill	\$81.15	\$113.68	\$146.20	\$200.42	\$254.63	\$345.30	\$428.42	\$519.09	\$602.21	\$776.00	\$942.23	\$1,206.69
	Existing Bill	\$87.45	\$124.70	\$161.95	\$224.04	\$286.13	\$376.80	\$459.92	\$550.59	\$633.71	\$807.50	\$973.73	\$1,238.19
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.20%	-8.84%	-9.73%	-10.54%	-11.01%	-8.36%	-6.85%	-5.72%	-4.97%	-3.90%	-3.23%	-2.54%
Large Diesel	Proposed Bill	\$81.15	\$113.68	\$146.20	\$200.42	\$254.63	\$345.30	\$428.42	\$519.09	\$602.21	\$776.00	\$942.23	\$1,206.69
	Existing Bill	\$87.45	\$124.70	\$161.95	\$224.04	\$286.13	\$376.80	\$459.92	\$550.59	\$633.71	\$807.50	\$973.73	\$1,238.19
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.20%	-8.84%	-9.73%	-10.54%	-11.01%	-8.36%	-6.85%	-5.72%	-4.97%	-3.90%	-3.23%	-2.54%
Small Diesel	Proposed Bill	\$81.15	\$113.68	\$146.20	\$200.42	\$254.63	\$357.33	\$452.47	\$555.17	\$650.31	\$848.15	\$1,038.44	\$1,338.98
	Existing Bill	\$87.45	\$124.70	\$161.95	\$224.04	\$286.13	\$388.83	\$483.97	\$586.67	\$681.81	\$879.65	\$1,069.94	\$1,370.48
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.20%	-8.84%	-9.73%	-10.54%	-11.01%	-8.10%	-6.51%	-5.37%	-4.62%	-3.58%	-2.94%	-2.30%
Old Crow	Proposed Bill	\$81.15	\$113.68	\$146.20	\$200.42	\$254.63	\$441.76	\$621.34	\$808.47	\$988.05	\$1,354.76	\$1,713.91	\$2,267.75
	Existing Bill	\$87.45	\$124.70	\$161.95	\$224.04	\$286.13	\$473.26	\$652.84	\$839.97	\$1,019.55	\$1,386.26	\$1,745.41	\$2,299.25
	Var. (\$)	-\$6.30	-\$11.03	-\$15.75	-\$23.63	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50	-\$31.50
	Var. (%)	-7.20%	-8.84%	-9.73%	-10.54%	-11.01%	-6.66%	-4.83%	-3.75%	-3.09%	-2.27%	-1.80%	-1.37%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	\$6.00	\$6.00	\$6.00	\$6.00
1st. Block Energy	\$0.0831	\$0.0831	\$0.0831	\$0.0831
2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider J	14.93%	14.93%	14.93%	14.93%
Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186
YECL Interim Rider R	5.00%	5.00%	5.00%	5.00%
Rate Stabilization Fund (1st block)				

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	\$6.00	\$6.00	\$6.00	\$6.00
1st. Block Energy	\$0.0831	\$0.0831	\$0.0831	\$0.0831
2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider J	14.93%	14.93%	14.93%	14.93%
Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186
YECL Interim Rider R (Aug 2008)	5.00%	5.00%	5.00%	5.00%
Rate Stabilization Fund (1st block)				
Proposed Rider U	-\$0.0150	-\$0.0150	-\$0.0150	-\$0.0150

Table 4.18
September 2008

Bill Comparisons: 2009 Proposed Rates Vs. Existing											Income Tax Rebate GST		0.00% 0.00%	
CUSTOMER CLASS:		GENERAL SERVICE - FEDERAL AND TERRITORIAL GOVERNMENT												
Zone		Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)	Monthly Consump. (kW.h)
		400	700	1000	1500	2000	2500	3000	3500	4000	5000	6000	7500	10000
		5.00	5.00	5.00	5.00	5.00	7.00	8.00	10.00	11.00	14.00	16.00	21.00	27.00
Hydro	Proposed Bill	\$135.28	\$191.76	\$248.24	\$342.38	\$436.52	\$532.47	\$616.43	\$712.38	\$796.33	\$976.24	\$1,144.15	\$1,420.01	\$1,851.78
	Existing Bill	\$151.12	\$219.48	\$287.84	\$401.78	\$515.72	\$611.67	\$695.63	\$791.58	\$875.53	\$1,055.44	\$1,223.35	\$1,499.21	\$1,930.98
	Var. (\$)	-\$15.84	-\$27.72	-\$39.60	-\$59.40	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20
	Var. (%)	-10.48%	-12.63%	-13.76%	-14.78%	-15.36%	-12.95%	-11.39%	-10.01%	-9.05%	-7.50%	-6.47%	-5.28%	-4.10%
Large Diesel	Proposed Bill	\$135.28	\$191.76	\$248.24	\$342.38	\$436.52	\$532.47	\$616.43	\$712.38	\$796.33	\$976.24	\$1,144.15	\$1,420.01	\$1,851.78
	Existing Bill	\$151.12	\$219.48	\$287.84	\$401.78	\$515.72	\$611.67	\$695.63	\$791.58	\$875.53	\$1,055.44	\$1,223.35	\$1,499.21	\$1,930.98
	Var. (\$)	-\$15.84	-\$27.72	-\$39.60	-\$59.40	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20
	Var. (%)	-10.48%	-12.63%	-13.76%	-14.78%	-15.36%	-12.95%	-11.39%	-10.01%	-9.05%	-7.50%	-6.47%	-5.28%	-4.10%
Small Diesel	Proposed Bill	\$135.28	\$191.76	\$248.24	\$342.38	\$436.52	\$543.92	\$639.33	\$746.74	\$842.15	\$1,044.96	\$1,235.78	\$1,545.99	\$2,035.03
	Existing Bill	\$151.12	\$219.48	\$287.84	\$401.78	\$515.72	\$623.12	\$718.53	\$825.94	\$921.35	\$1,124.16	\$1,314.98	\$1,625.19	\$2,114.23
	Var. (\$)	-\$15.84	-\$27.72	-\$39.60	-\$59.40	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20
	Var. (%)	-10.48%	-12.63%	-13.76%	-14.78%	-15.36%	-12.71%	-11.02%	-9.59%	-8.60%	-7.05%	-6.02%	-4.87%	-3.75%
Old Crow	Proposed Bill	\$135.28	\$191.76	\$248.24	\$342.38	\$436.52	\$624.34	\$800.16	\$987.98	\$1,163.80	\$1,527.44	\$1,879.08	\$2,430.54	\$3,321.64
	Existing Bill	\$151.12	\$219.48	\$287.84	\$401.78	\$515.72	\$703.54	\$879.36	\$1,067.18	\$1,243.00	\$1,606.64	\$1,958.28	\$2,509.74	\$3,400.84
	Var. (\$)	-\$15.84	-\$27.72	-\$39.60	-\$59.40	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20	-\$79.20
	Var. (%)	-10.48%	-12.63%	-13.76%	-14.78%	-15.36%	-11.26%	-9.01%	-7.42%	-6.37%	-4.93%	-4.04%	-3.16%	-2.33%

Existing Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	\$10.00	\$10.00	\$10.00	\$10.00
1st. Block Energy	\$0.1745	\$0.1745	\$0.1745	\$0.1745
2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider J	14.93%	14.93%	14.93%	14.93%
Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186
YECL Interim Rider R	5.00%	5.00%	5.00%	5.00%
Rate Stabilization Fund (1st block)				

Proposed Rates

	Hydro	L. Diesel	S. Diesel	Old Crow
Demand Charge	\$10.00	\$10.00	\$10.00	\$10.00
1st. Block Energy	\$0.1745	\$0.1745	\$0.1745	\$0.1745
2nd. Block Energy	\$0.1045	\$0.1045	\$0.1236	\$0.2577
Rider J	14.93%	14.93%	14.93%	14.93%
Rider F	\$0.0186	\$0.0186	\$0.0186	\$0.0186
YECL Interim Rider R (Aug 2008)	5.00%	5.00%	5.00%	5.00%
Rate Stabilization Fund (1st block)				
Proposed Rider U	-\$0.0396	-\$0.0396	-\$0.0396	-\$0.0396

APPENDIX 4.1
RATE SCHEDULES

RATE SCHEDULE - 32

SECONDARY ENERGY

AVAILABLE:

Secondary energy is available from time to time to General Service or Industrial customers in parts of the WAF and Mayo-Dawson systems as determined by Yukon Energy based on the availability of surplus hydro.

The rate is only available to new secondary loads in areas where there is sufficient surplus distribution system capacity at the time of connection. In areas where there is insufficient surplus distribution capacity at the time of connection, the customer will be required at that time to pay for any distribution upgrades required to service the new secondary load or, where the required upgrades are already planned for a future date, the cost of advancing those upgrades.

Yukon Energy has discretion to end subscription to the program (and limit quantities delivered) on a system when the supply of surplus energy on that system becomes fully contracted. The specific subscription limit will be dependent on the types of loads that enroll in future, their seasonality and load diversity.

APPLICABLE:

Secondary energy is applicable only to customers satisfying all of the following conditions:

- (1) The secondary energy is provided on a separate service fully interruptible at the request of the utility.
- (2) The utility distributing the secondary energy (i.e., Yukon Energy or YECL) is satisfied that the secondary energy usage by the customer is in excess of normal consumption and represents incremental electric usage displacing an alternative fuel source by an appliance primarily installed in order to provide space or process heating.
- (3) A viable alternative fuel source is available to the customer, capable of providing the same quantity of space or process heating in the event of electric power interruptions of unlimited duration.
- (4) Customers taking Secondary Energy will not be allowed to have these loads shifted to be served by any firm (primary) service without providing the distributing utility (i.e., Yukon Energy or YECL) with 12 months notice (unless waived at Yukon Energy's discretion). Once any such Secondary

Energy load is switched to firm service, it will not be able to switch back to Secondary Energy service in future.

RATE:

Charges for service in any one billing month during any Rate Period shall apply the Secondary Energy Charge for that Rate Period.

The Secondary Energy Charge for any three month Rate Period, starting January 1, 2005 and adjusted thereafter on the first day of every third subsequent month (i.e., on April 1, July 1 and October 1 in 2005 and similarly in each following year), is to be published and filed with the Board by Yukon Energy at least 30 days in advance of the Rate Period. The Secondary Energy Charge for any Rate Period is to be set in accordance with the following procedure:

Step A: Determine a price per MJ for heat energy from oil: The Oil Price Index (cents/litre net of GST) for the Rate Period (as determined below) divided by 38.2 MJ/litre to yield a price in cents per MJ.

Step B: Determine a price per MJ of delivered heat from oil: Divide the result from step A by an efficiency rate of 90%.

Step C: Convert price of delivered heat energy from oil to an equivalent price for heat energy from electricity: Multiply the result from step B by 3.6 MJ/kW.h to yield a price in cents per kW.h.

Step D: Set at 66.7% ratio: Multiply the result from Step C by 66.7% to yield the quarterly Secondary Energy Charge for the Rate Period in cents/kW.h.

The Secondary Energy Charge derived in Step D for any Rate period shall be applied to all Secondary Energy kW.h consumed in each month during that Rate Period.

The Oil Price Index for each Rate Period shall equal the lowest of the three most recently reported Retail Heating Fuel Price values for Furnace Oil in Whitehorse (as collected bi-weekly and reported by the Yukon Bureau of Statistics) prior to the 20th day of the mid-month in the prior Rate Period (e.g., for the Rate Period starting January 1, 2005, the three latest prices published prior to November 20, 2004).

In accordance with the above procedure, the Secondary Energy Charge for the three month Rate Period starting January 1, 2005 is 5.2 cents per kW.h.

INTERRUPTIONS:

Customers have two options with regards to interruption:

- (1) Customers can opt for installing a SCADA-controlled service that allows Yukon Energy to initiate interruptions on 15 minutes notice, as and when required only for actual real-time diesel generation being required on the respective system or for system emergencies or outages, or
- (2) Customers can have a standard metered service. Under this option, the customers' supply will be interrupted after 24 hours notice at any time that Yukon Energy forecasts a need to run diesel units for more than 10% of the hours in the subsequent ~~seven~~five day period, or that Yukon Energy begins running diesels for unforecast reasons and expects the diesel operation to continue for more than 48 hours.

INSTALLATION COST:

The customer is responsible for any cost of installing the separate service, metering and any SCADA load control apparatus that is in excess of the relevant Utility Investment provision in the Electrical Service Regulations. The customer is also responsible for any costs of upgrading or advancing distribution system capacity improvements necessitated by their Secondary Energy load.

**ELECTRIC
SERVICE
REGULATIONS:**

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

**FIRM MINE RATE
RATE SCHEDULE 39
INDUSTRIAL PRIMARY**

AVAILABLE:

Throughout the service areas of Yukon Energy Corporation ("YEC") and The Yukon Electrical Company Limited ("YECL") served by the Whitehorse-Aishihik-Faro and Mayo-Dawson systems.

APPLICABLE:

To all major industrial customers engaged in manufacturing, processing or mining with an electric service capacity in excess of 1,000 kW.

RATE:

Charges in any one billing month shall be the sum of the following:

- (a) Demand Charge of \$15.00/kV.A of Billing Demand
- (b) Energy Charge of 7.60¢/kW.h for all energy used.
- (c) Fixed Charge

For service to Minto mine site, the Fixed Charge each month shall equal the payments then required under the Power Purchase Agreement (the "**PPA**") dated February 8, 2007 as amended on May 14 between YEC and Minto Explorations Ltd. ("**Minto**") for monthly Capital Cost Contributions for transmission connection to the mine.

**PEAK
SHAVING
CREDIT:**

For customers with an established Winter Contract Load in good standing, a Peak Shaving Credit in each billing month equal to 50% of the Demand Charge times the Peak Shaved Load.

**MINIMUM
MONTHLY
BILL:**

The minimum monthly bill will be the sum of the Demand Charge and the monthly Fixed Charge, less any applicable Peak Shaving Credit.

**PEAK
SHAVED
LOAD:**

Peak Shaved Load in any billing month is the amount by which then nominated Winter Contract Load is less than the Billing Demand for the month.

**BILLING
DEMAND:**

The Billing Demand shall be the greater of:

- (a) the highest metered kV.A demand recorded in the current billing month, or
- (b) the highest metered kV.A demand recorded in the previous 12-month period including the current billing month, excluding the months April through September, or
- (c) the contract minimum demand.

**WINTER
CONTRACT
LOAD:**

A customer may, by six month written notice to YEC, nominate a Winter Contract Load at not less than two-thirds of the customer's contract maximum demand subject to the following conditions:

- a) the customer will thereby contract with YEC not to exceed the nominated Winter Contract Load whenever the temperature at Whitehorse is below -30 degrees Centigrade, based on YEC informing the customer by phone, fax or e-mail as to forecast and actual winter temperatures at Whitehorse as provided for in paragraph (b);
- b) YEC will inform the customer at least one hour in advance, and not more than one day in advance, of a forecast temperature at Whitehorse being below -30 degree Centigrade; thereafter, until YEC informs the customer otherwise, the customer will be responsible for ensuring that its metered kV.A demand does not exceed the Winter Contract Load during any hour when the actual temperature at Whitehorse is below -30 degrees Centigrade; YEC will inform the customer forthwith when the temperature at Whitehorse is no longer forecast to be below -30 degree Centigrade within the next 24 hours;
- c) the customer agrees that the contract for the nominated Winter Contract Load will continue until terminated by written notice of not less than 12 months by the customer to YEC;

- d) if during such contract period for the Winter Contract Load the customer's metered kV.A demand recorded, after YEC has provided notice as specified in paragraph (b), exceeds the Winter Contract Load when the temperature at Whitehorse is less than -30 degrees Centigrade, the Winter Contract Load contract will be terminated forthwith, the customer will forthwith be required to repay to YEC all Peak Shaving Credits determined within the previous 12 billing months, and the customer will also pay for that billing month to YEC as penalty an amount equal to four times the Demand Charge on the metered kV.A demand recorded in excess of the Winter Contract Demand; in addition, YEC reserves the right if so required to meet system loads when the temperature at Whitehorse is less than -30 degrees Centigrade during the then current month and the following 12 months to interrupt electricity supplied to the customer in excess of the previous Winter Contract Load.

**BASE
LOAD
ENERGY:**

A Base Load Energy amount per month may be established for a customer of 90% of forecast use when YEC expects to require diesel fuel generation to service use in excess of such a Base Load Energy amount. At such time, Rate Schedule 39 will be submitted to the Yukon Utilities Board for amendment to adjust the Energy rate as required for a two part rate that yields the same overall energy charge at forecast energy use, with all energy consumed in excess of the Base Load being charged at a rate reflecting the incremental cost of service using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use.

**RATE
MODIFICATIONS
APPLICABLE:**

For fuel adjustment rider, see Rider F. Rider F applied to energy charges only, set to \$0.0 for fuel price forecast filed November 20, 2006 and charged as follows:

- a) Fixed Rider F of 0.585 cents per kW.h charged only to Rate Schedule 39 customers to account for fuel price variance from price forecast filed November 20, 2006 to fuel price forecasts for 2009 as approved by the Board for Yukon Energy and YECL 2009 GRAs, plus
- b) Ongoing Rider F per kW.h as required to ensure consistency, after consideration of the Fixed Rider F of 0.585 cents per kW.h, with the Rider F applied to all applicable rate schedules to account for fuel price variance

from price forecasts as last approved by the Board for
Yukon Energy and YECL GRAs.

**ELECTRIC
SERVICE
REGULATIONS:**

The Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to YEC and every customer supplied with electric service by YEC in the Yukon Territory. Copies of the Electric Service Regulations are available for inspection in the offices of YEC during normal working hours.

RIDER U

YUKON ENERGY REVENUE REDUCTION RIDER

AVAILABLE: To all electric service throughout the Yukon Territory.

APPLICABLE: To all electric service retail rates except Rate Schedule 32, Rate Schedule 35, Rate Schedule 39, Rate Schedule 42 and Rate Schedule 43.

RATE: Surcharge/(refund) applicable to the base rates of the following rate classes:

For the first 1000 kW.h in any one billing month:

Residential Non Gov.	(1.36 cents/kW.h)
Residential Gov	(1.66 cents/kW.h)

For the first 2000 kWh in any one billing month:

General Service Non Gov.	(1.50 cents / kW.h)
General Service Municipal Gov.	(1.50 cents/kW.h)
General Service Gov. Fed. and Terr.	(3.96 cents / kW.h)

For all base rates:	
Street and Sentinel Lighting	(3.48%)



RATE SCHEDULE - 1160
RESIDENTIAL SERVICE
HYDRO, NON-GOVERNMENT

AVAILABLE: In Carcross, Carmacks, Champagne, Dawson, Elsa, Faro, Haines Junction, Johnson's Crossing, Keno, Marsh Lake, Mayo, Pelly Crossing, Ross River, Tagish, Teslin, Stewart Crossing and Whitehorse.

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

RATE: Charges for service in any one billing month shall be the sum of the following:

- | | | |
|-----|--------------------------|-------------------------|
| (a) | <u>Customer Charge</u> | \$11.90 |
| (b) | <u>Energy Charge</u> | |
| | For the first 1,000 kW.h | <u>8.509.86¢/kW.h</u> |
| | All over 1,000 kW.h | <u>16.0610.45¢/kW.h</u> |

MINIMUM MONTHLY BILL: Shall be \$11.90.

RATE MODIFICATIONS APPLICABLE: For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

**ELECTRIC
SERVICE
REGULATIONS:**

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



RATE SCHEDULE - 1260
RESIDENTIAL SERVICE
SMALL DIESEL, NON - GOVERNMENT

AVAILABLE: In Beaver Creek, Burwash, Destruction Bay, ~~Pelly Crossing~~ and Swift River.

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

RATE: Charges for service in any one billing month shall be the sum of the following:

- | | | |
|-----|--------------------------|------------------------------|
| (a) | Customer Charge | \$11.90 |
| (b) | Energy Charge | |
| | For the first 1,000 kW.h | ~~9.86~~ 8.50¢/kW.h |
| | All over 1,000 kW.h | ~~12.36~~ 17.97¢/kW.h |

MINIMUM MONTHLY BILL: Shall be \$11.90.

RATE MODIFICATIONS APPLICABLE: For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

ELECTRIC SERVICE

REGULATIONS:

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



RATE SCHEDULE - 1360

RESIDENTIAL SERVICE

LARGE DIESEL, NON - GOVERNMENT

AVAILABLE: In Watson Lake, Dawson, Upper Liard and Lower Post.

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

RATE: Charges for service in any one billing month shall be the sum of the following:

- | | | |
|-----|-----------------------------|-----------------------------------|
| (a) | Customer Charge | \$11.90 |
| (b) | Energy Charge | |
| | For the first
1,000 kW.h | ~~9.86~~ 9.868.50¢/kW.h |
| | All over 1,000 kW.h | ~~10.45~~ 10.4516.06¢/kW.h |

**MINIMUM
MONTHLY
BILL:** Shall be \$11.90.

**RATE
MODIFICATIONS
APPLICABLE:** For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

**ELECTRIC
SERVICE
REGULATIONS:** The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to

Effective: 2008/11/01

Supersedes: 1997/01/01 (Order 1996-8)

Page 2

the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.



RATE SCHEDULE - 1460

RESIDENTIAL SERVICE

OLD CROW DIESEL, NON - GOVERNMENT

AVAILABLE: In Old Crow

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

RATE: Charges for service in any one billing month shall be the sum of the following:

- | | | |
|-----|-----------------------------|--------------------------------|
| (a) | Customer Charge | \$11.90 |
| (b) | Energy Charge | |
| | For the first
1,000 kW.h | ~~9.86~~ 9.868.50¢/KW.h |
| | All over 1,000 kW.h | ~~25.77~~ 31.38¢/kW.h |

**MINIMUM
MONTHLY
BILL:** Shall be \$11.90.

**RATE
MODIFICATIONS
APPLICABLE:** For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

**ELECTRIC
SERVICE
REGULATIONS:** The Company's Electric Service Regulations approved by the Yukon Utilities Board form part of this rate schedule and apply to

Effective: 2008/11/01

Supersedes: 1997/01/01 (Order 1996-8)

Page 2

the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Electric Service Regulations are available for inspection in the offices of the Company during normal working hours.



RATE SCHEDULE – 1180

RESIDENTIAL SERVICE

HYDRO, GOVERNMENT

AVAILABLE:

In Carcross, Carmacks, Champagne, Dawson, Elsa, Faro, Haines Junction, Johnson's Crossing, Keno, Marsh Lake, Mayo, Pelly Crossing Ross River, Tagish, Teslin, Stewart Crossing and Whitehorse.

APPLICABLE:

To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or non-government use.

RATE:

Charges for service in any one billing month shall be the sum of the following:

(a)	Customer Charge	\$15.00
(b)	Energy Charge	
	For the first 1,000 kW.h	~~14.34~~ <u>12.68</u> ¢/kW.h
	All over 1,000 kW.h	~~10.45~~ <u>16.06</u> ¢/kW.h

**MINIMUM
MONTHLY
BILL:**

Shall be \$15.00.

**RATE
MODIFICATIONS
APPLICABLE:**

For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

**ELECTRIC
SERVICE
REGULATIONS:**

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



RATE SCHEDULE - 1280

RESIDENTIAL SERVICE

SMALL DIESEL, GOVERNMENT

AVAILABLE:

In Beaver Creek, Burwash, Destruction Bay, ~~Pelly Crossing~~ and Swift River.

APPLICABLE:

To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or non-government use.

RATE:

Charges for service in any one billing month shall be the sum of the following:

- | | | |
|-----|--------------------------|--------------------------------------|
| (a) | Customer Charge | \$15.00 |
| (b) | Energy Charge | |
| | For the first 1,000 kW.h | ~~14.34~~ <u>12.68</u> ¢/kW.h |
| | All over 1,000 kW.h | ~~12.36~~ <u>17.97</u> ¢/kW.h |

**MINIMUM
MONTHLY
BILL:**

Shall be \$15.00.

**RATE
MODIFICATIONS
APPLICABLE:**

For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

**ELECTRIC
SERVICE
REGULATIONS:**

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



RATE SCHEDULE - 1380
RESIDENTIAL SERVICE
LARGE DIESEL, GOVERNMENT

AVAILABLE: In Watson Lake, Dawson, Upper Liard and Lower Post.

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or non-government use.

RATE: Charges for service in any one billing month shall be the sum of the following:

- | | | |
|-----|---------------------------------|--------------------------------------|
| (a) | Customer Charge | \$15.00 |
| (b) | Energy Charge | |
| | For the first 1,000 kW.h energy | ~~14.34~~ <u>12.68</u> ¢/kW.h |
| | All other energy | ~~10.45~~ <u>16.06</u> ¢/kW.h |

MINIMUM MONTHLY BILL: Shall be \$15.00.

RATE MODIFICATIONS APPLICABLE: For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

**ELECTRIC
SERVICE
REGULATIONS:**

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



RATE SCHEDULE - 1480

RESIDENTIAL SERVICE

OLD CROW DIESEL, GOVERNMENT

AVAILABLE: In Old Crow

APPLICABLE: To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or non-government use.

RATE: Charges for service in any one billing month shall be the sum of the following:

- | | | |
|-----|------------------------------------|--------------------------------------|
| (a) | Customer Charge | \$15.00 |
| (b) | Energy Charge | |
| | For the first 1,000 kW.h | ~~14.34~~ <u>12.68</u> ¢/kW.h |
| | For energy in excess of 1,000 kW.h | ~~25.77~~ <u>31.38</u> ¢/kW.h |

MINIMUM MONTHLY BILL: Shall be \$15.00.

RATE MODIFICATIONS APPLICABLE: For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

**ELECTRIC
SERVICE
REGULATIONS:**

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



RATE SCHEDULE - 42

WHOLESALE PRIMARY

AVAILABLE:

To The Yukon Electrical Company Limited.

APPLICABLE:

For wholesale primary supply to The Yukon Electrical Company Limited.

RATE:

Energy Charge

All Energy consumed at 6.846.851¢ / kW.h

Energy Reconciliation Adjustment

Charges to YECL will be periodically adjusted to reconcile actual wholesale purchases to test year forecast purchases. To the extent that actual wholesale purchases fall short or exceed forecast wholesale purchases, an adjustment to the YECL bills will be made at a rate equal to 37.37 cents/kW.h. ~~the approved run-out rate for non-government residential service for the Hydro zone.~~ Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10% of the forecast wholesale purchases in any period.

**ELECTRIC
SERVICE
REGULATIONS:**

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

TAB 5
CAPITAL PROJECTS

5.0 CAPITAL PROJECTS

The largest component of Yukon Energy's rate base is investment in capital works (property, plant and equipment), planning and study (feasibility) costs and licensing costs. This section provides an overview of Yukon Energy's actual capital spending since the 2005 hearing on Required Revenues and Related Matters, as well as forecast capital spending for 2008 and 2009.

- **Overview of Capital Spending:** Provides a summary of the spending pressures faced by Yukon Energy in the test years and beyond.
- **Capital Works:** Reviews the capital spending on property, plant and equipment, including descriptions of each major project from 2005-2009 (over \$1 million) and for projects in excess of \$100,000 and up to \$1 million forecast to occur in 2008 and 2009. Tables 5.1 and 5.2 provide detailed project by project spending actuals and forecasts.
- **Spending on Deferred Costs:** Reviews the forecast spending on deferred cost projects (i.e., projects where costs are amortized over several years, such as planning and study costs, licensing activities, dam safety reviews, and overhauls) for major initiatives from 2005-2009 (over \$1 million), as well as for 2008 and 2009 initiatives over \$100,000 and up to \$1 million. Data in support is provided in Tables 5.3 to 5.7.

5.1 OVERVIEW OF CAPITAL SPENDING

Yukon Energy's capital spending aligns with the pressures being experienced today regarding system re-investment and overall load growth. In the test years, over 80% of Yukon Energy projected spending on capital works (\$51.210 million) is on major projects (\$42.579 million), each over \$1 million, and each having been previously reviewed by the YUB.

In contrast, Yukon Energy's level of "normal" or ongoing spending on capital works, outside of major projects over \$1 million, over the period 2005 (actual) to 2009 (forecast) varies from a low of approximately \$3.8 million (2008) to a high of \$6.0 million (2006) averaging \$5.1 million. This average is

unchanged from the average ongoing capital spending reported in the 2005 Required Revenues and Related Matters hearing also at approximately \$5.1 million¹ over the 2000-2005 period.

The continuing increases in load on the system (including potential for further new mine load connections as soon as 2010/2011), combined with a strong economic and environmental rationale for pursuing new renewable generation rather than baseload diesel, underlie significant initiatives in the test year related to planning and feasibility activities. As reviewed in detail in the 20-Year Resource Plan: 2006-2025 ("Resource Plan"), increases in load, particularly industrial load, can provide the opportunity to put in place new long-lived renewable generation that will provide benefits well beyond the typical life of any individual mine. However, in order to be ready to capture these opportunities, and avoid the costly requirement for diesel generation that would otherwise arise, early planning and feasibility work (as well as permitting work) is required. Spending on deferred costs addresses these planning, feasibility and permitting requirements as well as dam safety reviews, overhauls and rate case costs. Deferred cost expenditures averaged just under \$2 million per year from 2005 to 2007, and are projected at \$4.1 million for 2008 and \$15.1 million for 2009 (most of the projected 2009 expenditures are for work in progress related to potential new near term renewable generation development, and will therefore not affect test year amortization costs or net rate base).

5.2 CAPITAL WORKS

This section reviews (a) major capital works projects (projects over \$1 million), and (b) ongoing capital projects costing between \$100,000 and \$1 million, undertaken by Yukon Energy since the 2005 Required Revenues and Related Matters hearing, focusing on the 2008 and 2009 period.

¹ In that GRA, major projects over \$1 million were the Mayo-Dawson transmission line, Wind Turbine #2 and the AH1 rewind.

5.2.1 Major Projects Over \$1 million

The five major projects undertaken by Yukon Energy since 2005, each with costs in excess of \$1 million over the period 2005 (actual) to 2009 (forecast), have total projected costs of \$48.488 million by the end of 2009 (\$5.909 million in 2007, \$38.329 million in 2008 and \$4.250 million in 2009). Projected customer contributions offset \$39.639 million of these costs. Each major project is reviewed separately below (see also Tables 5.1 and 5.2):

- Carmacks-Stewart/Minto Spur Transmission Project (\$38.383 million, with customer and other contribution offsets of \$34.639 million).
- Minto Diesels Units (\$3.190 million).
- Whitehorse Mirrlees Diesel (WD3) Rebuild (\$1.1 million).
- Faro Mirrlees Diesel (FD1) Recommissioning (\$1.565 million).
- Aishihik Third Turbine (\$4.250 million in the test years, with contribution offsets of \$5.000 million).

5.2.1.1 Carmacks-Stewart/Minto Spur (CS/MS) Transmission Project

The CS/MS Transmission Project is being developed to connect the 138 kV Whitehorse-Aishihik-Faro ("WAF") and the 69 kV Mayo Dawson electricity grids. It involves the construction of a new 138 kV transmission line of approximately 172 km between the WAF grid at Carmacks and the Mayo-Dawson grid at Stewart-Crossing, along with new transmission substations in Carmacks and Pelly Crossing, and expansion of the existing Stewart Crossing substation.

The Stage One CSTP involves a new 138 kV transmission line of approximately 98 km between the WAF grid at Carmacks and Pelly Crossing, and a new switching station at Carmacks. It has been developed in conjunction with the 25 kV transmission line and related YEC substations (the "Minto Spur") required to connect Stage One of the CSTP in the Minto Landing area to the copper-gold project operated by Minto Explorations Ltd. ("Minto Explorations"). This stage is scheduled for completion by October, 2008.

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

Project History

- **Yukon Energy 20-Year Resource Plan:** The CSTP was included as a major project in the YUB hearing to review Yukon Energy's 20-Year Resource Plan 2006-2025, and was addressed in the January 2006 Resource Plan filed with the Minister, Yukon Energy's May 2006 Supplemental Update, Yukon Energy's November 9, 2006 Update (also known as Exhibit B-16 from the Resource Plan Hearing), two rounds of Board information requests to Yukon Energy, one round of information requests to Yukon Energy from intervenors, the public hearing transcript (November 14 to 16, 2006), the final and reply arguments of the parties, and the Board's January 15, 2007 Report to the Commissioner in Executive Council. In that report the Board noted that it could not make a firm recommendation in the absence of an approved Power Purchase Agreement between Yukon Energy and Minto Mine, but based on the information then provided (including evidence that the line could be developed such that ratepayers would not be adversely affected, but would see benefits from the project), Yukon Energy's proposed first stage of the line should proceed.² At this time the CSTP had yet to be designated pursuant to Part 3 of the Public Utilities Act. With respect to the second stage of the Carmacks-Stewart line, the Board agreed with Yukon Energy's strategy not to pursue this project without a firm commitment to connect the Carmacks Copper Mine, and under the same condition that ratepayers would not be adversely affected.
- **YESAB Review:** The CSTP and the Minto Spur together were included in Yukon Energy's October 13, 2006 Project Proposal Submission to the Yukon Environmental and Socio-economic Assessment Board ("YESAB") Executive Committee. The Executive Committee's

² The Board noted in its report to the Commissioner in Executive Council at page 32 that, "This view is based on the fact that the Minto Mine is under construction, the mine owners have secured financing to complete the mine, key terms of a PPA have been agreed to by YEC and the mine owners, and YEC has asserted that ratepayers would not be adversely affected by the expenditures required to implement this project."

Recommendations were issued November 7, 2007, and Decision Documents were issued accepting the recommendations November 14, by Selkirk First Nation, November 20 by Little Salmon-Carmacks First Nation, and November 23, 2007 by the YTG. All required permits and authorizations have since been issued to construct Stage One.

- **Part 3 Hearing Review:** On March 16, 2007, the Commissioner in Executive Council designated the CSTP as a regulated project under Part 3 of the Public Utilities Act. Yukon Energy was required to apply to the YUB for an Energy Project Certificate and an Energy Operation Certificate. A hearing process was established to review the project which included Interrogatories for Yukon Energy as well as oral hearing dates. Subsequently, on May 31, 2007, the YUB submitted its report to the Minister of Justice in accordance with section 41(1) of the Public Utilities Act, noting that the Board was satisfied as to the need for the project and recommending that an energy project certificate be granted for CSTP Stage One. The Energy Project Certificate was granted December 2007.

- **YUB PPA Review:** On February 8, 2007 Yukon Energy filed an application with the YUB for approval of the Power Purchase Agreement (“PPA”) between Minto Explorations and YEC for the supply of electricity by YEC from the WAF grid to the Mine from Stage One of the CSTP and the Mine Spur. The Board’s PPA Review included YEC response to information requests from the Board and intervenors, Argument and Reply Argument. In Order 2005-7, issued April 30, 2007 the Board denied the PPA as filed, directing Yukon Energy to revise the PPA based on the Board Order and re-file the revised version by May 31, 2007. Yukon Energy subsequently reached an agreement on May 14, 2007 with Minto Explorations to amend the PPA to incorporate the changes desired by the Board. The Amended PPA was filed with the Board and the PPA with amendments was approved by the Board in Order 2007-6. In Order 2007-6, the Board noted that the Yukon Government would be fixing Rate Schedule 39 “as required by the amended PPA”. On June 4, 2007, the Yukon Government issued Order-in-Council (“OIC”) 2007-94 to amended OIC 1995/90 to include provision that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary as attached to Schedule A of the OIC.

- 1 • **August 2008 Filing with Board to Approve Rate Schedule 39:** The Minto mine is
2 currently expected to be connected to Yukon Energy service through Stage One of the CSTP
3 and the Minto Spur by October 2008. Accordingly, prior to commencement of service to
4 Minto, it was necessary for Yukon Energy in August 2008 to seek Board approval for a Rate
5 Schedule 39 that conforms to the rate schedule attached as Schedule A to OIC 2007/94. This
6 application is currently pending.
7
- 8 • **May 25, 2007 Amendment to PPA:** On May 25, 2007 a further amendment regarding
9 changes to the Actual Daily Processing Level was agreed to between Yukon Energy and Minto
10 Explorations. This amendment provides greater protection to Yukon Energy (and now Yukon
11 Development Corporation, who has assumed from YEC the financial risk of the Minto Capital
12 Cost Contribution) in the event that increases to the processing level at the mine site result in
13 a shorter than anticipated mine life. Pursuant to this amendment, if Minto Explorations
14 applies to increase the Licensed Daily Processing Level as permitted under its Yukon Quartz
15 Mining Licence, then Minto Explorations is required (a) to provide documentation to Yukon
16 Energy that confirms the Mill Name Plate Daily Processing Level applicable after such
17 amendment and the Adjusted Mine Life, and (b) to pay the outstanding balance of the
18 Capital Cost Contribution, including accrued interest, to YEC, in full, no later than twelve
19 months prior to the end of the Adjusted Mine Life. These provisions would serve to modify
20 the requirement established by section 5.2(a) and (b) of the PPA which only require the
21 Capital Cost Contribution to be paid out in full by the seventh Annual Payment Date. The
22 amendment further notes that these provisions are intended only to provide for payment of
23 the Capital Cost Contribution sooner than otherwise provided for under the PPA, and under
24 no circumstances will such payment period be extended beyond the dates provided for in the
25 PPA.³

³ In 2008, Minto Explorations applied for (and received as of July 25, 2008) an amendment to its Quartz Mining Licence to increase its Licensed Daily Processing Level, requesting an increase of the average milling rate from 2,500 tonnes per day (tpd) to 3,200 tpd. Yukon Energy is currently seeking documentation from Minto Explorations as to the Adjusted Mine Life as provided for in the May 25, 2007 PPA Amendment.

Stage One CS/MS Cost Changes Since PPA and Part 3 Hearings

Currently, the net capital cost to Yukon Energy of the Stage One CS/MS development being brought into service in fall 2008, after all customer and other capital contributions, is forecast at \$3.744 million (as compared to zero net cost as forecast in the Part 3 hearing).

Since the Part 3 hearing, forecast Stage One CSTP costs have increased by approximately \$5.8 million (from \$22.60 million (2007\$) to approximately \$28.394 million), primarily reflecting increased civil and electrical substation construction costs and line construction costs (including cost increases required for the Tatchun Creek re-routing required by the YESAA assessment and permitting process). Since the Part 3 hearing, forecast capital cost contributions have increased by approximately \$2.0 million to \$24.650 million, including \$10.45 million from the Yukon Government, \$7.2 million from Minto Explorations, and \$7.0 million from Yukon Development Corporation (including approximately \$2.0 million as required by agreement with Yukon Energy pursuant to the PPA as amended May 14, 2007 [Section 3.1(m)] related to any amount of the Carmacks-Minto Landing Capital Cost Contribution principal amount in excess of \$7.2 million as required under Section 5.1 of the PPA as amended).

Since the PPA and Part 3 hearings, forecast Minto Spur capital costs have increased by \$6.159 million (from the PPA estimated in-service costs of \$3.83 million to current forecast costs of \$9.989 million). This increase reflects higher substation costs as well as higher line costs. Minto Explorations is responsible for the entire cost increase for the Minto Spur capital costs pursuant to the PPA. Section 5.4 of the PPA provides for an adjustment to the time period within which Mine Spur capital cost financing must be paid by Minto Explorations if the Mine Spur Capital Costs exceed \$4.8 million.⁴

5.2.1.2 Minto Diesel Units

At the time that the initial 20-year Resource Plan was prepared in 2005, the potential acquisition of the Minto Diesel units was not considered as a capacity option for the WAF system. Prior to the Resource

⁴ Under Section 5.4, a two year extension will be provided for payments under Section 5.2(b)(i) where (a) Minto has provided confirmation by December 31, 2008 under section 5.2(d) regarding its ability and commitment to process Additional Reserves at the Mine prior to December 31, 2017, sufficient to sustain an additional three years of processing at the Mine at the Daily Processing Level, and (b) the extension of the payments will not go beyond the date which Minto confirms in writing to the satisfaction of YEC that ore reserves at the Mine are planned to be processed at the Mine, provided the processing level planned is not less than the Daily Processing Level. Any extension of such payment period is now also limited under the provisions of the May 25, 2007 PPA amendment.

Plan Hearing, Yukon Energy identified as a possible near-term option the purchase four surplus high speed diesel units (6.4 MW) from Minto Mine as part of the PPA negotiations.⁵

As a condition of the Power Purchase Agreement (“PPA”) with Minto Explorations, Yukon Energy agreed to purchase the diesel generator units at the Minto mine site for \$2.24 million⁶ (\$0.35 million/MW purchase price). However, Yukon Energy’s obligation to purchase the diesel units at the mine site is subject to various conditions as set out in Section 10.2 of the PPA.⁷ In Order 2007-5, the Board determined that section 10.2 of the PPA provides adequate protection for YEC and Yukon ratepayers as to the condition of the units and that the price for the units, as determined in the PPA⁸.

However, in Order 2007-5 the Board also notes that before the units would be approved as an addition to rate base, Yukon Energy needed to demonstrate a need for the units and provide a business case supporting the option to purchase the units at the mine site, that included evidence that these units are required (based on the capacity planning criteria adopted in the 20-Year Resource Plan), and how the capacity addition stacks with other projects identified in the Resource Plan. In particular, Yukon Energy was to justify the purchase of the units as the least cost option.

On the two matters of further review noted by the YUB, price and need, the following points are noted:

- **Price of the Minto Diesel units:** During the PPA review process, Yukon Energy noted that the cost for the Minto units would be competitive with the costs estimated for the Mirrlees Life Extension Project during the Resource Plan hearing (\$0.457 million/MW per the supplementary filing Exhibit 16). Further, the definition of “Diesel Units Purchase Price” in the PPA provides for deductions from the overall \$2.24 million purchase price based on considerations related to depreciation and maintenance expenses related to actual use in excess of stipulated hours of operation. Updated comprehensive price information continues to reflect this conclusion:

⁵ In Interrogatory response YUB-YEC-2-10(f).

⁶ As noted during the PPA hearing process, the negotiated purchase price for the diesels reflects a proxy for the estimated market value in the event that Minto had proceeded to buy out the Cat Leases and then sell these units to other off-site users.

⁷ Purchase of the units is conditional upon Yukon being satisfied (after inspecting the units) that that the condition of such Diesel Units is consistent with the representations and warranties provided by Minto in the PPA (including the completion of a minor or if necessary a major overhaul on each unit) and that the units are otherwise in good condition and fit for their intended purpose at the time of purchase by Yukon Energy.

⁸ See Order 2007-5 at page 19.

- 1 - **Minto Diesel units:** The purchase price for the Minto diesel units remains the \$2.24
2 million price per the PPA (i.e., no reduction in price for unit condition has been assumed).
3 Approximately \$200,000 in immediate work is required in order to convert the Minto
4 diesel units to standby use for the winter 2008/09 (primarily related to winterization and
5 heating systems). Future expenditures on these units of \$0.75 million are planned for
6 2009 for such items as a more solid building/foundation, SCADA connection and
7 improved remote start and visibility. Accordingly, the cost for these units approximates
8 \$0.498 million/MW. Acquiring the units also provides Yukon Energy with some flexibility
9 over the longer planning horizon. For example, the costs incurred to acquire the diesels
10 may be more readily recovered once commitments to the mine have elapsed (compared
11 to refurbished Mirrlees units), since once the requirements of the PPA have been met,⁹
12 Yukon Energy may elect to either relocate the diesels to another location on the system,
13 or sell the diesels.
- 14 - **Whitehorse Mirrlees units:** The YUB Resource Plan report recommended proceeding
15 with the Faro Mirrlees recommissioning project, which is currently nearing completion.
16 The subsequent Mirrlees capacity available for refurbishment (3 units totalling 14 MW) is
17 located at Whitehorse, now budgeted to occur (as noted in Tab 2) in 2008 (unit #3, 5
18 MW, \$1.1 million, plus an additional \$0.535 million generator rewind for 2010), 2010
19 (unit #2, 5 MW, \$1.250 million plus \$0.435 million for the generator, all to be completed
20 in 2010), and 2012 (unit #1, 4 MW, \$1.050 million, no required generator rewind) with a
21 series of projects on “common” systems occurring in 2007 (\$0.468 million), 2008 (\$0.450
22 million) and anticipated for the following years (2010-2012, \$1.465 million). The timing
23 on refurbishment of unit #1 is flexible, including the option of ‘mothballing’ the unit for
24 some period of time to target a later refurbishment, if not required at 2012. Assuming
25 completion of the three units totalling approximately \$4.370 million plus approximately
26 \$2.384 million in common costs¹⁰ spread over the period to 2012, the cost per MW of
27 capacity is approximately \$0.482 million.

⁹ Section 10.5 sets out the conditions governing removal of the diesels from the Mine site. Section 10.5 (a) provides that YEC may remove two of the Diesel Units from the site or sell or otherwise dispose of them to a third party at any time after two years after the Commencement of Delivery. Section 10.5 (b) provides that the remaining units may be removed or sold by YEC any time after the earlier of (i) the eighth annual payment date or (ii) discharge of the YEC Security. 10.5 (c) provides that YEC must provide Minto with notice of an intention to sell or remove the units from the site and offer to sell the units to Minto on terms as set out in section 10.5(c).

¹⁰ Includes \$0.469 million in 2007 for cooling system upgrade, \$0.450 million in 2008 for electrical upgrades, cooling system replacement, and auxiliary systems replacement, and \$1.465 million in future years through 2012. Tables 5.1 and 5.2 include these costs up to the end of 2009 under “Ongoing Capital – Generation”.

In short, the costs per MW for the Minto diesels (\$0.498 million/MW) remain fully competitive with the Mirrlees refurbishment costs (\$0.482 million/MW), and well below costs for 6.4 MW of new diesel generation at the mine site (estimated at \$6.6 million, or \$1.035 million per MW). Purchase of the Minto diesels adds additional low cost options for YEC to augment its winter peaking diesel capacity to meet growing WAF loads.

- **Need for the Minto Diesel Units:** At the time of the Resource Plan, Yukon Energy indicated that the Whitehorse Mirrlees were now at retirement stage and that YEC planned to proceed with a full life extension project on these diesel units, assuming one unit per summer, with each unit back in service by the following winter. This requirement existed even without any Minto mine load in order to avoid a WAF winter peak capacity shortfall under the N-1 capacity planning criteria (and assuming retirement would otherwise occur for these units). The proposed approach to refurbishing system capacity was not without risks, most notably the potential that the work on any of the units may not be completed in time for the following winter, which would lead to capacity shortfalls.

As of the Resource Plan, Yukon Energy forecast “base case” non-industrial firm WAF load for 2009 of approximately 58 MW, which is still applicable.¹¹ Absent the Minto diesels but with the Faro Mirrlees re-commissioning and the WD3 Mirrlees refurbishment both completed by winter 2008/09, the N-1 capacity surplus for 2009 would be only approximately 3 MW.¹² In short, absent the Minto diesels, there would remain limited ability to refurbish the remaining Mirrlees except in the summer months. Further non-industrial growth on the WAF system (approximating upwards of 1 MW per year) and/or retirement of any of these Mirrlees units would quickly erode this surplus.

Given the flexibility provided by the purchase of the Minto diesels, YEC can now undertake refurbishment of the Whitehorse Mirrlees units at a lower risk and more measured pace. Further, at the PPA hearing, Yukon Energy indicated that it may reassess the timing of the

¹¹ The firm peak WAF load forecast indicated in this Application at Table 2.4 of 62 MW for 2009 includes industrial loads of approximately 4 MW.

¹² This assumes WD1 at a derated condition of 3.2 MW, WD2 at a derated condition of 4.2 MW, WD3 at a full 5 MW and Faro Mirrlees at 5 MW.

Mirrlees Life Extension project as needed in the context of the available near term diesel capacity available to the WAF system from the Mine site.¹³

In addition to the above noted benefits of the Minto diesels, there are other benefits from acquiring these units:

- The diesel units are located near key major loads at the end of long transmission line. At times when WAF diesel generation is required, having these units at this location reduces line losses in addition to providing greater grid support. As noted during the YESAB review¹⁴, and during the PPA hearing process,¹⁵ between two and three of the Diesel units at the Mine Site would rank next to the top of the WAF diesel generation stacking order. This reflects the capability of these units to supply expected Mine load levels at efficient fuel operation levels¹⁶ when diesel generation is required on WAF.
- These units can be run without any emissions impact in Whitehorse.
- In the near term the units provide cost effective contingency protection until such time as other potential major mine loads (such as Carmacks Copper), and capacity supply options are better clarified.

5.2.1.3 Whitehorse Mirrlees Diesel Generator (WD3) Rebuild

As noted above in respect of the Minto diesels, the present plan and timing for the Whitehorse Mirrlees refurbishment project is one 5 MW unit in 2008 (mechanical; the generator rewind will occur in 2010), one 5 MW unit in 2010, and the 4 MW unit anticipated to be completed in 2012 if the capacity is required at that time. If not required, the 4 MW unit may be removed from service (“mothballed”) pending optimum timing for this capacity to be brought back into service. In 2008, \$1.1 million is budgeted under major projects for the 5 MW unit WD3 (plus \$0.450 million budgeted under ongoing capital [Generation] for various systems upgrades, as noted in Section 5.2.2.2).

¹³ This was noted in Yukon Energy’s Final Argument at page 15, as well as in YUB-YEC-1-8(1) and YCS-YEC-1-3(a).

¹⁴ See YESAB Adequacy response YESAB-YEC-2-5 and YESAB-YEC-3-1.

¹⁵ See Interrogatory response YUB-YEC-1-8(2).

¹⁶ Taking into account the diesels expected 3.7 kW.h/ litre fuel efficiency plus the line loss credit when serving Mine loads.

5.2.1.4 Faro Mirrlees Diesel (FD1) Recommissioning

This is the first of four Mirrlees diesel units being rebuilt to provide added capacity and reliability. The 20-Year Resource Plan identified 14.7 MW of new capacity as a minimum requirement to meet the Corporation's near-term capacity requirements by 2012. The option of refurbishing or replacing the Faro Mirrlees at a comparable cost to the Whitehorse Mirrlees was identified during the Resource Plan hearing in the supplementary filing, Exhibit 16.

Since the Faro Mirrlees unit has not been in service for several years, and was not included as part of Yukon Energy's reserve capacity, recommissioning will provide an additional 5 MW of "new" capacity to the grid and, as such, was a very attractive source of capacity. The YUB agreed with this assessment in its Recommendations regarding the 20-Year Resource Plan, noting at page 34 that "the previously retired Mirrlees unit, currently situated at the Faro plant, should be the one to proceed first, as it would contribute 5 MW of capacity and could be started at any time without impacting the rest of the existing capacity."

Work on this unit began in 2007 and will be completed in 2008, with \$0.407 million in costs in 2007 and \$1.158 million budgeted for 2008. The project is expected to be complete in 2008.

5.2.1.5 Aishihik Third Turbine

This near term project was identified in Yukon Energy's 20-Year Resource Plan. During the Part 3 hearing process for CSTP, the implications of the relationship between Stage One of the CSTP and the need for and timing of the Aishihik 3rd Turbine was reviewed. In the YUB report to the Minister regarding the Part 3 Review of the CSTP, the YUB recommended that, "if Stage One of the CSTP were to go forward, then by implication, there is an accelerated need for the third turbine at Aishihik. The Board accepts the submissions that on an opportunity basis for diesel displacement, with connection of new mine loads, there is economic justification to accelerate the construction of the Aishihik third turbine. This view and recommendation is consistent with the view expressed by the Board in its 20-Year Resource Plan Report."¹⁷

¹⁷ YUB Report re: Part 3 Review of CSTP at page 7.

The addition of a seven megawatt turbine installed at the existing Aishihik generation station at a cost of approximately \$8.5 million will help to reduce future diesel generation through both more efficient use of water at Aishihik, as well as better ability to use the plant to meet short-term peak loads (as an alternative to diesel generation). The Yukon Government has committed \$5 million of no-cost capital towards the project.¹⁸ These government funds allow the project to proceed on an accelerated basis to provide net benefits without waiting until new mine connection arrangements are confirmed.

Construction costs are forecast to be \$750,000 in test year 2008 with an additional \$3,500,000 in test year 2009 (a further \$4,250,000 is forecast for 2010). Yukon Energy costs for this project will be offset by Yukon Government funding contributions totalling \$1,500,000 in 2008 and \$3,500,000 in 2009 (for a total of \$5,000,000 over the period).

5.2.2 Projects \$100,000 to \$1 Million

The ongoing capital works spending on property, plant and equipment is forecast at \$3.803 million for projects added to ratebase in 2008 and \$4.828 million for 2009,¹⁹ as set out in Table 5.1 (with details in Table 5.2); forecast customer contributions related to these capital works is \$0.430 million in 2008 and \$0.400 million in 2009. Capital works projects budgeted at between \$100,000 and \$1 million for the 2008 and 2009 period, with \$100,000 or more forecast spending in at least one of these two years, total \$2.37 million in 2008 and \$3.14 million in 2009, and are described below:

- Distribution Projects (\$575,000 in 2008 and \$575,000 in 2009);
- Generation Projects (\$500,000 in 2008 and \$430,000 in 2009);
- General Plant and Equipment Projects (\$1,296,000 for 2008 and \$1,466,000 for 2009); and
- Transmission Projects (\$670,000 in 2009).

¹⁸ On March 30, 2007, Canada announced \$5 million in funding for the Yukon as part of a trust fund set up to help reduce greenhouse gas emissions and air pollutants, and the Yukon Government announced that the funds will be used for the Aishihik 3rd Turbine Project.

¹⁹ Excluding spending on major projects over \$1 million.

5.2.2.1 Distribution Projects \$100,000 to \$1 Million

Distribution project expenditures forecast in 2008 and 2009 include routine spending on small projects under \$100,000 (totaling \$86,000 in 2008 and \$125,000 in 2009), as well as the following projects between \$100,000 and \$1million (totaling \$575,000 in 2008 and \$575,000 in 2009, prior to offsets by customer contributions of \$400,000 in each year).

Customer Extensions - \$475,000 (2008) offset by Customer Extensions Customer Contribution - \$400,000 (2008); \$475,000 (2009) offset by Customer Extensions Customer Contribution - \$400,000 (2009)

Yukon Energy is required to provide service to new customers coming onto the system, and consequently, customer extensions are forecast and budgeted as a capital items without identifying specific projects. Most costs of customer extensions are covered by customer contributions pursuant to the Electrical Service Regulations.

Land Management and Easement Project - \$100,000 (2008) and \$100,000 (2009) (Completed in 2009)

This program will continue to secure easements for Yukon Energy's distribution lines over 2008 and 2009. Having registered easements in place enhances customer relations and increases the efficiency of Yukon Energy's operations.

5.2.2.2 Generation Projects \$100,000 to \$1 million

Generation project expenditures forecast in 2008 and 2009 include small projects under \$100,000 (totaling \$483,000 in 2008 and \$389,000 in 2009), as well as the following projects between \$100,000 and \$1.0 million (totaling \$500,000 in 2008 and \$430,000 in 2009).

P 126 Mirrlees Electrical Upgrades - \$150,000 (2008); P 126 Mirrlees Cooling System Replacement - \$150,000 (2008); P 126 Mirrlees Auxiliary Systems Replacement - \$150,000 (2008)

As noted above, the Whitehorse Mirrlees life extension project encompasses work on individual units as well as a number of related projects on the "common" plant systems. This plan is particularly focused on the Mirrlees associated auxiliary components, as well as replacing the deteriorated switchgear and associated power cables.

Whitehorse Dam Spill Regulation Improvements - \$25,000 (2008) and \$200,000 (2009)
(Completed in 2009)

The spillway gates on the Whitehorse Dam were not built to regulate water flows on the Yukon River; however, they have served this function since the construction of Yukon Energy's Fourth Wheel in 1985. This has resulted in excessive wear on the gate hoist machinery and has required extra labour every winter to ensure that the gates do not freeze. In 2008, Yukon Energy will undertake a study to determine the optimal solution to this issue, with the expectation that it be implemented in 2009.

Wareham Intake Walkway - \$25,000 (2008) and \$125,000 (2009) (Completed in 2009)

Poor weather, water levels and floating docks have in the past created access problems to the Wareham Dam intake building. Yukon Energy requires a reliable means of accessing the Wareham Dam intake building year round, and plans to build a steel catwalk that extends from a nearby bank and that would be permanently attached to the intake building. Conceptual and detailed design will be undertaken in 2008 with construction to commence in 2009.

Wareham Intake Rock Scaling - \$105,000 (2009)

A removal, scaling or stabilizing of the slopes will be required in the event that the engineering assessment to be undertaken in 2008 deems the rock face above, or surrounding, the Wareham intake unstable. A rock slide could block the intake or damage the intake building.

5.2.2.3 General Plant and Equipment Projects \$100,000 to \$ 1 Million

General plant and equipment project expenditures forecast in 2008 and 2009 include small projects under \$100,000 in each year (totaling \$708,000 in 2008 and \$953,000 in 2009), as well as the following projects between \$100,000 and \$1.0 million in at least one of these years (totaling \$1,296,000 for 2008 and \$1,466,000 for 2009).

Vehicle Purchases - \$209,000 (Completed in 2008); \$288,000 (Completed in 2009)

In 2008, three service bodies are expected to need replacing, and in 2009 two service bodies are expected to need replacing. In order to qualify for replacement, Yukon Energy vehicles must meet two of three requirements: the vehicle must be at least seven years old, it must have at least 160,000 kilometres on the odometer, or its repair and maintenance costs must be at least 15 percent of its replacement value.

Bucket Truck - \$130,000 (2008)

Day-to-day service work can be performed with a small bucket truck, a vehicle that is relatively economical and versatile and that does not require extensive operator training. Yukon Energy currently does not have a bucket truck and has been using its digger truck for required day-to-day service work. The digger truck is designed for use on much larger projects (such as construction projects), and using it for day-to-day operations is causing unnecessary wear and tear on the digger, which could lead to safety issues. Yukon Energy plans to purchase one bucket truck, alleviating unnecessary wear and tear on the digger by ensuring that it is used only for its intended purpose.

Off-Road Maintenance Vehicle Purchase - \$150,000 (2008) and \$300,000 (2009) (Completed in 2009)

Yukon Energy currently leases a 1979 Nodwell from Arctic Power, and is responsible for the repair costs. Because this unit is old, breakdowns are more frequent, increasing costs substantially. Since there are no other booms in the Yukon that can access remote areas, this also limits Yukon Energy's ability to access remote locations in order to make repairs. It is more economical for Yukon Energy to purchase a new unit and boom specific to Yukon Energy's requirements. A down payment of \$150,000 in 2008 will be followed by an additional payment of \$300,000 upon arrival of the asset in 2009.

SCADA Replacement -\$150,000 (2008) and \$118,000 (2009) (Completed in 2009)

The existing VMS-based SCADA system has been in service since 1997. Due to the fact that this is an older system, upgrades and new application software are not always available. The VMS platform is also likely to be discontinued within the next few years. An upgraded system will be easier to use and will incur lower annual maintenance costs.

Disaster Recovery Plan/Business Continuity Plan Development – \$150,000 (2008) and \$75,000 (2009) (Completed in 2009)

Since Yukon Energy provides an essential service to Yukoners it must be prepared for a possible extended power failure, fire, flood or other potential disaster that could affect operations. Developing a disaster recovery and business continuity plan is an important part of an overall framework for identifying and managing risk. Such a plan would involve data collection and risk assessment, a design of disaster recovery strategies, implementation, and on-going disaster recovery plan testing.

Financial Systems Software Replacement -\$125,000 (2008) and \$450,000 (2009) and \$425,000 (2010) (Completed in 2010)

Yukon Energy currently uses a software package called J.D. Edwards to track financial information. Over 2008, management will complete a replacement system needs assessment and a product review, and present recommendations to the Board of Directors. Implementation will begin in 2009 with completion of the project scheduled for mid-2009. This project remains a work in progress in 2009 with an additional \$425,000 in spending forecast for 2010.

Electronic Document Management - \$125,000 (2008) and \$100,000 (2009) and \$100,000 (2010) (Completed in 2010)

Yukon Energy currently does not have a formal electronic data management system. A formal system designed to maintain, control and safeguard electronic records is critical in order to ensure that records are easily accessible, are the correct versions when located, and can be proven to be authentic and reliable. In 2008, Yukon Energy hired a records management consultant to assess records management issues and propose solutions. In 2009, a consultant will assist with implementation and technical configuration, test software and train staff. This project remains a work in progress in 2009 with additional \$100,000 in spending forecast in 2010.

Main Office Sprinkler System - \$100,000 (2009)

Yukon Energy is proceeding with installing a wet sprinkler system in accordance with the National Fire Protection Agency and the Canadian Fire Code. When Yukon Energy's office building was constructed in 1999 a sprinkler system was not required to meet building and fire codes (such a system is still not required for that purpose), and while the current fire monitoring system is designed for personnel safety only, (i.e., to allow staff to safely exit the building), there is no suppression system to prevent a fire from destroying the building and its contents. Past experience has demonstrated that it can take years to recover from such a loss. The project commenced in 2007 and is expected to be complete in 2009.

Power Line Carrier Takhini-AH Replacement - \$155,000 (2008)

The communications requirements for the Aishihik Hydro facility are currently provided from Takhini to Aishihik via a power line carrier which has limited capacity in its bandwidth and data rates. The present band rate is limited to 1,200 bps, while the required band rate for the consolidation of voice (telephone), data (control signals), SCADA (supervisory control by the SCC) and internet is 8,100 bps. The required

band rate may be achieved by replacing the existing system with a new high-speed digital power line carrier.

Server Replacements - \$102,000 (2008) (Completed in 2008) and \$35,000 (2009) (Completed in 2009)

It is necessary to replace servers before their warranty expires. This activity is being undertaken as part of Yukon Energy's redeployment/upgrading/replacement cycle for IT equipment, and is a proactive and preventive approach to mitigate risk of server failure.

5.2.2.4 Transmission Projects \$100,000 to \$1 million

Transmission project expenditures forecast in 2008 and 2009 include routine spending on projects under \$100,000 (totaling \$155,000 in 2008 and \$220,000 in 2009), plus the following projects between \$100,000 and \$1.0 million (totaling \$670,000 in 2009).

L170 Line Assessment Phase 2 Carmacks- Faro - \$100,000 (2009) and \$165,000 (2010) (Completed in 2010)

The line from Takhini to Carmacks and Faro was built approximately 30 years ago. Over 2006 and 2007 line assessment was undertaken from Takhini to Carmacks. The remainder of the line to the Faro mine substation needs to be assessed in 2008 to allow for planning and maintenance work. This project remains a work in progress in 2009 with an additional \$165,000 in spending forecast for 2010 and beyond.

WAF Transmission Upgrades - \$175,000 (2009)

Transmission lines on the WAF system were constructed in the late 1960's to mid-1970's and replacement of old or damaged structures are required in order to maintain reliability. Required work includes upgrades to insulators, cross arms, dead end insulators and any damage or accelerated wear. Some poles are also becoming infested with carpenter ants and require treatment. These lines are critical to the operation of the WAF system. L-171 supplies Yukon Energy's winter generation from Aishihik plant to Whitehorse while L 170 connects Whitehorse to Faro. WAF transmission upgrades have continued since the 2005 hearing where it was noted that little work had been carried out prior out to that time and that work on the project was expected to continue into 2008 and total approximately \$500,000.

L169/L170 Pole Treatment - \$115,000 (2009)

Some poles are becoming infested with carpenter ants and require treatment. These lines are critical to the operation of the WAF system.

L250 2008 Transmission Line Upgrades - \$100,000 (2009)

Due to wet ground conditions, parts of the L250 transmission line, from Mayo to Keno, are in need of attention and repair. Poles are rotting at ground level, and are leaning or falling over. Insulators have small cracks, and are also flashing over during rain storms, causing outages. While much of this line has been upgraded over the past several years, the completion of this work is critical to improving reliability to the system that feeds Elsa and Keno.

Dead End Insulators - \$180,000 (2009)

The glass insulators, known as dead end insulators, on the transmission lines between Whitehorse and Faro are aging (some are more than 30 years old) and need to be replaced. New insulators will be installed over two years, ensuring we have reliability on the Whitehorse-Aishihik-Faro grid.

5.3 DEFERRED COSTS

This section reviews (a) major deferred cost projects (projects over \$1 million), and (b) other deferred cost projects costing between \$100,000 and \$1 million, undertaken by Yukon Energy since the 2005 Required Revenues and Related Matters hearing, focusing on the 2008 and 2009 period.

Ongoing resource planning activities indicate that the current hydro generation surplus (after CSTP Stage One and Minto connection, and before any secondary sales) at long-term average flows will likely now be fully utilized by firm sales on WAF sometime between 2011 and 2014. Connection of additional industrial loads, which could potentially occur as soon as 2010/2011 (see Section 2.2.2.2), could lead to 50 to 100 GW.h of near term baseload diesel generation (2010-2015 time period) in the event that no new renewable resource generation is in-service in the near term to meet these grid loads.²⁰ The major deferred project costs are directed at renewable resource development projects identified as potential

²⁰ By way of example, by 2015 Minto plus Carmacks Copper and Keno Hill mine loads are projected to require 77 GW.h of new generation beyond WAF/MD hydro generation capability with current facilities, Aishihik 3rd Turbine, and CSTP Stage Two. Absent new renewable resource generation on these grids, this requirement would be supplied from existing diesel generation. At 30 cent/kW.h, 77 GW.h of diesel generation would incur added annual fuel costs of approximately \$23 million and added CO2 emissions of about 53,900 tonnes per year.

opportunities (in combination) to displace 50 to 100 GWh of diesel generation in the 2010-2015 near term time period.

5.3.1 Major Projects Over \$1 Million

There are four major deferred cost projects with costs exceeding \$1 million for the test years, totaling \$2.5 million in 2008 and \$15.3 million in 2009 (with projected customer offset of \$1.0 million in 2009). All of these costs are projected to remain work in progress during the test years, and therefore do not affect projected test year amortization expenses or net rate base.

Mayo B (\$1.7 Million In 2008; \$6.5 Million in 2009; total of \$8.2 Million over the 2 test years)

Mayo B has been identified as a potential priority near term hydro generation expansion opportunity to displace about 38 GW.h/yr of baseload diesel generation that would otherwise be required when additional industrial loads such as the Keno Hill and/or Carmacks Copper mines connect to the grids. The current test year budgets address planning, engineering, YESAA and permitting activities, and potential tendering activities, to protect an earliest feasible in-service date (currently late 2011) for this project. These budgets and schedules are subject to ongoing review after completion of geotechnical and environmental field studies currently being completed this fall, as well as ongoing review of projected mine loads and the timing for new renewable generation requirements.

Other Generation Feasibility (\$800,000 in 2008; \$6.8 Million in 2009; total of \$7.6 Million over the 2 test years)

Other generation feasibility budgets of approximately \$2.6 million (\$0.4 million in 2008, \$2.2 million in 2009) address planning, engineering, YESAA and permitting activities, and potential tendering activities, during the test years to protect earliest feasible near term in-service dates for potential WAF hydro generation enhancement projects affecting existing Aishihik and Whitehorse generation (Gladstone Diversion project [18 GW.h/y], small scale Atlin winter storage project [18 GW.h/y], and Marsh Lake fall-winter storage project [7.7 GW.h/y]). The balance of these test year budgets (\$0.4 million in 2008 and \$4.6 million in 2009) address pre-feasibility and feasibility studies for potential longer-term (circa 2015) and larger scale generation options (e.g., 100-300 GW.h/yr), including geothermal generation options and larger scale hydro generation such as Hoole. These budgets are subject to ongoing review after completion of field studies and initial desk studies currently being completed this fall, as well as ongoing review of projected mine loads and the timing for new renewable generation requirements.

Western Copper – Grid Connection YESAA & PPA - \$1 Million (2009) offset by customer contribution of \$1 Million (2009)

Western Copper has requested a grid connection from the Stage One CSTP to its planned mining project at the Carmacks Copper mine site. Funds budgeted for 2009 will be used for the necessary planning, engineering, permitting/YESAA review and negotiation of a power purchase agreement. These amounts are anticipated to be fully recovered from Western Copper.

CSTP Stage Two – Grid Connection Design and Contracting - \$1 Million (2009)

Stage Two CSTP final engineering design, costing and tendering activity is anticipated to be required during 2009 to protect potential in-service as may be required (in response to new mine loads) in 2010 or 2011. The budget and timing for this activity is subject to ongoing review.

5.3.2 Projects between \$100,000 and \$1 Million

The projected total 2008 and 2009 spending on deferred cost activities outside of major projects over \$1 million (as described in Section 5.3.1) totals \$1.617 million in 2008, as set out in detail in Table 5.6, and \$802,000 for 2009 as set out in detail in Table 5.7. Deferred costs incurred from 2005 to 2007 include spending on the Resource Plan (\$434,000) as well as PPA negotiation and due diligence (\$797,000). Spending in 2008 and 2009 on each deferred cost activity between \$100,000 and \$1 million is reviewed below (totaling \$1,353,000 for 2008 and \$906,500 for 2009):

GRA Phase 1 Revenue Review - \$800,000 (2008)

This spending addresses the costs of preparing and filing a 2008/2009 Phase I GRA, as well as full regulatory review. Any joint YEC/YECL cost of service and rate design filing is to be undertaken at a date to be determined, and is not included in this projected cost.

Hydro Storage and Generation Pre-feasibility (\$130,000 in 2008; \$501,000 in 2007)

Yukon Energy has been actively assessing options to increase hydro generation. This project was carried out to target options that could increase renewable power generation by up to 50 GW.h annually in the near term through one or a combination of projects. Starting in 2008, efforts are focused on Mayo B as well as a series of other specific near term major projects (see Section 5.3.1).

Wareham Intake Rock Face Assessment (\$100,000 in 2008)

A number of years ago, the rock face in the vicinity of the Mayo hydro plant intake fell and damaged the intake building. The rock face was bolted and netted. It has been approximately 15 years since the work was performed and an assessment is necessary to determine if the rock is stable, or if it is a potential hazard to the intake building. This is critical upstream of the headgate where there is a large section of rock that has never been bolted or netted.

Aishihik Runner Up-Rate Study - \$110,000 (2008)

Preliminary investigations have determined that it is possible to substantially increase capacity of the two Aishihik units. Yukon Energy plans to explore this further by undertaking a hydro unit up-rate study. This study will examine the impact of increasing a unit's load capacity on all components of the turbine-generator.

Aishihik Water License Renewal – (\$167,000 in 2008; \$130,000 in 2009)

The Fisheries Act Authorization for Aishihik requires that Yukon Energy monitor the fish populations in Aishihik Lake on an annual basis. Yukon Energy's Aishihik water license also requires a subsistence fishery monitoring program be undertaken. Funds have been allocated to fulfill both of these obligations as well as required Heritage Mitigation and Annual Compensation Payments.

Dam Safety Review \$150,000 (2009)

As per the Canadian Dam Association Guidelines, high hazard dams must have an external review every 5 years. Whitehorse, Marsh Lake, Aishihik facilities were last reviewed in 2005. The next round of dam safety reviews are scheduled for 2010. Spending in 2009 is on activities required to be prepared for the reviews. During the reviews, all hydro facilities are inspected, including Whitehorse, Aishihik, and Mayo.

Mayo Lake Dam Assessment - \$100,000 (2009)

The Mayo Lake dam is a wooden structure that is expected to be approaching end-of-life. Yukon Energy intends to hire a structural engineer to perform an assessment of the dam and make recommendations for repair.

Alexco Mine – Feasibility and Permitting - \$300,000 (2009); with customer contribution of \$300,000 (2009)

Due to strong base metal prices over the past few years there has been a resurgence in Yukon mining activity. Yukon Energy is aware of the development plans for Alexco Resource Corp. (Elsa), which has a target production date of 2010. This budget provides for undertaking infrastructure planning, engineering, environmental and permitting work and other forms of due diligence as may be required to connect this customer in 2010, and that may result from a purchase power agreement with the customer. All costs for these studies and activities are planned to be charged to the mining customer.

Investigate International Financial Reporting Standards - \$46,000 (2008); \$105,500 (2009)

In January 2011, Canadian accounting standards will be converting to International Financial Reporting Standards ("IFRS"). In order to have statements with comparative numbers Yukon Energy must start using the international standards in January 2010. Since IFRS is new to the Corporation, the implications of implementing IFRS for Yukon Energy are unknown. Yukon Energy will need to undertake an in-depth investigation in order to develop a full understanding of what the organization must do to prepare for the conversion to IFRS standards.

Dawson Diesel 1 Overhaul - \$121,000 (2009)

Following the manufacturer's recommended maintenance schedule, this generator requires a major rebuild. Major overhauls are typically conducted after 40,000 hours of use.

YUKON ENERGY CORPORATION
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT
(\$000S)

Table 5.1
September 2008

Description	2005	Actual 2006	2007	Forecast	
				2008	2009
SUMMARY - RECONCILIATION OF PROPERTY, PLANT AND EQUIPMENT					
Work in Progress (WIP), Beginning of Year	1,940	2,369	1,263	7,552	1,500
Total Major Projects			5,909	38,329	4,250
Ongoing Capital					
Total Transmission	1,327	809	593	155	890
Total Distribution	1,326	848	611	661	700
Total Generation	669	2,175	1,886	983	819
Total General Plant & Equipment	2,304	2,158	2,091	2,004	2,419
Subtotal Ongoing Capital	5,626	5,990	5,182	3,803	4,828
Total Expenditures	5,626	5,990	11,091	42,132	9,078
includes: AFUDC	102	51	93	735	162
Transfer to RSFR		-79	-99		
Transferred to Income Statement	-93		-16		
Total WIP Adjustments and Transfers	-93	-79	-115	0	0
Transfer to Ratebase	-5,104	-7,017	-4,686	-48,184	-6,203
WIP end of year	2,369	1,263	7,552	1,500	4,375
Opening PPE in-service	217,581	219,747	225,304	229,301	276,342
Transfer from WIP	5,104	7,017	4,686	48,184	6,203
Other Adjustments	-1,196	-649	-136		
Retirements	-1,742	-811	-553	-1,143	-260
Closing PPE in-service	219,747	225,304	229,301	276,342	282,285
Opening Total PPE (in-service plus WIP)	219,521	222,116	226,567	236,853	277,842
Change to total PPE	2,595	4,451	10,286	40,989	8,818
Closing total PPE	222,116	226,567	236,853	277,842	286,660
RECONCILIATION OF CUSTOMER CONTRIBUTIONS					
Opening Customer Contributions WIP	570	118	209	4,674	1,500
Customer Contributions Received	577	734	215	1,930	3,900
CSTP Customer Contributions			4,450	30,189	
less: transfer to Rate Base	-1,029	-643	-201	-35,293	-400
Customer Contributions WIP end of year	118	209	4,674	1,500	5,000
Opening Gross Customer Contributions in Service	12,801	13,830	14,472	14,673	49,966
Transfers from WIP	1,029	643	201	35,293	400
Retirements, Disposals and Adjustments					
Closing Gross Customer Contributions in Service	13,830	14,472	14,673	49,966	50,366
Opening Total Contribution (in-service plus WIP)	13,371	13,948	14,682	19,347	51,466
Change to total Contribution	577	734	4,665	32,119	3,900
Closing total Contribution	13,948	14,682	19,347	51,466	55,366

YUKON ENERGY CORPORATION
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT
(\$000S)

Table 5.2
September 2008

Description	2005	Actual 2006	2007	Forecast 2008	2009
Major Projects					
Carmacks Stewart/Minto Spur Transmission Line Phase I			5,502	32,881	
Minto Diesels				2,440	750
FD1 Re-Build			407	1,158	
P126 WD3 Re-build				1,100	
AH3 Construction				750	3,500
Total Major Projects	0	0	5,909	38,329	4,250
Transmission					
M/D Transmission Line Deficiencies	509	123			
Stewart Crossing 3 Phase Upgrade	225				
2005 WAF Transmission Upgrades	158				
M/D Vibration Dampeners	125				
L-170 Yukon River Crossing	104	183			
PT Substation South Fox Lake		120			
Elsa Line Upgrade		96			
2006 WAF Transmission Upgrades		92			
L171 Aishihik River Crossing		74			
2007 WAF Transmission Upgrades			254		
L174 Protection Co-ordination Study			87		
Mayo - Dawson Transmission Line Drawings				50	
Dead End Insulators					180
WAF Transmission Upgrades					175
L169/L170 Pole Treatment					115
L250 2008 Transmission Line Upgrades					100
L170 Assessment Phase 2 Carmacks - Faro					100
Transmission Line Assessment and Repairs					75
S164 Reactor Replacement					75
Blocking Switches					50
Other projects under 50K	207	120	253	105	20
Total Transmission	1,327	809	593	155	890
Distribution					
Land Management & Easement Project	108				
Yard Grading at Kulan	76				
Land Management & Easement Project		113			
PCB Related Expenses		92			
Land Management & Easement Project			90		
Transformer Replacement			71		
Marshall Cr AG Subdivision Pole Change			51		
Customer Extensions	983	373	96	475	475
Land Management & Easement Project				100	100
Distribution Improvements				50	50
S250 Voltage Regulator Automation					50
Other projects under 50K	159	270	304	36	25
Total Distribution	1,326	848	611	661	700

YUKON ENERGY CORPORATION
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT
(\$000S)

Table 5.2
September 2008

Description	2005	Actual 2006	2007	Forecast	
				2008	2009
Generation					
WH1 Trunion Bushing	370				
Mayo Hydro Plant Extension	70				
AH2 Rewind Stator		721			
AH2 Rewind Mechanical		305			
AH2 Rewind Rotor		268			
Aishihik Cable Replacement		241			
AH2 Protection Upgrade		88			
Mayo Alternate Power Source		65			
S150-52-19 Breaker Replacement		55			
WH4 Life Extension Project			550		
P126 Mirrlees Cooling System Upgrade			469		
Underground Fuel Piping Remediation/Replacement			142		
WH3 & P125 Governor Upgrade			127		
Balance of Plant Mechanical & Civil			83		
AH1 Protection Upgrade			59		
P126 Mirrlees Electrical Upgrades				150	
P126 Mirrlees Cooling System Replacement				150	
P126 Mirrlees Auxiliary Systems Replacement				150	
RTU Upgrade FDO Faro				77	
Callison Synch Condenser PLC				68	
AH0 Current Transformer Replacements				67	
Purchase & Installation of Time Synchronizers				58	
Faro PLC				54	
WH0 Improve Spill Regulation				25	200
Wareham Intake Walkway				25	125
Wareham Intake Rock Scaling					105
RTU Upgrade P127					80
AH0 Deluge System					69
WD4 Control Upgrade					60
Hydrocarbon Containment and Detection Systems for Diesel Plants					50
Air Emission Control Systems					50
Other projects under 50K	228	432	456	160	80
Total Generation	669	2,175	1,886	983	819

YUKON ENERGY CORPORATION
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT
(\$000S)

Table 5.2
September 2008

		Actual		Forecast	
Description	2005	2006	2007	2008	2009
General Plant & Equipment					
Transportation Equipment (Purchase)	404				
Drury Creek Rebuild	154				
Whitehorse Rapids Instrument Upgrade	99				
Firewall Repatriation	87				
PCB Testing, Disposal & Replacement	71				
San Storage	66				
Electric Boiler Replacement P126	66				
PC/Laptop Replacement	65				
Printers, Scanners & Copiers	59				
SCADA Control Diesel Plant & Calsn	56				
Crane Truck		268			
Fibre Installation (MH to DP)		248			
NND FN C-6 SBDVN		168			
Server Replacements		143			
Transportation Equipment (Purchase)		137			
Mayo Feeder Relocation		114			
Small Building Fire Alarm System		100			
S150-52-15 Breaker Replacement		88			
Routers Hubs & Switches		65			
Mayo Lake Trash Rack Improvements		56			
PC/Laptop Replacements		53			
Communications Network Improvements		51			
Transportation Equipment (Purchase)			441		
VM Ware Implementation			161		
Web Server			102		
Kulan Forklift			100		
Communications Network Improvements			97		
PC/Laptop Replacements			93		
SCADA Control Diesel Plant & Calsn			93		
SCC UPS Addition			78		
Main Office Sprinkler System			76		
Office Space Renovations			72		
Office Building 3 Floor Cooling			67		
Digital Radio Replacement			54		
Vehicle Purchases 2006-2010 updated 2008 BP				209	288
Power Line Carrier Takhini - AH Replacement				155	
Off-Road Maintenance Vehicle Purchase				150	300
SCADA Replacement				150	118
DRP/BCP Plan Development				150	75
1 Bucket Truck				130	
Financial Systems Software Replacement (JDE)				125	450
Electronic Document Management				125	100
Server Replacements				102	35
Hatchery Upgrades				67	
Communications Network Improvements				65	56
Security Risk Management (2008)				50	50
Callison Site Work & Warehousing				50	
Main Office Sprinkler System					100
Exchange Server Replacement					97
P126 Mirrlees Bay Exhaust Fans					65
Repeater Install-Mount Berdeau (Carmacks)					65
Waste Management Storage Systems					65
Fish Ladder Building Upgrades					60
Other projects under 50K	1,177	667	657	476	496
Total General PPE	2,304	2,158	2,091	2,004	2,419
TOTAL	5,626	5,990	11,091	42,132	9,078

	Total expenditures				Amortization Rate and Method	Accumulated Amortization		
	Dec 31	Act 2005	Actual			Dec 31	Act 2005	Actual
	2004	Additions	Transfers	2005		2004	expenses	2005
Completed Projects-feasibility:								
Fuel Additive Pilot	4	0	0	4	SL-5 years	3	1	4
WH4 Exciter Replacement	0	0	0	0	SL-5 years	0	0	0
Flow Monitoring	45	0	0	45	SL-5 years	36	9	45
Aish Forest Asses & Trail Log	20	0	0	20	SL-5 years	16	4	20
Assess Mayo/keno Line	105	0	0	105	SL-5 years	30	21	51
Wh4 Vibration Analysis Study	31	0	0	31	SL-5 years	11	6	17
Project Costing Feasibility	26	0	0	26	SL-5 years	9	5	14
M/D Communication Study	30	0	0	30	SL-5 years	9	6	15
Vegetation Management Study	2	0	0	2	SL-5 years	1	0	1
Physical Site Security Audit	17	0	0	17	SL-5 years	7	3	10
System Protection Study	108	0	0	108	SL-5 years	43	22	65
Corporate Data Base Study	11	0	0	11	SL-5 years	4	2	6
Secondary Sales	17	0	0	17	SL-5 years	7	3	10
Infrastructure Plan Study Phase 1	49	0	0	49	SL-10 years	4	5	9
Generation Asset Assessment	62	0	0	62	SL-10 years	5	6	11
Transmission Line Assessment	82	0	0	82	SL-10 years	7	8	15
Carmacks/stewart Feasibility Study	2	0	0	2	SL-5 years	0	0	1
WAF Power Flow Study	0	0	82	82	SL-5 years	0	10	10
Secondary Sales Technical Standard	0	0	28	28	SL-5 years	0	3	3
Substation Asset Assessment	0	0	85	85	SL-10 years	0	5	5
Infrastructure Plan (phase2)	0	0	125	125	SL-10ears	0	7	7
Fishway Redevelopment	0	0	15	15	SL-5 years	0	1	1
Transmission Extension	0	0	85	85	SL-10 years	0	4	4
Powerline Easement Assessment	0	0	26	26	SL-5 years	0	2	2
Wh4 Intake Seismic Assessment	0	0	43	43	SL-5 years	0	2	2
Infrastructure Plan Final Report	0	0	66	66	SL-5 years	0	2	2
Atlin/Jakes Corner Grid Extension	0	0	33	33	SL-5 years	0	0	0
Wh4 Static Exciter Assessment	0	0	21	21	SL-5 years	0	0	0
Trans Small Load Stepdown	0	0	23	23	SL-5 years	0	0	0
Subtotal	609	0	631	1,240		191	138	330
Work In Progress (WIP):								
WAF Power Flow Study	0	82	-82	0		0	0	0
Secondary Sales Technical Standard	0	28	-28	0		0	0	0
Substation Asset Assessment	0	85	-85	0		0	0	0
Infrastructure Plan (phase2)	0	125	-125	0		0	0	0
Fishway Redevelopment	0	15	-15	0		0	0	0
Transmission Extension	0	85	-85	0		0	0	0
Powerline Easement Assessment	0	26	-26	0		0	0	0
Wh4 Intake Seismic Assessment	0	43	-43	0		0	0	0
Infrastructure Plan Final Report	0	66	-66	0		0	0	0
Atlin/Jakes Corner Grid Extension	0	33	-33	0		0	0	0
Wh4 Static Exciter Assessment	0	21	-21	0		0	0	0
Trans Small Load Stepdown	0	23	-23	0		0	0	0
Infrastructure Plan Peer Review	0	342	0	342		0	0	0
Resource Plan Phase 1	0	11	0	11		0	0	0
Carmacks-Stewart Transmission Line	0	205	0	205		0	0	0
P126 Bince Of Plant Assmnt	0	30	0	30		0	0	0
Subtotal	0	1,219	-631	588		0	0	0
Total Feasibility	609	1,219	0	1,828		191	138	330
Completed Projects-relicensing:								
Aishihik License Renewal	6,752	0	839	7,590	SL to 2019	1,751	353	2,104
Whitehorse License Renewal	96	0	0	96	SL to 2025	25	3	29
Mayo Relicensing Renewal	28	0	0	28	SL to 2025	10	1	10
Subtotal	6,876	0	839	7,715		1,786	357	2,143
Work In Progress (WIP):								
Fish Monitoring	0	118	-118	0		0	0	0
Aishihik License Annual Payment	0	25	-25	0		0	0	0
Boat Ramp (north End)	0	643	-643	0		0	0	0
Aishihik Village Well	0	11	-11	0		0	0	0
Aishihik License Annual Payment	0	25	-25	0		0	0	0
Aishihik Heritage Erosion Protection	0	17	-17	0		0	0	0
Aishihik Dyke Upgrades	0	139	0	139		0	0	0
Aishihik Rocky Point Berm Study	0	9	0	9		0	0	0
Aishihik Control Structure Upgrades	0	55	0	55		0	0	0
Aishihik Heritage Plan	0	43	0	43		0	0	0
Aishihik Chemi Narrows Erosion Protection	0	7	0	7		0	0	0
Aishihik Fish Monitoring	0	47	0	47		0	0	0
Subtotal	0	1,138	-839	300		0	0	0
Total Relicensing	6,876	1,138	0	8,014		1,786	357	2,143
Total Dam Safety	135	96	0	231	SL-5 years	109	33	142
Total Deferred Study Costs	7,619	2,453	0	10,073		2,086	528	2,615
Total Deferred Downsizing	334	0	0	334	SL-7 years	167	48	215
Total Overhauls	0	0	0	0	SL-5 years	0	0	0
Rate Case (completed)								
2005 Required Revenue Hearing	325	607	0	932	SL-3 years	0	311	311
Total Deferred Costs	8,279	3,060	0	11,339		2,254	887	3,141
Net Deferred Costs								
								8,199

	Total Expenditures				Amortization Rate and Method	Accumulated Amortization		
	Dec 31	Act 2006		Actual		Dec 31	Act 2006	Actual
	2005	Additions	Transfers	2006		2005	Expenses	2006
Completed Projects-feasibility:								
Assess Mayo/keno Line	105	0	0	105	SL-5 years	51	21	72
Wh4 Vibration Analysis Study	31	0	0	31	SL-5 years	17	6	24
Project Costing Feasibility	26	0	0	26	SL-5 years	14	5	19
M/D Communication Study	30	0	0	30	SL-5 years	15	6	21
Vegetation Management Study	2	0	0	2	SL-5 years	1	0	1
Physical Site Security Audit	17	0	0	17	SL-5 years	10	3	13
System Protection Study	108	0	0	108	SL-5 years	65	22	86
Corporate Data Base Study	11	0	0	11	SL-5 years	6	2	8
Secondary Sales	17	0	0	17	SL-5 years	10	3	13
Infrastructure Plan Study Phase 1	49	0	0	49	SL-10 years	9	19	28
Generation Asset Assessment	62	0	0	62	SL- years	11	24	35
Transmission Line Asses	82	0	0	82	SL-10 years	15	31	46
Carmacks/stewart Feasibility Study	2	0	0	2	SL-5 years	1	0	1
WAF Power Flow Study	82	0	0	82	SL-5 years	10	16	26
Secondary Sales Technical Standard	28	0	0	28	SL-5 years	3	6	9
Substation Asset Assessment	85	0	0	85	SL-10 years	5	22	27
Infrastructure Plan (phase2)	125	0	0	125	SL-10 years	7	32	40
Fishway Redevelopment	15	0	0	15	SL-5 years	1	3	4
Transmission Extension	85	0	0	85	SL-10 years	4	20	24
Powerline Easement Assessment	26	0	0	26	SL-5 years	2	5	7
Wh4 Intake Seismic Assessment	43	0	0	43	SL-5 years	2	9	11
Atlin/jakes Corner Grid Extention	33	0	0	33	SL-5 years	0	7	7
Wh4 Static Exciter Assessment	21	0	0	21	SL-5 years	0	4	4
Trans Small Load Stepdown	23	0	0	23	SL-5 years	0	5	5
Infrastructure Plan Final Report	66	0	-35	31	SL-5 years	2	6	8
Mayo Dam Service Life Assessment	0	0	18	18	SL-5 years	0	3	3
Resource Plan Phase 1	0	0	205	205	SL-5 years	0	24	24
Fish Screen Assessment	0	0	1	1	SL-5 years	0	0	0
Infrastructure Plan Peer Review	0	0	188	188	SL-5 years	0	9	9
Insulation Coordination Study	0	0	21	21	SL-5 years	0	0	0
P126 Balance Of Plant Assessment	0	0	54	54	SL-5 years	0	0	0
Subtotal	1,171	0	452	1,623		261	316	577
Work In Progress (WIP):								
Insulation Coordination Study	0	21	-21	0				
Mayo Dam Service Life Assessment	0	18	-18	0		0	0	0
Infrastructure Plan Peer Review	342	9	-351	0		0	0	0
Resource Plan Phase 1	11	-3	-7	0		0	0	0
Fish Screen Assessment	0	1	-1	0		0	0	0
Carmacks-stewart Trans Line	205	-204	0	1		0	0	0
P126 Balance Of Plant Assessment	30	24	-54	0		0	0	0
Resource Plan Phase 2	0	679	0	679		0	0	0
L170 Line Assessment	0	7	0	7		0	0	0
2006 Dam Safety Upgrades	0	62	0	62		0	0	0
Carmacks-stewart Trans Line Phase 2	0	785	0	785		0	0	0
Western Copper Transmission Line	0	29	0	29		0	0	0
Minto Copper Distribution Line	0	171	0	171		0	0	0
Marsh Lake Fall Storage	0	51	0	51		0	0	0
Southern Lakes Hydrology Study	0	10	0	10		0	0	0
2006 Yukon River Downstream Icing	0	20	0	20		0	0	0
Carmacks-stewart Transmission Line Phase 3	0	138	0	138		0	0	0
Subtotal	588	1,818	-452	1,954		0	0	0
Total Feasibility	1,759	1,819	0	3,577		261	316	577
Completed Projects-relicensing:								
Aishihik License Renewal	7,590	-76	599	8,113	SL to 2019	2,104	396	2,501
Whitehorse License Renewal	96	0	0	96	SL to 2025	29	3	32
Mayo Relicensing Renewal	28	0	0	28	SL to 2025	10	1	11
Subtotal	7,715	-76	599	8,237		2,143	401	2,544
Work In Progress (WIP):								
Aishihik License Annual Payments	0	25	-25	0				
Aishihik Heritage Plan	43	6	0	49		0	0	0
Aishihik Chemi Narrows Erosion Protection	7	0	-7	0		0	0	0
Aishihik Control Structure Upgrades	55	291	-345	0		0	0	0
Aishihik Dyke Upgrades	139	12	-150	0		0	0	0
Aishihik Rocky Point Berm Study	9	1	-10	0		0	0	0
Aishihik Fish Monitoring	47	0	-47	0		0	0	0
2006 Aishihik Fish Monitoring	0	38	0	38		0	0	0
Aishihik Chemi Narrow Berm	0	12	0	12		0	0	0
Rocky Point Remediation	0	15	0	15		0	0	0
N. Aishihik Berm Final Grading	0	13	-13	0				
Subtotal	300	414	-599	115		0	0	0
Total Relicensing	8,014	338	0	8,352		2,143	401	2,544
Total Dam Safety	231	-18	0	213	SL-5 years	142	23	164
Total Deferred Study Costs	10,004	2,138	0	12,142		2,546	739	3,286
Total Deferred Downsizing	334	0	0	334	SL-7 years	215	48	263
Total Overhauls	0	0	0	0	SL-5 years	0	0	0
Rate Case (completed)								
2005 Required Revenue Hearing	932	0	0	932	SL-3 years	311	311	622
Total Deferred Costs	11,271	2,138	0	13,408		3,072	1,098	4,170
Net Deferred Costs								9,238

	Total Expenditures				Amortization Rate and Method	Accumulated Amortization		
	Dec 31	Act 2007	Actual			Dec 31	Act 2007	Actual
	2006	Additions	Transfers	2007		2006	Expenses	2007
Completed Projects-feasibility:								
Assess Mayo/keno Line	105	0	0	105	SL-5 years	72	21	93
WH4 Vibration Analysis Study	31	0	0	31	SL-5 years	24	6	30
Project Costing Feasibility	26	0	0	26	SL-5 years	19	5	24
M/D Communication Study	30	0	0	30	SL-5 years	21	6	27
Vegetation Management Study	2	0	0	2	SL-5 years	1	0	2
Physical Site Security Audit	17	0	0	17	SL-5 years	13	3	17
System Protection Study	108	0	0	108	SL-5 years	86	22	108
Corporate Data Base Study	11	0	0	11	SL-5 years	8	2	11
Secondary Sales	17	0	0	17	SL-5 years	13	3	17
Infrastructure Plan Study Phase 1	49	0	0	49	SL-10 years	28	5	33
Generation Asset Assessment	62	0	0	62	SL-10 years	35	6	41
Transmission Line Assessment	82	0	0	82	SL-10 years	46	8	55
Carmacks/stewart Feasibility Study	2	0	0	2	SL-5 years	1	0	2
WAF Power Flow Study	82	0	0	82	SL-5 years	26	16	42
Secondary Sales Technical Standard	28	0	0	28	SL-5 years	9	6	15
Substation Asset Assessment	85	0	0	85	SL-10 years	27	8	35
Infrastructure Plan (phase2)	125	0	0	125	SL-10 years	40	13	52
Fishway Redevelopment	15	0	0	15	SL-5 years	4	3	7
Transmission Extension	85	0	0	85	SL-10 years	24	8	32
Powerline Easement Assessment	26	0	0	26	SL-5 years	7	5	12
WH4 Intake Seismic Assessment	43	0	0	43	SL-5 years	11	9	19
Infrastructure Plan Final Report	31	0	0	31	SL-5 years	8	6	15
Atlin/jakes Corner Grid Extension	33	0	0	33	SL-5 years	7	7	13
WH4 Static Exciter Assessment	21	0	0	21	SL-5 years	4	4	9
Trans Small Load Stepdown	23	0	0	23	SL-5 years	5	5	9
Mayo Dam Service Life Assessment	18	0	0	18	SL-5 years	3	4	7
Resource Plan Phase 1	205	0	0	205	SL-5 years	24	41	65
Fish Screen Assessment	1	0	0	1	SL-5 years	0	0	0
Infrastructure Plan Peer Review	188	0	0	188	SL-5 years	9	38	47
Insulation Coordination Study	21	0	0	21	SL-5 years	0	4	4
P126 Balance Of Plant Assessment	54	0	0	54	SL-5 years	0	11	11
Resource Plan Phase 2	0	0	229	229	SL-5 years	0	0	0
L170 Line Assessment	0	0	214	214	SL-5 years	0	0	0
2006 Dam Safety Upgrades	0	0	27	27	SL-5 years	0	0	0
Wareham Spillway Wall Raise	0	0	9	9	SL-5 years	0	0	0
Marsh Lake Fall Storage	0	0	63	63	SL-5 years	0	0	0
2006 Yukon River Downstream Icing	0	0	147	147	SL-5 years	0	0	0
Customer Billing System Replacement	0	0	52	52	SL-5 years	0	0	0
Subtotal	1,623	0	739	2,362		577	276	853
Work In Progress (WIP):								
Carmacks-Stewart Transmission Line	1	-1	0	0		0	0	0
Resource Plan Phase 2	679	-450	-229	0		0	0	0
L170 Line Assessment	7	207	-214	0		0	0	0
2006 Dam Safety Upgrades	62	74	-27	109		0	0	0
Carmacks-stewart Transmission Line Phase 2	785	-785	0	0		0	0	0
Western Copper Transmission Line	29	-3	0	25		0	0	0
Minto Copper Distribution Line	171	-171	0	0		0	0	0
Marsh Lake Fall Storage	51	11	-63	0		0	0	0
Southern Lakes Hydrology Study	10	90	0	100		0	0	0
2006 Yukon River Downstream Icing	20	127	-147	0		0	0	0
Wareham Spillway Wall Raise	0	9	-9	0		0	0	0
Customer Billing System Replacement	0	52	-52	0		0	0	0
Carmacks-stewart Trans Line Phase 3	138	-138	0	0		0	0	0
Hydro Storage & Generation Pre-feasibility	0	501	0	501		0	0	0
Wareham Intake Rock Face Assessmt	0	1	0	1		0	0	0
Minto Mine Ppa	0	768	0	768		0	0	0
Mayo Wareham Liquefaction Analysis	0	99	0	99		0	0	0
Subtotal	1,953	388	-739	1,603		0	0	0
Total Feasibility	3,577	388	0	3,965		577	276	853
Completed Projects-relicensing:								
Aishihik License Renewal	8,113	0	274	8,386	SL to 2019	2,501	448	2,948
Whitehorse License Renewal	96	0	0	96	SL to 2025	32	3	35
Mayo Relicensing Renewal	28	0	0	28	SL to 2025	11	1	12
Subtotal	8,237	0	274	8,511		2,544	452	2,996
Work In Progress (WIP):								
Aishihik Heritage Plan	49	4	0	52		0	0	0
Aishihik License Annual Payments	0	25	0	25		0	0	0
2006 Aishihik Fish Monitoring	38	1	-39	0		0	0	0
Aishihik Chemi Narrow Berm	12	1	0	14		0	0	0
Rocky Point Remediation	15	191	-206	0		0	0	0
2007 Aishihik Fish Monitoring	0	82	0	82		0	0	0
Aishihik Control Upgrade	0	9	-9	0		0	0	0
North Aishihik Boat Launch Riprap	0	19	-19	0		0	0	0
Subtotal	115	332	-274	173		0	0	0
Total Relicensing	8,352	332	0	8,684		2,544	452	2,996
Total Dam Safety	213	0	0	213	SL-5 years	164	22	186
Total Deferred Study Costs	12,141	720	0	12,861		3,286	750	4,035
Total Deferred Downsizing	334	0	0	334	SL-7 years	263	48	311
Total Overhauls	0	0	0	0	SL-5 years	0	0	0
Rate Case (completed)								
2005 Required Revenue Hearing	932	0	0	932	SL- years	622	311	932
Work In Progress(wip):								
Yub 2007-7 & 9 - Resource Plan	643	0	0	643		0	0	0
Yub 2007-7 & 9 - PPA Review	243	0	0	243		0	0	0
Yub 2007-8 - Part 3 Hearing	185	0	0	185		0	0	0
Subtotal	1,071	0	0	1,071		0	0	0
Total Rate Case	2,003	0	0	2,003		622	311	932
Total Deferred Costs	14,479	720	0	15,199		4,170	1,108	5,278
Net Deferred Costs								9,921

	Total Expenditures				Amortization Rate and Method	Accumulated Amortization		
	Dec 31	FRCST 2008		Forecast		Dec 31	FRCST 2008	Forecast
	2007	Additions	Transfers	2008		2007	Expenses	2008
Completed Projects-feasibility:								
Assess Mayo/keno Line	105	0	0	105	SL-5 years	93	11	105
Wh4 Vibration Analysis Study	31	0	0	31	SL-5 years	30	2	31
Project Costing Feasibility	26	0	0	26	SL-5 years	24	2	26
M/D Communication Study	30	0	0	30	SL-5 years	27	3	30
Infrastructure Plan Study Phase 1	49	0	0	49	SL-10 years	33	5	37
Generation Asset Assessment	62	0	0	62	SL-10 years	41	6	47
Transmission Line Assessment	82	0	0	82	SL-10 years	55	8	63
Carmacks/stewart Feasibility Study	2	0	0	2	SL-5 years	2	0	2
WAF Power Flow Study	82	0	0	82	SL-5 years	42	16	58
Secondary Sales Technical Standard	28	0	0	28	SL-5 years	15	6	20
Substation Asset Assessment	85	0	0	85	SL-10 years	35	8	44
Infrastructure Plan (phase2)	125	0	0	125	SL-10 years	52	13	65
Fishway Redevelopment	15	0	0	15	SL-5 years	7	3	10
Transmission Extension	85	0	0	85	SL-10 years	32	8	41
Powerline Easement Assessment	26	0	0	26	SL-5 years	12	5	17
Wh4 Intake Seismic Assessment	43	0	0	43	SL-5 years	19	9	28
Infrastructure Plan Final Report	31	0	0	31	SL-5 years	15	6	21
Atlin/Jakes Corner Grid Extension	33	0	0	33	SL-5 years	13	7	20
Wh4 Static Exciter Assessment	21	0	0	21	SL-5 years	9	4	13
Trans Small Load Stepdown	23	0	0	23	SL-5 years	9	5	14
Mayo Dam Service Life Assessment	18	0	0	18	SL-5 years	7	4	10
Resource Plan Phase 1	205	0	0	205	SL-5 years	65	41	107
Fish Screen Assessment	1	0	0	1	SL-5 years	0	0	0
Infrastructure Plan Peer Review	188	0	0	188	SL-5 years	47	38	84
Insulation Coordination Study	21	0	0	21	SL-5 years	4	4	8
P126 Balance Of Plant Assessment	54	0	0	54	SL-5 years	11	11	22
Resource Plan Phase 2	229	0	0	229	SL-5 years	0	46	46
L170 Line Assessment	214	0	0	214	SL-5 years	0	43	43
2006 Dam Safety Upgrades	27	0	0	27	SL-5 years	0	5	5
Wareham Spillway Wall Raise	9	0	0	9	SL-5 years	0	2	2
Marsh Lake Fall Storage	63	0	0	63	SL-5 years	0	13	13
2006 Yukon River Downstream Icing	147	0	0	147	SL-5 years	0	29	29
Customer Billing System Replacement	52	0	0	52	SL-5 years	0	10	10
Minto Mine Ppa	0	0	776	776	SL-12 years	0	16	16
Southern Lakes Hydrology Study	0	0	160	160	SL-5 years	0	0	0
Hydro Storage & Generation Pre-feasibility	0	0	631	631	SL-5 years	0	53	53
Mayo Wareham Liquefaction Analysis	0	0	103	103	SL-5 years	0	10	10
2006 Dam Safety Upgrades	0	0	111	111	SL-5 years	0	11	11
Aishihik Runner Up-Rate Study	0	0	110	110	SL-5 years	0	0	0
Aishihik River Icing Study	0	0	59	59	SL-5 years	0	1	1
Wareham Dam Reliability Study	0	0	55	55	SL-5 years	0	0	0
Wareham Intake Rock Face Assessmt	0	0	101	101	SL-5 years	0	5	5
Subtotal	2,209	0	2,106	4,314		699	468	1,168
Work In Progress (WIP):								
Aishihik Runner Up-rate Study	0	110	-110	0		0	0	0
Aishihik River Icing Study	0	59	-59	0		0	0	0
Wareham Dam Reliability Study	0	55	-55	0		0	0	0
2006 Dam Safety Upgrades	109	2	-111	0		0	0	0
Western Copper Transmission Line	25	0	0	25		0	0	0
Southern Lakes Hydrology Study	100	60	-160	0		0	0	0
Hydro Storage & Generation Pre-feasibility	501	130	-631	0		0	0	0
Wareham Intake Rock Face Assessmt	1	100	-101	0		0	0	0
Minto Mine Ppa	768	8	-776	0		0	0	0
Mayo Wareham Liquefaction Analysis	99	4	-103	0		0	0	0
Mayo B	0	1,700	0	1,700		0	0	0
Other Generation Feasibilities	0	800	0	800		0	0	0
Investigate International Financial Reporting Standards	0	46	0	46		0	0	0
Subtotal	1,603	3,074	-2,106	2,571		0	0	0
Total Feasibility	3,811	3,074	0	6,885		699	468	1,168
Completed Projects-relicensing:								
Aishihik License Renewal	8,386	0	340	8,726	SL to 2019	2,948	469	3,417
Whitehorse License Renewal	96	0	0	96	SL to 2025	35	3	39
Mayo Relicensing Renewal	28	0	0	28	SL to 2025	12	1	13
Whitehorse Air Emissions	0	0	76	76		0	0	0
Subtotal	8,511	0	416	8,926		2,996	473	3,469
Work In Progress (WIP):								
Aishihik License Annual Payments	25	0	-25	0		0	0	0
Aishihik Heritage Plan	52	10	-62	0		0	0	0
Aishihik Chemi Narrow Berm	14	1	-14	0		0	0	0
2007 Aishihik Fish Monitoring	82	26	-108	0		0	0	0
Aishihik Heritage Mitigation-update	0	25	-25	0		0	0	0
Aishihik Fish-monitoring	0	80	-80	0		0	0	0
Aishihik License Annual Payments	0	25	-25	0		0	0	0
Whitehorse Air Emissions	0	76	-76	0		0	0	0
Subtotal	173	243	-416	0		0	0	0
Total Relicensing	8,684	243	0	8,926		2,996	473	3,469
Total Dam Safety	213	0	0	213	SL-5 years	186	13	200
Total Deferred Study Costs	12,708	3,317	0	16,025		3,882	955	4,836
Total Deferred Downsizing	334	0	0	334	SL-7 years	311	24	334
Total Overhauls	0	0	0	0	SL-5 years	0	0	0
Rate Case (completed)								
Yub 2007-7 & 9 - Resource Plan	643	0	0	643	SL-10 years	0	64	64
Yub 2007-7 & 9 - Ppa Review	243	0	0	243	SL-12 years	0	20	20
Yub 2007-8 - Part 3 Hearing	185	0	0	185	SL-45 years	0	4	4
Gra Phase 1 Revenue Review	0	800	0	800	SL-2 years	0	400	400
Total Rate Case	1,071	800	0	1,871		0	489	489
Total Deferred Costs	14,113	4,117	0	18,230		4,192	1,467	5,659
Net Deferred Costs								12,571

	Total Expenditures				Amortization Rate and Method	Accumulated Amortization		
	Dec 31	FRCST 2009		Forecast		Dec 31	FRCST 2009	Forecast
	2008	Additions	Transfers	2009		2008	Expenses	2009
Completed Projects-feasibility:								
Infrastructure Plan Study Phase 1	49	0	0	49	SL-10 years	37	5	42
Generation Asset Assessment	62	0	0	62	SL-10 years	47	6	54
Transmission Line Assessment	82	0	0	82	SL-10 years	63	8	71
Carmacks/Stewart Feasibility Study	2	0	0	2	SL-5 years	2	0	2
WAF Power Flow Study	82	0	0	82	SL-5 years	58	16	75
Secondary Sales Technical Standard	28	0	0	28	SL-5 years	20	6	26
Substation Asset Assessment	85	0	0	85	SL-10 years	44	8	52
Infrastructure Plan (phase2)	125	0	0	125	SL-10 years	65	13	77
Fishway Redevelopment	15	0	0	15	SL-5 years	10	3	13
Transmission Extension	85	0	0	85	SL-10 years	41	8	49
Powerline Easement Assessment	26	0	0	26	SL-5 years	17	5	22
Wh4 Intake Seismic Assessment	43	0	0	43	SL-5 years	28	9	36
Infrastructure Plan Final Report	31	0	0	31	SL-5 years	21	6	27
Atlin/Jakes Corner Grid Extension	33	0	0	33	SL-5 years	20	7	26
Wh4 Static Exciter Assessment	21	0	0	21	SL-5 years	13	4	17
Trans Small Load Stepdown	23	0	0	23	SL-5 years	14	5	18
Mayo Dam Service Life Assessment	18	0	0	18	SL-5 years	10	4	14
Resource Plan Phase 1	205	0	0	205	SL-5 years	107	41	148
Fish Screen Assessment	1	0	0	1	SL-5 years	0	0	1
Infrastructure Plan Peer Review	188	0	0	188	SL-5 years	84	38	122
Insulation Coordination Study	21	0	0	21	SL-5 years	8	4	12
P126 Balance Of Plant Assessment	54	0	0	54	SL-5 years	22	11	32
Resource Plan Phase 2	229	0	0	229	SL-5 years	46	46	91
L170 Line Assessment	214	0	0	214	SL-5 years	43	43	86
2006 Dam Safety Upgrades	27	0	0	27	SL-5 years	5	5	11
Wareham Spillway Wall Raise	9	0	0	9	SL-5 years	2	2	3
Marsh Lake Fall Storage	63	0	0	63	SL-5 years	13	13	25
2006 Yukon River Downstream Icing	147	0	0	147	SL-5 years	29	29	59
Customer Billing System Replacement	52	0	0	52	SL-5 years	10	10	21
Minto Mine Ppa	776	0	0	776	SL-12 years	16	65	81
Southern Lakes Hydrology Study	160	0	0	160	SL-5 years	0	32	32
Hydro Storage & Generation Pre-feasibility	631	0	0	631	SL-5 years	53	126	179
Mayo Wareham Liquefaction Analysis	103	0	0	103	SL-5 years	10	21	31
2006 Dam Safety Upgrades	111	0	0	111	SL-5 years	11	22	33
Aishihik Runner Up-Rate Study	110	0	0	110	SL-5 years	0	22	22
Aishihik River Icing Study	59	0	0	59	SL-5 years	0	12	12
Wareham Dam Reliability Study	55	0	0	55	SL-5 years	0	11	11
Wareham Intake Rock Face Assessmt	101	0	0	101	SL-5 years	5	20	25
Diesel Seismic Study - Dawson, Whitehorse, Faro	0	0	70	70	SL-5 years	0	0	0
Customer Billing System	0	0	75	75	SL-5 years	0	0	0
Mayo Lake Dam Assessment	0	0	100	100	SL-5 years	0	0	0
Subtotal	4,123	0	245	4,368		975	685	1,660
Work In Progress (WIP):								
Diesel Seismic Study - Dawson, Whitehorse, Faro	0	70	-70	0		0	0	0
Customer Billing System	0	75	-75	0		0	0	0
Mayo Lake Dam Assessment	0	100	-100	0		0	0	0
Western Copper - Grid Connection Yesaa & Ppa	25	1,000	0	1,025		0	0	0
Western Copper - Grid Connection Yesaa & Ppa (cust Contributic	0	-1,000	0	-1,000		0	0	0
Mayo B	1,700	6,500	0	8,200		0	0	0
CSTP Stage II	0	1,000	0	1,000		0	0	0
Other Generation Feasibilities	800	6,800	0	7,600		0	0	0
Alexco Mine - Feasibility & Permitting	0	300	0	300		0	0	0
Alexco Mine - Customer Contribution	0	-300	0	-300		0	0	0
Feasibility Studies And Engineering Assesments	0	50	0	50		0	0	0
Investigate International Financial Reporting Standards	46	106	0	151		0	0	0
Subtotal	2,571	14,701	-245	17,026		0	0	0
Total Feasibility	6,694	14,701	0	21,394		975	685	1,660
Completed Projects-relicensing:								
Aishihik License Renewal	8,726	0	130	8,856	SL to 2019	3,417	491	3,908
Whitehorse License Renewal	96	0	0	96	SL to 2025	39	3	42
Mayo Relicensing Renewal	28	0	0	28	SL to 2025	13	1	14
Whitehorse Air Emissions	76	0	0	76	SL-3 years	0	25	25
Subtotal	8,926	0	130	9,056		3,469	520	3,989
Work In Progress (WIP):								
Aishihik Fish-monitoring	0	80	-80	0		0	0	0
Aishihik Heritage Mitigation-update	0	25	-25	0		0	0	0
Aishihik License Annual Payments	0	25	-25	0		0	0	0
Subtotal	0	130	-130	0		0	0	0
Total Relicensing	8,926	130	0	9,056	SL-licence	3,469	520	3,989
Total Dam Safety	213	150	0	363	SL-5 years	200	13	213
Total Deferred Study Costs	15,833	14,981	0	30,813		4,643	1,219	5,862
Total Deferred Downsizing	0	0	0	0	SL-7 years	0	0	0
Dawson Diesel 1 Overhaul	0	121	0	121	SL-5 years	0	0	0
Total Overhauls	0	121	0	121		0	0	0
Rate Case (completed)								
Gra Phase 1 Revenue Review	800	0	0	800	SL-2 years	400	400	800
Yub 2007-7 & 9 - Resource Plan	643	0	0	643	SL-10 years	64	64	129
Yub 2007-7 & 9 - Ppa Review	243	0	0	243	SL-12 years	20	20	41
Yub 2007-8 - Part 3 Hearing	185	0	0	185	SL-45 years	4	4	8
Total Rate Case	1,871	0	0	1,871		489	489	977
Total Deferred Costs	17,704	15,102	0	32,805		5,132	1,707	6,839
Net Deferred Costs								25,966

TAB 6
BOARD DIRECTIVES

6.0 BOARD DIRECTIVES

This Tab reviews directives contained in Board Decisions since the submission of the 2005 Required Revenues and Related Matters application, and (where relevant) Yukon Energy's response.

In addition to the directives issued since 2005, Order 1996-7 directed YEC and YECL to design a rate rebalancing program that would target all customer class revenue/cost ratios of 90% to 110% over a ten year period.

- In Yukon Energy's 2005 Required Revenues and Related Matters Application, Yukon Energy noted that no action had been taken on the directive as of the date of filing.
- The Board addressed the issue during the 2005 hearing in Order 2005-1.
- In response, YEC/YECL jointly filed a required report with the Board in August 2005 that provided information on the revenue to cost ratios by customer class for both companies using the most recent cost of service allocation study, including comments on the implementation of a rate shift program over 10 years.
- Yukon Energy and YECL have each filed revenue requirement applications with the Board in 2008 for the test years 2008 and 2009. These submissions do not address cost of service or rate design work related to any rate shift program or rate rebalancing as between customer classes. Such matters will be addressed, as required by the Board, in future submissions following consideration of the current revenue requirement applications.¹

6.1 ORDER 2005-12

On December 13, 2004, Yukon Energy filed with the Yukon Utilities Board an Application for 2005 Required Revenues and Related Matters requesting approvals to establish a 2005 revenue requirement as well as changes to Secondary Energy Rate Schedules effective January 1, 2005, for interruptible surplus hydro generation. The 2005 Revenue Requirements were approved subject to Board ordered

¹ See further explanation and information; see Tab 1, Section 1.1.1 of this Application.

adjustments, and Yukon Energy re-filed amended schedules from Tab 7 which were approved by the Board in Order 2005-17.

Order 2005-12 resulted in a number of specific Board directions. Most of these directives related to 2005 revenue requirements, and accordingly were incorporated into the revised refiling approved in Order 2005-17. The remaining outstanding directives are noted below:

Directive #4

- The Board approves the YEC proposal to record an amount equal to any interest forgiven on the Mayo Dawson Note, less any portion that is used to cover costs incurred to supply power to Dawson. The YEC proposal was to assign this amount to the IST; however, due to the IST being denied, YEC is directed to establish a Rate Base deferral account to record the amount.*

No interest was forgiven on the Mayo Dawson note in the period 2005 to 2007. Accordingly no deferral account was established.

Directive #15

- The Board approves total capital expenditures related to the Mayo-Dawson transmission line in Rate Base in the amount of \$29,046,000 as of October 1, 2003. The mid-year Rate Base impact for 2005 will be \$29,046,000, less applicable depreciation expense as of the in-service date of October 1, 2003. To the extent that further costs are incurred on the Mayo Dawson line due to the claims and counter claims between Chant Construction and YEC, those costs would similarly be disallowed. Cost recoveries from Chant Construction are to be recorded in an interest-bearing deferral account for review and disposition by the Board.*

Yukon Energy has recorded all further project-related costs, including all costs associated with the claims process, outside of rate base and revenue requirement. The claims process with Chant Construction is now complete, and there were no recoveries to Yukon Energy. Accordingly, no interest bearing account has been established.

Directive #18

- The Board requires that YEC discontinue recording an annual provision for FRSR effective January 1, 2005. The Board orders a variance from Generally Accepted Accounting Principles and requires that the December 31, 2004, balance in the FRSR account remain as a liability to be utilized for dismantling costs that are incurred in 2005 and future years. The Board requires YEC to inform Intervenors and stakeholders when the balance of the FRSR liability account reaches \$2.0 million.*

As shown in Tab 7, the balance in the FRSR liability remains well above \$2.0 million. In future, Yukon Energy will inform the Board and stakeholders when the balance reaches \$2.0 million.

6.2 ORDER 2007-5 – MINTO POWER PURCHASE AGREEMENT

On February 9, 2007, Yukon Energy filed the Minto PPA for review and approval by the Board.

Order 2007-5 denied the Minto Power Purchase Agreement (“PPA”) as filed, and directed Yukon Energy to file a revised PPA Agreement by May 31, 2007. On May 14, 2007, Yukon Energy subsequently reached an agreement with Minto Explorations to amend the PPA to incorporate the changes desired by the Board. In Board Order 2007-6 (dated May 25, 2007) the Board approved the PPA as amended on May 14, 2007 and noted that it had “reviewed the filing and agrees that it meets the intent of Board Order 2007-5.”

Outstanding matters related to Board Order 2007-5 are as follows:

Board Finding 1: Firm Mine Rate

- Until such time as a decision is rendered in the next GRA, the board will accept Rate 39 on an interim basis as proposed by YEC.*

Board Order 2007-6 acknowledged the fact that the Yukon Government would be fixing Rate Schedule 39 “as required by the amended PPA”. This was done in OIC 2007/94. Yukon Energy filed an application with the Board August 25, 2008 for approval of this Rate Schedule.

Board Finding 3: COS Models

- The Board reiterates its earlier direction that YEC and YECL provide a complete COS study and rate design with their next GRA. The COS is to include updated studies on allocators and to look at the feasibility of direct assigning assets, where applicable to certain rate classes. Further the Board expects to see justification on the allocation of transmission assets. For the next GRA the Board directs both YEC and YECL to provide their electronic COS models and to distinctly show costs as being related to generation, transmission, and distribution. Further, generation costs are to be separated based on each generation type (i.e., hydro, diesel, wind etc). This will enable testing of costs to serve all rate classes, including Rate 35.*

As reviewed in Tab 1 (sections 1.1.3 and 1.1.4), YEC and YECL responded in August 2007 to the Board in part on these matters, indicating proposed timing for filing the current GRAs and the need to address separately (in timing for both preparation and for review) revenue requirements for each utility ("Phase I" matters) versus a consolidated filing on rate design and cost of service for each function and rate class ("Phase II" matters) related to the YEC/YECL consolidated rate revenue requirement and OIC 1995/90 directives. Yukon Energy and YECL committed to work together as required, after the current GRA Phase I filings, to file a cost of service study for a separate future "Phase II" proceeding dealing with cost of service ("COS") matters. The above directive focuses on specific information to be addressed in such a COS study, and YEC/YECL have yet to determine all of the matters that can be effectively addressed in such a future filing.

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

As noted in this Application, in light of the rate design issues now arising (see Tab 4, particularly section 4.4), and the referenced OIC rate directive, Yukon Energy is currently

proposing that, as a first priority, future joint YEC/YECL attention be directed as soon as practicable at identifying and assessing rate design options for General Service rate classes to promote economy and efficiency in accordance with OIC 1995/90. Yukon Energy further proposes that joint YEC/YECL action to prepare a COS study be assigned a lower priority, with delayed timing as appropriate.

Board Finding 5: Rate 35 Audit and Control Measures and Board Finding 6: Rate 35 Amendment

- ***Board Finding 5: Should Minto pursue Rate 35, proposed audit and control measures and reporting requirements must be established between YEC and Minto, and then YEC is to file these with the Board. YEC is not to implement Rate Schedule 35 until such approval has been granted; and***
- ***Board Finding 6: The Board directs YEC to amend the wording for Rate Schedule 35 when such an opportunity arises.²***

As noted in Tab 4 (Section 4.2.2), Minto Explorations has yet to pursue service under Rate Schedule 35, nor to provide proposed audit and control measures. Board Finding 5 was fully adopted by Yukon Energy and Minto Explorations in the PPA as amended May 14, 2007 (approved by Order 2007-6).

Yukon Energy will amend the wording of the rate schedule to be more “generic”, as directed in Board Finding 6, when and if the opportunity presents itself for potential use of this schedule by other new industrial customers. This is not anticipated within the test years or in the period thereafter so long as hydro (or equivalent) generation surpluses are not available to supply such secondary energy sales.

² The Board noted at page 8 of Appendix A to Order 2007-5 that the terminology for Rate Schedule 35 should be amended if and when other industrial loads present opportunities for use of such a rate and stated that “Generic wording, instead of wording specific to one customer, is a preferred approach for rate schedules. Therefore, the Board directs YEC to amend the wording for Rate Schedule 35 at such time as the opportunity arises for other industrial loads to make use of Rate 35.”

Board Finding 10: Maximum Utility Investment

- The Board directs both YEC and YECL to review and refine their investment policies for industrial customers and to include recommendations within their next GRA, which is expected to be filed by October 31, 2007. The policies should clarify to potential industrial customers what the utility will invest in new facilities and provide consistency in the approach when construction facilities to serve new loads.*

Yukon Energy is continuing to examine options, based on the current PPA experience with Minto, where joint partnership of industry, Yukon Energy and the Yukon Government can best enable development of critical new bulk power supply infrastructure in a cost effective manner as regards all Yukon ratepayers. In this regard, the current Electric Service Regulations (ESRs) as amended by the Board in the 2005 YEC hearing, provide direction on the maximum investment that each utility can consider with regard to connecting new loads. The Board has made recommendations to the Yukon Government with regard to consideration of industrial loads in capacity planning criteria, as well as other resource planning matters, and action or responses on these recommendations has not yet occurred from the Yukon Government.

Maximum Investment Policies will be reviewed as part of any future YEC/YECL proceeding addressing the ESRs.

Board Finding 15: Minto Diesel Units

- The Board does not accept the purchase of the Diesel Units as part of the PPA. YEC is free to purchase the units; however, at this time the Board cannot provide any assurance to YEC that the units would be approved as an addition to rate base. However, it is open to YEC to develop an appropriate business case supporting the need for the Diesel Units and include it for consideration in its next GRA.*

The business case of the Minto diesel units is reviewed under Tab 5.

Board Finding 19: Ratchet and Demand Rate Issues

- ***Ratchet issues and changes to demand rate should be addressed in YEC's next GRA.***

Ratchet and Demand issues will be reviewed as part of any future YEC/YECL Phase II proceeding dealing with rate design matters.

6.3 BOARD ORDERS 2007-7, 2007-8, 2007-9 AND 2008-1

Cost awards were determined subsequent to the Resource Plan hearing, the PPA hearing and the Part 3 hearing process. In each of Order 2007-7, 2007-8, 2007-9 and 2008-1 the Board provided the following directive related to hearing cost awards:

- **All hearing costs shall be recorded in a Hearing Reserve Account. YEC shall include in its next GRA a proposal as to the appropriate dispensation of the Hearing Reserve Account and a proper allocation of the costs in the account to the different rate classes.**

In response to Board Orders 2007-7, 2007-8, 2007-9 and 2008-1, costs noted in Table 6.1 have been included into a hearing reserve account as noted in Tab 5 Amortized Costs, Tables 5.6 and 5.7. YEC is proposing to amortize the Resource Plan hearing costs over 10 years, PPA hearing costs over 12 years and CSTP hearing costs over 45 years, as set out in Tab 5. Allocation of costs in the account to different rate classes will be dealt with separately as part of a Phase II proceeding dealing with a Cost of Service Study.

**Table 6.1
Cost Awards 2007-7, 2007-8, 2007-9 and 2008-1**

	Resource Plan Costs	PPA Costs	Part 3 Costs
Yukon Energy	451,091.29	168,506.24	117,681.96
YECL	6,087.36	7,433.16	350.01
UCG	7,733.87	2,667.64	10,637.11
UCG Consultant	5,386.50	3,276.00	
UCG Legal Counsel	19,924.50	6,783.00	
YCS	2,747.50	822.50	341.25
Peter Percival	98.00	2,756.25	
Government of Yukon	151,922.02	51,364.30	56,322.00
Total	644,991.04	243,609.09	185,332.33

1 Note: This Table includes cost awards for GST which are not included in Table 5.6 and 5.7.

TAB 7
FINANCIAL SCHEDULES

Yukon Energy Corporation

September 2008 Filing

Schedule Index

1	Computation of Rate Base
2	Computation of Allowance for Working Capital
2A	Effect of GST on Working Capital
3	Continuity Schedule of Property, Plant and Equipment
4A	Cost of Capital Calculation - 2005 - 2007 Actuals
4B	Cost of Capital Calculation - 2008 Forecast
4C	Cost of Capital Calculation - 2009 Forecast
5	Utility Revenue Requirement
6	Statement of Earnings
7	Statement of Retained Earnings
8	Balance Sheet
9	Financing Summary
10	Reconciliation of Utility Income to Net Earnings
11	Summary of Customers, Energy Sales and Revenues
12	Summary of Operating and Maintenance Expenses
13	Summary of Cost of Long - Term Debt

Yukon Energy Corporation
Computation of Rate Base
(\$000s)

Schedule 1
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Property, Plant and Equipment									
2	Year end balance	S.3 L.5	225,081	222,115	226,573	236,853	277,842	277,842	286,660	286,660
	Deduct:									
3	Accumulated depreciation (note 1)	S.3 L.10	71,749	69,718	73,664	78,492	83,097	83,097	89,424	89,424
4	Construction-in-progress	S.3 L.11	410	2,369	1,253	7,552	2,571	1,500	5,446	4,375
5	Disallowed assets	S.3 L.12	200	200	200	200	200	200	200	200
6	Miscellaneous reserves	S.3 L.13	9,896	9,974	8,879	8,354	8,084	8,084	7,814	7,814
7	Total deductions		82,255	82,261	83,996	94,598	93,951	92,881	102,883	101,812
	Add:									
8	Deferred study costs (note 2)	S.3 L.15	6,959	7,458	8,857	8,827	11,189	11,189	24,951	24,951
9	Less: Studies in Progress (note 3)	S.3 L.16				(2,847)	(2,571)	(2,571)	(17,026)	(17,026)
10	Other deferred costs (note 4)	S.3 L.17	118	119	71	23	(0)	(0)	121	121
11	Accum. Disallowed depreciation	S.3 L.18	62	62	66	70	74	74	78	78
12	Total additions		7,139	7,639	8,994	6,074	8,692	8,692	8,124	8,124
	Net plant in Service									
13	Current year-end balance	S.3 L.20	149,965	147,493	151,571	148,329	192,582	193,653	191,900	192,971
14	Previous year-end balance		147,023	147,023	147,493	151,571	148,329	148,329	192,582	193,653
15	Total		296,988	294,516	299,064	299,899	340,911	341,982	384,482	386,624
16	Mid-year balance		148,494	147,258	149,532	149,950	170,456	170,991	192,241	193,312
18	Mid-year rate case expense		473	473	466	690	1,070	1,226	1,070	1,137
19	Working capital	S.2 L.9	3,213	3,146	2,974	2,962	3,108	3,122	3,182	3,197
20	Adjustments for CSTP (Note 5)						(928)	(928)		
21	Gross Rate Base		152,179	150,877	152,971	153,602	173,705	174,411	196,493	197,646
	Deduct:									
	Contributions for extensions									
22	Current year-end balance		13,972	13,948	14,681	19,347	51,466	51,466	55,366	55,366
23	Contributions in WIP		-	118	209	4,674	1,500	1,500	5,000	5,000
24	Current year-end balance in-service		13,972	13,830	14,472	14,673	49,966	49,966	50,366	50,366
25	Accumulated amortization of contributions		2,170	2,150	2,495	2,852	3,389	3,389	4,480	4,480
26	Net current year-end balance in-service		11,802	11,680	11,977	11,821	46,576	46,576	45,886	45,886
27	Previous year-end balance		10,971	10,971	11,680	11,977	11,821	11,821	46,576	46,576
28	Total		22,773	22,651	23,657	23,798	58,397	58,397	92,462	92,462
29	Mid-year balance		11,386	11,325	11,828	11,899	29,199	29,199	46,231	46,231
30	Net Rate Base	S.5 L.1	140,793	139,552	141,143	141,703	144,506	145,212	150,262	151,415

Note 1: Including Reserve for Future Removal and Site Restoration

Note 2: Planning and Study costs, Relicensing and Dam Safety costs.

Note 3: Prior to 2007, studies in progress were not tracked for the purposes of determining ratebase

Note 4: Deferred Overhauls and deferred downsizing.

Note 5: CSTP is assumed in service on Oct. 1st, 2008, net ratebase impacts is adjusted downward \$928k based on 91 services days compared to typical inservice mid-year ratebase impact of \$1,857k.

Yukon Energy Corporation
Computation of Allowance for Working Capital
(\$000s)

Schedule 2
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Operating and maintenance	S.5 L.5	10,939	11,344	11,178	12,116	12,421	12,628	13,230	13,489
2	Taxes other than income	S.5 L.6	250	246	249	256	256	256	256	256
3	Non-allowable expenses		(435)	(272)	(57)	(83)	(85)	(85)	(85)	(85)
4	Cash operating expenses		10,754	11,318	11,370	12,288	12,592	12,799	13,401	13,660
5	27/365 in 2005		796	837	841	909	931	947	991	1,010
6	Inventory (Three year average)		2,546	2,442	2,264	2,164	2,211	2,211	2,279	2,279
7	GST Impact on working capital	S.2A L.11	(129)	(133)	(131)	(111)	(35)	(36)	(88)	(92)
8	Working capital	S.1 L.19	3,213	3,146	2,974	2,962	3,108	3,122	3,182	3,197

Yukon Energy Corporation
Effect of GST on Working Capital
(\$000s)

Schedule 2A
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Expenses subject to GST		10,816	10,394	10,043	15,571	48,161	49,168	27,425	27,683
2	GST Rate		7.00%	7.00%	6.50%	6.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		757	728	652	934	2,408	2,458	1,371	1,384
4	Day Factor		14	14	14	14	14	14	14	14
5	Recoverable portion of GST impact		29	28	25	36	92	94	53	53
6	Revenue subject to GST		25,744	26,124	27,398	27,899	28,991	29,576	32,082	32,933
7	GST blended rate		6.41%	6.41%	5.95%	5.49%	4.58%	4.58%	4.58%	4.58%
8	GST payable		1,650	1,675	1,630	1,533	1,327	1,354	1,469	1,508
9	Day factor		35	35	35	35	35	35	35	35
10	Payable portion of GST impact		158	161	156	147	127	130	141	145
11	Net impact of GST on working capital	S.2 L.7	(129)	(133)	(131)	(111)	(35)	(36)	(88)	(92)

Yukon Energy Corporation
Continuity Schedule of Property, Plant and Equipment
(\$000s)

Schedule 3
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Property, Plant and Equipment									
2	Balance at beginning of year		219,526	219,526	222,115	226,573	236,853	236,853	277,842	277,842
3	Increases to PPE (Table 5.1)	S.9 L.2	5,555	4,300	4,687	10,280	42,132	42,132	9,078	9,078
4	Retirements, disposals and adjustments (note 1)		-	(1,711)	(229)	-	(1,143)	(1,143)	(260)	(260)
5	Balance at end of year	S.1 L.2	225,081	222,115	226,573	236,853	277,842	277,842	286,660	286,660
6	Accumulated depreciation (including Future Removal Reserve)									
7	Balance at beginning of year		66,482	66,482	69,718	73,664	78,492	78,492	83,097	83,097
8	Depreciation expense	S.6 L.7	5,267	5,083	5,132	5,302	5,747	5,747	6,587	6,587
9	Retirements, disposals and adjustments (note 1)		-	(1,847)	(1,186)	(473)	(1,143)	(1,143)	(260)	(260)
10	Balance at end of year		71,749	69,718	73,664	78,492	83,097	83,097	89,424	89,424
	Deduct:									
11	Construction-in-progress	S.1 L.4	410	2,369	1,253	7,552	2,571	1,500	5,446	4,375
12	Disallowed assets	S.1 L.5	200	200	200	200	200	200	200	200
13	Miscellaneous reserves (note 2)	S.1 L.6	9,896	9,974	8,879	8,354	8,084	8,084	7,814	7,814
14	Total		10,506	12,543	10,332	16,106	10,854	9,784	13,460	12,389
	Add:									
15	Deferred study costs (note 3)	S.1 L.8	6,959	7,458	8,857	8,827	11,189	11,189	24,951	24,951
16	Less: Studies in Progress	S.1 L.9		-	-	(2,847)	(2,571)	(2,571)	(17,026)	(17,026)
17	Other deferred costs	S.1 L.10	118	119	71	23	(0)	(0)	121	121
18	Accum. Disallowed depreciation	S.1 L.11	62	62	66	70	74	74	78	78
19	Total		7,139	7,639	8,994	6,074	8,692	8,692	8,124	8,124
20	Net Property, Plant and Equipment	S.1 L.13	149,965	147,493	151,571	148,329	192,582	193,653	191,900	192,971

Note 1: largely relate to retirements and disposals, as well as charges against the Reserve for Future Removal and Restoration (salvage)

Note 2: Includes Fire Insurance Reserve, Deferred Dewatering Revenues and the Reserve for Injuries and Damages

Note 3: Planning and Study costs, Relicensing and Dam Safety Review costs.

Yukon Energy Corporation
Cost of Capital Calculation
2005 Approved and 2005-2006 Actual
(\$000s)

Schedule 4A
September 2008

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
Final 2005 Approved							
1	Long-Term debt	S.13 L.14	86,858	60.0%	84,475	5.12%	4,327
2	Common Stock	S.8 L. 28	<u>57,906</u>	<u>40.0%</u>	<u>56,318</u>	<u>9.05%</u>	<u>5,097</u>
3	Total	S.5 L.3	<u>144,764</u>	<u>100.0%</u>	<u>140,793</u>	<u>6.69%</u>	<u>9,424</u>
2005 Actual							
4	Long-Term debt	S.13 L.14	86,836	60.0%	83,731	5.18%	4,339
5	Common Stock	S.8 L. 28	<u>57,891</u>	<u>40.0%</u>	<u>55,821</u>	<u>9.46%</u>	<u>5,279</u>
6	Total	S.5 L.3	<u>144,727</u>	<u>100.0%</u>	<u>139,552</u>	<u>6.89%</u>	<u>9,619</u>
Actual 2006							
7	Long-Term debt	S.13 L.14	88,588	60.0%	84,686	5.47%	4,631
8	Common Stock	S.8 L. 28	<u>59,058</u>	<u>40.0%</u>	<u>56,457</u>	<u>10.59%</u>	<u>5,978</u>
9	Total	S.5 L.3	<u>147,647</u>	<u>100.0%</u>	<u>141,143</u>	<u>7.52%</u>	<u>10,609</u>

Yukon Energy Corporation
Cost of Capital Calculation
2007 Actual and 2008 Forecast
(\$000s)

Schedule 4B
September 2008

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
Actual 2007							
1	Long-Term debt	S.13 L.14	90,124	60.0%	85,033	5.49%	4,666
2	Common Stock	S.8 L. 28	<u>60,063</u>	<u>40.0%</u>	<u>56,670</u>	<u>9.45%</u>	<u>5,358</u>
3	Total	S.5 L.3	<u>150,187</u>	<u>100.0%</u>	<u>141,703</u>	<u>7.07%</u>	<u>10,024</u>
Updated Forecast for 2008 - Existing							
4	Long-Term debt	S.13 L.14	91,948	60.0%	86,715	5.67%	4,915
5	Common Stock	S.8 L. 28	<u>61,279</u>	<u>40.0%</u>	<u>57,791</u>	<u>9.55%</u>	<u>5,519</u>
6	Total	S.5 L.3	<u>153,227</u>	<u>100.0%</u>	<u>144,506</u>	<u>7.22%</u>	<u>10,434</u>
Proposed 2008 - Full GRA							
7	Long-Term debt	S.13 L.14	91,807	60.0%	87,138	5.68%	4,947
8	Common Stock	S.8 L. 28	<u>61,185</u>	<u>40.0%</u>	<u>58,074</u>	<u>8.64%</u>	<u>5,017</u>
9	Total	S.5 L.3	<u>152,992</u>	<u>100.0%</u>	<u>145,212</u>	<u>6.86%</u>	<u>9,965</u>

Yukon Energy Corporation
Cost of Capital Calculation
2009 Forecast
(\$000s)

Schedule 4C
September 2008

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
Updated Forecast for 2009 - Existing							
1	Long-Term debt	S.13 L.14	94,193	60.0%	90,154	6.16%	5,558
2	Common Stock	S.8 L. 28	<u>62,800</u>	<u>40.0%</u>	<u>60,108</u>	<u>11.03%</u>	<u>6,632</u>
3	Total	S.5 L.3	<u>156,993</u>	<u>100.0%</u>	<u>150,262</u>	<u>8.11%</u>	<u>12,189</u>
Proposed 2009 - Full GRA							
4	Long-Term debt	S.13 L.14	93,520	60.0%	90,850	6.19%	5,626
5	Common Stock	S.8 L. 28	<u>62,346</u>	<u>40.0%</u>	<u>60,566</u>	<u>8.64%</u>	<u>5,233</u>
6	Total	S.5 L.3	<u>155,865</u>	<u>100.0%</u>	<u>151,415</u>	<u>7.17%</u>	<u>10,859</u>

Yukon Energy Corporation
Utility Revenue Requirement
(\$000s)

Schedule 5
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Net rate base	S.1 L.30	140,793	139,552	141,143	141,703	144,506	145,212	150,262	151,415
2	Average Rate of return on rate base		6.69%	6.89%	7.52%	7.07%	7.22%	6.86%	8.11%	7.17%
3	Utility income	S.10 L.1	9,424	9,619	10,609	10,024	10,434	9,965	12,189	10,859
4	Utility expenses									
5	Operating and maintenance (note 1)	S.6 L.3	10,939	11,344	11,178	12,116	12,421	12,628	13,230	13,489
6	Taxes other than income	S.6 L.4	250	246	249	256	256	256	256	256
7	Amortization of deferred costs	S.6 L.5	1,096	889	1,098	1,108	978	1,467	1,219	1,707
8	Reserve for Injuries and Damages	S.6 L.6	100	100	100	100	50	50	50	150
9	Depreciation	S.6 L.7	5,267	5,083	5,132	5,302	5,747	5,747	6,587	6,587
10	Amortization of contributions	S.6 L.8	(601)	(589)	(615)	(627)	(807)	(807)	(1,361)	(1,361)
11	Disallowed depreciation		(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
12	Donations		(85)	(71)	(57)	(83)	(85)	(85)	(86)	(85)
13	Disallowed Expenses (note 2)		(350)	(201)						
14	Total utility expenses		16,612	16,797	17,081	18,167	18,556	19,251	19,891	20,739
15	Revenue Requirement		26,036	26,416	27,690	28,191	28,991	29,217	32,081	31,599
16	Faro Dewatering Account transfer		292	292	292	292	0	0	0	0
17	Revenue required after transfer from Faro de-watering account	S.6 L.1	25,744	26,124	27,398	27,899	28,991	29,217	32,082	31,599

Note 1: Includes fuel expenses and purchased power.

Note 2: Operating and Maintenance Expenses in Schedules 6 and 5 include \$47,000 for training costs and \$102,000 for Board of Director's costs that were disallowed by the YUB in Order 2005-12. These amounts are removed in Schedule 5 as "disallowed expenses" and not included in Yukon Energy's revenue requirement. Included in disallowed expenses for 2005 approved and 2005 actuals is \$201,000 for rate case expenses that were not allowed by the Board pursuant to Order 2005-17 (the difference between \$851k spending by YEC and the \$650k allowed by the Board in Order 2005-17)

Yukon Energy Corporation
Statement of Earnings
(\$000s)

Schedule 6
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Revenues (note 1)	S.5 L.17	25,744	26,124	27,398	27,899	28,991	29,217	32,082	31,599
2	Operating expenses									
3	Operating and maintenance	S.12 L.15	10,939	11,344	11,178	12,116	12,421	12,628	13,230	13,489
4	Taxes other than income	S.5 L.6	250	246	249	256	256	256	256	256
5	Amortize deferred costs	S.5 L.7	1,096	889	1,098	1,108	978	1,467	1,219	1,707
6	Reserve for Injuries and Damages	S.5 L.8	100	100	100	100	50	50	50	150
7	Depreciation	S.3 L.8	5,267	5,083	5,132	5,302	5,747	5,747	6,587	6,587
8	Amortization of contributions	S.5 L.10	(601)	(589)	(615)	(627)	(807)	(807)	(1,361)	(1,361)
9	Faro Dewatering Account transfer	S.5 L.16	(292)	(292)	(292)	(292)	-	-	-	-
10	Total		16,759	16,781	16,849	17,963	18,645	19,340	19,981	20,828
11	Operating income		8,985	9,343	10,548	9,937	10,345	9,877	12,100	10,770
12	Other income									
13	Allowed for Funds Used	S.10 L.2	17	101	54	138	790	790	798	798
14	Miscellaneous (note 2)	S.10 L.3 + 9	(809)	(1,121)	(819)	(222)	(350)	(350)	-	-
15	Total		(792)	(1,020)	(765)	(84)	440	440	798	798
16	Other expenses									
17	Interest expense	S.10 L.4	4,449	4,500	4,845	4,946	5,212	5,212	5,807	5,792
18	Total		4,449	4,500	4,845	4,946	5,212	5,212	5,807	5,792
19	Net earnings	S.10 L.9	3,744	3,822	4,939	4,907	5,573	5,104	7,092	5,777

Note 1: Revenues reported on Yukon Energy's audited Financial Statements (Tab 9) include the Faro Dewatering transfer, which is set out in the above schedule as an offset to costs consistent with the presentation in Yukon Energy's 2005 RRRA proceeding. Revenues in Yukon Energy's audited Financial Statements also include the total recoveries from sales to related parties, while the costs of providing these services is included in Operating and Maintenance; the above schedule includes these revenues from related parties on a net basis.

Note 2: Miscellaneous primarily consistent of write-downs of Mayo-Dawson (2005, per Board Order 2005-12) plus write-offs of ongoing Mayo Dawson legal claim proceeding amounts.

Yukon Energy Corporation
Statement of Retained Earnings
(\$000s)

Schedule 7
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Balance at beginning of year		18,424	18,400	19,381	20,735	21,391	21,391	23,167	22,980
	Add:									
2	Net earnings	S.6 L.19	3,744	3,822	4,939	4,907	5,573	5,104	7,092	5,777
3			22,168	22,222	24,320	25,642	26,964	26,495	30,259	28,757
	Less:									
4	Common dividends	S.9 L.5	2,781	2,841	3,585	4,251	3,797	3,515	5,825	5,043
5	Balance at end of year	S.8 L.27	19,387	19,381	20,735	21,391	23,167	22,980	24,434	23,714

Yukon Energy Corporation
Balance Sheet
(\$000s)

Schedule 8
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Current assets									
2	Cash (<i>and equivalents</i>)		1,867	4,067	5,950	6,236	3,486	2,705	(8,115)	(9,723)
3	Accounts receivable		3,969	4,020	4,226	3,726	20,082	20,082	19,393	19,393
4	Fuel, materials and supplies		2,426	2,100	2,040	2,352	2,241	2,241	2,244	2,244
5	Prepaid expenses		184	218	181	185	185	185	185	185
6	Total		8,446	10,405	12,397	12,500	25,995	25,213	13,707	12,099
7	Long Term Receivables		53	(33)	500	463	463	0	463	0
8	Funds Held in Trust		788	791	821	856	891	891	927	927
	Fixed assets									
9	Property, plant and equipment, cost (note 2)	S.1 L.2	225,081	222,115	226,573	236,853	277,842	277,842	286,660	286,660
10	Accumulated depreciation + future removal	S.1 L.3	71,749	69,718	73,664	78,492	83,097	83,097	89,424	89,424
11	Contributions for extensions, net	S.1 L.26	11,802	11,798	12,186	16,495	48,076	48,076	50,886	50,886
12	Total		141,530	140,599	140,723	141,865	146,668	146,668	146,350	146,350
13	Deferred charges (note 2)		7,705	8,195	9,238	9,921	12,259	12,571	26,142	25,965
14	Total assets		158,523	159,958	163,680	165,607	186,278	185,345	187,591	185,343
15	Current liabilities									
16	Interim Capital Financing		-	-	-	-	-	-	-	-
17	Accounts payable and accrued (note 1)		1,821	3,273	4,142	4,900	20,915	20,915	19,680	19,680
18	Current portion of long-term debt		1,376	1,454	3,212	3,367	3,944	3,944	4,043	4,043
19	Total		3,197	4,727	7,354	8,268	24,859	24,859	23,723	23,723
20	Miscellaneous liabilities									
21	Trust liability		788	791	821	856	1,398	1,398	1,068	1,068
22	Deferred revenue		8,174	8,166	7,896	7,626	7,356	7,356	7,086	7,086
23	Regulatory Liabilities		1,775	1,775	1,483	1,191	1,191	728	1,191	728
24	Long-Term Debt		86,203	86,119	86,392	87,276	89,308	89,026	91,090	90,026
25	Total liabilities		100,137	101,578	103,946	105,217	124,112	123,367	124,158	122,631
	Shareholder's Equity									
26	Common shares		39,000	39,000	39,000	39,000	39,000	39,000	39,000	39,000
27	Retained earnings	S.7 L.5	19,387	19,381	20,735	21,391	23,167	22,979	24,434	23,713
28	Total		58,387	58,381	59,735	60,391	62,167	61,979	63,434	62,713
29	Total liabilities and shareholder's equity		158,523	159,958	163,680	165,607	186,278	185,345	187,591	185,343

Note 1: Yukon Energy's audited financial statements include in "current portion of long-term debt" any "true-up" principal payable on the Flexible Term Note as of December 31 of the year that are not actually paid until January of the following year once the calendar year WAF loads are confirmed. The above balance sheet reports these amounts as "accounts payable" in order to reflect their status as short-term payments and not properly long-term debt being used to finance ratebase.

Note 2: At year-end 2007, Yukon Energy's audited financial statements recorded \$0.793 million as capital assets that are classed above as "deferred charges" and are set out in Table 5.5. This is the Minto Mine PPA negotiation and due diligence costs (\$0.768 million to year-end 2007), as well as costs incurred for planning the potential Western Copper Transmission Line Connection (\$0.025 million).

Yukon Energy Corporation
Financing Summary
(\$000s)

Schedule 9
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Funds Required									
2	Additions to property, plant and equipment	S.3 L.3	5,555	4,300	4,687	10,280	42,132	42,132	9,078	9,078
3	Additions to deferred costs		1,957	2,241	2,140	1,791	3,317	4,117	15,102	15,102
4	Repayments of long-term debt		1,339	1,368	1,554	3,211	3,429	3,429	3,944	3,944
5	Common dividends	S.7 L.4	2,781	2,841	3,585	4,251	3,797	3,515	5,825	5,043
6	Increase in Long-Term Receivables		100	14	633	63	50	50	50	150
7	Increase in Trust Assets		16	19	30	35	35	35	36	36
8	Asset Retirement/Disposal/Salvage		-	136	957	473	-	-	-	-
9	Total		11,748	10,919	13,586	20,106	52,759	53,277	34,035	33,353
10	Funds available from operations									
11	Net earnings	S.6 L.19	3,744	3,822	4,939	4,907	5,573	5,104	7,092	5,777
12	Add: Non-cash expenses such as									
13	depreciation		5,862	5,483	5,715	5,883	5,968	6,457	6,495	7,084
14	Increase in Customer Contributions		600	576	733	4,666	32,119	32,119	3,900	3,900
15	Increase in Regulatory Liabilities		(292)	(292)	(292)	(292)	-	-	-	-
16	Decrease (increase) in working capital		(963)	(1,530)	(1,123)	656	2,520	3,301	11,053	11,879
17	Increase in Trust Liabilities		16	19	30	35	542	542	(330)	(330)
18	Total		8,966	8,078	10,001	15,855	46,722	47,523	28,210	28,310
19	Cash deficiency		2,781	2,841	3,585	4,251	6,037	5,754	5,825	5,043
20	Long-term funds required									
21	Issue common shares		-	-	-	-	-	-	-	-
22	Issue long-term debt		2,781	2,841	3,585	4,251	6,037	5,755	5,825	5,043
23	Total		2,781	2,841	3,585	4,251	6,037	5,755	5,825	5,043

Yukon Energy Corporation
Reconciliation of Utility Income to Net Earnings
(\$000s)

Schedule 10
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Utility Income (Return on Rate Base)	S.5 L.3	9,424	9,619	10,609	10,024	10,434	9,965	12,189	10,859
	Add:									
2	Allowance for funds used	S.6 L.13	17	101	54	138	790	790	798	798
3	Other income (expenses)	S.6 L.14	(809)	(1,121)	(819)	(222)	(350)	(350)	-	-
			<u>8,632</u>	<u>8,599</u>	<u>9,844</u>	<u>9,940</u>	<u>10,874</u>	<u>10,405</u>	<u>12,987</u>	<u>11,657</u>
	Less:									
4	Interest - long-term	S.6 L.17	4,449	4,500	4,845	4,946	5,212	5,212	5,807	5,792
5	Donations	S.5 L.12	85	71	57	83	85	85	86	85
6	Disallowed costs	S.5 L.13	350	201	-	-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	4	4	4	4	4	4	4	4
			<u>4,888</u>	<u>4,776</u>	<u>4,905</u>	<u>5,033</u>	<u>5,301</u>	<u>5,301</u>	<u>5,897</u>	<u>5,881</u>
8	Net earnings		3,744	3,822	4,939	4,907	5,573	5,104	7,091	5,777
9	Net earnings per financial statements	S.6 L.19	<u>3,744</u>	<u>3,822</u>	<u>4,939</u>	<u>4,907</u>	<u>5,573</u>	<u>5,104</u>	<u>7,091</u>	<u>5,777</u>

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues
(\$000s)

Schedule 11
September 2008

Line No.	Description	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
						Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Residential								
2	Customers	1,302	1,336	1,365	1,390	1,416	1,416	1,432	1,432
3	Sales in MWh	10,201	10,169	10,665	10,908	11,155	11,155	11,183	11,183
4	MWh sales per customer	7.8	7.6	7.8	7.8	7.9	7.9	7.8	7.8
5	Revenue (\$000s)	1,208	1,215	1,267	1,313	1,319	1,315	1,335	1,305
6	Cents per KWh	11.84	11.95	11.88	12.04	11.83	11.79	11.94	11.67
7	General Service								
8	Customers	447	450	447	450	450	450	457	457
9	Sales in MWh	16,808	18,438	17,037	17,507	18,193	18,193	19,543	19,543
10	MWh sales per customer	37.6	41.0	38.1	38.9	40.4	40.4	42.8	42.8
11	Revenue (\$000s)	2,305	2,470	2,301	2,376	2,442	2,442	2,637	2,637
12	Cents per KWh	13.71	13.40	13.51	13.57	13.42	13.42	13.49	13.49
13	Industrial								
14	Sales in MWh	0	0	0	0	6,845	6,845	29,023	29,023
15	Revenue (\$000s)	0	0	0	0	709	749	3,142	3,312
16	Cents per KWh	7.00	7.00	7.00	7.00	10.36	10.94	10.83	11.41
17	Street lights								
18	Sales in MWh	252	257	270	275	278	278	278	278
19	Revenue (\$000s)	65	66	69	71	71	71	71	71
20	Cents per KWh	25.75	25.64	25.64	25.62	25.64	25.64	25.63	25.63
21	Space lights								
22	Sales in MWh	13	14	14	14	14	14	15	15
23	Revenue (\$000s)	2	3	3	3	3	3	3	3
24	Cents per KWh	19.76	21.89	21.48	22.00	21.82	21.82	21.54	21.54
25	Total Company - Firm Retail and Industrial								
26	Customers	1,749	1,786	1,812	1,840	1,866	1,866	1,889	1,889
27	Sales in MWh	27,274	28,878	27,987	28,705	36,485	36,485	60,042	60,042
28	Revenue (\$000s)	3,580	3,754	3,641	3,763	4,545	4,580	7,188	7,328
29	Cents per KWh	13.13	13.00	13.01	13.11	12.46	12.55	11.97	12.21
30	Wholesale sales								
31	Sales in MWh	234,542	237,419	251,861	254,914	258,989	258,989	266,926	266,926
32	Revenue (\$000s)	16,043	16,239	17,227	17,436	17,715	17,719	18,258	18,287
33	Cents per KWh	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.85
34	Total Company - Firm								
35	Sales in MWh	261,816	266,296	279,847	283,619	295,474	295,474	326,968	326,968
36	Revenue (\$000s)	19,623	19,993	20,868	21,199	22,259	22,300	25,446	25,615
37	Cents per KWh	7.49	7.51	7.46	7.47	7.53	7.55	7.78	7.83
38	Secondary								
39	Sales in MWh	20,613	18,933	22,185	24,225	20,557	20,557	16,613	16,613
40	Revenue (\$000s)	854	767	917	1,000	850	1,396	688	1,369
41	Cents per KWh	4.14	4.05	4.13	4.13	4.13	6.79	4.14	8.24
42	Total Company								
43	Sales in MWh	282,428	285,229	302,032	307,844	316,031	316,031	343,581	343,581
44	Revenue (\$000s)	20,477	20,760	21,785	22,200	23,109	23,696	26,134	26,984
45	Cents per KWh	7.25	7.28	7.21	7.21	7.31	7.50	7.61	7.85
46	Rider J	5,173	5,246	5,451	5,585	5,756	5,756	5,823	5,823
47	Rider U						-218		-1,334
48	Post-GRA Reconcil Req'd (Note 2)						-141		
49	Total Sales of Power	25,649	26,006	27,236	27,785	28,866	29,093	31,957	31,474
50	Other Revenues	95	118	161	115	125	125	125	125
51	Total Revenues (note 1)	25,744	26,124	27,398	27,899	28,991	29,217	32,082	31,599

Note 1: Per Schedule 6, revenues do not include approved transfers from the Faro Mine Dewatering Account

Note 2: Yukon Energy is seeking to calculate Rider U to address the \$1.334 million annual rate reduction in 2009, and to apply this same Rider to 2008 starting November 1, 2008. The Rider was not developed to refund the precise value of calculated surplus in 2008. Following final approval of YEC's GRA, 2008 revenue requirements and Rider U refunds will be reconciled and any additional necessary adjustments will be addressed in the YEC refiling following a final YUB Order. At this time the estimated amount that will need to be credited is \$142,000, subject to revisions to YEC's revenue requirements as ordered by the Board, and also revisions to reflect any alteration in the timing for a revised CSTP in-service date after the October 1, 2008 date assumed in the above schedule.

Yukon Energy Corporation
Summary of Operating and Maintenance Expenses
(\$000s)

Schedule 12
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Forecast		Forecast	
							Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
1	Utility operations									
2	Production		2,872	2,958	3,179	3,281	2,771	2,771	2,977	2,977
3	Transmission and distribution		1,297	1,151	1,344	1,306	1,626	1,626	1,793	1,793
4	General		571	727	783	848	899	899	952	952
5	Administration and general (note 1)		4,953	5,141	4,824	5,511	5,845	5,845	6,148	6,148
6	Insurance (excluding auto)		910	909	813	814	914	914	952	952
7	Sub-total		<u>10,603</u>	<u>10,887</u>	<u>10,944</u>	<u>11,761</u>	<u>12,056</u>	<u>12,056</u>	<u>12,822</u>	<u>12,822</u>
8	Donations		85	72	56	83	85	85	85	85
9	Sub-total		<u>85</u>	<u>72</u>	<u>56</u>	<u>83</u>	<u>85</u>	<u>85</u>	<u>85</u>	<u>85</u>
10	O&M not including fuel and									
11	purchased power		<u>10,688</u>	<u>10,959</u>	<u>11,000</u>	<u>11,844</u>	<u>12,141</u>	<u>12,141</u>	<u>12,907</u>	<u>12,907</u>
12	Fuel		213	137	126	218	227	434	270	528
13	Purchased power		38	48	52	53	53	53	54	54
14	Sub-total		<u>251</u>	<u>185</u>	<u>178</u>	<u>271</u>	<u>280</u>	<u>487</u>	<u>324</u>	<u>582</u>
15	Total operating and maintenance	S.6 L.3	<u>10,939</u>	<u>11,144</u>	<u>11,178</u>	<u>12,115</u>	<u>12,421</u>	<u>12,628</u>	<u>13,230</u>	<u>13,489</u>
Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:										
16	Reserve for Injuries and Damages			100	100	100	50	50	50	150
17	Property Taxes			246	249	256	256	256	256	256
18	less: Donations			<u>-72</u>	<u>-56</u>	<u>-83</u>	<u>-85</u>	<u>-85</u>	<u>-85</u>	<u>-85</u>
19	O&M per Tab 3			11,233	11,293	12,116	12,362	12,362	13,128	13,228

Note 1: In 2005 actuals, administration and general expenses exclude \$201,000 which was spent on rate case but disallowed by YUB. Consequently the 2005 Actuals in the above table is \$201,000 lower than reported on the full Statement of Earnings in Schedule 6.

Yukon Energy Corporation
Summary of Cost of Long - Term Debt
(\$000s)

Schedule 13
September 2008

Line No.	Description	Cross Ref.	Approved 2005	Actual 2005	Actual 2006	Actual 2007	Existing 2008	Proposed 2008	Existing 2009	Proposed 2009
General Purpose Long-Term Debt Balance										
1	Canada Flexible Term Note (7%)		27,895	27,867	27,317	26,751	26,081	26,081	25,143	25,143
2	TD Note (7.81%)		8,945	8,946	8,392	7,804	7,163	7,163	6,471	6,471
3	YDC Loan #12 (5.88%)		27,313	27,313	27,313	25,706	24,100	24,100	22,493	22,493
4	YDC Loan #13 (6.03%)		3,689	3,649	3,649	3,649	3,649	3,649	3,649	3,649
5	YDC Loan #14 (5.40%)		2,781	2,841	2,841	2,841	2,841	2,841	2,841	2,841
6	YDC Mayo-Dawson Note (6.55%)		16,957	16,957	16,507	16,057	15,607	15,607	15,157	15,157
7	YDC Loan #15 (5.34%)				3,585	3,585	3,585	3,585	3,585	3,585
8	YDC Loan #16 (5.28%)					4,251	4,251	4,251	4,251	4,251
9	YDC Loan #17 (5.28%)						3,797	3,515	3,797	3,515
10	YDC Loan #18 (5.28%)								5,825	5,043
11	Minto Diesel (7.50%)						2,179	2179	1,921	1921
12	Current year-end balance		87,579	87,573	89,604	90,644	93,252	92,970	95,133	94,069
13	Previous year-end balance		86,137	86,100	87,573	89,604	90,644	90,644	93,252	92,970
14	Mid Year		86,858	86,836	88,588	90,124	91,948	91,807	94,193	93,520
Interest Costs										
15	Canada Flexible Term Note (7%)		759	814	1,074	1,083	1,255	1,255	1,712	1,712
16	TD Note (7.81%)		722	720	681	635	587	587	535	535
17	YDC Loan #12 (5.88%)		1,606	1,606	1,606	1,582	1,488	1,488	1,393	1,393
18	YDC Loan #13 (6.03%)		222	220	220	220	220	220	220	220
19	YDC Loan #14 (5.40%)		0	0	153	153	153	153	153	153
20	YDC Mayo-Dawson Note (6.55%)		1,140	1,140	1,111	1,081	1,052	1,052	1,022	1,022
21	YDC Loan #15 (5.34%)					191	191	191	191	191
22	YDC Loan #16 (5.28%)						224	224	224	224
23	YDC Loan #17 (5.28%)								200	186
24	YDC Loan #18 (5.28%)									
25	Minto Diesel (7.50%)						42	42	155	155
26	Total Cost of Interest		4,449	4,500	4,845	4,946	5,212	5,212	5,807	5,792
27	Mid-Year Cost of Debt		5.12%	5.18%	5.47%	5.49%	5.67%	5.68%	6.16%	6.19%

TAB 8
RETURN ON EQUITY

8.0 RETURN ON EQUITY

This Tab reviews the proposed basis for determining the return on equity allowed for Yukon Energy in 2008 and 2009, including the following:

- Background
- Yukon Energy Fair ROE for 2008 and 2009

8.1 BACKGROUND

Yukon Energy's rate base is financed by two main sources of capital: long-term debt and shareholder's equity. In respect of the equity component, Yukon Energy's rates are required to include "provision to recover a fair return on the Corporation's equity, less on-half of one per cent (0.5%)" per Order-in-Council ("OIC") 1995/90 Section 2, as amended by OIC 1998/32 Section 1 (see Tab 10 of this Application). In past General Rate Application's ("GRA"), including the 1996/97 GRA, Yukon Energy's allowed return on equity ("ROE") has been set by the Board based on being 0.5% below the ROE awarded for YECL, notwithstanding that Yukon Energy as a generation utility would typically be understood to face considerably higher risk levels than YECL with its focus on distribution.

A number of approaches may be used to determine a fair level of return on equity. For YUB proceedings up to the 1996/97 GRA, YECL employed an analytical approach that incorporated expert assessment of the various risks and general market conditions to which the utility was exposed. Yukon Energy's return was set commensurate with the level set for YECL.

For both the 1998 rate revision, as well as the 2005 Required Revenues and Related Matter proceeding, Yukon Energy proposed that the return on equity be set by reference to the British Columbia Utilities Commission ("BCUC") formulaic approach.¹ In the 2005 proceeding, it was noted that several regulated jurisdictions across Canada had adopted similar "formulaic" approaches towards establishing ROE's,

¹ In 2005, Yukon Energy noted that it was not proposing to use this approach as an annual on-going ROE adjustment mechanism for the following reasons:

- The process used in BC to make annual adjustments had evolved over several years, applies to the overall jurisdiction (as opposed to a single utility) and was fairly complicated with a detailed approach understood by the utilities and the intervenors. In BC's case, a specific hearing had been convened to consider and determine the specific issue and set an approach for all utilities under the BCUC's jurisdiction, and there have been specific reviews of approach since it was established. It was noted that a comparable approach would need to be undertaken that established ground rules appropriate to the Yukon context and that involved both Yukon utilities.
- Although Yukon Energy could propose an annual adjustment on its own, there was considerable concern that without good rules in Yukon, this could become a cumbersome and difficult annual process for relatively little benefit.

including British Columbia, Alberta, the National Energy Board, Manitoba, Ontario and Newfoundland. Generally, under this approach the forecast Long Canada Bond Yields are used as a proxy for a “risk-free” cost of capital, with appropriate adjustments incorporated to reflect the additional risks of equity compared to debt and the specific risks related to each specified utility.

In the 2005 hearing, the Board determined that the rate of return requested and the Application of the BCUC approach was reasonable, given Yukon Energy's level of risk in relation to other utilities within their peer group. It was noted by the Board that this was an expedient means of determining return for that period, and did not necessarily impose a precedent in the Yukon.² The Board agreed with Yukon Energy's assessment with respect to “risk premiums”, i.e., that it fell somewhere between PNG at 65 basis points and FortisBC at 40 basis points, given the level of risk experienced by Yukon Energy in relation to other utilities within its peer group. Consequently, the Board agreed with YEC's assessment that 9.05% (9.55% less 0.5% per OIC 1998/32) was an appropriate rate of return on common equity for Yukon Energy, and noted that Yukon Energy remained at risk for their forecast annual deliveries, OM&A and capital expenditures for 2005.

8.2 YUKON ENERGY FAIR ROE FOR 2008 AND 2009

For the test years, Yukon Energy proposes that the BCUC approach continue to form the basis for establishing fair returns on a forecast basis for each test year, as it has for all Yukon YUB proceedings since the 1996/97 GRA. In addition to providing continuity for Yukon proceedings and practice, this approach continues to offer simple, transparent and cost-effective determination of a consistent fair return for utilities in Yukon. For 2008, the BCUC determinations for this year are already available (from November 2007), and as such can be finalized at this time. For 2009, the BCUC calculations and the underlying Consensus Forecasts will not be available until approximately the end of November 2008, and Yukon Energy proposes to incorporate the ROE arising from these calculations into the final requested 2009 Revenue Requirements, to be confirmed at that time. As in the 2005 hearing, Yukon Energy is not proposing at this time any automatic ongoing adjustment of the return on equity beyond the test years. An overview of the proposed approach for 2008 is as follows:

- Step 1 – Determine Low-Risk Benchmark utility ROE based on BCUC determination for 2008:
The low-risk benchmark utility ROE for Yukon for 2008 will be set by the Board equal to the

² Appendix A to Board Order 2005-12, page 45.

BCUC calculation for 2008, as calculated by BCUC in its determination on November 22, 2007.³ This rate is calculated based on the following:

- The average of the 3 month (4.3%) and 12 month (4.7%) forecasts (4.5%); plus
- The average yield spread between 10-year and 30-year bonds reported in the Financial Post for all trading days in October 2007 (0.049%);
- The approved benchmark return on equity is 9.145% assuming a 30-year long Canada bond yield of 5.25 %. Where the forecast yield is greater or less than 5.25%, a sliding scale adjustment raises or lowers the benchmark ROE by 75% of the change in the forecast yield on long-term Canada Bonds;
- The unrounded allowed low-risk benchmark utility ROE at 8.619%; and
- The rounded allowed low-risk benchmark utility ROE at 8.62%.

- Step 2 – Apply Yukon Energy Fair Return on Equity by incorporating the risk premium for Yukon Energy: The established approach requires that the appropriate ROE in 2008 for individual utilities will incorporate the risk premium that the Board has previously determined for each utility relative to the low-risk benchmark utility allowed ROE. In Order 2005-12 the Board approved a proposed Yukon Energy fair return set equal to 52 basis points above the low-risk benchmark utility ROE to reflect the specific conditions of Yukon Energy.

- Step 3 – Determine Yukon Energy allowed ROE by deducting 50 basis points from the Yukon Energy Fair Return on Equity: For test year 2008, the Yukon Energy allowed ROE is required to be set equal to the Yukon Energy fair return on common equity less 50 basis points (0.5%) to reflect the OIC 1998/32 adjustment. The end result is a return on equity for Yukon Energy that is 2 basis points above the low-risk benchmark utility rate of return calculated by the BCUC in November 2007 (52 basis point utility specific adder less 50 basis point OIC reduction).

Accordingly, the Yukon Energy proposed ROE for 2008 is 8.64%.

³ Letter No. L-93-07 states "pursuant to BCUC Decision dated June 10, 1994 regarding Return on Common Equity and Order No. G-35-94 as amended by Order No. G-80-99 and Order No. G-109-01 and Order No G-14,06, the Commission has determined that the current ROE automatic adjustment mechanism results in an allowed return on common equity of 8.62 percent for a low-risk benchmark utility in 2008." The calculation and other documentation in support of this finding were attached to this letter.

1 For 2009, Yukon Energy proposes that the ROE be set using the same approach, based on the BCUC
2 determinations to be released approximately at the end of November, 2008. For the purposes of this
3 filing document, a 2009 “placeholder” ROE of 8.64% has been utilized, to be consistent with 2008. Yukon
4 Energy proposes to file amendments to this Application as required after BCUC releases its determination
5 for 2009, incorporating the adjusted ROE for 2009 in the requested approvals for 2009 at that time. This
6 will allow the updated values to be available in advance of required Board determinations on this
7 application.

TAB 9
2007 AUDITED FINANCIAL STATEMENTS

Yukon Energy Corporation
Financial Statements
December 31, 2007

Management's Responsibility for Financial Reporting

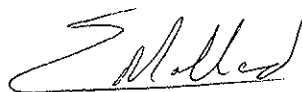
Management is responsible for the preparation of the financial statements and all other financial information relating to the Corporation contained in this annual report. The financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industry in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the financial statements.

Management has established internal accounting control systems to meet its responsibilities for reliable and accurate reporting. These systems include policies and procedures, the careful selection and training of qualified personnel and an organizational structure that provides for the appropriate delegation of authority and segregation of responsibilities.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management and the independent auditor to discuss auditing and financial matters to assure that management is carrying out its responsibilities and to review the financial statements. The auditors have full and free access to the Audit Committee and management.



David Morrison
President and CEO



Ed Mollard
Chief Financial Officer

April 11, 2008

Yukon Energy Corporation

Financial Statements

December 31, 2007

Page

Auditor's Report	2
Balance Sheet	3
Statement of Income, Other Comprehensive Income and Retained Earnings	4
Statement of Cash Flows	5
Notes to Financial Statements	6-25



AUDITOR'S REPORT

To the Board of Directors of Yukon Energy Corporation

I have audited the balance sheet of Yukon Energy Corporation as at December 31, 2007 and the statements of income, other comprehensive income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. My responsibility is to express an opinion on these financial statements based on my audit.

I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In my opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Further, in my opinion, proper books of account have been kept by the Corporation and the financial statements are in agreement therewith and the transactions of the Corporation that have come to my notice during my audit of the financial statements have, in all significant respects, been in accordance with the *Public Utilities Act* and regulations, the *Business Corporations Act* and regulations, and the articles and the bylaws of the Corporation.

Sheila Fraser, FCA
Auditor General of Canada

Vancouver, Canada
April 11, 2008

Yukon Energy Corporation

Balance Sheet

(in thousands of dollars)

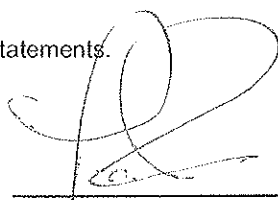
As at December 31,	2007	2006
Assets		
Current		
Cash	\$ 6,237	\$ 5,952
Accounts receivable (Notes 5 and 16)	3,726	4,226
Materials and supplies	2,352	2,039
Prepaid expenses	186	181
	12,501	12,398
Deferred uninsured losses (Note 6)	463	500
Diesel contingency fund (Notes 4 and 7)	856	821
Property, plant and equipment (Note 8)	164,394	157,992
Deferred charges (Note 9)	9,128	9,238
	\$ 187,342	\$ 180,949
Liabilities		
Current		
Accounts payable (Note 16)	4,119	3,531
Current portion of long-term debt (Notes 13 and 16)	3,416	3,253
Regulatory liabilities (Note 10)	1,191	1,483
	8,726	8,267
Long-term pension liability (Note 17)	741	560
Deferred revenue (Note 11)	7,626	7,896
Contributions in aid of construction (Note 12)	16,495	12,187
Regulatory provision for future removal and site restoration costs	5,241	5,083
Diesel contingency fund (Notes 4 and 7)	856	821
Long-term debt (Notes 13 and 16)	87,263	86,397
	126,948	121,211
Shareholder's Equity		
Share capital		
Authorized: Unlimited number of a single class of shares with no par value		
Issued: 3,900 shares	39,000	39,000
Retained earnings	21,394	20,738
	60,394	59,738
	\$ 187,342	\$ 180,949

Contingencies and Commitments (Notes 18 and 19)

The accompanying notes are an integral part of the financial statements.

Approved by the Board


Chair


Director

Yukon Energy Corporation

Statement of Income, Other Comprehensive Income and Retained Earnings (in thousands of dollars)

For the year ended December 31,	2007	2006
Revenue (Note 16)		
Sales of power	\$ 28,077	\$ 27,528
Other	309	533
	28,386	28,061
Operating expenses		
Administration (Note 14)	7,399	7,461
Operations and maintenance (Note 15)	5,599	5,375
Amortization of property, plant and equipment	4,939	4,732
Amortization of deferred charges	1,108	1,098
	19,045	18,666
Income from operations	9,341	9,395
Other income		
Allowance for funds used during construction	138	54
Amortization of capital assistance	215	215
Interest income	259	220
	612	489
Other expenses		
Interest on long-term debt (Note 16)	4,946	4,845
Provision for deferred uninsured losses (Note 6)	100	100
	5,046	4,945
Net income	4,907	4,939
Other Comprehensive Income	-	-
Net income and Other Comprehensive Income	4,907	4,939
Retained earnings, beginning of year	20,738	19,382
Dividend	(4,251)	(3,583)
Retained earnings, end of year	\$ 21,394	\$ 20,738

The accompanying notes are an integral part of the financial statements.

Yukon Energy Corporation
Statement of Cash Flows
(in thousands of dollars)

For the year ended December 31,	2007	2006
Cash provided from Operations		
Cash receipts from customers	\$ 28,886	\$ 27,853
Cash paid to employees and suppliers	(13,900)	(14,988)
Interest paid	(4,946)	(4,845)
Interest received	259	220
	10,299	8,240
Cash (used for) provided from Financing		
Repayment of long-term debt	(3,222)	(1,501)
Contributions in aid of construction	4,665	733
	1,443	(768)
Cash used for Investment		
Additions to property, plant and equipment	(11,457)	(5,588)
	(11,457)	(5,588)
Net increase in cash	285	1,884
Cash, beginning of year	5,952	4,068
Cash , end of year	\$ 6,237	\$ 5,952

The accompanying notes are an integral part of the financial statements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

1. NATURE OF OPERATIONS

Yukon Energy Corporation (the "Utility") was incorporated under the *Yukon Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation, a corporation owned by the Government of Yukon. Yukon Energy Corporation generates, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes.

The Utility is subject to overall regulation by the Yukon Utilities Board ("YUB") and specific regulation by the Yukon Territory Water Board. Both boards are independent from the Utility.

Rate Regulation

All operations of the Utility are regulated by the YUB pursuant to the *Public Utilities Act*. There is no minimum requirement for the Utility to appear before the YUB to review rates. However, the Utility is not permitted to charge any rate for the supply of power that is not approved by an Order of the YUB. The Utility is subject to a cost of service regulatory mechanism under which the YUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment in rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The regulatory hearing process used to establish or change rates typically begins when the Utility makes an application for its proposed electricity rate changes over the next one or two forecast years. The YUB must ensure that its decision, which fixes electricity rates, complies with appropriate principals of rate making, all relevant legislation including the *Public Utilities Act* and directives issued by the Yukon Government through Orders-In-Council that specify how the interests of the customer and Utility are to be balanced.

The YUB typically follows a two-stage decision process. In the first stage, the total costs that the Utility will incur to provide electricity to its customers over the immediate future are approved. The approval of these costs determines the total revenues the Utility is allowed to collect from its customers. It is the responsibility of the YUB to examine the legitimacy of three classes of costs:

- the costs to the Utility to run its operations and maintain its equipment (personnel and materials);
- the cost associated with the amortization of all capital equipment; and
- the return on rate base (the costs related to borrowing that portion of rate base which is financed with debt, and the costs to provide a reasonable rate of return on that portion of rate base which is financed with equity).

As well, in the first stage, the YUB reviews the addition of costs to rate base and assesses these costs to ensure they are prudent.

In the second stage, the YUB approves how the revenue will be raised. This stage essentially determines the electricity rates for the various customer classes in the Yukon: residential, government, commercial and industrial. This process is guided mainly by requirements of Yukon Government Order-in-Council 1995/90 and can include a cost-of-service study which allocates the overall utility's cost of service to the various customer classes on the basis of appropriate costing principles.

Normally, the Utility applies for rates in advance of the applicable years. The last rate application was for the 2005 year. Interim hearings may be used between rate applications to deal with unforeseen circumstances which could result in the use of interim rates or riders until the next rate application when rates are reviewed and set as final.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

Water Regulation

The Yukon Territory Water Board pursuant to the *Yukon Waters Act* decides if and for how long the Utility will have a water license for the purposes of operating hydro generation stations in the Yukon. The licenses will also indicate terms and conditions for the operation of these facilities.

Capital Structure

The Utility's policy is to maintain a relatively constant capital structure of 60% debt and 40% equity. Annual dividends are declared to the parent and typically loaned back in order to maintain this ratio.

2. CHANGE IN ACCOUNTING POLICIES

Change in accounting policy

Effective January 1, 2007, the Utility adopted the new CICA Handbook Sections 3855, *Financial Instruments - Recognition and Measurement*, Section 3861, *Financial Instruments - Disclosure and Presentation*, Section 1530 – *Comprehensive Income*, and Section 3865, *Hedges*. As required by the new standards, prior period results have not been restated.

Under the new standards, financial assets and financial liabilities are initially recognized at fair value and are subsequently accounted for based on their classification. Held-to-maturity financial assets and loans and receivables and other financial liabilities are measured at amortized cost using the effective interest method. Held for trading and available for sale financial assets are measured at fair value. Financial liabilities are categorized as held for trading or other financial liabilities. Unrealized gains and losses on those assets categorized as available for sale are temporarily recorded in other comprehensive income until the gains or losses are realized.

The Utility has classified its financial instruments as follows:

Accounts receivable	Loans and receivables
Accounts payable	Other liabilities
Long-term debt	Other liabilities

Pursuant to section 3855.88(e)(ii) of the CICA handbook, the Utility elected to look at all contracts entered into after January 1, 2003 for embedded derivatives. No embedded derivatives were found.

Section 1530 requires the presentation of Comprehensive Income, which consists of net income and other Comprehensive Income. Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources. Other Comprehensive Income comprises revenues, expenses, gains and losses that, in accordance with primary sources of GAAP, are recognized in Comprehensive Income, but excluded from net income. After having determined that it had no other Comprehensive Income item to report in its financial statements, the Utility has decided to comply with the new requirement in modifying the title of its Statement of Income and Retained Earnings which is now the Statement of Income, Comprehensive Income and Retained Earnings and in modifying the line Net income for the year to become Net Income and comprehensive income for the year. The adoption of section 1530 had no impact on opening retained earnings.

In adopting the new standard for financial instruments the Utility is required to adopt CICA Handbook Section 3865, *Hedges*. These standards do not have an impact on the financial statements because the Utility does not engage in the types of transactions addressed by this section.

Yukon Energy Corporation

Notes to Financial Statements (tabular amounts in thousands of dollars)

December 31, 2007

3. SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

The financial statements of the Utility have been prepared by management. They conform to Canadian generally accepted accounting principles ("GAAP") and take into account generally accepted methods and practices of regulated bodies. The regulatory accounting policies adopted by the Utility may differ from the accounting policies otherwise expected using GAAP. In particular, the timing of the Utility's recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that of a non-regulated enterprise. Impacts of accounting for rate regulated operations are further described in Note 4. Consequently, the significant accounting policies have been classified accordingly in the notes below:

Rate regulated accounting policies

Property, plant and equipment

Property, plant and equipment include an allowance for funds used during construction ("AFUDC") calculated at the weighted average cost of capital which was 7.81% for 2007 (2006 – 7.81%). Upon retirement or disposal, any gain or loss is charged to income in the current year for assets depreciated on an individual basis, or charged to accumulated depreciation for assets depreciated on a pooled basis.

Regulatory liabilities

Regulatory liabilities represent amounts ordered by the YUB to be held by the Utility on behalf of ratepayers. Typically these amounts are either refunded to the customers or applied to ratepayer deficits through the rate-setting process.

Deferred uninsured losses

As a means of self-insurance, the Utility provides for uninsured losses. An annual provision is approved by the YUB and collected through customer rates. Variances between the approved annual provision and actual costs incurred are deferred until the following general rate application or until a specific application is made to the YUB requesting recovery from or refund to customers.

Deferred charges

Deferred charges are recorded at cost less accumulated amortization.

Cost of feasibility studies and infrastructure planning are amortized on a straight-line basis over five years.

Regulatory hearing costs that are approved by the Yukon Utilities Board are amortized over three years. The remaining amounts in hearing costs at year end are waiting for an approval term by the Yukon Utilities Board. See note 4.

Other deferred charges are amortized to earnings on a straight-line basis over various terms approved by the Yukon Utilities Board.

Regulatory provision for future removal and site restoration costs

The Utility maintains a provision for the future removal of property, plant and equipment and the costs of site restoration related to those assets. Per YUB Order 2005-12 no additional provision is permitted. This account provides for the costs of demolishing, dismantling, tearing down, or otherwise disposing of an asset and any site restoration costs, net of actual recoveries. This account is not used when the costs relate to an asset retirement obligation.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

Deferred revenue

Deferred revenue represents a gain on fire insurance proceeds received related to a fire at the Whitehorse Rapids Generating Station in 1997. The gain is being amortized to income at the same rate as the replacement assets.

Diesel contingency fund

The Utility maintains a trust asset and an offsetting trust liability on behalf of ratepayers. The trust is used to reimburse the Utility for costs associated with diesel generation required when there is not sufficient water for hydraulic generation to meet demand. The Utility is required to file an annual report with the YUB on the fund's activity.

Generally Accepted Accounting Principles

Revenue recognition

All revenues for energy sales, including wholesale power sales, are recognized in the period earned. Revenue from the sale of power is recognized based on cyclical meter readings. Sales of power includes an accrual for electricity deliveries not yet billed.

Materials and supplies

Diesel fuel, materials and supplies are recorded at average cost. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined.

Property, plant and equipment

Property, plant and equipment is stated at cost which includes materials, direct labour, a proportionate share of directly attributable administration overhead, and finance charges capitalized during construction, less accumulated amortization.

Amortization is based on the straight-line method over the estimated economic life of the assets as follows:

Generation	
Hydro-electric plants	30 to 65 years
Diesel plants	25 to 45 years
Wind Turbines	30 years
Transmission	40 to 50 years
Distribution	25 to 40 years
Buildings	20 to 40 years
Transportation	9 to 31 years
Other equipment	5 to 20 years

Asset retirement obligations

On an annual basis, the Utility identifies legal obligations associated with the retirement of tangible long-lived assets. Where a reasonable estimate of the fair value of these obligations can be determined, the total retirement costs are to be recorded as a liability at fair value, with a corresponding increase to property, plant and equipment.

The Utility has determined that it has tangible long-lived assets with associated future legal obligations for retirement. As the Utility anticipates using the assets for an indefinite period, the date of removal of these assets cannot be reasonably determined, and therefore an asset retirement obligation has not been recorded. When the timing and amount of the retirement can be reasonably estimated, an asset retirement obligation and the corresponding increase in property, plant and equipment asset will be recognized.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

Contributions in aid of construction

Certain property, plant and equipment additions are made with the assistance of cash contributions from customers or capital assistance from the Utility's parent. These contributions are amortized to income on the same basis as the assets to which they relate. Amortization of contributions from customers is netted on the statement of income against amortization expense while amortization of capital assistance from the parent is disclosed separately under Other income.

Deferred water licensing costs

Costs related to obtaining water license renewals are deferred and amortized to earnings on a straight-line basis over the term of the license. The Utility operates its hydro generation facilities under three separate water licenses, with terms ranging from 17 to 25 years.

Employee pension plan

The Utility has a defined benefit pension plan which provides for pensions based on length of service and final average earnings. Employees joining the Utility after January 1, 2002 are not eligible to participate in the defined benefit plan. The cost of pension benefits is actuarially determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Adjustments resulting from the plan enhancements, actuarial gains and losses, and changes in assumptions are amortized over the expected average remaining service period of active employees. Pension costs include the current cost of service and amortization of past service benefits and plan enhancements, and actuarial gains and losses. Amortization is on a straight-line basis over the expected average remaining service period of active employees, which is currently 12 years. The transitional asset that arose when this policy was first applied is amortized over the average remaining service period of active employees expected to receive benefits under the benefit plan as of January 1, 2000. The expected return on plan assets is based on the fair value of these assets.

Measurement uncertainty

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. This mainly affects revenue, accounts receivable, property, plant and equipment, asset retirement obligations, and employee pension obligations. Actual results could differ by a significant amount from these estimates.

Management's estimates and assumptions, especially those affecting the reported amounts of assets and the Utility's ability to recover the cost of these assets through future rates, are subject to decisions of the Yukon Utilities Board as described in Note 3.

Future Accounting Changes – Financial Instrument Disclosures and Capital Disclosures

On December 1, 2006, the CICA issued three new accounting standards: Handbook Section 3862 *Financial Instruments – Disclosures*; Section 3863 *Financial Instruments – Presentation*; and Section 1535 *Capital Disclosures*. These standards apply to fiscal years beginning on or after October 1, 2007 and accordingly will be effective for the Utility on January 1, 2008.

Sections 3862 and 3863 replace Section 3861 *Financial Instruments – Disclosure and Presentation*, revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks. These sections are currently being assessed by management to determine the applicability and impact on the Utility's financial statements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

Section 1535 specifies the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance. This section is expected to have limited impact on the Utility's financial statements.

Section 3031 is a new recommendation for the measurement and disclosure of inventories. This section provides guidance on the determination of cost and its subsequent recognition as an expense, including any write down to net realizable value and on the cost formulas that are used to assign costs to inventories. The adoption of these recommendations is not expected to have a material impact on the earnings or assets of the Utility.

Effective January 1, 2009 the CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measure on a basis other than in accordance with primary sources of GAAP. The Utility is evaluating the possibility of using standards issued by the Financial Accounting Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of Canadian GAAP. This section is currently being assessed by management to determine the impact on the Utility's financial statements.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

Certain items in these financial statements are accounted for differently than they would be in the absence of rate regulation.

Where regulatory decisions dictate, the Utility defers certain costs or revenues as assets or liabilities on the balance sheet and records them as expenses or revenues in the statement of income as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the YUB renders a subsequent decision.

Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process.

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event:

	2007	2006	Expected remaining recovery/settlement (years)	For 2007: In the absence of Rate Regulation the Utility's Net Income would have increased (decreased) by:
Regulatory assets:				
Deferred charges (Note 9), net book value				
Feasibility studies	\$ 2,319	\$ 2,999	1 to 5	\$ 680
Downsizing costs	24	71	1	47
Hearing costs	1,071	311	Indeterminate	(760)
Dam safety review	27	49	2	22
Diesel contingency fund (Note 7)	856	821	Indeterminate	(35)
	4,297	4,251		(46)

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

Regulatory liabilities:				
Faro mine dewatering deferral revenue (Note 10)	1,191	1,483	Indeterminate	(292)
Deferred gain on fire insurance proceeds (Note 11)	7,626	7,896	28	(270)
Deferred uninsured losses (Note 6)	(463)	(500)	Indeterminate	37
Regulatory provision for future removal and site restoration costs	5,241	5,083	Indeterminate	158
Diesel contingency fund (Note 7)	856	821	Indeterminate	35
	14,451	14,783		\$ (332)
Net impact	\$ (10,154)	\$ (10,532)		\$ (378)

Regulatory assets

(a) Deferred charges

Deferred charges represent costs which have been deferred and are being amortized over various periods. In the absence of rate regulation, GAAP would require such costs to be recognized as expenses in the year incurred.

Feasibility studies

The costs of determining the feasibility of future capital projects that did not result in a capital project are deferred and amortized over five years as approved in the Utility's 1991/92 General Rate Application and re-confirmed in YUB Order 2005-12. In the absence of rate regulation, expenses in 2007 would have been \$680,000 lower (2006 - \$1,501,000 higher expenses).

Downsizing costs

Costs incurred to assist in downsizing the Utility's workforce are capitalized and amortized to expense over seven years as approved in the Utility's 1993/94 General Rate Application and reconfirmed in YUB Order 2005-12. In the absence of rate regulation, expenses in 2007 would have been \$47,000 lower (2006 - \$48,000 lower expenses).

Hearing costs

These costs are associated with the YUB regulatory proceedings that were held in 2005 and the Resource Plan Proceedings that were held for the Carmacks-Stewart Transmission Project in 2007. The costs consist primarily of legal and consulting costs incurred by the Utility and reimbursement of YUB and intervenor costs. YUB Order 2005-12 directed the Utility to defer and amortize the hearing costs over three years. YUB Order 2007-9 directed the Utility to record the Resource Plan Proceeding costs in a Hearing Reserve Account and in the next GRA to include a proposal on how to dispense with the Hearing Reserve Account. In the absence of rate regulation, expenses in 2007 would have been \$760,000 higher (2006 - \$311,000 lower expenses).

Dam safety review

The Utility has a program of conducting reviews of the safety of its dams in accordance with standards set by the Canadian Dam Association. External consultants are hired every five years with intermittent costs incurred in the interim periods. These costs are amortized over five years as approved by the Utility's 1991/92 General Rate Application and reconfirmed in YUB Order 2005-12. In the absence of rate regulation, expenses in 2007 would have been \$22,000 lower (2006 - \$40,000 lower expenses).

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

(b) Diesel contingency fund

The Diesel contingency fund ("DCF") was established by YUB Order 1996-6 through the Negotiated Settlement process. The DCF is administered by the Utility on behalf of the YUB, and as such is recorded as a trust asset and a trust liability. The DCF attracts interest based upon short-term bond rates in which the Utility invests the funds held in trust. Any negative balance attracts interest at the lowest short-term borrowing rate available to the Utility through its line of credit. Pursuant to YUB order 1996-6, the Utility from time to time is required to transfer amounts to or from the trust it maintains on behalf of ratepayers to reimburse the Utility for costs associated with diesel generation required when there is not sufficient water for hydraulic generation to meet demand. In the absence of regulation, GAAP would have required any interest earned or incurred to be included in the Utility's net income in the year in which they occurred. In the absence of rate regulation, the Utility's net income in 2007 would have been higher by \$35,000 from interest earned on the DCF (2006 - \$30,000 higher net income).

Regulatory liabilities

(c) Faro mine dewatering deferral revenue

As directed by YUB Order 1998-5, all revenues, less any incremental costs to provide the service, collected from the Faro Mine under Rate Schedule 34 (Faro Mine Firm Shutdown Power) prior to December 31, 2004, were deferred for the benefit of ratepayers pending direction from the YUB. YUB Order 2005-12 confirmed that effective January 1, 2005 the Faro minesite would be charged the General Service-Government rate so there will be no further increases to Faro Mine Dewatering Deferral Account. This order also enables the Utility to draw down on the Faro Mine dewatering revenue to fund its approved revenue shortfall. YUB Order 2007-2 set the approved 2007 revenue shortfall at \$292,000. In the absence of rate regulation, GAAP would have required only the recognition of actual sales earned during the year. As a result, the Utility's sales of power in 2007 would have been \$292,000 lower (2006 - \$292,000 lower). The period over which the remaining liability will be recognized as revenue for the benefit of ratepayers is dependent on future YUB Board orders and, therefore, cannot be estimated.

(d) Deferred gain on fire insurance proceeds

The deferred gain on fire insurance proceeds relates to a fire at the Whitehorse Rapids Generating Station in 1997 which, pursuant to Board Order 2000-3, is being amortized to income at the same rate as the replacement assets. In the absence of rate regulation, GAAP would have required the gain to have been completely recognized as income in the year received. As a result, the Utility's net income in 2007 would have been lower by the amount of the amortization of \$270,000 (2006 - \$270,000 lower).

(e) Deferred uninsured losses

The YUB has approved the use of a provision for uninsured damages and injuries as a means of self-insurance. The provision is maintained through an annual provision approved by the YUB. In order to eliminate the deficit rate payers held as a result of uninsured losses, the Utility was directed by YUB Order 2005-12 to transfer the insurance proceeds being held on behalf of rate payers of \$744,000 to the reserve for uninsured loss, and increase the annual provision from \$50,000 to \$100,000 for the years 2005 to 2007. In the absence of rate regulation, GAAP would require costs to be expensed as incurred and, therefore, expenses in 2007 would have been lower by \$37,000 (2006 - \$533,000 higher). The period over which the provision will be recovered is dependent on the magnitude of future actual losses incurred and cannot be estimated.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

(f) Regulatory provision for future removal and site restoration costs

Pursuant to amortization rates approved by the YUB in the Utility's previous general rate applications, under section 23(1)(b) of the Public Utilities Act, the Utility has maintained a reserve for future removal and site restoration costs. As a result of the YUB Order 2005-12, effective January 1, 2005, the Utility is required to maintain this reserve as a regulatory provision in addition to any asset retirement obligations. The provision is not to exceed the cumulative value of the provision at December 31, 2004 of \$5,757,000. In the absence of rate regulation, GAAP would have required the Utility to reverse the provision to retained earnings in 2004. YUB Order 2005-12 also directs the Utility to notify interveners and interested parties when the balance of the provision reaches \$2,000,000. Costs of dismantling capital assets, including site remediation, will be applied to this regulatory liability if they do not otherwise relate to an asset retirement obligation. In a non-regulated industry, future removal and site restoration costs would be limited to asset retirement obligations, and the removal and site restoration costs would be expensed in the year incurred if they did not relate to an asset retirement obligation. In the absence of rate regulation, the Utility's 2007 expense would have been lower by the amount of actual removal and site restoration costs incurred in the year of \$158,000 (2006 expenses - \$535,000 higher). The period over which the provision will be settled is dependent on the future costs of demolishing, dismantling, tearing down, or otherwise disposing of the asset, and site restoration net of actual recoveries, and is, therefore, indeterminate.

(g) Fuel price adjustment

OIC 1998/90 directs the YUB to permit the Utility to adjust electricity rates to reflect fluctuations in the price of diesel fuel. The amount by which actual fuel prices vary from the YUB approved rates is deferred and recovered from or refunded to customers in a future period.

In the absence of rate regulation, GAAP would require that actual diesel fuel expenses be included in the operating result of the year that they are incurred. In 2007, fuel expenses were deferred and consequently lower by \$72,000 (2006 - \$56,000 lower).

Other items affected by rate regulation

The Utility is required under the *Public Utilities Act* to obtain prior approval from the YUB before making changes to depreciation, amortization, and depletion rates and methods. The YUB permits an allowance for funds used during construction ("AFUDC"), based on the Utility's weighted average cost of capital, to be included in the rate base. AFUDC is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated over future periods as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFUDC component, will be approved for inclusion in future customer rates. Since AFUDC includes not only a cost of debt component, but also a cost-of-equity component, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

It is the Utility's policy to charge to income, in the year of disposal, any gain or loss upon retirement or disposal of land or vehicles. As approved by the YUB, the gain or loss on all other property, plant and equipment is charged to accumulated amortization and deferred and amortized over the expected life of the remaining pool of similar assets. In the absence of rate regulation, GAAP would require the gain or loss on the disposal or retirement of all property, plant and equipment to be included in income in the period of disposal or retirement.

YUB Order 2005-12 disallows the Utility from earning a return on any additional costs incurred with respect to the Mayo-Dawson line as a result of pursuing any claims or counter claims against the general contractor and directs the Utility to record any recoveries from the general contractor in an interest-bearing deferred account for future review and disposition by the YUB.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

The Utility's policy of maintaining a constant capital structure of 60% debt and 40% equity is reviewed by the YUB as part of the rate-setting process and in the determination of the return on rate base. In the absence of rate regulation, the Utility would determine the appropriate capital structure solely based on decisions by the Board of Directors of the Utility, which may differ from the current policy.

All amounts maintained as regulatory assets and liabilities are expected to be recovered or settled over the periods noted above. However, there are risks and uncertainties associated with the recovery or settlement related to potential future decisions of the regulator which could result in material adjustments to these assets and liabilities.

5. ACCOUNTS RECEIVABLE

	2007	2006
Wholesale energy sales	\$ 2,853	\$ 2,764
Retail energy sales	842	1,109
Other	31	353
	\$ 3,726	\$ 4,226

Wholesale energy sales are made to Yukon Electrical Company Limited, an unrelated company also regulated by the Yukon Utilities Board. Wholesale energy sales in 2007 were approximately \$18,402,000 (2006 - \$18,111,000).

6. DEFERRED UNINSURED LOSSES

	2007	2006
Opening balance	\$ (500)	\$ 33
Provision for uninsured losses	100	100
Losses incurred		
Asset replacements	(63)	(633)
Closing balance	\$ (463)	\$ (500)

7. DIESEL CONTINGENCY FUND

	2007	2006
Opening balance	\$ 821	\$ 791
Interest	35	30
Closing balance	\$ 856	\$ 821

Diesel Contingency Funds are monies invested in a pooled market fund. The short-term securities held in the fund have an average maturity of less than 90 days. Earnings are distributed monthly on a pro-rata share of the total fund. Annual return on investment for 2007 was 4.63% (2006 - 4.08%). The fair market value of these investments is equal to the carrying amount.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

8. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2007 Net book Value	2006 Net book Value
Generation	\$ 138,983	\$ 49,066	\$ 89,917	\$ 91,317
Transmission	54,547	12,077	42,470	43,244
Buildings and other equipment	16,720	5,988	10,732	10,221
Distribution	15,360	5,357	10,003	9,483
Transportation	2,572	764	1,808	1,390
Land and land rights	1,119	-	1,119	1,074
Construction-in-progress	8,345	-	8,345	1,263
	\$ 237,646	\$ 73,252	\$ 164,394	\$ 157,992

9. DEFERRED CHARGES

	Cost	Accumulated Amortization	2007 Net book Value	2006 Net book Value
Deferred water licensing costs	\$ 8,683	\$ 2,996	\$ 5,687	\$ 5,808
Feasibility studies and infrastructure planning	3,172	853	2,319	2,999
Hearing costs	2,004	933	1,071	311
Downsizing costs	334	310	24	71
Dam safety review	213	186	27	49
	\$ 14,406	\$ 5,278	\$ 9,128	\$ 9,238

10. REGULATORY LIABILITIES

	2007	2006
Faro Mine Dewatering Deferral revenue		
Opening balance	1,483	1,775
Applied to revenue shortfall YUB Order 2007-2 (Note 3)	(292)	(292)
Closing balance	\$ 1,191	\$ 1,483

11. DEFERRED REVENUE

	2007	2006
Deferred gain on fire insurance proceeds – property and equipment (net of amortization and adjustments of \$3,977,000 (2006 - \$3,707,000))	\$ 7,626	\$ 7,896
	\$ 7,626	\$ 7,896

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

12. CONTRIBUTIONS IN AID OF CONSTRUCTION

			2007	2006
	Gross	Accumulated Amortization	Net	Net
Capital assistance from parent since 1998	\$ 13,305	\$ 1,492	\$ 11,813	\$ 7,579
Contributions from customers since 1998	4,303	416	3,887	3,792
Pre-1998 contributions	1,739	944	795	816
	\$ 19,347	\$ 2,852	\$ 16,495	\$ 12,187

The sources of contributions received prior to 1998 were not recorded separately.

13. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

	2007	2006
Yukon Development Corporation		
\$40,000,000 flexible term note bearing interest at 7% repayable in annual installments of up to \$1,000,000 principal, plus accrued interest and secured by mortgage over specific assets	26,789	27,316
\$27,313,661 term note bearing interest at 5.88%, payable monthly, and semi-annual principal payments commencing June 30, 2007 and ending December 31, 2023. The note is unsecured.	25,707	27,314
\$18,000,000 flexible term note related to the Mayo to Dawson Transmission Line project bearing interest at 6.55% repayable in annual installments of \$450,000 principal, plus accrued interest with the balance of \$307,000 due December 31, 2043. The note is unsecured.	16,057	16,507
Unsecured advance bearing interest at 6.03%, due one year after demand	3,649	3,649
Unsecured advance bearing interest at 5.403%, due one year after demand	2,839	2,839
Unsecured advance bearing interest at 5.34%, due one year after demand	3,583	3,583
Unsecured advance bearing interest at 5.28%, due one year after demand	4,251	-
TD Canada Trust		
\$12,400,000 term note bearing interest at 7.81% payable in monthly installments of \$102,000 interest and principal, with the balance due September 30, 2011. The note is guaranteed by the Yukon Government.	7,804	8,442
	90,679	89,650
Less current portion	3,416	3,253
	\$ 87,263	\$ 86,397

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

\$40,000,000 Flexible term note

The terms of the flexible term note provide for payments of principal and interest to be deferred and abated, respectively, if power sales on the Whitehorse-Aishihik-Faro electrical power distribution system are less than specified amounts. After adjusting for abated interest, the effective interest rate on this instrument for 2007 is 3.84% (2006 - 3.01%).

Mayo - Dawson Transmission Line Financing

The Utility obtained financing from its parent in the amount of \$18 million for a transmission line from the Mayo hydro generating station to Dawson City. The financing was obtained effective September 6, 2003, the date the transmission line came into service. The financing was made under terms that ensure that ratepayers are not paying more in any year than they would otherwise have paid if the transmission line had not been built and Dawson City had continued to be served by diesel generation. The maximum interest payable on the note in any year is determined by a formula which compares the costs and benefits of operating the line. For example, the costs include amortization, return on equity, and operating and maintenance expense. The benefits include diesel fuel costs not incurred. As per the agreement, total costs, including interest, cannot exceed the benefits.

If the costs of operating the line exceed the benefits in any year, Yukon Development Corporation will pay Yukon Energy Corporation the difference on or before March 31 of the next calendar year.

In 2007, benefits exceeded costs, which resulted in \$1,081,000 in interest paid to Yukon Development Corporation. (In 2006, benefits exceeded costs, which resulted in \$1,111,000 in interest paid to Yukon Development Corporation.)

Unsecured Advances

The Utility declared a dividend to the parent in the amount of \$4,251,000 (2006 - \$3,583,000) and this was loaned back to the Utility at an interest rate of 5.28% in order to maintain the capital structure. This advance is unsecured and due one year after demand.

Long -term debt repayment

Scheduled repayments for all long-term debt are as follows:

2008	3,415
2009	3,428
2010	3,484
2011	3,543
2012	3,609
Thereafter	73,200

\$ 90,679

Fair value

Fair value at December 31, 2007 of \$101 million (2006 - \$105 million) for all long-term debt was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

14. ADMINISTRATION EXPENSES

	2007	2006
Wages and benefits	\$ 3,202	\$ 2,767
General office	1,152	1,175
Insurance and taxes	1,069	1,062
Information systems	530	435
Regulatory loss	481	1,039
Training, recruitment and development	459	212
Environmental	173	145
Board of Directors	167	91
Intercompany services	146	372
Material management and contracting	20	163
	\$ 7,399	\$ 7,461

15. OPERATIONS AND MAINTENANCE EXPENSES

	2007	2006
Wages and benefits	3,246	3,129
Maintenance		
- building and vehicle	730	643
- hydro, diesel and wind	677	641
- lines and substations	567	664
Fuel	218	125
Water level measurement	161	173
	\$ 5,599	\$ 5,375

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

16. RELATED PARTY TRANSACTIONS

Except as disclosed elsewhere, the following table summarizes the Utility's related party transactions for the year:

	2007	2006
Revenue		
Sales of service to:		
- direct parent company	\$ 157	\$ 216
- wholly-owned subsidiary of parent company	-	31
	\$ 157	\$ 247
Rate Stabilization Fund subsidy revenue from:		
- direct parent company	\$ 310	\$ 432
Expense		
Payment of interest on long-term & short-term debt to:		
- direct parent company	\$ 4,311	\$ 4,164
Payment for financial information system usage to:		
- direct parent company	177	177
Other receipts		
Rural Electrification Support Program funding:		
- direct parent company	\$ -	\$ 86
Contributions for Carmacks Stewart Transmission Line		
- direct parent company	\$ 4,450	\$ -
Other payments		
Payment on contribution agreements to:		
- direct parent company	\$ 25	\$ 25

The transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Revenue from related parties is reported as Other revenue on the statement of income. The corresponding cost of providing these services is reported as part of administration expense on the statement of income.

Rate stabilization fund revenues are received from the parent in accordance with terms established by the Government of Yukon, which established the fund to protect certain ratepayers by minimizing the impact of rate increases. These revenues are reported on the statement of income as a component of sales of power.

Interest on long-term debt is included on the income statement under Other expenses.

Rural Electrification Support Program funds are received from the parent and are recorded as an offset to the capitalized cost of the respective project.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

At the end of the year, the amounts receivable from and due to related entities are as follows:

	2007	2006
Direct parent company		
Accounts receivable	\$ 76	\$ 179
Accounts payable	\$ 74	\$ 68
Current portion of long-term debt	\$ 2,776	\$ 2,609
Long-term debt	\$ 80,099	\$ 78,599

These balances are non-interest bearing and payable on demand except for long-term debt (Note 13).

17. PENSION COSTS AND OBLIGATIONS

The Utility sponsors a defined benefit pension plan which provides benefits based on length of service and final average earnings as follows:

- years of pensionable service;
- the average annual earnings during any five consecutive years of pensionable service where earnings are the highest; and
- the average of the years maximum pensionable earnings (Canada Pension Plan) for the same five year period

Annual cost of living increases to a maximum of 3.00% are provided to pensioners. The Utility contributes amounts as recommended by an independent actuary.

Employees make contributions to the plan as follows:

- 3.5% of earnings up to the year's maximum pensionable earnings; and
- 5.0% of earnings in excess of year's maximum pensionable earnings to a maximum of \$2,500 per year.

The Utility has contracted with external organizations to provide services of trustee, administrator and investment manager for the pension plan.

An actuarial valuation for funding purposes was performed as of January 1, 2007 by the consulting actuarial firm AON Consulting Inc. The next valuation for funding purposes will be conducted as of January 1, 2010. The pension costs and obligations were based on the data used in the January 1, 2007 funding valuation and have been projected to December 31, 2007 in accordance with generally accepted actuarial standards.

The fair value of the plan assets is based on market values as reported by Group Retirement Services, the plan's custodian as at December 31, 2007. The plan assets are invested in a pooled balanced fund. The distribution of assets by major asset class is as follows:

	December 31, 2007	December 31, 2006
Equities	51.0%	51.9%
Fixed Income Securities	38.2%	38.3%
Real Estate	10.8%	9.8%

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

Information about the Utility's defined benefit plan as at December 31, in aggregate, is as follows:

	2007	2006
Discount rate-accrued benefit obligation	5.50%	5.25%
Discount rate-benefit costs	5.25%	6.00%
Expected long-term rate of return on plan assets	6.50%	6.50%
Assumed rate of salary escalation	3.00%	3.00%
Assumed rate of pension indexing	2.50%	2.50%
Expected average remaining service period of active employees	12 years	14 years
Benefit obligation determined by actuarial valuation	\$ 10,010	\$ 9,181
Fair value of plan assets	7,500	7,006
Plan deficit	\$ 2,510	\$ 2,175
Unrecognised amount:		
- transitional asset	169	186
- net actuarial losses	(1,875)	(1,741)
Accrued benefit liability	\$ 804	\$ 620
Pension expense	\$ 493	\$ 506
Employer contributions	\$ 308	\$ 307
Employee contributions	\$ 113	\$ 115
Benefits paid	\$ 117	\$ 60

The accrued benefit liability has been recorded on the Utility's books of account and its current portion of \$63,000 (2006 - \$60,000) is included in accounts payable on the balance sheet.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the defined benefit plan. The Utility makes contributions to a Registered Retirement Savings Plan ("RRSP") on behalf of these employees and employees hired before January 1, 2002 who belonged to the defined benefit plan and elected to opt out of that plan. The RRSP is a defined contribution plan. The costs recognized for the period are equal to the Utility's contribution to the plan. During 2007, these were \$184,000 (2006 - \$149,000).

Total cash payments for employee future benefits for 2007, consisting of cash contributed by the Utility to its funded defined benefit pension plan and cash contributed directly to the RRSP were \$492,000 (2006 - \$456,000).

As at December 31, 2007, the Utility's defined benefit pension plan had 38 members (2006 - 40), and the RRSP had 41 members (2006 - 40 members).

18. CONTINGENCIES

Mayo to Dawson City transmission line project

The Utility completed the construction of the Mayo to Dawson City Transmission Line project during 2003. Subsequent to energization of the line, the Utility and the general contractor notified each other that they have numerous claims arising out of the agreement and the construction of the line. These claims total several million dollars on a net basis.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

Third party proceedings have been initiated by both the Utility and the general contractor against other consultants and subcontractors to the Project. Documents will be exchanged between all parties by July 14, 2008, and examinations for discovery will commence in the fall of 2008. The consolidated trial of all claims and third party claims is scheduled for 2010. To date, the Utility has insufficient information to assess the merits of the various claims.

19. COMMITMENTS

(a) Major Construction Project

(i) Power Purchase Agreement

On February 8, 2007, the Utility signed a Power Purchase Agreement (PPA) with Minto Explorations Limited (MEL). After review by the Yukon Utilities Board and due diligence by the Utility, the agreement was amended on May 14, 2007 and May 25, 2007, respectively.

Under the amended PPA (approved by the Yukon Utilities Board on Order 2007-6), the Utility agreed to construct a power line to the MEL mine site to deliver electricity from its grid for the mine's operation subject to various conditions to be met before the agreement could take full effect. The significant provisions include:

- a firm mine rate (as subsequently set out in OIC 2007/94),
- a low grade ore processing secondary energy rate,
- a minimum take-or-pay amount of \$12,000,000 to be paid by MEL within the first four years of service by the Utility,
- certain security to be provided to the Utility by MEL,
- a capital cost contribution by MEL to the Utility (for the full capital cost of the transmission line from Minto Landing to the mine site plus a contribution of \$7,200,000 towards the cost of the power line from Minto Landing to the existing grid at Carmacks),
- decommissioning costs to be paid to the Utility by MEL, and
- In consideration for assignment of four leased diesel generators with a combined continuous rating of 6.4 MW, YEC will pay MEL \$2,240,000 subject to certain conditions and adjustments.

The Utility has agreed in the PPA to finance MEL's capital contribution over seven years at an interest rate of 7.5% per annum, subject to conditions and potential adjustments, with MEL making payments annually.

The Yukon Development Corporation (YDC) and the Utility have agreed on certain matters related to the MEL capital cost contribution, including YDC's agreement:

- to assume from the Utility the financing risk of the MEL capital cost contribution and
- to guarantee all capital cost payments by MEL to the Utility under the PPA, and
- to pay directly to the Utility any amount in excess of \$7,200,000 of the contribution required by MEL towards the cost of the power line from Minto Landing to the existing grid at Carmacks.

All conditions required for the PPA to take full effect were cleared or waived by December 17, 2007.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

(ii) Construction Commitments

During 2007, the Utility entered into major contracts with third parties related to project management, survey, clearing and construction necessary to deliver power to the Minto mine site and the community of Pelly Crossing. The total approved budget (including planning costs) is \$37,700,000 and the line is anticipated to be energized by September 30, 2008. By year end, the Utility had spent \$6,300,000 on the project, which is recorded in property, plant and equipment. The Corporation has contribution commitments from the Government of Yukon for \$10,450,000 which is to be received the following year.

(iii) Project Agreement

On October 19 2007, the Utility signed a Project Agreement with the Northern Tutchone First Nations (NTFN). This agreement defines certain rights and obligations of the parties as they pertain to the Carmacks Stewart Transmission Project defined above. The Utility has granted the NTFN an option on certain terms and conditions to take over part or all of the financing being provided to the Minto Mine by the Utility in relation to the capital contribution made by the mine under the PPA agreement. The financing amount will be for all or part of the capital cost of the Mine Spur and the \$7,200,000 contribution to the main line. The option must be exercised prior to September 30, 2008 or such later date as to which the Utility agrees.

(b) Financial Information System Lease

The Utility leases a financial information system from the parent. Minimum lease payments for the remaining two years are as follows:

	2008	177
	2009	147
Total		\$ 324

(c) Aishihik Water Licence

The Yukon Territory Water Board issued a water use license in 2002, valid until December 31, 2019, for the Utility's Aishihik Lake facility. In addition to maintaining a minimum and maximum water level, this license commits the Utility to meet a number of future requirements including:

- annual payments of \$25,000 until 2011 for the purpose of construction and maintenance of a heritage camp and delivery of programs at the camp;
- Heritage Mitigation Plan. The Utility did not incur expenditures in 2007 on heritage projects, expects to spend up to \$7,500 in 2008 on heritage projects, and the balance which has not yet been determined in the future; and
- annual fish monitoring programs.

Fish monitoring programs are also required under an authorization provided by the federal government Department of Fisheries and Oceans, which is valid until December 31, 2019. The costs of meeting these requirements are accounted for as water licence costs in the year they are paid.

Yukon Energy Corporation

Notes to Financial Statements

(tabular amounts in thousands of dollars)

December 31, 2007

20. ENVIRONMENTAL LIABILITIES

The Utility's activities are subject to various federal and territorial laws and regulations governing the protection of the environment or to minimize any adverse impact thereon. The Utility conducts its operations so as to protect public health and the environment and believes its operations are materially in compliance with all applicable laws and regulations. Liabilities will be recorded when the occurrence of an environmental expenditure, related to present or past activities of the Utility, is considered probable and the costs can be reasonably estimated. To date, no such specific liabilities have been recorded in the Utility's accounts.

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2006 and 2007, Yukon Energy Corporation's financial instruments included cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying value of cash and cash equivalents, accounts receivable, accounts payable and long-term debt due within one year approximate their fair value due to the immediate or short-term maturity of these financial instruments.

All long-term debt is being classified as other than held for trading. The fair values of the long-term debt are estimated based on quoted market prices for the same or similar issues as well as the use of discounted future cash flows using current rates for similar financial instruments subject to similar risks and maturities. The fair value of long-term debt is described in Note 13.

The Utility also has access to a \$10 million line of credit. The renewal date on the line of credit is October 31, 2009. The account accrues interest on withdrawals at prime rate. The facility was not drawn on at year-end.

The Utility is not exposed to significant interest rate risk due to its long-term debt having fixed interest rates. The Utility's credit risk is minimal in that its primary customer is a regulated utility.

22. COMPARATIVE FIGURES

Certain 2006 figures have been reclassified to conform with the current year's presentation.

TAB 10
ORDERS IN COUNCIL

YUKON

CANADA

Whitehorse, Yukon

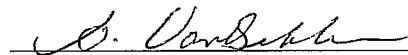
ORDER-IN-COUNCIL 2007/94

PUBLIC UTILITIES ACT

Pursuant to section 17 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows

1 The annexed *Major Industrial Customer Rate Directive* is hereby made.

Dated at Whitehorse, Yukon,
this 04 JUNE 2007.



Commissioner of Yukon/Commissaire du Yukon

YUKON

CANADA

Whitehorse, Yukon

DÉCRET 2007/ 94

LOI SUR LES ENTREPRISES DE
SERVICES PUBLICS

Le commissaire en conseil exécutif, conformément à l'article 17 de la *Loi sur les entreprises de services publics*, décrète :

1 Les *Instructions sur les clients industriels majeurs* paraissant en annexe sont établies

Fait à Whitehorse, au Yukon,
le 04 juin 2007.

PUBLIC UTILITIES ACT

LOI SUR LES ENTREPRISES DE SERVICES
PUBLICS

MAJOR INDUSTRIAL CUSTOMER DIRECTIVE

RÈGLEMENT SUR LES INSTRUCTIONS SUR LES
CLIENTS INDUSTRIELS MAJEURS

1 This order amends the Rate Policy Directive (1995).

2 The following subsection is added immediately after subsection 6(2) of the said Directive.

“(3) Despite subsection (1), the Board must ensure that the rates charged to Major Industrial Customers from January 1, 2008 until December 31, 2012 conform to Rate Schedule 39, Industrial Primary, attached hereto as Schedule A.”

3 This Order expires on January 1, 2013.

1 Le présent décret modifie les Instructions sur la politique tarifaire (1995).

2 L'article 6 est modifié par adjonction, après le paragraphe (2), de ce qui suit :

« (3) Malgré le paragraphe (1), la Commission veille à ce que les tarifs facturés aux clients industriels majeurs du 1^{er} janvier 2008 au 31 décembre 2012 respectent l'annexe tarifaire n° 39, Clients industriels, paraissant à l'annexe A. »

3 Le présent décret expire le 1^{er} janvier 2013.

SCHEDULE A

INDUSTRIAL PRIMARY

RATE SCHEDULE 39

Available

Throughout the service areas of Yukon Energy Corporation ("YEC") and The Yukon Electrical Company Limited ("YECL") served by the Whitehorse-Aishihik-Faro and Mayo-Dawson systems.

Applicable

To all major industrial customers engaged in manufacturing, processing or mining with an electric service capacity in excess of 1,000 kW.

Rate

Charges in any one billing month shall be the sum of the following:

- (a) Demand Charge of \$15.00/kV.A of Billing Demand
- (b) Energy Charge of 7.60¢/kW.h for all energy used.
- (c) Fixed Charge

For service to Minto mine site, the Fixed Charge each month shall equal the payments then required under the amended Power Purchase Agreement (the "PPA") dated May 14, 2007, between YEC and Minto Explorations Ltd. ("Minto") for monthly Capital Cost Contributions for transmission connection to the mine.

Peak shaving credit

For customers with an established Winter Contract Load in good standing, a Peak Shaving Credit in each billing month equal to 50% of the Demand Charge times the Peak Shaved Load.

Minimum Monthly Bill

The minimum monthly bill will be the sum of the Demand Charge and the monthly Fixed Charge, less any applicable Peak Shaving Credit.

Peak Shaved Load

Peak Shaved Load in any billing month is the amount by which then nominated Winter Contract Load is less than the Billing Demand for the month.

Billing Demand

The Billing Demand shall be the greater of:

- (a) the highest metered kV.A demand recorded in the current billing month; or
- (b) the highest metered kV.A demand recorded in the previous 12-month period including the current billing month, excluding the months April through September; or
- (c) the contract minimum demand.

Winter Contract Load

A customer may, by six month written notice to YEC, nominate a Winter Contract Load at not less than two-thirds of the customer's contract maximum demand subject to the following conditions:

- (a) the customer will thereby contract with YEC not to exceed the nominated Winter Contract Load whenever the temperature at Whitehorse is below -30 degrees Centigrade, based on YEC informing the customer by phone, fax or e-mail as to forecast and actual winter temperatures at Whitehorse as provided for in paragraph (b);
- (b) YEC will inform the customer at least one hour in advance, and not more than one day in advance, of a forecast temperature at Whitehorse being below -30 degree Centigrade; thereafter, until YEC informs the customer otherwise, the customer will be responsible for ensuring that its metered kV.A demand does not exceed the Winter Contract Load during any hour when the actual temperature at Whitehorse is below -30 degrees Centigrade; YEC will inform the customer forthwith when the temperature at Whitehorse is no longer forecast to be below -30 degree Centigrade within the next 24 hours;
- (c) the customer agrees that the contract for the nominated Winter Contract Load will continue until terminated by written notice of not less than 12 months by the customer to YEC;
- (d) if during such contract period for the Winter Contract Load the customer's metered kV.A demand recorded, after YEC has provided notice as specified in paragraph (b), exceeds the Winter Contract Load when the temperature at Whitehorse is less than -30 degrees Centigrade, the Winter Contract Load contract will be terminated forthwith, the customer will forthwith be required to repay to YEC all Peak Shaving Credits determined within the previous 12 billing months, and the customer will also pay for that billing month to YEC as penalty an amount equal to four times the Demand Charge on the metered kV.A demand recorded in excess of the Winter Contract Demand; in addition, YEC reserves the right if so required to meet system loads when the temperature at Whitehorse is less than -30 degrees Centigrade during the then current month and the following 12 months to interrupt electricity supplied to the customer in excess of the previous Winter Contract Load.

Base Load Energy

A Base Load Energy amount per month may be established for a customer of 90% of forecast use when YEC expects to require diesel fuel generation to service use in excess of such a Base Load Energy amount. At such time, Rate Schedule 39 will be submitted to the Yukon Utilities Board for amendment to adjust the Energy rate as required for a two part rate that yields the same overall energy charge at forecast energy use, with all energy consumed in excess of the Base Load being charged at a rate reflecting the incremental cost of service using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use.

Rate Modifications Applicable:

For fuel adjustment rider, see Rider F. Rider F applied to energy charges only, set to \$0.0 for fuel price forecast filed November 20, 2006.

Electric Service Regulations:

The *Electric Service Regulations* approved by the Yukon Utilities Board form part of this rate schedule and apply to YEC and every customer supplied with electric service by YEC in the Yukon Territory. Copies of the *Electric Service Regulations* are available for inspection in the offices of YEC during normal working hours.

Escalation of demand and energy charges

Demand and Energy charges for the directed changes are to be escalated once each calendar year, starting January 1, 2010, based on the latest percentage increase in the 12 month implicit chain price index for gross domestic product at market prices for Canada as reported by Statistics Canada.

Adjustment of fixed charge

The Fixed Charge is to be adjusted to provide for fixed monthly charges as set out in any Power Purchase Agreement, or amendments thereto, between a Major Industrial Customer and either Yukon Energy Corporation or the Yukon Electrical Company Limited, as approved by the Board.

ANNEXE A

CLIENTS INDUSTRIELS

ANNEXE TARIFAIRE N° 39

Offert

Dans l'ensemble des régions desservies par la Société d'énergie du Yukon (« SEY ») et la Yukon Electrical Company Limited (« YECL »), desservie par les systèmes de Whitehorse-Aishihik-Faro et Mayo-Dawson.

Applicable

À tous les clients industriels majeurs dont les activités sont la fabrication, le traitement ou l'exploitation d'une mine dont l'approvisionnement en électricité excède 1000 kW.

Tarif

Les tarifs facturés pour un mois de facturation sont la somme de ce qui suit :

- a) une prime de puissance de 15.00 \$/kVA de la demande facturée;
- b) le coût de l'énergie établi à 7,60¢/kWh pour toute l'énergie consommée;
- c) des frais fixes

Pour l'approvisionnement du site de la mine Minto, les frais fixes sont égaux aux paiements exigés en vertu de la convention d'achat intitulée *Power Purchase Agreement* (la « PPA »), avec ses modifications, datée du 14 mai 2007, conclue entre YEC et Minto Explorations Ltd. (« Minto ») pour la contribution mensuelle des coûts d'investissement pour le branchement de l'approvisionnement de la mine.

Crédit d'écrêtement de la demande de pointe

Pour les clients dont la charge hivernale maximale est en règle, le crédit d'écrêtement de la demande de pointe de chaque mois de facturation représente 50 % de la prime de puissance multipliée par la charge réduite pour la demande de pointe.

Facture mensuelle minimale

La facture mensuelle minimale est égale au total de la prime de puissance et des frais fixes mensuels, desquels est soustrait tout crédit d'écrêtement de la demande de pointe.

Charge réduite pour la demande de pointe

La charge réduite pour la demande de pointe pour un mois de facturation, représente la différence entre la charge hivernale maximale et la demande facturée pour le mois.

Demande facturée

La demande facturée est le montant le plus élevé de :

- a) la demande la plus élevée en kVA enregistrée au cours du mois de facturation courant;
- b) la demande la plus élevée en kVA enregistrée au cours des 12 derniers mois, y compris le mois de facturation courant, mais à l'exclusion des mois d'avril à septembre;
- (c) la demande minimale fixée par contrat.

Charge hivernale maximale

Un client peut, en donnant un préavis de six mois à la SEY, adopter une charge hivernale maximale qui représente au moins deux tiers de la demande maximale du client fixée par contrat, sous réserve des conditions suivantes :

- a) le client s'engage envers la SEY à ne pas excéder la charge hivernale maximale adoptée lorsque la température à Whitehorse est inférieure à -30 degrés Celsius d'après les renseignements fournis au client par la SEY par téléphone, télécopieur ou courriel relativement aux prévisions météorologiques et la température hivernale véritable à Whitehorse, en conformité avec l'alinéa b);
- b) YEC s'engage à informer le client au moins une heure à l'avance et au plus une journée à l'avance, si les prévisions météorologiques pour Whitehorse sont inférieures à -30 degrés Celcius. Dès lors et jusqu'à ce que la SEY l'avise du contraire, il incombe au client de veiller à ce que les kVA mesurés au compteur n'excèdent pas la charge hivernale au cours d'une heure pendant laquelle la température véritable à Whitehorse est inférieure à -30 degrés Celcius. La SEY informera immédiatement le client lorsque les prévisions météorologiques pour Whitehorse ne sont plus inférieures à -30 degrés Celcius pour les prochaines 24 heures;
- c) le client consent à ce que le contrat relatif à la charge hivernale maximale demeure en vigueur jusqu'à ce qu'il soit annulé par le client avec un préavis écrit d'au moins 12 mois à la SEY;
- d) si au cours de la période fixée par contrat pour la charge hivernale maximale, la demande en kVA mesurée au compteur du client excède la charge hivernale maximale, alors qu'un avis a été donné par la SEY en conformité avec l'alinéa b) et que la température à Whitehorse est inférieure à -30 degrés Celcius, le contrat relatif à la charge hivernale maximale est immédiatement résilié. Le client est dès lors tenu de rembourser immédiatement à la SEY tous les crédits d'écèlement de la demande de pointe accordés au cours des 12 derniers mois de facturation, ainsi que qu'une pénalité pour le mois courant qui représente quatre fois la prime de puissance sur la demande du client en kVA mesurée au compteur qui excède la charge hivernale maximale. De plus, la SEY se réserve le droit, si cela est nécessaire pour satisfaire aux besoins du système lorsque la température à Whitehorse est inférieure à -30 degrés Celcius au cours du mois alors en cours et les 12 mois suivants, d'interrompre l'alimentation en électricité du client qui excède la charge hivernale maximale.

Charge de base de l'énergie

Un montant de charge de base de l'énergie par mois peut être fixé pour le client qui consomme 90 % de la consommation anticipée lorsque la SEY prévoit devoir faire appel à la production d'énergie au carburant diesel pour alimenter l'usage qui excède ce montant de charge de base de l'énergie. L'annexe tarifaire n° 39 est alors soumise à la Régie des entreprises de service public du Yukon pour être modifiée afin d'ajuster le tarif de l'énergie de façon à établir un tarif à deux paliers qui permet la même charge d'énergie pour la consommation d'énergie anticipée, avec un taux qui tient compte du coût additionnel pour la production d'énergie au carburant diesel applicable à toute l'énergie consommée en plus de la charge de base. Le tarif réduit nécessaire pour permettre la même charge d'énergie pour la consommation anticipée est applicable à l'énergie restante.

Modifications des tarifs applicables :

Pour la clause additionnelle relative au coût du carburant, consulter la clause additionnelle F. La clause additionnelle F s'applique exclusivement aux coûts de l'énergie, fixés à 0,0\$ pour la prévision des prix de l'essence déposée le 20 novembre 2006.

Electric Service Regulations :

Les *Electric Service Regulations*, approuvés par la Régie des entreprises de service public du Yukon font partie intégrante de la présente annexe relative aux tarifs et s'appliquent à la SEY et à tous les clients qui reçoivent des services d'approvisionnement en électricité de la SEY au Yukon. Il est possible de consulter les *Electric Service Regulations* aux bureaux de la SEY pendant les heures normales d'ouverture.

Augmentation de la prime de puissance et du coût de l'énergie

La prime de puissance et le coût de l'énergie pour les modifications exigées font l'objet d'une augmentation par année civile à compter du 1^{er} janvier 2010 et reposent sur la plus récente augmentation de l'indice de prix en chaîne pour les 12 mois inclusivement, pour le produit intérieur brut aux prix du marché pour le Canada, établi par Statistique Canada.

Ajustement des frais fixes

Les frais fixes sont ajustés pour tenir compte des coûts mensuels fixes établis dans toute convention d'achat d'énergie, ou dans les modifications à celle-ci, conclue entre un client industriel majeur d'une part et la SEY ou la YECL, d'autre part et qui a été approuvée par la Régie.

YUKON TERRITORY

CANADA

Whitehorse, Yukon

ORDER-IN-COUNCIL 1998/32

PUBLIC UTILITIES ACT

Pursuant to section 17(1) of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows:

1. Order-in-Council 1995/90 is amended by revoking Order-in-Council 1997/203 and substituting the following section for it.

"2.(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on their equity used to finance their rate base.

(2) The Board must include in the rates of the Yukon Energy Corporation provision to recover a fair return on the Corporation's equity, less one-half of one per cent (.5%).

TERRITOIRE DU YUKON

CANADA

Whitehorse, Yukon

DÉCRET 1998/32

LOI SUR LES SERVICES PUBLICS

Le Commissaire en conseil exécutif, conformément au paragraphe 17(1) de la *Loi sur les services publics*, décrète ce qui suit :

1. Le décret 1995/90 est modifié en abrogeant le décret 1997/203 et en le remplaçant par ce qui suit.

"2. Sous réserve du paragraphe 2, la Commission doit prévoir dans les tarifs de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited les mesures pour réaliser un rendement équitable sur leur valeur nette utilisé pour financer leurs tarifs de base.

(2) La Commission doit inclure dans les tarifs de la Société d'énergie du Yukon des mesures pour réaliser un rendement équitable sur la valeur nette de cette dernière, moins 5 dixièmes pour cent (.5 %).

(3) When finalizing the interim 1997 rates made by Board Order 1997-6, the Board may adjust the 1997 fair return provided on Yukon Energy Corporation's equity and on Yukon Electrical Company Limited's equity."

(3) Lorsqu'elle met au point les tarifs intermédiaires de 1997 établis par l'ordonnance 1997-6 de la Commission, cette dernière peut rajuster le rendement équitable de 1997 découlant de la valeur nette de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited.~

Dated at Whitehorse, in the Yukon Territory,
this 3 day of March , 1998.

Fait à Whitehorse, dans le territoire du Yukon,
ce 3 mars 1998.



Commissioner of the Yukon/Commissaire du Yukon

YUKON TERRITORY

CANADA

Whitehorse, Yukon

Whitehorse, Yukon

ORDER-IN-COUNCIL 1997/ 203

PUBLIC UTILITIES ACT

On application by the Public Utilities Board to the Minister of Justice dated December 16, 1997 pursuant to section 17(3) of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows pursuant to section 17(3)(b) of the said Act:

1. Section 2 of the Rate Policy Directive (1995) is revoked and the following section is substituted for it:

"2.(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation provision to recover a normal commercial return on Yukon Energy Corporation's equity, less one-half of one percent (.5%).

(2) The Board may reduce the normal commercial return established in subsection (1) during the fiscal periods to which extraordinary circumstances such as the loss of revenues from the Anvil Range Mining Corporation or other major industrial customers apply."

Dated at Whitehorse, in the Yukon Territory,
this 22 day of December, 1997.


Commissioner of the Yukon/Commissaire du Yukon

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DÉCRET 1997/203

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

Suite à une demande de la Régie des entreprises de service public du Yukon au ministre de la Justice en date du 16 décembre 1997, conformément au paragraphe 17(3) de la *Loi sur les entreprises de service public*, le Commissaire en conseil exécutif ordonne ce qui suit, conformément à l'alinéa 17(3)b) de la même loi :

1. L'article 2 des Instructions sur la politique tarifaire (1995) est abrogé et remplacé par ce qui suit :

"2.(1) Sous réserve du paragraphe 2, la Régie prévoit dans les tarifs de la Société d'énergie du Yukon les mesures pour réaliser un rendement commercial normal sur sa valeur nette, moins 5 dixièmes pour cent (.5 %).

(2) La Régie peut réduire le rendement commercial normal établi au paragraphe (1) au cours de périodes fiscales affligées de circonstances sortant de l'ordinaire, tels que la perte de revenus en provenance d'Anvil Range Mining Corporation ou de tout autre client industriel d'importance."

Fait à Whitehorse, dans le territoire du Yukon,
ce 22 décembre 1997.

YUKON TERRITORY

CANADA

Whitehorse, Yukon

ORDER-IN-COUNCIL 1995/ 90

PUBLIC UTILITIES ACT

Pursuant to sections 17 and 18 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows:

1. Order-in-Council 1991/062 is hereby revoked.

2. The annexed Rate Policy Directive (1995) is hereby made.

Dated at Whitehorse, in the Yukon Territory,
this 29 day of May, 1995.

TERRITOIRE DU YUKON

CANADA

Whitehorse, Yukon

DÉCRET 1995/90

LOI SUR LES SERVICES PUBLICS

Le Commissaire en conseil exécutif, conformément aux articles 17 et 18 de la *Loi sur les services publics*, décrète ce qui suit :

1. Le décret 1991/062 est, par les présentes, abrogé.

2. Les instructions sur la politique tarifaire (1995), paraissant en annexe, sont par les présentes adoptées.

Fait à Whitehorse, dans le territoire du Yukon,
ce 29 mai 1995.


Commissioner of the Yukon/Commissaire du Yukon

RATE POLICY DIRECTIVE (1995)

INSTRUCTIONS SUR LA
POLITIQUE TARIFAIRE (1995)

Interpretation

1. In this Directive

"customer" refers to a purchaser of electricity;
«client»

"government customer" means a retail customer

(a) who is a federal or territorial department or agency;

(b) a body, other than one carrying on a business with a view to making a profit, that derives all or substantially all of its funding from a body referred to in paragraph (a); «client gouvernemental»

"isolated industrial customer" means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer; «client industriel isolé»

"major industrial customer" means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer; «client industriel majeur»

↘ "province" has the same meaning as in the *Interpretation Act*; «province»

"retail customer" means a customer of Yukon Energy Corporation or of The Yukon Electrical Company Limited, other than a major industrial customer

Définitions

1. Les définitions qui suivent s'appliquent aux présentes instructions :

«client» Acheteur d'électricité; "client"

«client au détail» Client de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited qui n'est ni un client industriel majeur, ni un client industriel isolé, ni un client en gros; "retail Customer"

«client en gros» La Yukon Electrical Company Limited lorsqu'elle achète de l'énergie de la Société d'énergie du Yukon; "wholesale customer"

«client gouvernemental» Client au détail qui est:

a) soit un organisme gouvernemental, un ministère fédéral ou territorial;

b) soit un organisme qui n'exploite aucune entreprise à des fins lucratives et dont le financement provient en totalité, ou pour l'essentiel, d'un organisme décrit à l'alinéa a); "government customer"

«client industriel isolé» Client qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont l'approvisionnement en électricité est indépendant de celui de tout autre client; "isolated industrial customer"

trial customer, an isolated industrial customer, or a wholesale customer; «client au détail»

“wholesale customer” means the Yukon Electrical Company Limited when it purchases electricity from Yukon Energy Corporation. «client en gros»

Normal return on equity

2. The Board must include in the rates of Yukon Energy Corporation provision to recover a normal commercial return on Yukon Energy Corporation's equity, less one-half of one per cent (.5%).

Normal principles to apply

3. Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with principles established in Canada for utilities, including those principles established by regulatory authorities of the Government of Canada or of a province regulating hydro and non-hydro electric utilities.

Retail rates: non-government customers

4.(1) The Board must fix rates for retail customers, other than government customers, in accordance with the following rate policy for Yukon,

(a) the rates for non-government retail customers must be sufficient to recover

«client industriel majeur» Client autre qu'un client industriel isolé qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont la demande de pointe d'électricité dépasse 1 MW. “major industrial customer”

«province» S'entend d'une province au sens de la *Loi d'interprétation*. “province”

Rendement normal sur la valeur nette

2. La Commission prévoit dans les tarifs de la Société d'énergie du Yukon les mesures pour réaliser un rendement commercial normal sur sa valeur nette, moins 5 dixièmes pour cent (.5 %).

Application des principes normaux

3. Sauf indication contraire dans les présentes instructions ou dans la loi, la Commission examine et approuve les tarifs aux clients selon les principes établis au Canada pour des services publics, y compris les principes établis par les organismes régulateurs des gouvernements fédéral et provinciaux réglementant les entreprises de services publics, que ces derniers soient reliés à l'électricité ou pas.

Tarifs au détail pour les clients non-gouvernementaux

4.(1) La Commission fixe les tarifs pour les clients au détail non-gouvernementaux selon la politique tarifaire suivante pour le Yukon :

a) les tarifs pour les clients non-gouvernementaux doivent suffire à

costs that are not to be recovered from government customers or from major industrial customers;

(b) rates for each class of non-governmental retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers;

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

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

générer les recettes nécessaires afin de recouvrer les coûts, lesquels ne doivent pas être récupérés des clients gouvernementaux ou des clients industriels majeurs;

b) les tarifs pour chaque catégorie de clients au détail non-gouvernementaux s'appliquent uniformément à la grandeur du Yukon et sans distinction entre la Société d'énergie du Yukon et la Yukon Electrical Company Limited.

(2) La Commission doit déterminer une série de primes de dépassement pour chaque catégorie visée de clients au détail non-gouvernementaux, lesquelles s'appliquent à la consommation de chaque client qui excède un niveau de consommation déterminée, au cours d'une période de facturation et un tel niveau de consommation déterminé par client ne peut s'appliquer qu'à la consommation atteignant 1 000 kWh ou plus pour la catégorie résidentielle de clients au détail non-gouvernementaux et de 2 000 kWh pour la catégorie de services généraux de clients au détail non-gouvernementaux.

(3) La Commission doit déterminer des primes de dépassement pour chaque catégorie de clients au détail non-gouvernementaux sur la base de principes pour l'élaboration des taux afin de favoriser l'efficacité et l'économie et, dans cette optique, des primes de dépassement peuvent être permises à l'intention de clients demeurant dans différentes communautés ou dans des zones où les taux diffèrent, en autant que ces primes de dépassement dans chaque catégo-

Retail rates: government customers

5.(1) The Board must fix rates for government customers in accordance with the following power rate policy for Yukon

(a) rates for government customers may be adjusted so as to simplify the rate structure and make the rates more consistent throughout Yukon;

(b) the rate for government customers in a community may not be lower than the rate for similar service to non-government retail customers in that community.

(2) Upon application of Yukon Energy Corporation, The Yukon Electrical Company Limited, or a customer, the Board must determine whether a customer is or is not a government customer.

Rates - major and isolated industrial customers

6.(1) The Board must ensure that the rates charged to major industrial power customers, whether pursuant to contracts or otherwise, are sufficient to recover the costs of service to that customer class; those costs must be determined

rie de clients au détail non-gouvernementaux soient les mêmes pour chaque communauté ou chaque zone tarifaire à travers le Yukon, conformément aux principes pour l'élaboration des tarifs.

Tarifs au détail pour les clients gouvernementaux

5.(1) La Commission fixe les tarifs pour les clients gouvernementaux selon la politique tarifaire énergétique du Yukon qui suit :

a) les tarifs pour les clients gouvernementaux peuvent être ajustés aux fins de simplifier la structure tarifaire et d'uniformiser les tarifs à la grandeur du Yukon;

b) le tarif pour les clients gouvernementaux dans une agglomération ne peut être moindre que le tarif pour un service semblable pour les clients au détail non-gouvernementaux dans cette agglomération.

(2) À la demande de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited, ou d'un client, la Commission prend une décision sur le statut de client gouvernemental d'un client.

Tarifs pour les clients industriels majeurs et isolés

6.(1) La Commission doit s'assurer que les tarifs facturés aux clients industriels majeurs, en vertu d'un contrat ou autrement, suffisent à recouvrer les coûts du service pour cette catégorie de clients. Ces coûts

by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same.

(2) Rates of isolated industrial customers served by Yukon Energy Corporation or The Yukon Electrical Company Limited must conform with any contract between the customer and Yukon Energy Corporation or The Yukon Electrical Company Limited and the costs and revenues related to those contracts may not be considered by the Board when establishing rates for other customers.

Wholesale rates

7. The Board must fix rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policy for Yukon:

(a) Yukon Energy Corporation shall sell electricity to The Yukon Electrical Company Limited at the same demand rate and the same energy rate throughout the Yukon and those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers;

(b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein.

sont déterminés en considérant tout le Yukon comme une zone tarifaire unique et les tarifs facturés par les deux services publics doivent être les mêmes.

(2) Les tarifs s'appliquant aux clients industriels et isolés desservis par la Société d'énergie du Yukon ou la Yukon Electrical Company Limited doivent être conformes à tout contrat entre le client et ces sociétés; les coûts et les revenus reliés à ces contrats ne peuvent être considérés par la Commission lorsqu'elle établit les tarifs pour d'autres clients.

Tarifs de gros

7. La Commission doit déterminer les tarifs facturés par la Société d'énergie du Yukon au client en gros selon la politique tarifaire du Yukon qui suit :

a) la Société d'énergie du Yukon vend de l'électricité à la Yukon Electrical Company Limited au même tarif de demande et au même tarif d'énergie à la grandeur du Yukon et ces tarifs doivent suffire à la Société d'énergie du Yukon pour recouvrer les coûts qui ne sont pas recouverts de ses autres clients;

b) le tarif de gros facturé à la Yukon Electrical Company Limited comprend les mesures appropriées pour permettre à la Société d'énergie du Yukon de recouvrer ses coûts de service au détail et ses coûts de service aux clients industriels majeurs au moyen de tarifs qui s'appliquent à ces services en vertu des présentes.

Fuel Price adjustment

8. The Board must permit Yukon Energy Corporation and The Yukon Electrical Company Limited to adjust their rates to retail customers, major industrial customers, and isolated industrial customers so as to reflect fluctuations in the prices for which the two utilities pay for diesel fuel, without the requirement for specific application to and approval of the Board.

Ajustement du prix du combustible

8. La Commission permet à la Société d'énergie du Yukon et à la Yukon Electrical Company Limited d'ajuster les tarifs facturés aux clients au détail, aux clients industriels majeurs et aux clients industriels isolés de manière à refléter les fluctuations des prix payés pour le mazout par ces deux sociétés, sans avoir à faire une demande particulière à la Commission pour obtenir son autorisation.
