YUKON ENERGY CORPORATION

2012/2013 GENERAL RATE APPLICATION

APRIL 2012

2012/2013 GENERAL RATE APPLICATION

TO THE YUKON UTILITIES BOARD (BOARD)

YUKON ENERGY CORPORATION

INTRODUCTION TO APPLICATION

Yukon Energy's 2012 and 2013 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 2012 and 2013 (the two "test years");
- Implement required changes to recover the costs for growing diesel generation requirements on the Integrated Grid, including changes to update and re-activate the Diesel Contingency Fund ("DCF") as of January 1, 2012, and to provide related adjustments required to Rate Schedule 42; and
- Implement overall rate adjustments through implementation of Rider J and Rider R (both applicable to retail and industrial customers) in order to recover the revenue shortfall in each test year.

Pursuant to the OIC 2012/68 direction, the Board must ensure until the end of 2013 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and, subject in 2012 to the 3.4% already approved effective January 1, 2012, to the class of major industrial customers. Consequently, for both 2012 and 2013, all proposed rate adjustments for retail customers and industrial customers apply equally, as percentages.

The Application includes the following:

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

OVERVIEW

Background

The current 2012 and 2013 Application represents the first requested increase in Yukon Energy firm retail rates for non-industrial customers since the 1998/1999 rate review that followed the closure of the Faro mine[1]. Despite continuing cost pressures over the past decade, Yukon Energy has been able to defer the need for a rate increase due to key planning activities and other measures to mitigate rate pressures as set out in Tab 1 (Section 1.2).

In 2005, Yukon Energy filed the Required Revenues and Related Matters Application to allow a full open book review of all Yukon Energy Revenue Requirement matters and to set out an orderly process to address key regulatory issues facing Yukon Energy going forward. This review did not seek any change in firm rates and implemented provisions that allowed firm rates to remain unchanged until the end of 2007.

In 2008, Yukon Energy filed a General Rate Application that sought a 3.48% rate decrease (later reduced to 2.47% after Order 2009-8 and 2009-10) in firm retail rates for non-industrial customers. This rate decrease was facilitated by the completion of the Carmacks-Stewart Transmission Line – Stage 1 which connected the Minto mine and Pelly Crossing to the Whitehorse-Aishihik-Faro ("WAF") grid and allowed for sale of surplus hydro to Minto mine through a Purchase Power Agreement ("PPA"). Completion of this grid connection provided net benefits to ratepayers through the applied for rate reductions, while securing a long-term legacy asset for the benefit of existing and future ratepayers.

Major industrial firm rates increased significantly in 2007[2] and, pursuant to OIC 2007/94, industrial rates were further increased in 2011 and 2012 (approximate 6.3% added increase).

Cost Pressures underlying the 2012 and 2013 Revenue Shortfall

Non-industrial and industrial load growth on the grid continues to be a key cost pressure underlying forecast revenue shortfalls for Yukon Energy, leading to higher diesel generation costs as well as a range of other generation and transmission cost pressures.

Overall, non-industrial grid load growth has been higher than past forecasts. Specifically, the 2006 Resource Plan used a long-term growth forecast of 1.85%/year, while 2011 resource planning forecasts use a 2.26%/year growth forecast. Based on current information to date, non-industrial grid load growth is

[1] The Rider J rate was originally approved in Order 1998-5 on an interim basis at 15.28%. In Order 1999-5 the rider was finalized at 18.74% effective December 1, 1999, and in Order 2003-02 the rider was reduced to 14.93% effective January 1, 2003.
[2] In 2007, in response to the Minto mine Power Purchase Agreement and OIC 2007/94, industrial rates as last approved in the 1996/97 GRA increased by approximately 20%.

presently tending to exceed this updated 2011 forecast. Ongoing non-industrial growth reflects overall Yukon economic expansion plus other factors such as an apparent increase in reliance on electric heat.

Industrial connected growth continues to be material – but industrial load growth to date also continues to bring higher revenues that tend to more than offset any related incremental costs.

Increased diesel generation costs related to grid load growth are a key cost pressure. As anticipated in Yukon Energy's 2008/2009 General Rate Application, continued non-industrial and industrial growth has effectively depleted the surplus hydro available since the 1998 Faro mine shut down, and the Yukon grid has reached the point today of requiring diesel generation to supply a growing share of new grid load under long-term average water conditions. With diesel once again "on the margin", as was the case (to a lesser extent) when the Faro mine was operating, measures are once again required to enable customer rates to recover diesel costs based on long-term average annual hydro generation (rather than fluctuating short-term hydro forecasts) and a reactivated Diesel Contingency Fund to address variances in diesel generation costs due to hydro generation variability. To mitigate the impact of incorporating full long-term average diesel costs into rates, the Application provides for diesel generation costs in the test years based on annual hydro generation forecasts slightly higher than forecast annual long-term average (with the result that forecast diesel generation is still less than long-term average). This revenue requirement measure is proposed for 2012 and 2013 to mitigate rate impacts in these years and facilitate transition to inclusion in future revenue requirements of the full diesel generation cost based on forecast annual long-term average hydro generation.

With the reality of increasing diesel costs in mind, since 2006 Yukon Energy has engaged intensively in planning and development activities required to identify the next generation of lower cost sources of supply for Yukon. In furtherance of these activities, since 2009, three additional major bulk power (generation and transmission) projects have been added to the Yukon system which have enhanced system performance and reduced Yukon diesel generation requirements.

1. **Mayo Hydro Enhancement Project ("Mayo B") –** Completed and in service in December 2011, this material legacy investment was pursued to ensure low cost renewable supply was available to displace costly diesel generation requirements forecast in 2012. The capital costs for the project were mitigated through Federal Green Infrastructure Fund ("GIF") funding and further funding assistance provided by the Yukon Government resulting in a reduction in net rate base impacts from $118.5 million (total cost) to $35 million forecast in this Application.

2. **Carmacks Stewart Transmission Project - Stage 2 –** Completed and energized in June 2011, this project will not have any net rate base impact due to 3rd party funding secured through the GIF and further funding from the Yukon Government.

3. **Aishihik 3rd Turbine –** Completed and in service December 2011 at a net cost to ratepayers of $8.8 million after $5 million of 3rd party contributions.

Ongoing growth since the 2008/2009 General Rate Application has continued to put significant pressure on the existing bulk power infrastructure (generation and transmission), and additional operation and capital costs are necessary to ensure continued safe and reliable service.

Further material planning and feasibility costs have also been incurred to allow YEC to undertake appropriate planning activities necessary to secure the next generation of low cost generation needed to meet ongoing demand without relying on costly baseload diesel generation. With continued unprecedented growth in Yukon, major planning and development activities continue in order to ensure the integrated system can meet load requirements in a cost effective and environmentally responsible manner.

Proposed Rider J and Rider R to Address Revenues Shortfalls in each of 2012 and 2013

The current level of existing firm rates result in a $3.455 million rate revenue shortfall in 2012, and a $7.685 million rate revenue shortfall in 2013 compared to revenue requirements set out in Tab 3. These shortfalls, which are outlined in Table 1 below, form the basis for the proposed rate increases in this Application.

Table 1
Yukon Energy Revenue Required from Rates ($000s)

	2012	2013
Revenue Requirement (from Table 3.1)	$39,857	$45,641
Less: Non-rate Revenues	$184	$184
Revenue Required from Firm Rates	$39,673	$45,457
Less: Revenues from Firm Sales at Existing Rates (including "Fixed" component of industrial Rider F)	$36,218	$37,772
Firm Rate Increase Proposed	$3,455	$7,685

Firm retail non-industrial rates within each non-government retail customer class (i.e., rates for residential, general service and lighting customer classes) are required by OIC 1995/90 to be equal throughout Yukon for both Yukon Energy and Yukon Electrical customers, subject to allowed variation for run-off rates to reflect incremental costs that differ for different rate zones. Pursuant to a new OIC 2012/68 direction, the Board must also ensure until the end of 2013 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and, subject in 2012 to the 3.4% already approved effective January 1, 2012, to the class of major industrial customers.

In accordance with the above direction, the Application proposes that the Yukon Energy revenue shortfall for 2012 and 2013 be recovered through Revenue Shortfall Riders applied as a 6.40% revenue shortfall Rider J charged in 2012 to all non-industrial retail firm rates and a 2.90%[3] revenue shortfall Rider J charged to all industrial firm rates, and as a 6.50% revenue shortfall Rider R charged in 2013 to all retail and industrial firm rates (including the 2012 shortfall Rider J). The Rider J increase applies to all major industrial firm rates then in effect pursuant to Order 2011-14, including the fixed Rider F charge of 0.211 cents/kWh and the 3.4% increase in energy and demand rates approved by Order 2011-14 effective January 1, 2012. The Rider R increase applies to all major industrial firm rates then in effect, including Rider J and the fixed Rider F charge.

Further consideration of cost of service and future rate design affecting retail and industrial customer classes is deferred until expiry of the OIC 2012/68 provisions.

SUMMARY OF REQUESTED ORDERS

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

1. **2012 and 2013 Revenue Requirement:** Approval of the forecast revenue requirement of $39.859 million for 2012 and $45.641 million for 2013, including approval, as required, of the following costs, revenues and other related provisions:

    a. **Fuel and Purchased Power Costs:** Fuel and purchase power costs forecast of $2.203 million and $3.113 million in 2012 and 2013 respectively, including approval to adjust diesel prices used in setting fuel costs to reflect current forecast conditions.

        i. **Update to the Diesel Contingency Fund ("DCF")**: Approval of the changes to the DCF as outlined in Appendix 3.2 and Attachment 3.2 to update the DCF's ability to protect ratepayers from fossil fuel cost changes due to fluctuations in water availability for hydro generation. The proposed updated approach would permanently switch "on" the DCF through use of a formulaic approach that would automatically adjust forecast annual long-term average hydro generation and related diesel (or other non-diesel fossil fuel) generation to reflect actual grid generation load. Based on this DCF proposal there will no longer be a "diesel on the margin" test for activating the DCF. The updated DCF also proposes that any secondary sales revenues after January 1, 2012 would be credited to the DCF[4].

[3] After the 3.40% increase effective January 1, 2012 (pursuant to Order 2011-14), the cumulative compound increase in 2012 for major industrial customers with the 2.90% Rider J increase is 6.40%.

[4] In the event there are secondary sales, secondary revenues will be credited directly to the DCF (without any Rider F related adjustment or impact for price changes), thereby helping to fund the long-term risks related to hydro generation water condition fluctuation. This treatment maintains a logical connection to the updated DCF and is intended to support rate stability going forward. Assigning secondary sales revenues to the DCF ensures that all such temporary revenues from surplus hydro conditions will go to funding future fossil fuel generation due to below average water conditions.

ii. **Diesel Generation Forecasts**: Diesel generation forecast at 66% of long-term average annual levels in 2012 and 59% of long-term average annual levels after 2012, as provided for in more detail in Tab 2 and Tab 3 of the Application.

b. **Non-Fuel Operating and Maintenance Costs:** Non-fuel operating and maintenance costs forecast of $17.496 million and $18.385 million in 2012 and 2013 respectively, including approval of the following matters:

i. **Faro Dewatering Account Funds:** Approval to apply $0.398 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.

ii. **Reserve for Injuries and Damages (RFID):** Approval of new RFID Policy (as provided in Appendix 3.1 of this Application), and, based on the results of the study provided in Appendix 12.5, approval to increase the annual appropriation to the Reserve for Injuries and Damages to $0.195 million from the current $0.100 million level starting in 2012, approval to apply the remaining $0.398 million of one-time funds from the Faro mine Dewatering Deferral Revenues against the RFID balance and approval to amortize $0.180 million of the remaining balance over a five year period (as discussed in Section 3.3.6 of Tab 3).

iii. **Secondary Sales Rate Revenues (collected under Rate Schedule 32):** In the event there are secondary sales, secondary sales revenues will be credited directly to the DCF as noted above, and will therefore not affect Yukon Energy revenues or income[5]. No approvals are being sought to change the Secondary Energy Rate Schedules.

c. **Depreciation and Amortization Expenses**: Approval of depreciation and amortization expenses forecast of $7.813 million for 2012 and $10.012 million for 2013 including the following related approvals:

i. **New Planning Cost Accounting Policy and transition provisions for the 2012 and 2013 test years:** Approval of the new planning cost accounting policy provided as Appendix 5.1, required to address material accumulated deferred costs in WIP and to mitigate impacts on ratepayers in the test years.

ii. **New Demand Side Management ("DSM") Accounting Policy:** Approval of the new DSM accounting policy provided as Appendix 5.2 and related deferred costs to be amortized over the test years.

[5] Due to the variability of secondary sales and the direct relationship between such sales and water availability, Yukon Energy would in any event forecast 0 GWh of secondary sales for the purposes of setting rates in the test years.

iii. **New Depreciation Rates:** Approval to reduce Yukon Energy's depreciation rates for fixed assets to reflect changes in service lives identified in depreciation study provided as Tab 10 of this Application.

iv. **Costs of current GRA:** An estimated "placeholder" expense of $1.100 million related to costs for the current GRA Application, anticipated to be incurred over 2012 and 2013 for preparation and review of the Application and reimbursement of related intervenor and YUB costs, to be amortized over the 2 test years (2012 and 2013). 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.

v. **Amortization of earlier regulatory and related costs**: Approval of the amortization of regulatory and other related costs incurred over the last several years, including the following:

- Approval of a forecast cost of $0.859 million related to Yukon Energy's 2011-2030 Resource Plan Update (to be amortized over five years consistent with the anticipated frequency of full Resource Plan updates);
- A total incurred cost of $0.026 million related to the regulatory review of the Rate Schedule 39 Escalation Proceeding to be amortized over two years;
- A total incurred cost of $0.313 million[6] related to the regulatory review of the 2009 Phase II Rate Application, to be amortized over two years; and
- A total incurred cost of $0.054 million related to the regulatory review of the Alexco Explorations Power Purchase Agreement, to be amortized over five years which is the currently anticipated economic life of the substantial terms of the PPA.

d. **Mid-Year 2012 and 2013 Forecast Rate Base:** Approval of mid-year forecast rate base costs of $223.020 million and $241.738 million for 2012 and 2013 respectively, including costs for capital works projects brought into service (or forecast to be brought into service) since the 2008/2009 General Rate Application, as well as deferred costs. This includes spending for 8 major capital projects (i.e., total costs over $1 million) forecast to be in service in the test years with a total net rate base cost of $66.1 million (after offsetting third party contributions of $128.5 million). Other capital spending on property, plant and

[6] Total approved Costs in Order 2011-8 for the Phase II Rate Application were $0.475 million. Approved costs for Government of Yukon and intervenors totaled $0.212 million. Yukon Energy's portion of these costs were $0.106 million. Combined with Yukon Energy's approved costs for the Phase II proceeding of $0.207 million this totals to $0.313 million.

equipment in rate base in the test years is forecast at $5.426 million for 2012 and $7.107 million for 2013 (with customer contributions of $0.4 million in each test year). Based on the new Planning Cost Accounting Policy, Yukon Energy is also seeking approval to include in rate base spending to date for deferred costs projects as noted in Tab 5, Section 5.3.

e. **Return on Rate Base:** Approval of $12.345 million in 2012 and $14.130 million in 2013, including an allowed rate of return on equity ("ROE") of 8.77% for both 2012 and 2013.

2. 2012 and 2013 Rates: Approval of the following rates to recover 2012 and 2013 revenue:

a. **2012 Retail and Industrial Rates:** Approval of 2012 Yukon Energy Revenue Shortfall Rider (Rider J) of 6.40% applicable to all YEC and YECL retail firm rates (all YECL recoveries from this rider would flow through to YEC), and a Rider J of 2.90% applicable to all major industrial firm rates then in effect pursuant to Order 2011-14, including the fixed Rider F charge of 0.211 cents/kWh.

b. **2013 Retail and Industrial Rates:** Approval of 2013 Yukon Energy Revenue Shortfall Rider (Rider R) applicable, starting January 1, 2013, to all YEC and YECL retail firm rates and to all industrial firm rates, including Rider J (all YECL recoveries from this rider would flow through to YEC). The Rider R increase applies to all major industrial rates then in effect, including Rider J and the fixed Rider F charge.

c. **Wholesale Rates (Rate Schedule 42):** Given that diesel is now forecast to be "on the margin", approval to trigger the Energy Reconciliation Adjustment ("ERA") provision of Rate Schedule 42 on an ongoing basis effective January 1, 2012, and to adjust the specific wording of the ERA as required to reflect updates to the DCF.

d. **Interim Refundable Rates effective July 1, 2012:** Approval to implement the above noted Rider J rate increases for retail and industrial customers for 2012 via an interim refundable rate rider effective on an interim refundable basis as at July 1, 2012. Less than two-thirds of the forecast 2012 revenue shortfall will be collected by this interim Rider J over 2012. Following receipt of final orders in this proceeding, including a final 2012 revenue requirement, any residual shortfall or surplus for each test year will be addressed pursuant to direction of the Board.

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. An overview of the following key factors is provided below:

- Risks related to low water and diesel on the margin conditions commencing January 1, 2012;

- Major Capital Projects in Service in Test Years;
- Significant planning activities undertaken since last GRA and new Planning Cost Accounting Policy; and
- Other Items.

Risks related to Low Water & Diesel on the Margin conditions commencing January 1, 2012

When the Faro mine was operating, a regulatory provision (now called the Diesel Contingency Fund or "DCF") was adopted to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro generation on WAF[7].

After the closure of the Faro mine in 1998, Yukon Energy's WAF system remained at load levels that presented very little risk of low water resulting in hydro generation shortfalls and costly requirements for diesel generation. However, Yukon Energy's 2008/2009 General Rate Application noted that due to material retail and industrial growth since 2001, loads were approaching levels where very low water conditions could cause material financial impacts necessitating sharp rate increases for customers.

The continued retail and industrial growth on the integrated system since 2009 has eliminated the hydro surplus and the system has once again returned to the point where diesel is on the margin.

The increased need for baseload diesel generation to supply growth means that there are increased ratepayer risks related to low water or drought conditions resulting from hydro generation shortfalls and costly requirements for diesel generation. This new reality necessitates updating and reactivating the DCF.

In the 2008 Diesel Contingency Fund Filing and the *Rider F – Fuel Adjustment Rider & Deferred Fuel Price Variance Policy* review Yukon Energy noted that the DCF operating rules required adjustment to address a number of new circumstances, including updating long-term average hydro generation values, DCF triggers, and potentially a means to address secondary sales. Further, following connection of the WAF and Mayo Dawson grids, there is also a requirement to adjust the DCF to deal with hydro generation on the integrated system (as opposed to only WAF hydro generation).

As Yukon Energy has previously noted, the DCF cannot effectively be triggered until the necessary changes in operating rules are reviewed and approved by the YUB. Attachment 3.2-1 of Appendix 3.2 includes a DCF Term Sheet that sets out the current provisions of the DCF and recommended adjustments to update the DCF.

[7] The DCF is designed to ensure that the Fund (and utility ratepayers), rather than YEC earnings, pay for or benefit from changes to grid diesel generation due to fluctuations in grid hydro generation due to water condition changes that are beyond utility control.

Reactivation of the DCF enables the Application to include diesel generation costs based on the forecast long-term average hydro generation, and for variances in diesel generation costs from the Application's forecast due to hydro generation variability to once again be addressed through the DCF without any impact on Yukon Energy earnings. As noted earlier, the current Application provides for diesel generation costs in the current test years based on annual hydro generation forecasts slightly higher than forecast annual long-term average (with the result that forecast diesel generation is still less than long-term average). This revenue requirement measure is proposed for 2012 and 2013 to mitigate rate impacts in these years and facilitate transition to inclusion in future revenue requirements of the full diesel generation costs based on forecast annual long-term average hydro generation. This rate mitigation measure reduces expected contributions to the DCF during the test years, and thereby reduces the DCF's ability to offset higher diesel generation costs when low water or drought conditions occur.

Major capital projects in service in test years

Significant investment in new infrastructure and re-investment in existing infrastructure have been undertaken over the period since 2009 to ensure that Yukon Energy can continue to meet Yukon load growth in a safe and reliable manner. Since that time, major legacy initiatives have been carried out to connect the WAF and Mayo Dawson grids and to enhance renewable hydro capability on the new integrated grid (CSTP Stage 2, Aishihik 3rd Turbine and Mayo B). Each of these projects had significant levels of external contributions that materially reduced rate base costs. Coordinated with these initiatives, Yukon Energy has also completed projects to enhance safety and reliability at the existing Mayo, Aishihik and Whitehorse hydro facilities.

The current Application considers an approximate $32.05 million growth in mid-year net rate base from 2009 approved to 2011 preliminary actual, with additional growth forecast in mid-year rate base of $61.72 million by 2013. The net rate base growth is considerably lower than the gross rate base related to total assets added to the system over this same period of approximately $213.46 million, reflecting an increase of $119.69 million in mid-year net contributions for all projects from 2009 approved to the 2013 forecast.

Notably, the three major projects in service in 2011 include approximately $128.5 million of total gross third party contributions that reduce the overall impact on ratepayers.

Significant planning activities undertaken since last GRA and new Planning Cost Accounting Policy

Both cost and environmental reasons provide strong incentives for Yukon Energy to expand the available complement of renewable generation, as well as transmission interconnections. Yukon Energy's 2008/2009 GRA reviewed the ongoing need to undertake significant planning activities to ensure the next generation of low cost supply resources is available to meet continued growth on the integrated grid and displace

requirements for costly diesel generation. Since 2009, growth in demand on the integrated grid has continued, driven by overall economic growth in Yukon.

The 2008/2009 test year planning cost budgets included in Work-in-Progress material expenditures for this next generation of power projects, and forecast further material expenditures were necessary for work extending beyond the test years. Since 2009, Yukon Energy has continued with the required planning work outlined in the 2008/2009 GRA. Given the unprecedented levels of planning costs incurred in WIP since 2009, a new planning cost accounting policy (provided in Appendix 5.1 to Tab 5) is included in this Application to ensure that these costs are addressed and included in rates in a manner that does not result in undue rate impacts for ratepayers.

Other Items

The Supporting Documents set out in detail a number of other items that are relevant to the Yukon Energy required revenues:

- **Depreciation Rates:** Yukon Energy is proposing to update its depreciation rates as reviewed at Tab 3. The Supporting Documents include at Tab 10 a copy of the most recent depreciation study conducted for Yukon Energy. The net impact of the depreciation rate change compared to existing rates is a reduction in depreciation costs net of contributions of approximately $2.3 to 2.4 million in the test years.

- **Mayo B Flexible Financing:** Yukon Energy secured in 2012 flexible debt long-term financing from YDC to mitigate ratepayer risks related to Mayo B costs exceeding 11 cents per KW.h (2012$) for diesel generation displaced in any year (see Appendix 5-3 for a review of this financing and a copy of the relevant Note).

- **Return on Equity:** Yukon Energy is proposing that the fair Return on Equity ("ROE") for 2012 and 2013 be set at 8.77% using the most recent available low risk utility benchmark and applying the Board approved risk premium for YEC of 52%. Tab 8 sets out the approach to setting Yukon Energy's ROE.

- **Rider F:** Both Yukon Energy and Yukon Electrical are protected against actual fuel price variances from GRA forecasts (as such variances affect diesel fuel generation costs) through the Deferral Fuel Price Variance Account (Rider F), and as a result all customer classes in Yukon today are subject to Rider F charges. Secondary sales price variances from the last Yukon Energy GRA forecast (2009) also currently go to the Rider F deferral account rather than to Yukon Energy's income.

The Application assumes that Yukon Energy Rider F account balances for 2012, and the portion of such balances for 2013 prior to final Board GRA approvals, will be adjusted as required to reflect final 2012 and 2013 Yukon Energy GRA fuel and secondary price forecast as approved by the Board, and that ongoing Rider F accounting thereafter (until the next Yukon Energy GRA) will address variances from the 2012 and 2013 approved price forecasts.

- **Faro Dewatering Account "regulatory liability":** Since 2005, transfers from this account have helped to address revenue requirement shortfalls and defer the requirement for rate adjustments. After the 2005 Required Revenues and Related Matters Review, transfers of up to $0.292 million per year were used to mitigate revenues requirement impacts from 2005 through 2007. The Faro Dewatering Account was also used in the 2008/2009 GRA to reduce revenue deficiencies in 2008 and 2009 after the final order approving the 2008 and 2008 Revenue Requirements and a collection rider was not required to collect the revenue shortfall that resulted from the Board's Order in that proceeding. Instead of a collection Rider, the revenue shortfall of $0.026 million in 2008 and $0.355 million in 2009 was addressed through use of the Faro Dewatering Account. The current Application proposes to transfer the remaining $0.398 million from the fund to partly address the balancing in the RFID account. This would fully deplete the Faro Dewatering Account.

- **IFRS Changes:** The Canadian Accounting Standards Board ("ASB") has allowed entities that meet the criteria for rate regulated activities to defer transition to IFRS for one year (two years beginning on or after January 1, 2012) and to continue to apply CGAAP until that time. Yukon Energy has elected to take this deferral option and will report under IFRS for the first time in its year ended December 31, 2012[8]. Yukon Energy has prepared its consolidated financial statements prior to fiscal year 2012 in accordance to CGAAP. A summary of expected transition to IFRS for Yukon Energy is provided as Appendix 6.2 of Tab 6. However, it is noted that the implementation of IFRS (and how provisions are interpreted and applied) will evolve up to December 31, 2012.

  For the purposes of the current Application Yukon Energy has implemented the following changes in accounting practice:

  - **General Overhead Allocation –** Under IFRS, general overhead allocations are specifically not allowed on capital projects. Accordingly, Yukon Energy has eliminated the pooling of overhead expenses for general allocation. In lieu of this, YEC staff now charge all capital related work to specific projects. Vehicle expenses that were previously included in the overhead pool are now also charged to projects based on the driver's labour coding. This

[8] In March 2012, the Accounting Standards Board of Canada indicated that it would defer for a further year (until January 1, 2013) the requirement for rate regulated entities to be IFRS compliant. Yukon Energy is considering whether to take the additional deferral at this time.

new treatment was adopted in 2011 – it is not expected that this change will have a material impact on the amount of overhead charged to capital.

- **Interest During Construction –** In lieu of earning a rate of return on assets under construction, the utility charges WIP projects at the weighted average cost of capital during the period the asset is being constructed. Under IFRS, entities are not permitted to charge projects for equity returns; accordingly, Yukon Energy has amended this policy to use a debt-only rate for AFUDC (Allowance for Funds Used During Construction) starting in 2011. At current rates, this will result in lower charges to capital (debt rates are less than equity).

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 2009 to 2010, preliminary actuals for 2011 and forecasts for 2012 and 2013.

The supporting documents also provide other background information relevant to the Application, including review of past Board Orders and directives since the 2008/2009 General Rate Application, details on specific elements of the Application 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 2008/2009 GRA.

- **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 2012 and 2013.

- **Tab 3 Revenue Requirement:** Provides detailed information on Yukon Energy's total forecast cost of providing service in 2012 and 2013, including operating and maintenance expenses, rate base, depreciation and amortization, return on rate base (including a fair return on equity) and stabilization matters.

- **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 2009 to 2011, as well as forecast capital spending for 2012 and 2013.

- **Tab 6 Board Directives:** Provides a review of past Board Orders and responses to outstanding directives since the 2008/2009 General Rate 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 2012 and 2013.

- **Tab 9 2010 Audited Financial Statements:** Provides a copy of Yukon Energy's latest audited financial statements.

- **Tab 10 Depreciation Study:** Provides a copy of the preliminary results of the KPMG Depreciation Study undertaken for Yukon Energy.

- **Tab 11 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.

- **Tab 12 Technical Reports Filed in Response to Board Directives:** Provides technical reports filed in response to Board Directives as reviewed in Tab 6.

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TAB 1
INTRODUCTION

1.0 INTRODUCTION

Yukon Energy's Application includes 12 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:

- Need for 2012 and 2013 Rate Increase;
- Measures since 1998 to Defer the Need for a Rate Increase;
- Factors Driving the Need for a 2012 and 2013 Rate Increase Requirement;
- Other Regulatory Concerns Addressed in Application; and
- Yukon Energy Rates and Bills.

1.1 NEED FOR 2012 AND 2013 RATE INCREASE

At this time Yukon Energy is seeking its first increase in retail rates since the 1998/1999 period.

As reviewed in more detail below, the increasing revenue requirement shortfalls since 2009 reflect the impact of Yukon's growth and the resulting increase in high cost diesel generation to meet customer needs, and the related growth in Yukon Energy's O&M and capital costs in order to responsibly meet growing customer requirements.

This point is highlighted by the Return on Equity ("ROE") results set out in Table 1.1 which demonstrate how ongoing cost pressures have eroded Yukon Energy financial performance since the 2008/2009 GRA, (resulting consistently in shortfalls from the 8.49% ROE approved by the Board for 2009 rates). ROE results for 2009 through 2011 reflect fuel costs for actual diesel generation (at GRA approved fuel prices) required for operations as the Diesel Contingency Fund was not activated in the 2009 GRA. The forecast ROE in each test year, absent new rates, shows continued material deterioration in financial performance underlining the need for increases in rates. Since the forecast ROE provided in Table 1.1 effectively assumes a no GRA scenario, the forecast diesel costs included in the 2012 and 2013 ROE are based on short-term forecast diesel requirements and do not assume reactivation of the Diesel Contingency Fund or diesel costs based on a percentage of long-term average hydro requirement (as included in the Application for the 2012 and 2013 test years).

Table 1.1

Return on Equity Earned by Yukon Energy

Year	ROE	
2009	7.92%	
2010	7.45%	
2011 FYF	6.59%	
2012 Forecast	4.38%	at existing rates without Application
2013 Forecast	-0.97%	at existing rates without Application

1.2 MEASURES SINCE 1998 TO DEFER THE NEED FOR A RATE INCREASE

In the 1996/97 GRA the Companies sought changes in rates necessitated by re-opening of the Faro mine. This included an average rate increase of 18% for the industrial class (and rate riders for other new mines), 4% increase for the government residential class, a 12% decrease to the general service non-government class and a 23% rate decrease to streetlight class. By 1998, a limited scope proceeding sought required adjustments to retail rates through Rider J to respond to the closure of the Faro mine in 1997 and 1998. The Rider J rate was originally approved in Order 1998-5 on an interim basis at 15.28%. In Order 1999-5, the rider was finalized at 18.74% effective December 1, 1999, and in Order 2003-02 the rider was reduced to 14.93% effective January 1, 2003.

In 2005, Yukon Energy filed the Required Revenues and Related Matters Application to allow a full open book review of all Yukon Energy Revenue Requirement matters and to set out an orderly process to address key regulatory issues facing Yukon Energy going forward[1]. This review did not seek any change in rates and implemented provisions (including Faro Dewatering Account transfers[2]) that allowed rates to remain unchanged until the end of 2007.

In 2008, Yukon Energy filed a General Rate Application that sought a 3.48% rate decrease (later reduced to 2.47% after Order 2009-8) in retail rates, reflecting benefits derived from completion of Stage 1 of the

[1] Aside from measures identified below, 2005 revenues and the requirements for added rates were also reduced through a favourable insurance settlement regarding the Whitehorse Rapids Fire and contributions from Yukon Development.
[2] By 2005, there were substantial Rate Schedule 34 collections (of about $2 million) from power sales for Faro Mine dewatering and other shutdown activities; these collections were set aside in a deferral account to be used for ratepayers' benefit subject to Board direction. After the 2005 Required Revenues and Related Matters review, transfers of up to $292,000 per year were used to mitigate revenue requirement impacts from 2005 through 2007.

Carmacks-Stewart Transmission Project and connection of the Minto mine. Faro Dewatering Account transfers also assisted in reducing rate requirements in 2008/2009[3].

Despite continuing cost pressures over the past decade, the 2005 and 2008/2009 applications outlined how Yukon Energy had deferred the need for a rate increase (and in fact reduced rates in 2008 and 2009) due to the following key planning activities and other measures to mitigate rate pressures which together reduced Yukon Energy's 2009 new rate revenue requirements by more than $6 million:

- **The completion of the Mayo Dawson Transmission Line (MDTL) in 2003** – Completion of this project effectively eliminated baseload diesel generation requirements in Dawson. Savings due to displacement of baseload diesel generation with surplus hydro generation available from Mayo (that would otherwise have been spilled) have provided net significant benefits to ratepayers from 2003 through to 2011 (for example, in 2008 alone there were 16.5 GW.h of saved diesel generation and net cost savings for ratepayers of $2.5 million[4])[5].

- **The 2008 completion of Carmacks-Stewart Transmission Project – Stage 1 (CSTP Stage 1)** – Completion of this project provided an approved 2.47%[6] reduction in 2009 rates for firm retail customers throughout Yukon to reflect benefits of added new firm sales of surplus hydro generation to the Minto mine (and Pelly Crossing) through interconnection with the WAF grid. Without this project, a rate increase would have been required[7].

[3] Order 2009-8 resulted in an adjustment in Rider J from 3.48% to 2.47% and, but for the use of the Faro Dewatering Fund, would have necessitated a collection rider to collect a revenue shortfall that occurred over the 11 months from January 1, 2009 to November 30, 2009 (a 1.67% rider would have been required). Instead of a collection Rider, the revenue shortfall of $0.026 million in 2008 and $0.355 million in 2009 was addressed through use of the Faro Dewatering Account.
[4] See response to YUB-YEC-1-13 filed during the Yukon Energy 2008/2009 GRA.
[5] Flexible debt financing arrangements through the Mayo Dawson Note ensured that ratepayers did not pay more in any year of the Project than the costs that would have been faced had Dawson remained on diesel generation. Increased diesel prices as well as ongoing depreciation of MDTL capital costs have subsequently ensured that no further interest reductions were triggered under the Mayo Dawson Note, i.e., the net ratepayer costs savings of $2.5 million estimated for 2008 included payment of full interest charges under this Note.
[6] The Yukon Energy 2008/2009 GRA sought a proposed rate reduction of $0.360 million in 2008 and $1.334 million in 2009 (3.48%) however this was reduced by Order 2009-8 to 2.47% ($0.966 million reduction in 2009).
[7] As noted in YUB-YEC-1-36 filed during the 2008/2009 GRA, without CSTP Stage 1 Yukon Energy's retail rate revenue requirement (prior to Order 2009-8) would have required a firm retail rate increase in 2009 of $1.238 million (+3.23% if applied as an across-the-board retail rate rider).

The rate reduction was possible because of third party contributions (for the CSTP Stage 1 and the spur line to the Minto mine) which reduced the total costs that were required to be put in rate base (from $40.484 million to $5.034 million[8])[9].

- **Material Secondary Sales Revenues since 1998** – Material secondary sales made feasible by the hydro surplus reduced the revenues required to be sought from ratepayers, and increases in these secondary sales rates were a major component of the 2005 Required Revenues and Related Matters review. Secondary revenues added $315,000 to income in 2003 and $416,000 in 2004 and provided material ongoing benefits through added revenues available to reduce firm rate revenues required in 2005 through 2010 with annual revenues averaging $0.874 million and ranging between $0.644 million and $1.066 million.

- **Debt Refinancing in 2003** – Debt refinancing at the end of 2003 reduced Yukon Energy costs in 2004 by almost $700,000 and such benefits continued beyond 2004.

- **Depreciation Study Changes in 2005** – In 2005, YEC initiated depreciation studies that resulted in reduced depreciation costs for approval of the YUB in setting rates. In the 2005 Required Revenues and Related Matters review, Yukon Energy updated its depreciation rates to reflect the Average Service Life (ASL) group procedure (instead of the Equal Group Life [ELG] procedure that was then currently in place). The net annual impact of the change in 2005 was a reduction of about $1.17 million in the depreciation expense (net of customer contributions and amortization of fire insurance recoveries) at proposed depreciation rates compared to the existing depreciation rates.

In addition to the above ratepayer savings noted in the 2005 and 2008/2009 applications, the following rate mitigation developments, and other measures since the 2009 GRA, have provided further ratepayer savings of $9.4 million in 2012[10] and $9.8 million in 2013:

- **The 2011 completion of Mayo B Enhancement Project, Stage 2 of Carmacks-Stewart Transmission Project, and Aishihik 3rd Turbine Project** – Completion of these projects in 2011 has reduced forecast diesel generation requirements for 2012/2013 and future years. Diesel

[8] See response to YUB-YEC-1-36 filed in the Yukon Energy 2008/2009 GRA.
[9] Contributions included $10.45 million from the Yukon Government, $7.2 million from Minto Explorations for the CSTP Main Line and $10.8 million for the Minto Spur line, and $7 million from YDC (including approximately $2 million as required by agreement with Yukon Energy pursuant to the Purchase Power Agreement (PPA) with Minto Mine 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).

reduction benefits will grow with load growth, e.g., at annual long-term average hydro generation the forecast diesel generation reduction in 2012 is 23.9 GW.h and in 2013 is 26 GW.h (reflects grid generation loads at range of 416 to 430 GW.h/year), and forecast diesel generation reduction increases to 34.9 GW.h at grid load of 500 GW.h/year, 42 GW.h/year at grid load of 650 GWh/year and 44.8 GW.h/year at grid load of 750 GW.h/year. The resulting forecast savings in diesel generation fuel (at long-term average hydro) and O&M costs equal approximately $7.6 million in 2012 and $8.2 million in 2013[11]; net of the annual costs included in the Application for these projects[12], ratepayer savings from these legacy projects approximate $5.6 million in 2012 and $5.9 million in 2013.

- **Debt Refinancing in 2011** – Debt refinancing was used in 2011 to defer the requirement to return to the Board for additional rate revenues at that time[13]. In 2011, YEC refinanced the YDC Flex Term Debt (FTD) [interest rate of 7%] and the YDC Mayo Dawson Note (MDN) [interest rate of 6.55%], as well as other YDC debt held by YEC, in order to reduce YEC's average debt cost (forecast for 2011 at approximately 5.45%)[14]. Refinancing at 4.25% in 2011 reduced costs by approximately $1.6 million in 2011 and $1.5 million in both test years.

- **Depreciation Study Changes for 2012 and 2013** – For the current GRA, Yukon Energy has updated its depreciation rates to reflect longer service lives for key assets (e.g., hydro plant). This update has reduced annual depreciation expense in the test years by approximately $2.3 to $2.4 million net of contributions.

[10] By way of comparison, recovery of $9.4 million of added costs through retail rates would require an 18.4% additional increase in 2012 rates for retail customers at the sales forecast in the Application.
[11] Assumes diesel fuel prices as proposed in the Application and O&M costs per 2009 GRA at 3 c/kW.h. The Application does not include diesel generation at 100% of long-term average hydro (and therefore these savings would be reduced in the context of the proposed test year revenue requirement).
[12] Total annual costs (depreciation and return) included in the Application for these new legacy generation and transmission assets approximate $2 million for 2012 and $2.3 million for 2013 (costs reflect impact of Mayo B Flexible Debt).
[13] On January 1, 2011 YEC entered into an agreement with YDC to renegotiate terms of all outstanding debt in the amount of $81,890,873 (excluding term note related to transmission line financing with an industrial customer).
[14] The term of this new loan is until December 31, 2015 with interest at 4.25% payable on the last day of each month.

1.3 FACTORS DRIVING THE NEED FOR A 2012 AND 2013 RATE INCREASE

The 2008/2009 General Rate Application indicated that Yukon was embarking on a new era of growth and development very different than the decade that followed the 1998 closure of the Faro mine[15].

After the shutdown of the Faro mine, diesel requirements were minimal on WAF (0.7 GW.h of diesel in 2000 and 0.1 GW.h of diesel by 2005). Over this period material surplus grid hydro generation was available on the WAF grid.

However, since 2005 non-industrial grid load growth has tended to be higher than forecast. For example, 2011 resource planning has forecast grid non-industrial growth at 2.26%/year, which was higher than the 1.85%/year forecast in the 2006 Resource Plan; furthermore, growth is presently tending to exceed 2011 resource planning forecasts. This growth reflects overall Yukon economic expansion plus other factors such as an apparent increase in reliance on electric heat.

More specifically, from 2005 to 2010, grid non-industrial sales steadily increased from 273 GW.h/year to 314 GW.h/year (a 41 GW.h increase over the period reflecting higher growth than was even forecast in the 2006 Resource Plan),[16] while grid industrial sales were minimal until late 2008 when the Minto mine was connected to the grid. Industrial sales grew thereafter to 30 GW.h in 2010 and 43 GW.h in 2011 (including the Alexco mine which connected to the grid in October 2010)[17]. Industrial load growth to date continues to bring higher revenues that tend to more than offset any related incremental costs.

Since 2009, the last test year, continued non-industrial retail and industrial growth depleted available surplus hydro generation increasing the relevance of diesel generation to the point where diesel is once again "on the margin". Industrial growth by the end of 2013 is expected to increase by approximately 33 GW.h over 2009 approved forecasts. Similar growth in retail sales is also expected over this period with 30.5 GW.h of growth in firm Wholesales expected by the end of 2013 over 2009 approved forecasts.

[15] The closure of the Faro Mine reduced industrial loads by approximately 180 GW.h/year, but it also dramatically reduced the loads in communities local to the mine (such as Faro, which reduced from an average residential customer count of 478 in 1996 to an average of 189 in 2001) and in major centres such as Whitehorse (Yukon Energy wholesales to YECL declined from 232 GW.h in 1996 to 217 GW.h in 2001). During this 1998-2001 period out-migration of about 10% of the Yukon's population occurred (over 3,000 people).

[16] Year over year increases over the period tended to exceed the 1.85% non-industrial percentage annual growth forecast in the 2006 Resource Plan, with annual growth ranging from a 1.8% annual increase in 2007 to a 5.5% annual increase in 2006.

[17] The Minto (32 GW.h) and Alexco (11 GW.h) mine loads combined in 2011 were only approximately 24% of the Faro Mine load in 1996 (179 GW.h).

This recent dramatic economic (and load) growth in Yukon has had a major impact on Yukon Energy. In addition to increasing costly diesel generation requirements, it has resulted in an unprecedented capital expansion program, and the need to increase the size of its operations (including its workforce) to meet these significant challenges. It is these factors that underlie current revenue requirements and the 2012 and 2013 proposed rate increase.

Increase in baseload diesel generation to meet load growth

Overall growth on the system has driven increased diesel generation costs. For example, 2011 preliminary actual results are more than $2 million higher than forecast diesel generation costs approved in Yukon Energy's 2009 rates. Notwithstanding major new capital assets that enhance hydro generation and reduce diesel generation impacts (see next sub-heading regarding Mayo B, CSTP and Aishihik 3rd Turbine), ongoing load growth during the test years and beyond is further increasing forecast baseload diesel generation. At forecast annual long-term average hydro with currently existing hydro generation facilities and licenses (which include material expansions since 2009 at Mayo and Aishihik), diesel costs in 2013 would be over $4.5 million higher than costs approved in 2009.

The Application marks a major transition in forecast annual long-term average baseload diesel generation needed to meet grid load growth, with such diesel generation requirements by 2013 exceeding 50% of incremental grid load growth (see Tab 3, Appendix 3.2, Tables 3.2-1 and 3.2-2 in Attachment 3.2):

- In 2011, at a grid generation load (excluding Fish Lake hydro and wind) of approximately 401 GW.h/year, annual long-term average diesel generation required (Table 3.2-1) approximated 5.6 GW.h and long-term average diesel generation would supply 30% of the next few GW.h of incremental added load growth.

- In 2012, at forecast grid generation load of approximately 416 GW.h/year, annual long-term average diesel generation required (Table 3.2-1) approximates 11.5 GW.h and long-term average diesel generation would supply 44% of the next few GW.h of incremental added load growth.

- In 2013, at forecast grid generation load of approximately 430 GW.h/year, annual long-term average diesel generation required (Table 3.2-2) approximates 18.2 GW.h and long-term average diesel generation would supply 56% of the next few GW.h of incremental added load growth.

The increased reliance on baseload diesel generation to supply growth beyond current hydro generation capability means, in addition to increasing annual fuel costs, that there are increased financial and

ratepayer cost risks related to hydro variability that necessitate the need to update and re-activate the Diesel Contingency Fund (DCF). By way of example, at grid loads forecast for 2013, in extreme low water years reduced hydro generation capability could require diesel generation exceeding 100 GW.h/year at an overall incremental cost (based on current diesel prices) exceeding $25 million. The Application includes provisions to reactivate the DCF to address these water-related risks regarding future diesel generation (see Section 3.6.2 and Tab 3, Appendix 3.2).

In order to mitigate rate impacts and ensure a transition to full operation of the DCF the current Application also provides for forecast diesel generation costs in rates for the test years based on hydro generation forecasts set at a percentage of forecast annual long-term average (as compared to being set at the full long-term average hydro generation forecasts). This specific revenue requirement measure is proposed for 2012 and 2013 in order to mitigate rate impacts in these years and facilitate transition to inclusion in revenue requirement of the full forecast diesel generation required with annual long-term average hydro generation.

Growth over the period and depletion of surplus hydro means secondary sales revenue benefits are no longer available on a reliable forecast basis going forward to reduce total revenues required to be collected in rates (although increased revenues relative to secondary sales have been secured through growth in firm sales). Secondary sales (and related revenues) are not forecast to be available in the test years and are not expected to be available on more than a limited basis going forward[18]. In order to enhance rate stability and augment the DCF funds available for future low water years, the Application proposes that any future secondary revenues be fully assigned to the DCF (which benefits ratepayers in dealing with future fossil fuel generation costs resulting from lower than average hydro generation) rather than be included as revenues to YEC.

[18] The 2008/2009 GRA forecast secondary sales for the test years, but noted the opportunity to sell secondary energy on an interruptible basis would be basically eliminated. The application noted at page 11 that 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 September 2010, due to low water conditions on the WAF and Mayo Dawson grids secondary sales were required to be shut off for an extended period (until August 2011) resulting in a loss of $1 million in net revenue compared to 2009 (however, approximately only half of this revenue was included in 2009 rates). Secondary sales were briefly available in fall 2011 and are only expected to be available on a limited basis going forward.

Material increase in capital expenditures to meet growing demand, and increase grid security and reliability

Significant investment in new infrastructure and re-investment in existing infrastructure has also been undertaken over the period since 2009 to ensure that Yukon Energy can continue to meet the unprecedented level of recent load growth in a safe and reliable manner. Specifically, there is an approximate $32.05 million growth in net rate base from 2009 approved to 2011 preliminary actual, and additional growth forecast of $61.72 million by end of 2013. The following is specifically noted:

1. **Gross Asset Growth (approximately $213.46 million)** – Gross asset growth over this same period has been much higher than net rate base growth and underscores the significant overall growth in assets required to ensure significant transmission and generation investments in the bulk power system are in place to meet this load growth where feasible with renewable resources (i.e., mid-year net rate base over this period excludes approximately $119.69 million of new net contributions, primarily for three legacy projects discussed below).

2. **Asset Additions** – Since 2009, YEC has successfully completed three major legacy asset investments opportunities identified in the 2006 Resource Plan[19] - all with significant third party contributions that limited impacts on ratepayers. The following major projects, in Work in Progress in 2008 and 2009 (and not included in rate base during the last GRA), are included in rate base for the 2012 and 2013 test years and comprise a material portion of the total growth in net rate base in the test years[20] (see Section 1.2 for review of resulting diesel generation fuel and O&M cost savings associated with these new assets).

    a. **Green Infrastructure Fund (GIF) Legacy Project – CSTP Stage 2 and Mayo B** – These projects were completed in 2011, connecting the two existing grids and expanding grid hydro capacity by approximately 10 MW. The Federal government committed up to $71 million of funding under the Green Infrastructure Fund. Further funding assistance was provided by the Yukon Government for both projects[21]. The total Mayo B project capital cost is forecast at approximately $116.6 million (excluding Mayo Lake) or $1.9 million less than the $118.5 million approved budget (excluding Mayo Lake). The Mayo B

[19] Carmacks-Stewart/Minto Spur Transmission Project ($40.484 million with customer and other contribution offsets of $35.450 million) was completed in 2008 and included in rate base in the 2008/2009 GRA with a net rate base impact of $5.034.
[20] Growth in mid-year net rate base in 2011 is approximately $32 million higher than the $148 million approved in 2009 rates, with additional $61.7 million growth in mid-year net rate base by 2013. By contrast gross asset growth has been much higher than net rate base growth (for example, mid-year rate base in 2013 excludes $128.5 million in total contributions for Mayo B, CSTP Stage 2, and Aishihik 3rd Turbine).
[21] Through an annual contribution for the principal and interest payments related to $52.5 million of YDC's required borrowing for the legacy projects (with up to $30.15 million of no cost funding assistance provided to Mayo B and the balance to CSTP Stage 2).

net rate base cost is forecast at $35 million with project costs offset by federal and Yukon Government contributions of approximately $81.6 million. It is expected that the CSTP Stage 2 project will be fully funded (approximately $41.9 million capital cost forecast) by a combination of federal and YDC contributions.

b. **Aishihik 3rd Turbine** – This project was completed in 2011; the $5 million funding provided to Yukon from Canada reduced rate base impacts from $13.8 million to $8.8 million.

3. **Refurbish Old Assets and Improve Grid Reliability** – Growth in net rate base reflects an ongoing need to refurbish old assets and improve grid reliability. This includes requirements for major investments in Mayo Hydro Substation Enhancements (approximately $10.1 million to be completed in 2012), the Aishihik Generation Station Redundancy (approximately $6.4 million, completed in 2011) and other projects such as Mayo Head Gate Repairs ($1.3 million), Wareham Intake Rock Scaling ($0.9 million), Wareham Dam Core Raise & Improvements ($0.5 million), and Wareham Spillway Upgrades (approx. $0.8 million).

Material increases in size of Yukon Energy to respond to load growth and major capital expansion program

Due to growing demand, and in order to ensure sufficient resources to fulfill its mandate, the Corporation has grown materially since 2009. This has resulted in material increases in operations and administration expenses.

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

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

Material increase in planning costs required to plan for unprecedented load growth

In Order 2009-8 following the 2008/2009 GRA, the need to plan for future load growth was specifically noted. The Board in that decision stated that it "understands that YEC does not have the 'luxury of waiting for these loads to, with full certainty, materialize before taking any action'" and further that, "YEC's obligation to serve does require it to plan the system to meet these expected loads and any other requirements that may arise"[22].

Accordingly, in order to ensure sufficient generation and transmission capability to meet growing power requirements on the integrated grid without relying only on high cost diesel generation, Yukon Energy has continued to invest in the significant resource planning activities as discussed during the 2008/2009 GRA[23].

In the case of industrial loads, new mine loads contemplated in the 2008/09 GRA included the Alexco mine and Carmacks Copper mine. The Alexco mine completed a PPA with Yukon Energy and was interconnected to the grid in October 2010 (increasing energy requirements by approximately 11 GW.h/year in 2011 with expected increased requirements in 2012 and 2013), while Carmacks Copper mine development was delayed due to regulatory issues and is currently not expected to develop until 2015 or 2016. However, additional potential industrial loads are expected to develop in the 2013 and 2015 time period that were not expected in 2009 – Whitehorse Copper Tailings (8.7 GW.h/year) is included in the Application load in 2013, Victoria Gold (95-105 GW.h/year) is forecast for potential connection by early 2015, and Brewery Creek has recently sought connection in mid to late 2013[24].

At the same time, non-industrial load growth has also grown at a rapid and increasing pace with new developments such as Whistle bend expected to have requirements as high as 10 MW.

The 2008/2009 GRA identified four major deferred planning studies projects with costs exceeding $1 million for the test years, totaling $2.5 million in 2008 and $4.3 million in 2009: Mayo B, Other Generation

[22] Paragraph 242 of Order 2009-8 notes, the Board "understands that YEC does not have the 'luxury of waiting for these loads to, with full certainty, materialize before taking any action.' Further, the Board notes that YEC's obligation to serve does require it to plan the system to meet these expected loads and any other requirements that may arise." Further the Board recognized the significant potential benefits that flow from such work, including: developing projects that are 'shelf ready' and able to proceed at some future date as circumstances warrant, feasibility work may also result in products that have other uses and applications of ongoing value to the utility; and there may also be benefits due to engaging with the local community and working with them through the issues; and the Board finds these benefits justify incurring the deferred costs" (paragraph 243).

[23] This is consistent with Order 2009-8 where the Board recognized the need for Yukon Energy to continue planning studies work in order to meet expected future load growth, and accepted the enduring benefits planning processes provide for rate payers.

[24] As noted in Tab 2 regarding Brewery Creek, Predator Mining Group contacted Yukon Energy in mid-February 2012 while the GRA Application was being prepared. Yukon Energy will update the Board at such time as there is more definitive information.

Feasibility projects undertaken to enhance the compliment of renewable generation projects in Yukon [including Marsh, Gladstone, Atlin, Hoole], Western Copper mine grid connection and CSTP Stage Two.

Subsequent to the 2008/2009 GRA, Mayo B and CSTP Stage 2 have proceeded to construction and are in service, while Western Copper grid connection has been delayed until Carmacks Coppers has resolved its regulatory issues.

Work on Other Generation Feasibility projects has continued since 2008/2009 in order to determine viability of supply options that can meet expected near-term energy requirements. In the 2008/2009 GRA it was noted that test year planning cost budgets would begin to include material expenditures for this next generation of power projects, but that these costs would remain in Work-in-Progress through the test years and not affect amortization or rate base costs in the 2008/2009 test years. Since 2009, Yukon Energy has carried out extensive feasibility planning studies to assess potential options for reducing diesel generation that would otherwise be required to supply future load growth, e.g., forecast deferred study costs to the end of 2012 and/or 2013 include $4.8 million for Marsh Lake Storage, approximately $3 million for DSM, $2.2 million for Atlin Storage, $4.4 million for Gladstone Diversion, $1.7 million for LNG (assumed transfer to fixed assets in the end of 2013 with $1 million additional spending as fixed assets project in 2013), $2.6 million for Geothermal, $2.1 million for Mayo Lake Storage Enhancement, and $1.6 million for Waste-to-Energy.

1.4 OTHER REGULATORY CONCERNS ADDRESSED IN APPLICATION

Aside from the need to address revenue requirement shortfalls at existing rates the current Application considers other regulatory concerns that need to be addressed at this time:

- **Update of Diesel Contingency Fund & Related Matters** – In 2008/2009 GRA it was noted that diesel would soon be "on the margin" on the integrated grid due to ongoing growth. The system is now considered to be at a point where diesel is once again "on the margin". This condition activates a number of regulatory provisions that have been dormant for the past decade, including the Diesel Contingency Fund (DCF) and the Energy Rate Adjustment (ERA) provisions of Wholesale Rate Schedule 42. Given the material changes on the system since these provisions were last active, there is a requirement to review and update the provisions so they reflect the new realities on the integrated grid (see Attachment 3.2 to Tab 3 for the proposed updates/adjustments to the DCF).

- **Mayo B Flexible Note** – In 2011, as committed in the Mayo B Part 3 Application reviewed by the Board, Yukon Energy secured flexible debt financing from the Yukon Development Corporation (YDC) to mitigate ratepayer risks related to Mayo B costs exceeding 11 cents per KW.h (2012$) for diesel generation displaced in any year (see Attachment 5.3 to Tab 5 for a review of this financing and a copy of the relevant Note).

- **Planning Costs Accounting Policy** – In the 2008/2009 GRA Yukon Energy reviewed the requirement to undertaken significant planning activities to ensure the next generation of low cost supply resources are available to meet growth on the integrated grid and displace requirements for costly diesel generation. Since that time, Yukon Energy has continued with the planning work outlined in the 2008/2009 GRA and has in general accrued these costs in Work in Progress (WIP) for review by the Board at the next GRA. The new planning cost accounting policy included in this Application (provided in Appendix 5.1 to Tab 5) is required to address the unprecedented levels of planning costs incurred in WIP since 2009 and ensure that these costs are included in rates in a manner that does not result in undue rate impacts for ratepayers.

- **Demand Side Management ("DSM") Accounting Policy** – Pursuant to the Board's direction Yukon Energy (in coordination with Yukon Electrical, Yukon Development Corporation and the Yukon Government) has engaged in material consultation and planning work related to the development of robust DSM programming for Yukon. Yukon Energy's accounting approach for deferral and amortization of DSM costs is provided in the DSM Accounting Policy provided as Appendix 5.2 to Tab 5.

- **IFRS Changes** – The Canadian Accounting Standards Board ("ASB") has allowed entities that meet the criteria for rate regulated activities to defer transition to IFRS for one year (to years beginning on or after January 1, 2012) and to continue to apply CGAAP until that time. Yukon Energy has elected to take this deferral option and will report under IFRS for the first time in its year ended December 31, 2012. Yukon Energy has prepared its consolidated financial statements prior to fiscal year 2012 in accordance to CGAAP. A summary of expected transition to IFRS for Yukon Energy is provided as Appendix 6.2 of Tab 6. However, it is noted that the implementation of IFRS (and how provisions are interpreted and applied) will evolve up to December 31, 2012[25].

[25] In March 2012, the Accounting Standards Board of Canada indicated that it would defer for a further year (until January 1, 2013) the requirement for rate regulated entities to be IFRS compliant. Yukon Energy is considering whether to take the additional deferral at this time.

For the purposes of the current Application Yukon Energy has implemented the following changes in accounting practice:

- **General Overhead Allocation** – Under IFRS, general overhead allocations are specifically not allowed on capital projects. Accordingly, Yukon Energy has eliminated the pooling of overhead expenses for general allocation. In lieu of this, YEC staff now charge all capital related work to specific projects. Vehicle expenses that were previously included in the overhead pool are now also charged to projects based on the driver's labour coding. This new treatment was adopted in 2011 – it is not expected that this change will have a material impact on the amount of overhead charged to capital.

- **Interest During Construction** – In lieu of earning a rate of return on assets under construction, the utility charges WIP projects at the weighted average cost of capital during the period the asset is being constructed. Under IFRS, entities are not permitted to charge projects for equity returns; accordingly, Yukon Energy has amended this policy to use a debt-only rate for AFUDC (Allowance for Funds Used During Construction) starting in 2011. At current rates, this will result in lower charges to capital (debt rates are less than equity); the overall impact is not expected to be material.

1.5 YUKON ENERGY RATES AND BILLS

Since Yukon Energy was established in 1987, rate matters related to Yukon Energy and Yukon Electrical (YECL) have been typically dealt with on a joint basis. This arrangement reflected YECL management of Yukon Energy prior to 1998 and the rate policy directives to the YUB set out since 1987 in various OIC's establishing equalized rates in Yukon (the most recent being OIC 1995/90), as well as the following more recent directives amending OIC 1995/90: OIC 2007/94, setting industrial rates until the end of 2012; OIC 2008/149 providing that, until the end of 2012, rate adjustments for all retail customers apply equally, when measured as percentages, to all classes of retail customers; and the recent OIC 2012/68 direction to the general effect (subject to conditions reviewed in Tab 4) that rate adjustments prior to the end of 2013 to retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers. Tab 11 provides copies of the current and recent 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 related to YECL income taxes and the Interim Electrical Rebate).

The following are major changes affecting firm rates and bills generally paid by Yukon Energy's customers since the 2008/2009 GRA and prior to the changes proposed in the Application:

1. **Rider F (Diesel Fuel Price Changes)** – Per direction provided in Order 2009-8 quarterly updates are filed with the Board and provided on each Companies' website. The current Rider F for all retail customers is 0.352 cents per kW.h and was last changed as at July 2011; the current Rider F will change to 0.420 cents per kW.h effective May 1, 2012. The May 2012 Rider F charges reflect variances in fuel prices since 2009 (from the 2008/09 GRA), with YECL amounts accounting for approximately 74% of the combined YEC/YECL shortfall (see March 21, 2012 filing with the Board on Rider F rate change).

2. **Interim Electrical Rebate (IER)** – The Government of Yukon provides for a 2.662 cents/kW.h rebate for up to first 1000 kW.h per month (first block) for residential non-government customers (since the termination of the RSF there is no longer similar rate relief for general service or municipal customers). This rebate was implemented in 2009 as an interim measure; it has continued to be extended since that time.

3. **Industrial Rate 39** – Board Order 2008-13 approved a final Rate Schedule 39 based on OIC 2007/94. A provision for Fixed Rider F was also approved as part of the 2009 Phase II Rate Application[26]. Order-in-Council 2007/94 provides for annual escalation of demand and energy charges, once per 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. Since 2010 there have been two adjustments to the Demand and Energy Charge included in Rate Schedule 39. On January 1, 2011 the demand charge and energy charge increased 2.8 percent[27]. On January 1, 2012, the demand charge and energy charge increased a further 3.4 percent[28] (cumulative 6.295% rate increase for industrial customers since 2009/2010). In April 2012, section 6(3) of OIC 2007/94 was replaced with a new

[26] Revenues for fixed Rider F were approved in Order 2009-10. The 2009 Phase II Rate Application sought and received approval to clarify implementation details with respect to the way Rider F is charged to the industrial class so as to implement the requirements for "Rider F to be set to zero for fuel price forecast filed November 20, 2006". Given the November 20, 2006 fuel price forecast is slightly different than the approved GRA fuel price (which is the zero-basis for Rider F for all other customers) it was necessary to implement a differential Rider F for the industrial customer of 0.211 cents/kW.h as approved in Yukon Energy's GRA compliance filing.

[27] From January 1, 2011 until December 31, 2012 the Rate Schedule 39 demand charge was $15.42/kV.A and the energy charge was 7.81 cents/kW.h. This change was approved on interim basis by Order 2010-15 and on final basis by Order 2011-04.

[28] As of January 1, 2012, the Rate Schedule 39 demand charge is $15.94/kV.A and the energy charge is 8.08 cents/kW.h plus a fixed Rider F charge of 0.211 cents/kW.h (approved on final basis by Order 2011-14).

OIC direction that in effect requires that Rate Schedule 39 as approved in Board Order 2011-14 continue until December 31, 2013, except that if rates charged to retail customers for all or part of 2012 are to be increased, then for that same period, only the greater of that increase and the percentage increase approved in Board Order 2011-14 [i.e., 3.4%] is to apply to the class of major industrial customers. Pursuant to the new OIC direction (OIC 2012/68), the Board must otherwise ensure until the end of 2013, that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customer and to the class of major industrial customers.

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 2012 and 2013.

The following items are reviewed in this tab:

- Overview;
- Sales Forecast;
- Power Generation; and
- Peak Demand Forecast and Reliable Capacity Requirement.

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 Integrated System[1].

Yukon Energy directly serves about 2,000 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 Integrated System (including those located in Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and Teslin, Pelly Crossing, Keno and Stewart Crossing) through its wholesale sales to Yukon Electrical Company Limited (YECL). Since 2005, non-industrial grid load growth supplied by Yukon Energy to Yukon Electrical and other grid retail customers has tended to be higher than forecast. For example, 2011 resource planning forecast grid non-industrial growth at 2.26%/year, which was higher than the 1.85%/year forecast in the 2006 Resource Plan; furthermore, growth is presently tending to exceed the 2011 resource planning forecast. This growth reflects overall Yukon economic expansion plus other factors such as an apparent increase in reliance on electric heat.

[1] In June 2011, the Whitehorse – Aishihik – Faro (WAF) grid and the Mayo-Dawson (MD) grid were inter-connected through Stage 2 of the Carmacks-Stewart Transmission Project (CSTP Stage 2).

Industrial sales under Primary Industrial Rate Schedule 39 currently include sales to the Capstone Mining Corp (Minto mine) and Alexco Resource Corp. (Alexco mine); industrial sales to Eagle Industrial Minerals (Whitehorse Copper Tailings or WHCT) are also forecast starting in 2013. No other major industrial customer sales are forecast for the test years[2]. Industrial load growth to date has continued to bring higher revenues that tend to more than offset any related incremental costs.

Yukon Energy hydro generation capability materially exceeded firm sales on both 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. With continued load growth on the WAF system, WAF surplus generation declined markedly and in the 2008/2009 General Rate Application (GRA), Yukon Energy noted that with completion of CSTP Stage 1 and connection of Minto mine, the WAF system was reaching a point where the material existing surplus hydro generation was nearing depletion at certain times of the year[3]. In subsequent proceedings, Yukon Energy noted that surplus hydro was diminishing and the system was returning in the near term to the condition of diesel on the margin [4].

Since the 2008/2009 GRA, ongoing events have demonstrated the depletion of surplus hydro generation and increasing relevance of diesel generation. As compared to the 0.95 GW.h diesel generation forecast for 2009 in the approved 2009 Compliance Filing, actual diesel generation exceeded 2.6 GW.h in 2009, 4.28 GW.h in 2010 and 10.55 GW.h in 2011 (excluding diesel requirements related to capital projects and hydro generation plant construction activities)[5]. Secondary sales have been interrupted on a sustained basis since September 2010 (except for temporary resumption in September 2011 due to high water in Aishihik Lake), and as a result of this sustained interruption a number of secondary sales customers have converted to primary supply for their electric heating loads.

[2] Per OIC 1995/90, an industrial customer is defined as "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."
[3] As reviewed in Section 2.3 of the 2009 Phase II Rate Application, the 2009 Consolidated Firm Revenue Requirements assumed for the 2009 test period that existing hydro was not forecast to be fully utilized. Only limited use of diesel generation for peaking and maintenance reasons was forecast on the WAF and MD grid systems.
[4] In the Mayo Hydro Enhancement Project (Mayo B) Part 3 Application and in the Yukon Energy and Yukon Electrical 2009 Phase II Rate Application, Yukon Energy noted that absent new sources of supply, material baseload diesel generation would be required in the 2012 to 2017 period. Further, for load growth beyond 2009 levels, and without new renewable generation, diesel would have to begin to be forecast to be on the margin in a small but increasing way, in order to ensure rates are appropriately recovering the average diesel consumption that would be required under the various potential water flow conditions that could arise.
[5] In 2010, diesel generation of 0.85 GW.h resulted from the construction activities due to capital projects. In 2011, Aishihik plant construction is estimated to have resulted in 3.18 GW.h [$0.8 million] of diesel generation due to shut downs required of the Aishihik generation plant, and Mayo B plant construction (extended Mayo A shut down for tunnel tie in work) is estimated to have resulted in 1.5 GW.h [$0.4 million] of diesel generation; a further 0.7 GW.h of diesel generation in 2011 was due to other capital projects. The costs for such diesel generation were charged to the capital costs for each respective project.

With new major legacy assets in service by the end of 2011[6], the majority of grid generation requirements in the test years (over 97%) will continue to be met with hydraulic generation based on annual long-term average hydro generation capability. However, as reviewed in Tab 1 (Section 1.3), forecast diesel generation included in this GRA is considerably higher than the levels approved in the 2009 GRA and the Application marks a major transition in forecast annual long-term average baseload diesel generation needed to meet grid load growth. Anticipated continuing load growth beyond the test years is expected to result in continued material increases in diesel generation requirements, driving the need to secure new lower cost sources of supply by 2015 to displace continued increases in baseload diesel requirements.

2.2 SALES FORECAST

Yukon Energy's actual sales for 2009 and 2010, preliminary actual sales for 2011 and forecast sales for 2012 and 2013 are summarized in Table 2.1 at the end of this tab.

Total forecast sales are 382.6 GW.h for the 2012 test year and 395.9 GW.h for the 2013 test year. Total forecast sales for 2012 include 296.0 GW.h of primary (firm) wholesale sales, 52.3 GW.h of primary Major Industrial sales, 34.3 GW.h of firm Retail sales (i.e., all firm sales other than wholesale or Major Industrial), and total forecast sales for 2013 include 298.2 GW.h primary wholesale sales, 62.3 GW.h Major Industrial sales, 35.3 GW.h firm Retail sales. No secondary sales are forecast to be available in the test years (see Section 2.2.4).

2.2.1 Wholesale Sales to Yukon Electrical

Yukon Energy's sales on the Integrated System are primarily made up of firm wholesale sales to Yukon Electrical.

Each year Yukon Electrical provides Yukon Energy with an Integrated Grid firm wholesale purchase power forecast reflecting its forecast grid firm retail sales less its forecast generation from its Fish Lake hydro plant. Yukon Energy reviews and adjusts the Yukon Electrical forecasts in light of the most recent information available.

[6] CSTP Stage 2 in service in June 2011, Mayo B and Aishihik Third Turbine in service in December 2011.

For GRA forecast purposes, available preliminary actual results for 2011 were considered and the 2011 actual YECL wholesale sales were adjusted to reflect expected in-service of a new Fish Lake hydro unit #1 in 2013[7] and to reflect adjustments for weather conditions based on 10 year average Heating Degree Days (HDD)[8]. A percentage growth increase of 2.26% per year was then applied to the adjusted 2011 actual wholesale sales (normalized assuming operation of both Fish Lake units) for each of 2012 and 2013[9] and additional sales were included for 2012 to reflect continuing shut down of Fish Lake Unit #1 until January 2013.

2.2.2 Major Industrial

The 2012 and 2013 test years include three Major Industrial customers (each are reviewed separately below):

- Minto mine (in service in late 2008);
- Alexco mine (in service in late 2010); and
- Whitehorse Copper Tailings (forecast in service starting in mid-2013).

No sales are forecast under Rate Schedule 35 – Low Grade Ore Processing Secondary Energy Rate. This rate cannot be utilized until audit and control measures and reporting requirements have been developed and filed with the Yukon Utilities Board for approval. Given that secondary sales are not currently forecast to be available during the test years and Rate Schedule 35 loads would only be served as a lower priority service than Rate Schedule 32 Secondary Sales loads, it is not expected that this rate would be applicable during the test years.

[7] Unit #1 failed in March 2010. Per discussions with Yukon Electrical management in fall 2011, this unit is currently expected to be back in service in January 2013.

[8] Variations in the annual generation at Yukon Electrical's Fish Lake hydro plant can have an impact on Yukon Energy's wholesale sales. In 2011, the actual wholesales to Yukon Electrical were 290.5 GW.h, 5.14% higher than 2010 actual wholesales because of (a) unavailability of hydro generation from Unit 1 of Fish Lake hydro generation plant (added 4.35 GW.h to the 2011 sales) and (b) colder than normal weather (HDD analysis showed that the temperature in Whitehorse was colder in 2011 than the 10-year average and that the estimated impact added 1 GW.h to the 2011 sales). The average annual growth rate of 2.26% was applied to the adjusted 2011 wholesales of 285.1 GW.h (290.5 GW.h - 4.35 GW.h – 1 GW.h=285.1 GW.h) and 4.35 GW.h for Unit 1 of Fish Lake plant added back to wholesales forecast in 2012 as commencing of this unit is now expected to be in the beginning of 2013.

[9] The average annual increase of 2.26% was determined based on an average of the WAF average growth rate (2.18%) and 2.34% (reflecting Whitehorse residual use growth). The WAF average growth rate of 2.18% per year for 2001-2010 was calculated by excluding Pelly Crossing sales starting late 2008 (0.275 GW.h in 2008, 2.584 GW.h in 2009 and 2.691 GW.h in 2010) and including Faro site dewatering sales after Faro mine closure charged as "Industrial" prior to 2005. The Whitehorse residential use growth rate of 2.34% per year was calculated based on City of Whitehorse population for the 2001-2010 period (averaging 1.8% per year based on Yukon Bureau of Statistics, Annual Reports - 2001-2008, Monthly Reports of Dec. 2009 and 2010) and the weather normalized average annual increase in residential usage per customer (0.52% per year based on Weather normalized UPC data for 2001-2007 as filed in Yukon Electrical 2008-2009 GRA; 2008-2010 data as provided by Yukon Electrical).

The GRA forecast also does not include any potential reduction in revenues related to use of the peak shaving rate option included in Rate Schedule 39 Industrial Primary. Electing to take service under this provision requires at least six months advance notice from the customer, and to date, such notice has not been provided.

Yukon Energy is working to develop and deliver an audit pilot program as part of ongoing DSM initiatives. At the current time, an audit of the Alexco mine facilities has been undertaken. However, audit recommendations have not yet been implemented, and consequently, no provision for savings has been forecast in the test years. The industrial sales forecasts also do not include any potential reduction in revenues related to use of the peak shaving rate option as provided for in Rate Schedule 39.

2.2.2.1 Minto Mine [Capstone Mining Corp.]

Forecast industrial sales to Minto mine for 2012 are 39.3 GW.h and for 2013 is 43 GW.h[10].

In January 2011, Minto pre-paid in full the Capital Cost Contribution required pursuant to the Power Purchase Agreement with Minto (Minto PPA)[11].

In April 2011, pursuant to the Minto PPA, YEC agreed to increase Minto's mine Firm Electricity requirements for Maximum Electric Demand up to 6.5 MVA and for Electric Energy up to 43 GW.h per calendar year (by Q3 2012)[12]. It is currently assumed Minto will remain at this level until late 2019. This increase in firm electricity requirement was subject to YEC upgrading substation equipment to accommodate the increased load, and Minto's payment of all of YEC's actual and reasonably incurred costs associated with the upgrade[13].

2.2.2.2 Alexco Mine [Alexco Resources Corp.]

Alexco commenced operation as an industrial customer pursuant to Rate Schedule 39 Industrial Primary Rate and the Alexco PPA[14] in October 2010[15]. Forecast industrial sales for 2012 are 13.1 GW.h (includes

[10] Based on forecast consumption at rates of 34 GW.h/year for Q1 2012, 37 GW.h/year for Q2, and 43 GW.h/year for Q3 onwards.
[11] Minto PPA approved by Order 2007-6.
[12] Pursuant to the Minto PPA [Section 4.5], Minto is required to provide written notice of the specified amount of the requested increase and YEC will have to determine if the facilities have transmission capacity to maintain that increased demand, as well as any potential requirement for an increase to the mine firm rate related such increase.
[13] Costs estimated at $25,000 at time of agreement.
[14] PPA approved by YUB Order 2011-01.

3.1 GW.h per quarter for Bellekeno mine and District Mill plus 0.1 to 0.2 GW.h per quarter for Silver King), and for 2013 are 14.6 GW.h (includes 3.1 GW.h per quarter for Bellekeno mine and District Mill plus 0.5 to 0.6 GW.h per quarter for Silver King).

Alexco is expected to develop further mines and mills in the Mayo-Keno area (as described in Figure C-1 Schedule C of the PPA) during its operating life; however, at this time due to uncertainty regarding the timing of such developments, power requirements for additional mines are not assumed in the load forecast. These additional mines are also expected to require development of mine electrical distribution facilities (that pursuant to the Alexco PPA would be fully paid for by the mine). Such facilities have yet to be developed.

2.2.2.3 Whitehorse Copper Tailings [Eagle Industrial Minerals]

Eagle Industrial Minerals is actively looking into processing the old Whitehorse Copper mine tailings for magnetite. Operations are expected to consist of a small mill to separate the magnetite from the balance of the tailings with no mining or major milling required. The site is located just south of Whitehorse off of the ski hill road and has an existing three phase 34 kV power nearby (to the vicinity of the old mill).

A YESAB proposal for this mine was submitted by Eagle Industrial Minerals on March 14, 2011. As of December 2011, the application stage changed to Information Request with the YESAB Whitehorse Designated Office. A Water Use licence application is expected to be submitted to the Yukon Water Board in 2012 (subsequent to completion of the YESAB process).

It is expected that Whitehorse Copper Tailings would commence service in Q3 of 2013 as an industrial customer of Yukon Energy and that a PPA will be negotiated in 2012 in order to facilitate delivery of power to the mine site. The expected forecast load requirement for 2013 is 4.8 GW.h per year from the start of July to the end of November with 2.0 MW of peak demand.

The expected mine life is six to seven years commencing in July 2013. After 2013, the mine is expected to operate nine months out of each year (March through November) at a typical annual load of 8.6 GW.h.

[15] Prior to October 2010 Alexco received service as a general service customer of YEC on the Mayo Dawson grid, purchasing power in the Keno Hill area to carry out exploration, bulk sampling and other mine development activities as well as management and reclamation activities of the Keno Hill District assets of the former United Keno Hill mine Corporation.

2.2.2.4 Update on Other Mines

Yukon is currently experiencing a mining resource boom driven by world commodity market demands. Mineral exploration expenditures and claims in Yukon have recently climbed to record high levels, which may increase the future potential industrial load and new capacity planning requirements. No other new mines are currently forecast to connect into the Integrated System within the test years for this GRA; however, in mid-February 2012 the developer of Brewery Creek mine (Predator Mining Group Inc.) near Dawson City informed Yukon Energy that it would like to discuss connection to the grid (approximate 15 km connection line would be needed to the 69 kV Mayo-Dawson line), potentially by as soon as mid-2013 with a load of 3.7 MW. Yukon Energy is pursuing this potential connection with the Predator Mining Group and will update the Board at such time as there is more definitive information.

Potential near-term mines currently expected to seek grid connection soon after the 2012/2013 test years are noted as follows:

- **Carmacks Copper Mine (Copper North Mining Corp., formerly Western Copper Corporation)** – Carmacks Copper mine, which is being developed by Copper North Mining Corp., completed its YESAB review process in September 2008[16]. Development of the project was delayed due a 2010 Yukon Water Board determination to not issue a water licence for the project[17]. Subsequent to a court ruling on the Yukon Water Board decision, Western Copper announced in March 2011 that it had initiated engineering studies to determine whether certain aspects of the project could be modified to improve the project's reclamation process and thus satisfy the main concern of the Yukon Water Board, and that it is working with regulatory authorities in Yukon to establish the next steps towards getting the project fully licensed. A February 2012 press release from Copper Mining North Corp., indicated commencement of work on a Feasibility Study update for the project to provide an up to date development plan, capital and operating cost estimate and financial analysis. The report is expected to be issued by July 2012 and include engineering and design work associated with recent proposed project changes.

  The projected earliest in service date for Carmacks Copper would be 2015, with an expected annual requirement averaging approximately 52 GW.h/year and a mine life of at least six years. Peak demand is assumed at 8 MW in winter and 10 MW in summer.

[16] Subsequent Decision Documents accepted the YESAB recommendation that the project proceed.
[17] See referenced decision at following link - http://www.yukonwaterboard.ca/registers/quartz/qz08-084/QZ08-084%20Reasons%20May%2010%20final.pdf.

In order to connect the Carmacks Copper mine to the Integrated System, a new spur line connecting the mine with the CSTP Stage 1 will need to be licenced and constructed, and Yukon Energy will need to have concluded a power purchase agreement with Copper North Mining Corp. that is then reviewed and approved by the Yukon Utilities Board.

- **Eagle Gold [Dublin Gulch] (being developed by Victoria Gold Corp.)** – A preliminary feasibility study for this mine project was completed with results announced on March 9, 2010, and a full feasibility study was announced in January 2011[18]. Victoria Gold has filed its Project Proposal with YESAB (December 2010[19]), and on December 16, 2011, commenced the Screening Report stage of review. Victoria Gold has also announced a Letter of Intent with Yukon Energy and is expected to enter into a Power Purchase Agreement with Yukon Energy in 2012[20].

  Victoria Gold has included grid connection within the scope of the development and expects to be in service and seek connection by late 2014. The current expected load forecast is in the range of 95-105 GW.h/year for more than seven years. Peak demand is currently assumed at 13 MW - however, a lower winter peak demand may apply.

2.2.3 Yukon Energy Firm Retail Sales

Yukon Energy firm retail sales are comprised of sales to residential, general service, street light and space light customer classes served directly by Yukon Energy. The 2013 forecast indicates a 2.6% average annual increase in Yukon Energy's non-industrial retail sales over 2009 (actual).

In sum, retail sales grew by 7.95% in 2010 over 2009 (actual), declined by 0.26% in 2011 over 2010, and are forecast at the same level for 2012 as in 2011. Retail sales are expected to grow by 2.9% in 2013 over 2012. The decline in retail sales in 2011 relates primarily to a decrease in retail sales in the general service class due to a decrease in Faro mine dewatering sales in combination with Alexco mine commencing service as an industrial customer in October 2010.

[18] On March 9, 2010, Victoria Gold announced the results of a Preliminary Feasibility Study which highlighted the development of a mine at Eagle Gold with production to start in 2013 and to average approximately 170,000 ounces of gold per year with cash operating costs to be below US$500/oz. On January 25, 2011 Victoria Gold announced that Wardrop was engaged to complete a NI 43-101 compliant Feasibility Study for the Eagle Gold mine project.
[19] Announced December 20, 2010 – see link: http://www.vitgoldcorp.com/index.cfm?returnid=8144&newsid=1559&pagepath=Media_releases&id=8144.
[20] Victoria Gold announced LOI with Yukon Energy February 7, 2011 noting expectation to complete PPA by Q2 2011; see following link: http://www.vitgoldcorp.com/index.cfm?returnid=8144&newsid=1649&pagepath=Media_releases&id=8144.

2.2.3.1 Residential Sales

Firm residential retail sales have grown from 11,676 MW.h in 2009 (actual) to 12,325 MW.h in 2012 (forecast) and 12,408 MW.h in 2013 (forecast). The average annual growth rate is 1.5% in 2013 (forecast) compared to 2009 (actual). This reflects ongoing modest growth in the number of customers and the average use per customer over the previous three years.

2.2.3.2 General Service Sales

The 2013 forecast indicates a 3.15% average annual increase in Yukon Energy's general service sales over 2009 (actual).

In sum, firm general service retail sales in 2009 (actual) were 19,672 MW.h, and are forecast to increase to 21,693 MW.h in 2012 and 22,620 MW.h in 2013.

- Actual sales in 2010 were higher by 15.5% compared to 2009 (actual) due to dewatering sales to Faro site after the Faro mine closure (an increase of 0.8 GW.h) and sales to Alexco for bulk sampling operations as a general service customer as the billed sales to Alexco were under 1 MW.

- Sales in 2011 (FYF) decreased by 6.2% over 2010 actual sales due to Alexco mine commencing service as an industrial customer under Rate Schedule 39.

The Faro mine site load is forecast to remain steady over the forecast years.

2.2.3.3 Lighting (Street lights and Space lights)

Firm retail sales for streetlights are forecast to remain relatively constant at 279 MW.h for both 2012 (forecast) and 2013 (forecast). Firm retail sales for space lights are forecast to be 15 MW.h for both forecast 2012 and forecast 2013, at the same level as in 2009 GRA approved sales.

2.2.4 Secondary Sales

Due to the material surplus of hydro generation available on WAF after the Faro mine closure in 1998, surplus hydro generation was available for the secondary sales over the period extending to 2010[21]. However, ongoing non-industrial load growth and connection of the new industrial loads to the grid also reduced surplus hydro available for secondary sales over this period. In this regard, secondary sales have been interrupted on a sustained basis since September 2010 and are not forecast to be available during the test years[22].

Secondary sales were resumed briefly in September 2011 due to higher water in Aishihik Lake, which otherwise would have been spilled. Total secondary sales in 2011 were only 0.6 GW.h.

To the extent secondary sales become available in the test years, YEC proposes to credit the secondary sales revenue directly to the Diesel Contingency Fund (DCF). It is expected that secondary sales would only become available due to higher water flows. Crediting any additional revenues on this basis is consistent with the principles underlying the DCF and would serve to stabilize revenues and rates in the test years[23].

2.3 POWER GENERATION

Hydro generation remains the predominant source of generation forecast for the test period, and is expected to be supplemented by diesel generation as required. There is also a small amount of wind generation available on the system. Table 2.2 provides a summary of forecast power generation by source.

Total generation is based on the sum of total sales plus losses. Losses are forecast at 8.7% for each of the test years[24].

[21] In 2009 total secondary sales were 17.4 GW.h (including 16.8 GW.h to YECL) and in 2010 secondary sales decreased to 10.5 GW.h (including 10.2 GW.h to YECL).
[22] In September 2010, Yukon Energy interrupted secondary sales on a sustained basis due to water conditions and expectations of potential requirements for diesel generation over the next 12 months. As a result of this sustained interruption, a number of secondary sales customers converted to primary supply for their electric heating loads increasing firm loads. Rate Schedule 32 does not permit secondary sales customers that have converted to firm sales to revert back to secondary.
[23] In prior test years net revenues derived from secondary sales went towards lowering rates compared to what would otherwise be required for firm customers throughout Yukon.
[24] Commencing Mayo B hydro generation and Aishihik Third turbine, as well as connection of two grids (WAF and MD) is expected to lower line losses. However, for the test years, average of 2010-2011 actual losses (rounded to one decimal place) was used considering added station service in new hydro units and added new transmission line.

2.3.1 Integrated Grid Hydro Generation

In June 2011, the WAF and Mayo-Dawson grids were inter-connected through completion of CSTP Stage 2.

The new integrated grid, including the new Mayo Hydro Enhancement Project (Mayo B) and Aishihik Third Turbine hydro unit, has 92 MW of installed YEC hydro generation, of which approximately 72 MW can be relied upon for the winter peak. The Integrated System typically operates with Whitehorse Hydro as first-on generation (outside of wind and Fish Lake) as a largely run-of-river plant. Mayo and Aishihik are used to supplement this run-of-river generation to achieve the required output.

The predominance of hydro generation on the Yukon system, combined with the fact that Yukon is isolated from other grids outside the territory, means that other forms of backup capacity are required to supplement available hydro to meet the system's winter/spring seasonal generation constraints, and to provide reliable energy generation in drought years.

- **Winter constraints** – Seasonal water storage is typically needed for hydro facilities to be fully utilized in winter. In Yukon, controlled seasonal storage exists at Aishihik and to a much lesser extent at Mayo, but is largely unavailable at Whitehorse. As grid load increases, there is an increasing need to rely on diesel generation to meet base load energy requirements in winter and early spring when the peak is high and hydro water flows are constrained.

- **Drought-flood year constraints** – In addition to seasonal supply constraints, systems predominantly based on hydro generation resources such as the Yukon grid are vulnerable to drought (low water) conditions. In these circumstances, hydro generation must be supplemented by diesel generation. Hydro-based systems must also anticipate flood (high water) conditions where the need to rely on diesel or other reliable forms of generation could potentially be eliminated under current forecast load conditions.

Forecast hydro generation proposed in Table 2.2 for the GRA test years is 408.1 GW.h (98.1% of total load) in 2012 and 419.4 GW.h (97.5% of total load) in 2013. As reviewed in Section 2.3.2 below, this forecast hydro generation in each test year is 1.0% [2012] to 1.8% [2013] higher than long-term average hydro generation at the forecast generation loads.

2.3.2 Diesel Generation

Between 1998 and 2008, the existing diesel infrastructure was utilized primarily as reserve capacity to meet peak or short-term emergencies. Since 2008, diesel generation has increased materially relative to the approved 2009 GRA forecast due to load growth and reduced surplus hydro generation.

As reviewed in Tab 1 (Section 1.3), forecast load growth in the test years will result in significant forecast annual long-term average diesel generation levels[25] (11.5 GW.h in 2012 and 18.2 GW.h in 2013[26]). The existing diesel plant is capable of providing energy well in excess of these levels[27].

The term "diesel on the margin" is a concept that has in the past triggered stabilization mechanisms (DCF), cost recovery provisions (Rate Schedule 42 Energy Reconciliation Adjustment (ERA) provisions[28]) or other rate design mechanism (e.g., stepped rates in Rate Schedule 39). Many of these provisions were last active in the mid to late 1990s when the Faro mine was in operation and diesel was last on the margin. However, since diesel is now forecast to be on the margin in the test years these mechanisms once again become relevant and important.

Focusing on the DCF, water-availability risks are beyond the control of the utility and are therefore ultimately borne by ratepayers rather than the utility. The DCF stabilization mechanism was established to protect ratepayers against severe swings in rates as a result of swings in hydro availability and related fluctuations in incremental fuel and O&M costs for diesel generation. The DCF provides for ratepayer funds to be set aside during years with above-average water availability in order to pay for higher-than-normal incremental diesel generation costs during years of below-average water availability.

Since the mid-1990s there have been material changes to the Integrated Grid, including integration of the WAF and MD grids, and new hydro generation at Mayo and Aishihik, which have materially changed

[25] Annual long-term diesel generation is determined by annual long term average hydro generation available to supply forecast grid loads. Annual long-term average hydro generation is forecast at 404.18 GW.h at forecast 2012 load and 411.95 GW.h at forecast 2013 load. Table 2.2 shows forecast wind generation in each test year. Annual long-term average hydro generation for the Integrated System is estimated based on currently installed generation, test year grid load forecasts, and existing water licences, using 28 water years of record; as such, long-term average hydro generation reflects the average of all known water conditions rather than a short-term forecast of generation expected in the two specific test years based on current water conditions. The Mayo B Part 3 Application and the 2009 Phase II Rate Application analysis subsequent to the Yukon Energy 2008/2009 GRA indicated that approximately $1 million in diesel generation costs would have been included in rates in 2009 if rates had been set to reflect long term average hydro capability at that time and the related long term average diesel generation requirement (approximately 4 GW.h at then forecast 2009 loads).

[26] If diesel costs at 100% of annual long term average hydro generation levels were included in rates in the test years the GRA diesel generation costs would increase materially from approximately $2.2 million and $3.1 million in 2012 and 2013 respectively (at 66% and 59% of long term average diesel generation) to approximately $3.3 million and $5.2 million.

[27] At 90% capacity factor existing YEC/YECL grid diesel capacity (44.2 MW) could provide almost 350 GW.h per year of electricity.

[28] When diesel is on the margin for the WAF system, the ERA provisions of Rate Schedule 42 are triggered and in effect result in a two block inverted wholesale rate. See discussion provided in Tab 4, Section 4.6.

long-term average hydro generation forecasts[29]. These fundamental changes mean that the overall relationships between forecast loads and likely hydro generation in any one year are very different than what was experienced in 1996/97 when the DCF was originally approved. Yukon Energy has previously noted that the DCF and the ERA provisions of Rate Schedule 42 are required to be updated prior to reactivation. The current Application includes recommended steps to update the DCF and ERA mechanism (as described in Tab 3, Attachment 3.2 for the DCF and in Tab 4, Section 4.6 for the ERA) and, on that basis, assumes that the DCF and ERA mechanisms are reactivated effective January 1, 2012.

In order to provide for a transition from 2009 GRA rates to once again setting rates based on annual long term average hydro generation (as was done in 1996/97, the last time diesel was on the margin), and in order to reactivate the DCF and ERA, the diesel generation under the Proposed forecast in Table 2.2 for the test years is set at about 59 to 66% of what would be required at annual long-term average hydro generation and hydro generation accordingly set at slightly above (approximately 101 to 102%) long-term average hydro generation[30]. This approach takes advantage of current favorable water supply conditions, providing an opportunity to begin replenishing the DCF funds without immediately increasing rates and to reflect the cost of diesel generation requirements with hydro generation levels set at long-term average levels.

Yukon Energy's resulting forecast generation as proposed in Table 2.2 for the test period is made up of 98.1% hydro in 2012 and 97.5% hydro in 2013, with required diesel generation comprising 1.8% to 2.5% of total system generation (7.5 GW.h in 2012 and 10.7 GW.h in 2013). Forecast fuel prices have increased slightly since levels approved in 2009 GRA application (by approximately 9-14 cents/litre) to a forecast of diesel prices in each of the test years of $1.1680/litre in Dawson, $1.0885/litre in Faro, $1.0966/litre in Mayo and $1.0513/litre in Whitehorse as reviewed in Tab 3.

[29] These changes, in combination with grid load changes, modify projected long-term average hydro generation at any different grid load level and shown how such hydro generation varies in response to grid load levels, reflecting 28 water years of record.

[30] In order to enable reactivation of the DCF and ERA, the GRA diesel generation forecast formally uses a percentage of long term average hydro generation forecasts (i.e., 101.0% in 2012 and 101.8% in 2013 [and any subsequent non-GRA years, until modified by the YUB]) in order to determine diesel generation forecasts for the test years. DCF implementation for the test years and beyond is to be based on these stipulated percentages of long-term average hydro generation, i.e., Yukon Energy payments into (or receipts from) the DCF will be determined as required in each year based on actual hydro generation relative to "expected" hydro generation at actual load levels and the stipulated percentage of long-term average hydro generation. Accordingly, the "Proposed" diesel generation forecasts in each test year are below levels that would apply under long-term average hydro generation levels. In addition, this transition proposal also allows for the possibility that future GRAs will assume a lower cost fuel other than diesel (e.g., LNG) to supply base load generation on the margin.

Yukon Energy forecasts average efficiency for diesel generation of 3.77 kW.h/litre in Whitehorse, 3.8 kW.h/litre in Faro and 3.72 kW.h/litre in Dawson and 3.37 kW.h/litre in Mayo, based on 2011 averages[31]. The overall grid average efficiency (3.67 kW.h/litre) is an increase from the 2009 GRA Application efficiency, where the approved forecast simple average efficiency was set at 3.6 kW.h/litre.

2.4 PEAK DEMAND FORECAST AND RELIABLE CAPACITY REQUIREMENT

As indicated in Table 2.2, the peak demand for the Integrated System is forecast to be 80.1 MW in 2012 and 81.1 MW in 2013[32]. In the 2009 GRA, peak forecast for WAF system was 62 MW.

At these forecast peak levels for the test years (which exceed reliable winter hydro generating capacity of approximately 72 MW), diesel generation will be required to supply firm energy demand.

Yukon Energy included an extensive review of its system capacity planning criteria in the 2006 Resource Plan. This review was undertaken in consultation with Dr. Roy Billinton and Dr. Rajesh Karki (experts from the University of Saskatchewan). The following criteria were developed and adopted in 2006 for Yukon capacity planning purposes on the WAF and MD grids:

- **Loss of Load Expectation (LOLE)** – In 2006, Yukon Energy incorporated into its capacity planning criteria a probability based measure to evaluate the maximum loads that the WAF system can safely carry by identifying the potential interruption of service for any customer (forecast of the average number of system outages per year). The LOLE criterion also recognizes the role of transmission reliability, where relevant[33]. In 2006, the system-wide capacity planning criteria for WAF and MD provided that each system would be planned not to exceed a Loss of Load Expectation of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment.

[31] It is not practical under most situations to forecast the precise diesel units that will be dispatched to serve firm loads when needed under test year forecast loads. The diesel generation forecast may occur anywhere on the Integrated System (e.g., generation could occur at Whitehorse, Faro, Mayo or Dawson).
[32] Peak demand for the YEC grid generation is forecast based on the combined winter peak forecast for firm non-industrial load (based on estimated 2010-2011 average annual load factor for this load) and for firm industrial loads. Higher than 2012 forecast peak was achieved January 17, 2012 (80.96 MW at temperature -38 degrees C in Whitehorse and -46 degrees C in Dawson/Mayo).
[33] The WAF system has substantial hydro generation availability that is directly affected by certain transmission; the WAF system also has been trending to an increasing probability of longer outages as it expands (particularly with expansion of residential and commercial loads and major reductions in industrial load). Yukon Energy has therefore now incorporated the LOLE approach, with recognition of transmission reliability where relevant, into its system planning criteria to better protect all of its firm customers from generation-related outages.

- **Emergency (or "N-1") Standard** – The capacity planning review in 2006 also recognized that the LOLE function is an average that does not indicate how long any particular outage will last, or the potential severity of consequences for customers. To address the severity of a potential outage, Yukon Energy incorporated a second test – the N-1 standard which determines system capacity assuming the loss of the system's single largest generating or transmission-related generation resource. This standard does not include industrial loads as part of the assessment. It ensures there is sufficient grid generation installed to meet firm residential and commercial customers' loads when a failure occurs to the single largest system component[34].

- **WAF and MD Community Criteria** – Grid-served communities over about 300 people, other than Whitehorse (and, due to the earlier mine, the community of Faro), typically have local diesel generation installed to serve a dual purpose: overall grid support similar to major diesel installations at Whitehorse or Faro, as well as local supply during transmission outages. This reality has applied at Ross River, Carmacks, Haines Junction, and Teslin, but has not been traditionally applied at Carcross. It was also not applied at smaller centres below 300 people. For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more will be considered as a preferred location for new diesel units, assuming the community does not already have backup from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support and in times of line failures would provide local generation for the communities where they are located.

In 2011, as part of the five-year update to the 2006 Resource Plan, Yukon Energy re-engaged Dr. Billinton and Dr. Karki to evaluate the capability of the new system (including the integration of WAF and MD grids, and the completion of Mayo B), focusing on the question of whether the 2 hours/year loss of load expectation planning target, measured using the existing software and modeling approach[35], continues to be appropriate for the updated and integrated grid system. Doctors Billinton and Karki reviewed various system permutations and modeling approaches, including more detailed and data intensive methods than previously applied to Yukon's integrated power system, under both the pre-interconnection (WAF only) and post-interconnection (WAF/MD) configurations.

[34] In 2006, it was noted that for WAF the single most critical system component is the Aishihik transmission line and the largest single potential loss of supply would be 30 MW due to loss of transmission line from Aishihik to Whitehorse. Under this standard, each integrated system (WAF and MD) was planned in 2006 to be able to carry the forecast peak winter loads under the largest single contingency (known as the N-1), excluding major industrial loads which typically maintain sufficient on-site generation for their own emergency purposes.

[35] For example, the analysis included consideration of the Aishihik transmission line in overall generation adequacy assessment, but not other specific transmission lines.

This review was concluded in fall 2011 and the results are being internally reviewed by Yukon Energy at this time. This review confirmed that the previous approach used for WAF was reasonable for the integrated system, subject to the 25 km line L172 between Takhini and Whitehorse being appropriately reinforced within the next few years so as to provide no line constraint through this line segment. Yukon Energy is in the process of reviewing and assessing the results. Once this assessment is complete the most prudent option will be implemented to address this concern.

Subject to the 25 km line L172 between Takhini and Whitehorse being appropriately reinforced, the existing hydro and diesel infrastructure will meet the LOLE and N-1 capacity planning requirements in both test years at the forecast grid loads:

- Installed YEC and YECL grid capacity that can be relied upon for the winter peak in both 2012 and 2013 is approximately 116.6 MW (72.4 MW of hydro, including YECL's Fish Lake hydro, and 44.2 MW of diesel);
- For N-1 assessment of the reliable capacity, excluding Fish Lake hydro to meet the YEC load:
    - The reliable capacity is reduced to 77.5 MW for the N-1 event (in addition to removing 0.4 MW for Fish Lake hydro, assumes 37.0 MW at Aishihik and 1.75 MW at Haines Junction are not available at Whitehorse because of an interruption to the Aishihik transmission line).
    - This remaining reliable capacity is available to meet the projected non-industrial grid winter peak load (excluding an estimated 1 MW at Haines Junction that is not supplied by the grid under N-1) of approximately 70.3 MW in 2012 and 71.0 MW in 2013.
    - In summary, under N-1, there is surplus capacity of approximately 7.2 MW in 2012 and 6.5 MW in 2013.
- For the updated LOLE assessment of YEC load, industrial peak load in excess of approximately 12 MW[36] is added to the projected N-1 non-industrial grid load and then compared with the 77.5 MW reliable capacity – on this basis, a surplus is still forecast for each test year (9.4 MW surplus in 2012 and 8.4 MW surplus in 2013).

[36] This is higher than 2006 Resource Plan estimate. The updates include integration of WAF and MD grids, completion of Mayo B and Aishihik Third Turbine, the updated CEA unavailability rate for the Aishihik line, and ongoing changes in the overall grid load factor (updates of unit ratings, change in load distribution). The estimate excludes 1 MW for Haines Junction peak load as N-1 capacity planning requirements exclude this peak load.

Table 2.1
Summary of Customers, Energy Sales and Revenues

Line No.	Description	2009 Approved	2009 Actual	2010 Actual	Preliminary 2011	Forecast 2012	Forecast 2013
1	**Residential**						
2	Customers	1,432	1,457	1,472	1,515	1,526	1,536
3	Sales in MWh	11,183	11,676	11,386	12,710	12,325	12,408
4	MWh sales per customer	7.8	8.0	7.7	8.4	8.1	8.1
5	Revenue ($000s)	1,335	1,386	1,359	1,694	1,803	1,815
6	Cents per KWh	11.9	11.9	11.9	13.3	14.6	14.6
7	**General Service**						
8	Customers	457	442	455	464	460	467
9	Sales in MWh	19,543	19,672	22,719	21,305	21,693	22,620
10	MWh sales per customer	42.8	44.5	50.0	45.9	47.1	48.5
11	Revenue ($000s)	2,637	2,696	2,942	3,218	3,582	3,735
12	Cents per KWh	13.5	13.7	12.9	15.1	16.5	16.5
13	**Industrial**						
14	Sales in MWh	29,023	29,355	30,255	43,259	52,309	62,364
15	Revenue ($000s)	3,203	3,190	3,311	4,599	6,179	7,383
16	Cents per KWh	11.0	10.9	10.9	10.6	11.8	11.8
17	**Street lights**						
18	Sales in MWh	278	496	283	283	279	279
19	Revenue ($000s)	71	60	74	82	88	88
20	Cents per KWh	25.5	12.1	26.3	29.0	31.6	31.6
21	**Space lights**						
22	Sales in MWh	15	26	14	14	15	15
23	Revenue ($000s)	3	3	3	3	4	4
24	Cents per KWh	21.5	12.0	21.7	24.0	26.8	26.8
25	**Total Company - Firm Retail & Ind.**						
26	Customers	1,889	1,899	1,927	1,979	1,986	2,003
27	Sales in MWh	60,042	61,225	64,658	77,571	86,621	97,685
28	Revenue ($000s)	7,249	7,335	7,689	9,596	11,656	13,025
29	Cents per KWh	12.1	12.0	11.9	12.4	13.5	13.3
30	**Wholesale sales**						
31	Sales in MWh	267,747	267,229	276,345	290,541	296,000	298,228
32	Revenue ($000s)	18,314	18,279	18,902	21,940	24,562	24,747
33	Cents per KWh	6.8	6.8	6.8	7.6	8.3	8.3
34	**Total Company - Firm**						
35	Sales in MWh	327,789	328,455	341,003	368,112	382,621	395,913
36	Revenue ($000s)	25,563	25,613	26,591	31,535	36,218	37,772
37	Cents per KWh	7.8	7.8	7.8	8.6	9.5	9.5
38	**Secondary**						
39	Sales in MWh	7,584	17,384	10,489	552	0	0
40	Revenue ($000s)	470	1,066	644	46	0	0
41	Cents per KWh	6.2	6.1	6.1	8.3	0.0	0.0
42	**Total Company**						
43	Sales in MWh	**335,373**	**345,839**	**351,492**	**368,665**	**382,621**	**395,913**
44	Revenue ($000s)	**26,033**	**26,679**	**27,234**	**31,581**	**36,218**	**37,772**
45	Cents per KWh	**7.8**	**7.7**	**7.7**	**8.6**	**9.5**	**9.5**

Note:
1. Excludes revenues from Rider J and other revenues.

Table 2.2
Summary of Energy Balance, Losses, Peak and Load Factor

Line No.	Description	2009 Approved	2009 Actual	2010 Actual	Preliminary 2011	Existing Forecast 2012	Proposed Forecast 2012[1]	Existing Forecast 2013	Proposed Forecast 2013[2]
	Sales and Losses								
1	Total Energy Sales	335,373	345,839	351,492	368,665	382,621	382,621	395,913	395,913
2	Losses - MWh	28,359	28,007	30,764	32,101	33,288	33,288	34,444	34,444
3	Losses - %	8.5%	8.1%	8.8%	8.7%	8.7%	8.7%	8.7%	8.7%
4	Total Generation	363,732	373,846	382,255	400,766	415,909	415,909	430,357	430,357
	Source - MWh								
	Hydro Generation								
5	Whitehorse	228,573	223,775	233,806	231,501	232,207	229,245	232,231	230,124
6	Aishihik	103,110	118,680	111,710	132,340	121,661	120,109	130,037	128,857
7	Mayo	30,613	28,507	31,528	20,588	59,533	58,774	60,977	60,424
8	Total Hydro	362,296	370,962	377,044	384,429	413,402	408,128	423,244	419,405
9	**Wind Turbine**	491	238	85	402	239	239	238	238
	Diesel Generation								
10	Whitehorse	0	1,722	2,417	6,571	1,142	3,878	3,462	5,510
11	Faro	550	413	272	1,654	323	1,142	980	1,622
12	Dawson	395	509	2,404	7,170	802	2,522	2,432	3,583
13	Mayo	0	1	34	539				
14	Total Diesel	945	2,645	5,127	15,935	2,268	7,542	6,875	10,714
	Source - %								
15	**Hydro Generation**	99.6%	99.2%	98.6%	95.9%	99.4%	98.1%	98.3%	97.5%
16	**Diesel Generation**	0.3%	0.7%	1.3%	4.0%	0.5%	1.8%	1.6%	2.5%
17	**Wind Generation**	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
	Peak - MW								
	Integrated System	N/A	N/A	N/A	76.9	80.1	80.1	81.1	81.1
18	**WAF**	62	60.9	67.3	N/A	N/A	N/A	N/A	N/A
19	**MD**		5.1	6.9	N/A	N/A	N/A	N/A	N/A

Notes;

1 Hydro generation at 101% of long-term average at 404.18 GW.h (diesel at 66% of requirement based on long-term average hydro).

2 Hydro generation at 101.8% of long-term average at 411.95 GW.h (diesel at 59% of requirement based on long-term average hydro).

3 Diesel generation in 2011 includes requirements related to generation capital projects at Aishihik and Mayo hydro generating plants.

4 Diesel generation forecasts include diesel fuel required for maintenance.

5 Diesel generation forecasts under the "Existing" assumption (i.e., without a GRA) are calculated based on 2009 approved efficiency and fuel price.

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 rates charged to Yukon Energy's retail customers, industrial customers and wholesale customers, 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); and
- Stabilization Mechanisms.

3.1 OVERVIEW

This Tab summarizes the revenue requirement for Yukon Energy for test years 2012 and 2013, as well as comparative figures for 2009 and 2010 actuals, and 2011 preliminary actuals.

There are three major components to Yukon Energy's 2012 and 2013 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.

Table 3.1 compares Yukon Energy's forecast 2012 and 2013 revenue requirement to the 2009 Board approved revenue requirement, as well as for 2009 actuals, 2010 actuals and 2011 preliminary actual costs or Full Year Forecast ("FYF"). The forecast revenue requirements for 2012 and 2013 are $39.857

million and $45.641 million respectively, which are higher than 2009 approved revenue requirement by a difference of $8.826 million and $14.610 million respectively.

Table 3.1
Yukon Energy Revenue Requirement
($000)

					Forecast		Forecast	
	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Existing 2012	Proposed 2012	Existing 2013	Proposed 2013
Fuel and Purchased Power	$ 497	$ 658	$ 1,183	$ 2,746	$ 642	$ 2,203	$ 1,866	$ 3,113
Non-Fuel Operating and Maintenance	13,178	14,401	14,353	15,943	17,365	17,496	18,254	18,385
Depreciation and Amortization	6,869	6,555	6,656	6,901	9,988	7,813	13,177	10,012
Return on Rate Base	10,488	10,095	10,185	8,704	8,407	12,345	4,658	14,130
Revenue Requirement/Revenue	$ 31,031	$ 31,709	$ 32,377	$ 34,294	$ 36,402	$ 39,857	$ 37,956	$ 45,641

Note:
1. 2009 actuals reflect impacts of YUB orders (2009-8 and 2009-10) - net impact of $0.241 million decrease of 2008 net earnings and increase of 2009 net earnings.

In general, Yukon Energy's forecast 2012 and 2013 revenue requirements primarily reflect proposed adjustments to diesel generation requirements and fuel prices, changes in fixed asset depreciation and amortization rates, planning study cost policy changes, changes to the proposed return on equity ("ROE") as well as changes to labour and non-labour costs relative to 2009 GRA approved forecast ("2009 approved") numbers, the last test year reviewed by the Board during Yukon Energy's 2008/2009 GRA application.

The forecast Fuel and Purchase Power cost increases by 526% from 2009 approved to the 2013 forecast as proposed in the Application, with a $1.70 million increase from 2009 approved to the 2012 proposed forecast and by a further $0.91 million increase in 2013 over 2012 forecast. These increases reflect higher loads, adjusted fuel prices (small increase), and provisions for diesel being required based on a percentage of long-term average hydro generation (i.e., forecast diesel generation is set at a percentage of requirements based on long-term average hydro generation). Fuel and Purchased Power costs in 2011 were higher than the proposed forecast for 2012 (for further detail see discussion in section 3.2).

The forecast Non-Fuel Operating and Maintenance cost increases by 40% from 2009 approved to the 2013 forecast as proposed in the Application. This forecast cost increases by $4.3 million in 2012 over 2009 approved, and by a further $0.89 million in 2013 over the 2012 forecast.

Forecast Depreciation and Amortization costs increase by 46% from 2009 approved to the 2013 forecast as proposed in the Application. The forecast cost increases by $0.95 million in 2012 over 2009 approved,

and by a further $2.2 million in 2013 over 2012. Amortization of deferred costs increase by $3.15 million from 2009 approved to the 2013 forecast in the Application, including costs for planning studies, regulatory activities and licensing costs related to Yukon Energy's ongoing generation and transmission requirements. Although cost of property, plant and equipment increased by $234 million (82%) in 2013 over 2009 approved, net depreciation costs decreased by $0.016 million, reflecting lower amortization rates, as well as contributions to the Mayo B, CSTP Stage 2 and to the other project costs from Yukon Government and Yukon Development Corporation.

The forecast Return on Rate Base increases by 35% from 2009 approved to the 2013 forecast as proposed in the Application. The forecast cost increases by $1.86 million in 2012 over 2009 approved costs, and by a further $1.78 million in 2013 over 2012 forecast. The Return on Rate Base increase is due primarily to the increase in mid-year rate base (i.e., an increase of 63% for 2013 over 2009 approved, or approximately 13% average increase per year). Mid-year rate base reflects added Mayo B, Aishihik Third Turbine and other project net costs after received contributions. Debt costs, as part of Return on Rate Base, increase by only $0.187 million in 2013 over 2009 approved cost of $5.463 million, reflecting refinancing during the period to reduce existing average debt costs and the Flexible Note financing arranged for the Mayo B Project. Equity return increased by $3.45 million in 2013 over 2009 approved cost of $5.025 million, due to the increased mid-year rate base and the updated ROE at 8.77% (as compared with 8.49% approved in 2009).

Each of the above categories of the 2012 and 2013 revenue requirement is reviewed in detail below.

3.2 FUEL AND PURCHASED POWER

Fuel and Purchased Power costs as set out in Table 3.2 for 2012 and 2013 test years increase to $2.203 million and $3.113 million respectively (from $0.497 million in 2009 approved), reflecting higher loads, adjusted fuel prices and provisions for diesel being required based on annual long-term average hydro generation[1]. Due to low water conditions and non-activation of the DCF, fuel costs in 2011 were material, at levels higher than the 2012 forecast and comparable to the 2013 forecast.

[1] See discussion in Attachment 3.2 to Appendix 3.2 and Tab 4, Section 4.6 - forecast diesel generation is set at a percentage of requirements based on annual long-term average hydro generation.

Table 3.2[2]
Fuel and Purchased Power
($000)

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Fuel	443	$ 622	$ 1,145	$ 2,708	$ 602	$ 2,163	$ 1,826	$ 3,073
Purchased Power	54	36	38	38	40	40	40	40
Total Fuel and Purchased Power	$ 497	$ 658	$ 1,183	$ 2,746	$ 642	$ 2,203	$ 1,866	$ 3,113

Note:
1. Actual 2009 fuel cost of $0.814 million was reduced by $0.192 million to reflect Board order 2009-8 impacts.

The quantity of fuel required on Yukon Energy's grid system since 2008 is reflected in YEC's annual fuel costs (as the DCF was not activated), showing impacts of growing loads and fluctuating water conditions. Diesel generation increased from a 2009 approved forecast of 0.945 GW.h (which was well below the 2009 actual by approximately 1.7 GW.h) to 4.28 GW.h in 2010 actual and to approximately 10.55 GW.h in 2011 actual (excluding diesel requirements related to hydro generation plant construction activities as noted in Tab 2[3]). Diesel generation in late 2010 and early 2011 reflected below average water conditions and non-activation of the DCF. Growth over this period reflects growth in both non-industrial and industrial loads. Industrial load growth is the result of the addition of a new industrial load late in 2010 (the Alexco mine) and continued operation of the Minto mine.

Due to reduced surplus hydro generation caused by material increases in load, diesel is forecast in the test years to be on the margin[4] at annual long-term average hydro generation levels[5].

As reviewed in Section 2.3.2, diesel generation requirements included for the test years are forecast to exceed short-term forecast requirements (which include currently favourable stored water conditions).

[2] Fuel cost forecasts in Table 3.2 for 2012 and 2013 include cost of required diesel fuel for maintenance of diesel units.
[3] In 2010 diesel generation of 0.85 GW.h is resulted from the construction activities due to capital projects. In 2011 Aishihik plant construction is estimated to have resulted in 3.18 GW.h [$0.8 million] of diesel generation in 2011 due to shut downs required of the Aishihik generation plant, and Mayo B plant construction (extended Mayo A shut down for tunnel tie in work) is estimated to have resulted in 1.5 GW.h [$0.4 million] of diesel generation, and 0.7 GW.h due to other capital projects. The costs for such diesel generation was charged to the capital costs for each respective project.
[4] The term "diesel on the margin" is a concept that traditionally triggered stabilization mechanisms such as the Diesel Contingency Fund or "DCF". These provisions were last active on a sustained basis in the mid to late 1990's when the Faro mine was in operation. As reviewed in Section 2.3.2, Attachment 3.2 to Appendix 3.2 and Tab 4, Section 4.6, the current Application includes recommended steps to update the DCF mechanism and, on that basis, assumes that the DCF mechanism is reactivated effective January 1, 2012.
[5] See Section 2.3.2. The Mayo B Part 3 Application and the 2009 Phase II Rate Application analysis subsequent to the Yukon Energy 2008/2009 GRA indicated that approximately $1 million in diesel generation costs would have been included in rates in 2009 if rates had been set to reflect long-term average hydro capability at that time and the related long-term average diesel generation requirement (approximately 4 GW.h at then forecast 2009 loads).

However, these test year forecasts are adopted to address the transition to annual long-term average levels and potential future use of LNG at a materially lower cost than diesel, and are consequently lower in each year than the levels that would be required assuming annual long-term average hydro generation[6].

Forecast diesel generation is 7.5 GW.h in 2012 (66% of diesel requirement assuming long-term average hydro generation) and 10.7 GW.h in 2013 (59% of diesel requirement assuming long-term average hydro generation).

Forecast fuel prices for the 2012/2013 test years are $1.0513 per litre for Whitehorse, $1.0885 per litre for Faro, $1.168 per litre for Dawson and $1.0966 per litre for Mayo and reflect the most recent fuel prices for YEC. This is higher than the fuel price forecast at the 2009 approved fuel prices of $0.96/litre, $0.992/litre, $0.975/litre and $0.967/litre respectively.

Yukon Energy forecasts average efficiency for fuel of 3.77 kW.h/litre in Whitehorse, 3.83 kW.h/litre in Faro and 3.72 kW.h/litre in Dawson and 3.37 kW.h/litre in Mayo, is based on 2011 averages. The overall grid average efficiency (3.67 kW.h/litre) is an increase from the 2009 GRA efficiency, where the approved forecast average efficiency was 3.6 kW.h/litre.

For 2012, total forecast diesel generation of 7.5 GW.h is forecast to require 2.0 million litres of diesel fuel (including diesel fuel required for mechanical maintenance purposes). For 2013, total forecast diesel generation of 10.7 GW.h is forecast to require 2.85 million litres of diesel fuel (including diesel fuel required for mechanical maintenance purposes).

Purchased power costs relate to power purchased by Yukon Energy at Johnson's Crossing from YECL. Approved costs in 2009 were $0.054 million. Actual costs were $0.036 million in 2009, $0.038 million in 2010 and 2011 FYF, and are forecast to be $0.040 million for both test years.

3.3 NON-FUEL OPERATING AND MAINTENANCE EXPENSES

The total non-fuel operating and maintenance expense approved in 2009 GRA was $13.178 million.

[6] Diesel generation forecast for base load generation in the forecast test years at annual long-term average hydro generation levels is 11.5 GW.h in 2012 and 18.2 GW.h in 2013. As reviewed in Table 2.2 (Tab 2), the Application forecasts diesel generation in each test year at approximately 59 to 66% of these long-term average levels.

Table 3.3 indicates the actual expense for 2009 and 2010 was $14.4 million and $14.35 million respectively, and increased to $15.8 million in 2011. Total operating and maintenance costs are forecast to increase to $17.496 million for 2012 and $18.385 million for 2013. This is a $4.3 million increase in 2012 over 2009 approved (33% increase) and further $0.89 million increase in 2013 over 2012 forecast (5% increase).

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

					Forecast		Forecast	
	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Existing 2012	Proposed 2012	Existing 2013	Proposed 2013
Labour	$ 6,880	$ 7,663	$ 7,720	$ 8,343	$ 9,185	$ 9,185	$ 9,378	$ 9,378
Production[1]	798	963	1,236	1,478	1,449	1,449	1,437	1,437
Transmission	612	755	476	714	760	760	853	853
Distribution	178	114	111	184	201	201	226	226
General O&M	858	1,002	1,010	1,195	1,094	1,094	1,154	1,154
Administration	2,544	2,729	2,621	2,859	3,429	3,429	3,885	3,885
Insurance and Reserve for Injuries/Damages	1,052	887	887	874	935	1,066	995	1,126
Property Taxes	256	288	291	297	312	312	326	326
Total OM&A (Tab 7, Schedule 10)	$ 13,178	$ 14,401	$ 14,353	$ 15,943	$ 17,365	$ 17,496	$ 18,254	$ 18,385

Note:
1. Production function includes Fish Ladder cost for 2009-2013 years, which was under Administration function in 2009 GRA.

An increase in non-labour expense makes up $2.0 million, or 47%, of the $4.3 million increase in 2012 forecast over 2009 approved costs, and an increase in non-labour expense makes up $0.696 million, or 78%, of the $0.890 million increase in 2013 forecast over 2012 forecast. The average annual increase in non-labour expenses is 9.4% (2013 expenses over 2009 approved).

The remainder of the $4.3 million increase in 2012 forecast over 2009 approved costs is comprised of an increase in labour expense in 2012 of $2.305 million (53% of total increase over 2009 approved) and in 2013 of $0.193 million over 2012 forecast (22% of total increase over 2012 forecast). This reflects additional positions, as well as negotiated and step increases. Full Time Equivalent (FTE) positions are forecast to increase by 12.26 FTEs in 2013 compared to 2009 approved with most of the increase in 2010 (7.38 FTEs). The average annual increase in salaries per FTE is 4.3% from 2009 approved to 2013

forecast. Detailed information on the labour increases by function is provided in the following sections. The Yukon Energy employee complement is shown in Table 3.4.

Table 3.4
Employee Complement History

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	GRA 2012	GRA 2013
President	2.50	4.50	5.50	5.50	4.50	4.50
Communications	1.00	1.00	1.00	1.00	1.00	1.00
Human Resources & Info. Mgmt.	7.00	5.00	6.00	7.10	6.25	6.25
Resource Planning and Environment	1.00	2.00	2.00	6.00	7.00	7.00
Finance, Cust. Acctg. & Purchasing	12.81	14.08	13.69	15.75	17.00	17.00
Operations	40.10	40.61	41.49	41.44	41.25	41.25
Engineering Services	12.00	12.00	15.44	14.00	13.00	13.00
Health, Safety & Environment	3.33	2.00	2.00	2.00	2.00	2.00
Total	79.74	81.19	87.12	92.79	92.00	92.00

Note:
1. The employee complement numbers are net of allocation to YDC.

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 2012 are forecast to be higher than 2009 approved costs by $1.48 million, and by $0.042 million increase in 2013 over 2012 forecast.

Table 3.5
Production Costs
($000)

					Forecast		Forecast	
	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Existing 2012	Proposed 2012	Existing 2013	Proposed 2013
Labour	$ 2,179	$ 2,796	$ 2,943	$ 2,994	$ 3,003	$ 3,003	$ 3,057	$ 3,057
Diesel	194	333	297	615	425	425	439	439
Hydro	560	602	895	852	938	938	909	909
Wind	8	6	6	5	27	27	18	18
Operation Supervision	36	22	38	6	59	59	72	72
Total Production	$ 2,977	$ 3,759	$ 4,179	$ 4,472	$ 4,452	$ 4,452	$ 4,494	$ 4,494

Increases in non-labour expenses through 2011 are due to ongoing increases on materials, supplies and services, as well as increases due to new hydro units in-service.

Approximately 56% of the forecast increase in 2012 over 2009 approved is due to higher labour cost ($0.824 million increase in 2012 over 2009 approved).

3.3.2 Transmission

Transmission cost increases since 2009 are shown in Table 3.6.

Table 3.6
Transmission Costs
($000)

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Labour	$ 482	$ 453	$ 319	$ 396	$ 431	$ 431	$ 440	$ 440
Brushing	377	387	268	434	505	505	639	639
Other Non-Labour	235	369	208	280	255	255	214	214
Total Transmission	$ 1,094	$ 1,208	$ 795	$ 1,110	$ 1,190	$ 1,190	$ 1,293	$ 1,293

Forecast non-labour costs are $0.760 million in 2012 and $0.853 million in 2013. Overall test year forecasts are only slightly higher than 2009 approved non-labour costs ($0.148 million higher in 2012 with a $0.093 increase in 2013 forecast over 2012 forecast). The increases primarily arise from the completion of CSTP Stage Two and connection of the MD and WAF grids, as well as required increases in brushing activities.

Overall brushing costs increase by $0.128 million in 2012 forecast over 2009 approved costs with an additional $0.134 million increase in 2013 forecast over 2012 forecast.

Order 2009-8, following the 2008/2009 GRA, directed Yukon Energy to undertake a study into brushing activities of similar utilities and report its findings to the Board, and also to include a written brushing policy to outline Yukon Energy's approach and explain the manner in which the budget for any year was derived[7]. In response to the Board Order, YEC undertook a brushing survey of North American utilities on

[7] Order 2009-8 Directive #7.

industry best practice. As well, the company commissioned a quantitative audit and assessment of our vegetation control practices with the objective of developing a cyclical brushing strategy which met YEC's goals of cost effectiveness, safety, and security of energy transmission. The study recommended an annual brushing plan which would allow YEC to meet these goals. The transmission brushing estimate for 2012 is based on working to this plan and to these cost estimates. Additionally, the study also recommended investigating Integrated Vegetation Management (IVM) methods to reduce the long-term cost of brushing YEC's transmission network. IVM study plots will be undertaken to prove cost viability and to support future licensing of treatments. In 2012 Yukon Energy is field testing the recommendations (e.g., herbicide treatments) prior to developing a formal policy. Costs for these activities are included in 2012 forecast amounts. The noted studies are provided in Tab 12, Appendix 12.1 and Appendix 12.2.

Labour costs are $0.05 million lower in 2012 forecast compared to 2009 approved cost, and increase over the 2012 forecast by only a $0.010 million in the 2013 forecast.

3.3.3 Distribution

Costs of operating and maintaining the distribution system since 2009 are set out in Table 3.7.

Table 3.7
Distribution Costs
($000)

					Forecast		Forecast	
	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Existing 2012	Proposed 2012	Existing 2013	Proposed 2013
Labour	$ 521	$ 546	$ 477	$ 473	$ 579	$ 579	$ 592	$ 592
Brushing	46	17	16	68	93	93	113	113
Other Non-Labour	132	97	96	116	108	108	113	113
Total Distribution	$ 699	$ 660	$ 588	$ 657	$ 780	$ 780	$ 819	$ 819

Overall, forecast distribution non-labour costs are $0.201 million in 2012, a $0.023 million increase over 2009 approved costs. Forecast costs in 2013 are $0.026 million higher than 2012 forecasts. Forecast brushing costs in 2012 are $0.047 million higher than 2009 approved, and in 2013 are $0.020 million higher than 2012 forecast. Forecast other non-labour costs for 2012 and 2013 are below the 2009 approved costs and cost experienced in 2011 (but slightly higher than 2009 and 2010 actual costs).

Forecast distribution labour costs increase by $0.051 million (an 11% increase) in 2012 compared to 2009 approved costs, and increase by $0.013, million in 2013 over 2012 forecast (a 2% increase).

3.3.4 General Operation and Maintenance

Yukon Energy incurs expenses categorized as "General" with respect to 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)

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Labour	$ 94	$ 143	$ 184	$ 141	$ 245	$ 245	$ 250	$ 250
Transportation	394	401	419	449	427	427	451	451
Maintenance of Company Owned Properties	384	471	489	650	581	581	611	611
SCADA Communication	80	130	102	96	86	86	93	93
Total General O&M	$ 952	$ 1,145	$ 1,194	$ 1,336	$ 1,339	$ 1,339	$ 1,405	$ 1,405

Total forecast cost increases in the General O&M categories since the 2008/2009 GRA relate largely to a $0.236 million increase in forecast non-labour expenses in 2012 over 2009 approved costs (61% of total increase). Maintenance of Company Owned Property expenses are forecast to increase by $0.197 million (approximately 51% increase) in 2012 over 2009 approved costs. Transportation and SCADA communication expenses are forecast to increase by 8.4% and 7.5% respectively in 2012 over 2009 approved costs. Total General O&M non-labour expense is forecast to increase by 5.4% in 2013 over 2012 forecast.

General O&M labour expense is forecast to increase by $0.151 million in 2012 over 2009 approved costs and further increase by only $0.006 million in 2013 over 2012 forecast.

3.3.5 Administration

Administration expense in the 2012 and 2013 forecasts are approximately $2.2 million and $2.77 million greater, respectively, than 2009 approved expenses, as shown in Table 3.9.

Table 3.9
Administration
($000)

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Labour	$ 3,605	$ 3,725	$ 3,797	$ 4,338	$ 4,927	$ 4,927	$ 5,038	$ 5,038
Resource Planning	17	18	24	128	26	26	26	26
Communications	105	98	119	98	306	306	295	295
Customer Accounting	206	182	185	194	190	190	191	191
Environmental Mgmt	52	50	82	152	338	338	569	569
General	734	886	611	804	910	910	1,099	1,099
Information Systems	425	595	548	388	569	569	607	607
Fish Hatchery	136	159	176	140	182	182	187	187
Fish Ladder[1]	26							
Safety	162	187	201	177	177	177	189	189
Training	211	205	150	184	260	260	260	260
Recruitment	169	138	192	83	120	120	120	120
Board of Directors	148	113	100	289	180	180	168	168
Union	26	9	72	25	23	23	23	23
Regulatory Affairs	57	27	77	156	34	34	34	34
Material Management	43	-6	64	18	33	33	35	35
Contracting	11	60	17	8	15	15	16	16
Professional Development	15	9	2	15	17	17	17	17
DSM Administration					49	49	49	49
Total Administration	$ 6,148	$ 6,453	$ 6,418	$ 7,197	$ 8,357	$ 8,357	$ 8,923	$ 8,923

Note:
1. Fish Ladder cost for 2009-2013 included in Production Function.

The labour expense forecast for 2012 is $1.3 million higher than the 2009 approved cost and the forecast for 2013 is $0.110 million higher than the 2012 forecast. The average annual increase in labour expenses in 2012 and 2013 over 2009 approved expenses is 11% and 8.7% respectively.

The average annual increase in forecast non-labour expense in 2012 and 2013 over 2009 approved expense is 10.5% and 11.2% respectively. Notable increases have occurred in General, Communications and Environmental Management, offset to some extent by reductions in other expenses:

- **Communications** (forecast increase of $0.201 million by 2012 over 2009 approved expense and decrease by $0.011 million in 2013 from 2012 forecast): Increased costs relate to implementation

of an on-going public information campaign which accounts for approximately $0.2 million of the total budget and $0.05 million for upgrading YEC's web site.

- **Environmental Management** (forecast increase of $0.286 million by 2012 over 2009 approved expense, increase of $0.231 million in 2013 over 2012 forecast and $0.517 million over 2009 approved expense): Increased contractor and consultant expenses (of approximately $0.173 million) relate to various permit requirements which will be met by engaging consultants to conduct monitoring and other projects. A significant portion of these costs relate to new requirements with addition of Mayo B and CSTP, which increase in scope in 2013 as the result of monitoring of required Mayo B fish habitat compensation measures (salmon rearing channel, anticipated monitoring and adaptive management costs). Costs also include Aishihik FAA liaison and management (approximately $0.050 million), as well as biological monitoring related to the Aishihik Water Use Licence (approximately $0.080 million).

- **General** (forecast increase of $0.176 million by 2012 over 2009 approved expense, increase of $0.189 million in 2013 over 2012 forecast and $0.365 million over 2009 GRA approved forecast).

- **Information Systems** (forecast increase of $0.144 million by 2012 over 2009 approved expense, and an increase of $0.038 million in 2013 over 2012 forecast and $0.182 million over 2009 GRA approved forecast). The addition of new staff since 2009 has added requirements for purchase of new computer equipment and related support (i.e., additional licence fees). Over this period licence fees have increased by approximately $0.050 million and data circuits (for network communications) have increased in cost by approximately $0.060 million. Other expenditures relate to communications and Sharepoint support from consultants.

- **DSM Administration** (this is a new administrative expense category in the test years, with forecast expense of $0.049 million in each of 2012 and 2013). Expenditures included in DSM Administration costs may include administration and other general overhead expenditures, staff training and specific expenditures related to information programs and advertising that are not directly attributed to a specific DSM program[8].

[8] See the DSM Accounting Policy provided as Appendix 5.2 of Tab 5.

Administration labour increased between 2009 approved and 2012 forecast 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 added since 2009:

- The need for a strong IT department has grown in tandem with the Corporation and its growing dependence on computer technology. Further, an IT Security Audit determined a high level of risk to YEC's system and data for a network of this size and sensitivity. While significant improvements have been made to security best practices, there are continuing needs to address IT issues in order to ensure that the Corporation is not exposed to a security incident. Consequently the following positions have been required:

    - **Network Administrator to Manager of IT (2009/10):** Due to growing IT needs and the requirement to implement a strategy to address security best practices, the Director of Human Resources required assistance of a Manager of IT with technical expertise to help manage and lead this essential department and to help develop both short and long-term plans to meet Yukon Energy's continuing IT needs. Consequently, the Network Administrator was moved to a new position as Manager of IT.

    - **IT Help Desk (2009):** 0.25 Casual IT Technical Support – An individual was required to undertake the support work that had been performed by former Network Administrator. It was cost efficient to have an entry level support person undertake this time consuming work and to backfill some of the more routine tasks so that more senior personnel (e.g., Network Administrator and Manager IT) could implement the IT Preventive Maintenance Plan. Duties included scanning computers for potential viruses, entry level and routine duties previously performed by the Network Administrator (i.e. user support) and assistance in annual roll out of replacement computers.

    - **SQL/Sharepoint Administrator (2010):** Yukon Energy was dependent on one database technician to run all critical systems (e.g., SharePoint, ERP, SCADA). This is not considered sufficient from a risk perspective - especially considering current and expected future operational requirements. Sharepoint is a powerful tool for managing data, however, it requires a number of additional network services to be maintained in order to function properly. Therefore, an individual with experience in this area was hired.

- With continued growth in Yukon and the need to pursue new lower cost sources of generation to meet demand on the Integrated Grid, the size and scope of YEC's major projects are expected to continue. This has necessitated the following new staff positions:

    - **Manager Resource Planning (2011):** This Director of Major Projects coordinates the development and implementation of short and long-term strategies, budgets and work plans to ensure efficient and cost effective delivery of capital projects. In 2011, the Director, Resource Planning & Regulatory Affairs moved to the position of Director of Major Projects, specifically with the focus on planning for expansion of generation using LNG. Consequently, a Manager of Resource Planning is required to manage the resource planning department led by the previous Director.

    - **Resource Planning Engineer (2011):** Given the scale of resource planning and development activities required to meet growing demand in Yukon, a resource planning engineer is required to assist the Manager of Resource Planning with ongoing work. Workload in this department is very high and there are no available resources to take on additional work requirements mainly in the feasibility and planning stages of work including public, community and First Nations consultation and engagement. Yukon Energy also needs to ensure transition planning in order to retain valuable corporate knowledge and experience as experienced staff leave the Corporation or retire.

    - **Environmental Coordinator (2011):** Given the scale of resource planning and development activities required to meet growing demand in Yukon, a term environmental coordinator is required to assist the Environment Manager with activities that include monitoring of environmental protection and regulatory compliance for capital projects; routine operations and maintenance activities, particularly those activities undertaken by contractors; contractor orientations; assisting with implementation, monitoring, and auditing of the updated EMS across YEC's operations and facilities in 2011; assisting with training and refresher programs for YEC staff; and assisting with research and special studies related to pre-feasibility stage resource planning projects.

- Energy conservation is an important element in helping YEC meet Yukon's growing energy demands, and in 2011 an Energy Conservation Department was created to work with stakeholders on Yukon-wide energy conservation programs and also focus on Yukon Energy's Demand Side Management programs. This required the following new staff positions:
    - **Manager, Energy Conservation (2011):** Required to manage the department, including work with stakeholders on Yukon-wide programs and Yukon Energy specific DSM programs.
    - **Energy Conservation Administrator (2011):** This position will provide support to the Energy Conservation Manager.
- Over the course of 2011 and 2012 Yukon Energy is undertaking a major transition to a new financial system. This has required the following positions to help backfill resources allocated to the transition and also to ensure the Corporation can continue to meet new requirements and demands.
    - **Backfill Controller (to cover the Controller for the Enterprise System Conversion) (2011):** The former Controller moved to a new position focused on the implementation of the new financial system. A Backfill Controller is required as a backup to cover the Controller for the Enterprise System Conversion during the period when the new financial system is being implemented.
    - **Financial Administrator (New Position 2012) – Finance – new position (2012):** There is a need for administrative support to capital project managers in completing, monitoring and maintaining records pertinent to the process (e.g., PIDs, authorizations for expenditure, purchasing documents, RFPs). This position will also assist with production and analysis of capital project reporting.

Administration labour cost increases since 2009 also include the administration components of the following positions:

- **Communications and Protection Control Technologist (2010):** Due to increased workloads, and the fact that one of the existing maintenance electricians has been on restricted duties since January 2010, a second position is required.
- **Permanent Part Time Plant Operator – Faro (2010):** In 2009, staff complement in the community of Faro consisted of one Senior Powerline Technician and a part time (0.65) casual operator to assist with general maintenance and diesel unit operation as required.

Since that time, the Senior PLT relocated to the Mayo service area. This transfer created a void in the level of service in the community. In the event the backup diesel units needed to be started, it would take a minimum of 2.5 hours to deploy an employee from Mayo to Faro, or alternatively approximately 4.5 hours to dispatch an employee from Whitehorse to Faro, in the best of conditions. On this basis, a permanent part time position was created to better serve the community.

- **Capital Mechanic (2010):** There is an ongoing need to return to a staffing complement in Engineering Services. Current and foreseeable mechanical capital project work requires a mechanic to conduct this work.

- **Capital Electrician (2010):** The current and foreseeable electrical capital project work justifies the ongoing need to the return to a staffing complement in Engineering Services that includes an electrician dedicated to capital projects.

- **Manager Electrical Operations and Manager of SCC and Mechanical** – In 2009, there was a Director of Operations and a Manager of Operations. In 2012, the Director position was discontinued and the Manager of Operations was moved to a new position as Coordinator of Capital Projects. The Coordinator of Capital projects oversees certain special capital projects such as Brushing and ROW, the Transmission Test and Treat Program, and AMP Best Maintenance Practices. The following two new positions created to replace the Director of Operations: (1) Manager of SCC and Mechanical; and (2) Manager of Electrical Transmission and Distribution created to provide leadership to both the electrical maintenance and transmission/distribution groups due to the vacant Director, Operations position. These positions report to the Director, Engineering Services. There is no net impact on the employee compliment due to these changes.

- **Safety Coordinator** – Meeting health and safety standards is a priority for the Corporation and there are ongoing requirements related to documentation, orientation, program development, incident investigation and prevention and inspections, as well as requirements to liaise with regulators, the CEA, other safety associations, policy development, training and budgeting. The size and scope of the Health and Safety Manager's position with ongoing development and maintenance of the safety program has proven to be challenging – not only in geographical size but in work load. In 2009, an acting Safety Coordinator was appointed and took over documentation responsibilities (that had been undertaken by the Term Documentation Specialist) as well as many other safety related duties.

- **Term SCC Operator (2011):** A term SCC Operator will be added to accommodate medical issues of the current SCC Operator. The addition of a two year term SCC Coordinator position will support the dayshift operator from Monday through Friday, during the busiest part of the workday. This position will also provide support to the Manager SCC and T&D while ensuring the economic dispatch of power and performing power system monitoring.

3.3.6 Insurance and Reserve for Injuries 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)

					Forecast		Forecast	
	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Existing 2012	Proposed 2012	Existing 2013	Proposed 2013
Insurance	$ 952	$ 787	$ 787	$ 774	$ 835	$ 835	$ 895	$ 895
Reserve Appropriation (RFID)	100	100	100	100	100	231	100	231
Total	$ 1,052	$ 887	$ 887	$ 874	$ 935	$ 1,066	$ 995	$ 1,126

Note:
1. Actual 2009 reserve appropriation was reduced from $0.150 million to $0.1 million to comply with YUB Order 2009-8.

Yukon Energy's costs for insurance are forecast to decrease by $0.117 million and $0.057 million from 2009 approved to 2012 and 2013 forecasts respectively.

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. 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 RFID; 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 2009, Yukon Energy's Reserve for Injuries and Damages balance has grown from negative $0.111 million (after the YUB Order 2009-8 approvals to transfer $0.413 million of one-time funds from Faro Mine Dewatering Deferral Revenues against this balance)[9] to negative $0.578 million at year-end 2011

[9] YUB Order 2009-10.

(negative amounts represent an excess of charges to the RFID compared to appropriations to the RFID). Pursuant to Board Order 2009-8, the appropriation against the RFID was set at $0.100 million per year.

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

1. **Increase the annual appropriation to the RFID, starting 2012, to $0.195 million per year:** In response to concerns raised by the Board and intervenors during the 2008/2009 General Rate Application (i.e., that insufficient justification was provided for the proposed annual appropriation to the RFID) Yukon Energy had an actuarial consultant (IAO Actuarial Consulting Services Inc. – An Aon Company ("AON")) prepare an actuarial valuation of YEC's RFID as at December 31, 2009[10]. The results of this study are provided as Appendix 12.5 to Tab 12. In sum, AON reviewed historical losses and exposures for the program to evaluate YEC's RFID, estimated the ultimate losses as at December 2009, and determined the annual provision for the RFID. The estimated annual provision, based on information as at December 31, 2009, was $0.195 million.

   Actual expenses were $0.133 million in 2009, $0.421 million in 2010 and $0.246 million in 2011. As shown in Table 3.11 below, the 10-year average of actual expenses is $0.229 million. This further demonstrates the justification to increase annual appropriations to the RFID to at least $0.195 million at this time.

2. **Transfer $0.398 million of one-time funds from Faro Mine Dewatering Deferral Revenues against the RFID balance:** In the 2008/2009 GRA, Yukon Energy sought approval to apply funds from this reserve against the Reserve for Injuries and Damages to address the then current balance in the RFID at that time. Yukon Energy is proposing a similar approach for the 2012/2013 GRA. The balance in the Faro Mine Dewatering Account as of year-end 2009 was $0.398 million[11]. The proposed transfer from the Faro Mine Dewatering Account would reduce the remaining balance to zero and reduce the current balance in the RFID from $0.578 million to $0.180 million.

3. **Amortize $0.180 million of the remaining balance over 5-year period:** The current balance in the Reserve is well into negative range ($0.578 million at year-end 2011 and $0.180

[10] "Yukon Energy Corporation Actuarial Valuation as at December 31, 2009" September 27, 2010 IAO Actuarial Consulting Services Inc. – An Aon Company.

[11] Pursuant to Orders 2009-8 and 2009-10, the account balance in the Faro Mine Dewatering Account was reduced from approximately $1.191 million at the start of 2008 to approximately $0.398 million at year end 2009 due to the applied for transfer of funds to the Reserve of $0.413 million as well as additional transfers to address revenues deficiencies following the final Order on the GRA, i.e., $0.026 million in 2008 and $0.355 million in 2009.

million after $0.398 million transfer from Dewatering Account). In order to address this balance, Yukon Energy seeks approval to amortize this balance over 5-year period (approximately $0.036 million per year).

Based on the above, RFID expenses for each of the test years are forecast at $0.231 million.

Table 3.11
RFID Annual Charges 2002-2011
($000)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	10 Year Average
Annual Charges	$105	$383	$167	$14	$633	$63	$128	$133	$421	$246	$229

In Order 2009-8, following the 2008/2009 GRA, the Board ordered Yukon Energy to undertake a risk management study of other utilities and to provide a written policy outlining the criteria for charging items to the RFID[12]. The studies were undertaken, as directed, in order to support the development of an RFID policy for Yukon Energy and to respond to concerns raised by the Board and intervenors in the last GRA. This policy is provided as Appendix 3.1 to Tab 3 and the directed studies are provided in Tab 12 Appendix 12.3 and Appendix 12.4.

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 2009, increasing from $0.256 million in 2009 GRA compliance to $0.312 million in 2012 and $0.326 million in 2013 (see Table 3.12).

Table 3.12
Property Taxes
($000)

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Property Taxes	$ 256	$ 288	$ 291	$ 297	$ 312	$ 312	$ 326	$ 326

[12] Directive #8 noted: The Study should examine and provide results that among other things: maximizes the benefits of tradeoffs between the deductible amounts proposed to be used on property insurance, the additional costs of making claims on its existing insurance and the size of uninsured claims; and outlines the criteria used to include an item in the Reserve, i.e. materiality threshold, probability of the event occurring, etc.

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 2012 mid-year forecast rate base is $223.0 million (an increase of $75.0 million from 2009 approved mid-year rate base) and 2013 forecast is $241.7 million (an increase of $18.7 million from 2012 mid-year forecast).

Mid-year net plant in service, which includes unamortized deferred costs (other than rate case expenses), as well as physical plant net of depreciation, is forecast to increase to $383.15 million in 2012[13] (a $193.07 million increase over 2009 approved mid-year balance), and to $399.57 million in 2013[14]. The major increase in 2012 primarily reflects Mayo B hydro generation facility, of the Carmacks-Stewart Transmission Project - Stage 2 and Aishihik Third Turbine.

Increases in net plant in service since the 2008/2009 GRA were offset largely by increased mid-year contributions for extensions ($167.25 million in 2012 and $166.02 million in 2013 or higher by $120.9 million in 2012 over 2009 approved and $119.7 million higher in 2013 over 2009 approved). The balance of the increase in net rate base from mid-year 2009 approved to mid-year 2013 reflects increased working capital ($0.92 million increase in 2012 over 2009 approved and $0.16 million in 2013 over 2012 forecast), and unamortized rate case expense ($1.98 million increase in 2012 over 2009 approved and $0.90 million increase in 2013 over 2012 forecast). A detailed summary of the spending undertaken by Yukon Energy since the 2008/2009 GRA, as well a forecast capital spending for 2012 and 2013, is provided in Tab 5 of this Application.

Yukon Energy's forecast proposed 2012 and 2013 expense related to depreciation of capital assets and amortizing other deferred charges is $7.81 million and $10.01 million respectively as shown in Table 3.13.

[13] This includes $13.4 million Feasibility Study costs, $5.07 million Relicensing costs, $0.48 million Deferred Overhaul costs and $0.083 million deferred Dam Safety costs.
[14] This includes $18.5 million Feasibility Study costs, $5.56 million Relicensing costs, $1.95 million Deferred Overhaul costs and $0.059 thousand deferred Dam Safety costs.

Table 3.13
Depreciation and Amortization
($000)

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Fixed Asset Depreciation	$ 6,522	$ 7,210	$ 7,365	$ 7,898	$ 11,726	$ 8,414	$ 12,398	$ 8,985
Less: Customer contribution	-1,091	-1,896	-1,846	-2,175	-4,533	-3,536	-4,582	-3,569
Less: Amortization of fire insurance recoveries	-270	-270	-270	-270	-270	-262	-270	-262
Plus: Amortization of deferred charges	1,707	1,511	1,407	1,447	3,065	3,198	5,632	4,859
Total Depreciation & Amortization	$ 6,869	$ 6,555	$ 6,656	$ 6,901	$ 9,988	$ 7,813	$ 13,177	$ 10,012

Notes:
1. Fixed asset depreciation is reduced by disallowed depreciation of $0.004 million (YUB 1992-1)
2. Amortization of deferred charges for 2009 are reduced by disallowed expenses of $0.224 million (YUB 2009-11).

Depreciation cost changes reflect changes in the assets in service as well as adjustments to depreciation arising from Yukon Energy's new depreciation study undertaken by KPMG, addressed below and included in Tab 10 of this filing. The new depreciation rates affect the fixed asset depreciation as well as the rate at which customer contributions are amortized. Fixed asset depreciation expense (net of contributions) decreases in each of 2012 and 2013 forecast compared to 2012 and 2013 existing by $2.307 million and $2.392 million respectively.

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, Yukon Government and Federal Government). This offset has grown from $1.091 million in 2009 approved to $3.536 million in 2012 and $3.569 million in 2013. The largest growth in credits relates to the Mayo B, Carmacks-Stewart Transmission Line - Stage 2, and Aishihik Third Turbine which are the source of substantial contributions from the Federal Government, Yukon Government and Yukon Development Corporation as set out in Tab 5.

The largest component of deferred charges relates to planning and study costs, regulatory hearing costs and licensing costs related to maintaining licences of YEC's hydro facilities and air emission permits.

The amortization of planning costs is the largest component of the deferred costs, which is primarily studies of the existing system and options for expanding the quantity of renewable generation,[15] as well

[15] As set out in Tab 5.

as studies related to the safety and reliability of the system, and other small projects. The requirement for Yukon Energy to undertake significant planning activities to ensure the next generation of low cost supply resources are available to meet growth on the integrated grid and displace requirements for costly diesel generation was reviewed in the 2008/2009 GRA[16]. Since that time, Yukon Energy has continued with the planning work outlined in the 2008/2009 GRA. The new planning cost accounting policy included in this Application (provided in Appendix 5.1) is required to address the unprecedented levels of planning costs incurred in Work in Progress (WIP) since 2009 and ensure that these costs are included in rates in a manner that does not result in undue rate impacts for ratepayers.

Forecast amortization of feasibility studies costs increase to $1.64 million in 2012 and $2.69 million in 2013 (a $2.0 million increase from 2009 approved expense) as set out in Tab 5[17]. Under this approach large projects in Feasibility WIP (expenses to date >$1 million) are closed out before the end of the test period and amortized over 10 years to mute rate impacts over this period. This includes close outs in 2011 of Atlin Storage ($2.314 million) and Geothermal ($1.947 million) and close outs in 2012 of Marsh Lake Storage ($4.030 million), Gladstone Diversion ($3.893 million) and Waste-to-Energy ($1.128 million net of contributions). All other projects in Feasibility WIP (less than $ 1million) are closed out over the test period and begin to be amortized over 5 years. The justification for these deferred cost expenditures is addressed in Tab 5, Section 5.3.

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

- **Regulatory costs ($0.972 million in 2012 and $1.252 million in 2013 compared to $0.489 million in 2009 approved)**, including the impacts of amortizing the current GRA over 2 years, 2008/09 Phase II GRA costs over 2 years, the Resource Plan cost over 5 years and DSM proceeding over 10 years and other projects as set out in Tab 5.

- **Relicensing Costs ($0.562 million in 2012 and $0.758 million in 2013 compared to $0.520 million in 2009 approved forecast)**, Dominated by the Aishihik relicensing amortization costs ($0.496 million), as well as other relicensing costs.

[16] In Order 2009-8 the Board noted it "understands that YEC does not have the 'luxury of waiting for these loads to, with full certainty, materialize before taking any action.' Further, the Board notes that YEC's obligation to serve does require it to plan the system to meet these expected loads and any other requirements that may arise." Further, the Board indicated awareness that not all studies would result in developed projects, and noted the following enduring benefits to ratepayers may result from such work and justify the costs (1) having projects that are 'shelf ready' and able to proceed at some future date as circumstances warrant; (2) feasibility work resulting in products that have other uses and applications of ongoing value to the utility; (3) engagement with the local community and working with them through the issues; and the Board finds these benefits justify incurring the deferred costs." (Order 2009-8 paragraph 243).

[17] See Tab 5 Table 5.6 and Table 5.7 for 2012 and 2013 forecasts.

The deferred cost amortization also includes amortization of dam safety reviews ($0.024 million for each test year) and amortization of deferred overhauls ($0.128 million in 2013). The justification for these deferred cost expenditures is addressed in Tab 5, Section 5.3.

3.4.1 Depreciation Study

Yukon Energy has undertaken a review of its depreciation rates and provisions, using an external expert (KPMG). The result of this review is a significant change in the Corporation's service lives for certain major assets. The updated Yukon Energy depreciation study is provided in Tab 10 of this filing.

Given the various factors and data available for the analysis, Yukon Energy has determined it appropriate to update its depreciation rates based on the results of the KPMG study. Certain of Yukon Energy's major assets (e.g., certain hydro plant, diesel production and main transmission assets) are indicated to have longer service lives than calculated in the depreciation study conducted in YEC's 2005 Required Revenues and Related Matters filing. With longer service lives the required annual deprecation provision is lower. As set out in Table 3.14 below, this factor decreased the 2012 depreciation expenses by approximately 33% ($2.307 million, net of customer contributions and amortization of fire insurance recoveries), and decreased 2013 depreciation expense by approximately 32% ($2.392 million, net of customer contributions and amortization of fire insurance recoveries).

Table 3.14
Comparison of Depreciation at Existing and Proposed Rates
($000)

	2012 Forecast		2013 Forecast	
	at Existing Rates	at Proposed Rates	at Existing Rates	at Proposed Rates
Fixed Asset Depreciation	$ 11,726	$ 8,414	$ 12,398	$ 8,985
Less: Customer contribution	-4,533	-3,536	-4,582	-3,569
Less: Amortization of fire insurance recoveries	-270	-262	-270	-262
Total	$ 6,922	$ 4,616	$ 7,546	$ 5,154
Net Change		-2,307		-2,392

Note:
1. Fixed asset depreciation is reduced by disallowed depreciation of $0.004 million.

3.5 RETURN ON RATE BASE (INTEREST COSTS AND ROE)

The total forecast proposed return on Yukon Energy's rate base for 2012 is $12.345 million and for 2013 is $14.130 million as shown in Table 3.1 (see Section 3.1). This is comprised of average interest costs related to the Corporation's debt, and a fair return on shareholder equity (as discussed more fully in Tab 8).

As set out in Table 3.15, Yukon Energy seeks approval of a forecast average cost of capital of 5.54% for 2012 and 5.85% for 2013. 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 2008/2009 GRA proceeding[18].

[18] Since 1992, Yukon Energy has maintained a balance of 60% long-term debt and 40% equity. 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 financing rate base at year end, while retaining a minimum of cash in the utility outside of amounts required to finance the ongoing capital programs. Maintaining a 60% debt: 40% equity ratio also requires equity injection depending of the capitalization of rate base in the end of the year.

Table 3.15
Cost of Capital

	2009 GRA compliance	Actual 2009	Actual 2010	FYF 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
Average Cost of Debt	6.15%	6.22%	6.38%	3.61%	3.40%	3.38%	3.91%	3.90%
Return on Equity	8.49%	7.92%	7.45%	6.59%	4.38%	8.77%	-0.97%	8.77%
Average Cost of Capital	7.09%	6.90%	6.82%	4.84%	3.79%	5.54%	1.96%	5.85%

Yukon Energy's forecast mid-year net rate base capital structure in the end of 2012 is comprised of $133.8 million in long-term debt and $89.2 million in common equity, and in the end of 2013 forecast to be $145.0 million and $96.7 million respectively (see Schedule 4B and Schedule 4C of Tab 7).

3.5.1 Costs of Debt

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

- **Yukon Development Corporation:** In January 2011 the following long-term financings (total of $81.891 million) were refinanced through Yukon Development Corporation's new long-term debt at 4.25% interest rate in order to reduce the interest payments (resulting interest payment reductions equal approximately $1.6 million in 2011 and approximately $1.5 million in both test years):
    - **The balance of the Canada Flex Term Note ($24.111 million):** The Flexible Term Note was flexible debt financing (at the full face interest rate of 7%) which forgave interest and deferred principal payments when the level of Yukon Energy sales on the WAF grid was less than 310 GW.h per year. The actual interest rates were 6.94% in 2009 and 7% in 2010 as the actual sales in WAF system were higher than 310 GW.h year and forecast to be higher in the following years keeping the interest rate at 7%. The outstanding balance at December 31, 2010 was $24.111 million.
    - **Yukon Development Corporation Flexible Promissory Note (for Mayo-Dawson Project) ($14.707 million):** 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

face interest rate on the note was 6.55% and, due to the present substantial benefits to ratepayers arising from the Mayo-Dawson line the interest paid in 2009 and 2010 were at face rate of 6.55%. The outstanding balance at December 31, 2010 was $14.707 million.

- **Yukon Development Corporation ($20.887 million):** $27.314 million term note bearing interest at 5.88%, payable monthly and semi-annual principal payments commenced June 30, 2007. The outstanding balance at December 31, 2010 was $20.887 million.
- **Yukon Development Corporation ($22.186 million):** Unsecured advances (dividends declared to YDC in prior years and lent back to the utility) of $22.186 million at different interest rates (4.65%-6.03%) as the outstanding balance at December 31, 2010.

- **TD Canada Trust Note:** The outstanding balance on the TD Canada Trust term note at year-end 2012 is $3.938 million and $2.945 million at year-end 2013. This note has an effective interest rate of 7.81% with monthly principal and interest payments, and is due in 2016.

- **Yukon Development Corporation Mayo B Promissory Note ($21.9 million):** The Mayo B Promissory Note is a flexible debt provision at the maximum face interest rate of 5.46% which forgives the interest expense if the Integrated Grid load is lower than Minimum Grid Load as set in Schedule 1 of the Mayo B Promissory Note; if the calculated interest expense is negative then YDC pays that amount in order to reduce the impact to ratepayers. If the load in the range between Maximum Grid Load and Minimum Grid Load then interest expense is calculated as follows:
  - 5.46% * (Actual Load – Minimum Grid Load)/Range for the year[19].

Detailed information on the Promissory Note provided in Tab 5, Appendix 5.3 of this Application.

- **Yukon Development Corporation:** In order to maintain 60% debt and 40% equity ratio a new long-term debt of $19.148 million is estimated to be provided in 2011. The interest rate is 5% per year (based on most recent external borrowing and assuming guarantee as in the past by the Yukon Government for such external borrowings) with monthly principal and interest payments, and is due in 2041.

[19] Maximum Grid Load set at 515 GW.h at first year and decreasing by 7 GW.h each year (years 1-16) and by 2 GW.h (years 17-21) to a minimum of 400 GW.h. Minimum Grid Load set at 415 GW.h at first year and decreasing by 2 GW.h each year to a minimum of 375 GW.h. The Range is difference between Maximum Grid Load and Minimum Grid Load.

- **Yukon Development Corporation:** In order to maintain 60% debt and 40% equity ratio a new long-term debt of $22.911 million is forecast to be provided in 2012. The interest rate is forecast at 5% per year (based on most recent external borrowing and assuming guarantee as in the past by the Yukon Government for such external borrowings) with monthly principal and interest payments, and is due in 2042.

- **Yukon Development Corporation:** In order to maintain 60% debt and 40% equity ratio a new long-term debt of $10.09 million is forecast to be provided in 2013. The interest rate is forecast at 5% per year (based on most recent external borrowing and assuming guarantee as in the past by the Yukon Government for such external borrowings) with monthly principal and interest payments, and is due in 2043.

3.5.2 Return on Common Equity

As reviewed in Tab 8, YEC has updated its forecast Return on Equity (ROE) based on a review of ROE methods and results in other jurisdictions to determine a reasonable low risk utility benchmark to use for the purposes of the current GRA filing[20]. This review indicated that while the British Columbia Utilities Commission (BCUC) low risk utility benchmark has been used in proceedings since the 1996/97 GRA, the low risk utility benchmark in that jurisdiction has not been subject to review since 2009 (and as a consequence may be out of date). By contrast, the Alberta Utilities Commission (AUC) has recently completed a Generic Cost of Capital proceeding (with a Decision dated December 2011).

The recent AUC proceeding has determined the benchmark ROE for a low risk utility to be 8.75% (by contrast, the more dated 2009 BCUC benchmark would provide for a low risk utility ROE in the 9.5% range). It is proposed that the more recent low risk utility benchmark of 8.75% be adopted for the purposes of setting rates for Yukon Energy in the test years with the previously accepted risk premium of 52% applied to this benchmark. This methodology would increase the ROE by 0.28% from the YUB's last approved ROE[21].

[20] Since the late 1990s, Yukon Energy has relied upon a low risk utility benchmarking approach along with a reasonable risk premium of 52% (based on BCUC precedents for similar electric utilities) as a simplified approach that reduces overall cost to the ratepayer through eliminating the requirement of costly expert assessment and testimony.
[21] The ROE for Yukon Energy for the test years is based on 8.75% low risk utility benchmark plus the 52% risk premium for Yukon Energy (approved in 2008/2009 GRA) and subtracting 50% pursuant to direction provided in OIC 1995/90. OIC 1995/90 requires that the Yukon Utilities Board include in rates for Yukon Energy provision to recover a fair return on the Corporation's equity, less one-half of one per cent (0.5%). See Tab 8 for more detailed review.

Based on above Yukon Energy's forecast return on equity for the test years is 8.77% for both 2012 and 2013.

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:

- Rider F; and
- Diesel Contingency Fund (DCF).

3.6.1 Rider F

The Deferred Fuel Price Account ("Rider F") is established and maintained 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.

Based on proposed changes to the DCF whereby any secondary sales revenues after January 1, 2012 would be credited directly to the DCF (and thereby not affect Yukon Energy revenues or income), it is proposed that Rider F no long be affected by variations in the ongoing quarterly adjustments to the prices of secondary sales, i.e., any secondary sales revenues after January 1, 2012 would be credited to the DCF without any Rider F related adjustment or impact for price changes.

3.6.2 Diesel Contingency Fund (DCF)

The Diesel Contingency Fund ("DCF") was established in the 1996/97 GRA Negotiated Settlement. The DCF is designed to ensure that the Fund (and utility ratepayers), rather than YEC earnings, pays for or benefits from changes to grid diesel generation due to fluctuations in grid hydro generation due to factors

such as water condition changes that are beyond utility control. With the DCF in place, the YUB can set customer rates based on long-term forecast hydro generation rather than short-term forecast hydro generation. The DCF is maintained to address ongoing fluctuations in diesel requirements (and related fluctuations in rates, up or down) that ratepayers would otherwise be exposed to due to annual water availability. In effect, the DCF operates to smooth rate impacts so that ratepayers are not subject to ongoing rate instability from year to year depending on whether it is a flood or drought year.

The DCF balance as at December 2011 is $0.902 million. This balance has been retained in the Fund (with interest) and no amounts (beyond interest) have been either credited or debited to the fund since December 31, 2007.

Connection of the WAF and Mayo Dawson grids, and commencing the new hydro facilities (Mayo B and Aishihik Third turbine) has required update of the methods of operation of the DCF.

Yukon Energy seeks approval of the proposed updates/adjustments detailed in Appendix 3.2, Attachment 3.2 of the Application. Based on these updates/adjustments, YEC also seeks approval to reactivate the DCF for YEC diesel generation costs effective January 1, 2012 with ongoing annual DCF determinations to be made based on the percent of long-term hydro generation applicable in any year as provided for in the last GRA approved revenue requirement forecast assumptions.

APPENDIX 3.1
YUKON ENERGY RFID POLICY

YUKON ENERGY	FINANCE POLICY FA-014	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Chief Financial Officer	Reserve for Injuries and Damages
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2012	February 2015	President & CEO

1.0 Purpose

1.1 The Reserve for Injuries and Damages ("RFID") is utilized to address uninsured and uninsurable losses, and associated costs, as well as the deductible portion of insured losses.

1.2 The reserve serves two purposes: (1) it allows for an appropriate balance to be maintained between self-insurance, deductibles, commercial insurance and sudden and accidental losses; and, (2) it allows the costs in question to be smoothed over a number of years to avoid rate instability for ratepayers.

2.0 Background

2.1 An RFID account is a risk management tool commonly used by regulated utilities to address uninsured and uninsurable losses in a manner that allows for smoothing of rate impacts over time[1]. If an uninsured or uninsurable loss occurs, and it meets defined criteria, then the value of the loss is charged against the balance in the RFID[2].

2.2 The Corporation's RFID has been approved by the Yukon Utilities Board ("Board") and is funded through an annual appropriation which is also approved by the Board. Historically, this amount has fluctuated between $50,000 and $150,000 per year.

2.3 A recent study commissioned by the Corporation has concluded that an annual appropriation of $195,000 per year is appropriate; however, this annual appropriation has not yet been approved by the Board.

3.0 Annual appropriation to the RFID

3.1 Subject to the approval of the Board, the RFID will be funded and raised through an annual appropriation of $195,000 with no specific limits on surpluses or deficits.

[1] Due to the nature of these losses, the timing and quantum of the loss cannot be forecast accurately. Consequently, an annual appropriate to the reserve is approved in rates. This amount is charged to the reserve and effectively "builds up" the account over time.

[2] This expectation would be that the accumulation of annual appropriations will net out against losses incurred. However, historically, the account tends to go negative (losses exceed accumulated appropriation); at the next GRA, the utility will ask to be made whole for this amount.

4.0 Criteria

4.1 Uninsured and uninsurable losses and associated costs will be charged to the RFID if they meet the following criteria:

(a) The loss exceeds $10,000;
(b) The loss was sudden and accidental and not the result of normal wear and tear;
(c) The incident was of significance to the operation of the unit; and
(d) The loss was one of low probability, not normally expected to occur in a typical operating year.

4.2 The deductible portion of insured losses and any portion of a loss not covered by insurance and not related to betterment of the asset, and any extra expense related to an uninsurable or uninsurable unplanned plant outages[3] will also be charged to the RFID.

[3] For example, the loss of a hydro generating unit may require the utility to burn diesel to meet demand. Unless the utility specifically purchases Extra Expense coverage for this loss, these amounts are uninsured.

APPENDIX 3.2
UPDATE TO DIESEL CONTINGENCY FUND (DCF)

APPENDIX 3.2: UPDATE TO DIESEL CONTINGENCY FUND (DCF)

INTRODUCTION

Board Order 2011-15 included the following directive at page 9:

- The Board accepts the commitment of YEC to address all DCF issues in the next GRA and directs YEC to address any changes necessary in the operating rules, administration and revised revenue requirements pertaining to the DCF in its next GRA. Also, the Board requires that YEC provide a specific definition of the term "diesel on the margin". The Board directs that YEC complete its review and bring the necessary changes before the Board at the earliest of its next GRA or July 1, 2012.

This attachment responds in full to this Board directive. It provides a summary of components of the current Diesel Contingency Fund (DCF or Fund) as per the Negotiated Settlement approved in Order 1996-7; June 2, 1999 letter to the Yukon Utilities Board regarding Diesel Contingency Fund Filings - 1996 to 1998; and October 7, 1999 letter to the Yukon Utilities Board regarding Comments on the Diesel Contingency Fund report.

BACKGROUND

Based on past practice and current rules, the DCF applied only to the Whitehorse-Aishihik Faro (WAF) grid. When operative, the DCF account for WAF could be either credited or debited each month for one of two reasons with regard to WAF operations:

- **When diesel is "on the margin[1]"** (defined as diesel being used to meet long-term firm energy requirements of the WAF system, not just periodic peaking requirements), the account stabilizes the diesel costs related to water flow variations. In these situations (i.e., with diesel on the margin), when hydro varies positive or negative from the long-term average forecast, that variance is met effectively one for one with changes in diesel generation compared to what would have occurred had the hydro variance not occurred. This happened, for example, in the periods of 1996-1998 when the Faro mine was operating, and was last triggered for January 1998.

[1] In the Yukon Energy 2008/2009 GRA filing it was noted that the DCF would 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 hydro system over the course of a long period (many months to years). Yukon Energy did not anticipate a requirement for such a Fund to be in operation during 2008 and 2009. Until "diesel is on the margin" the Fund cannot be triggered and amounts cannot be debited or credited to the Fund.

- **When diesel in not on the margin,** the account can in certain circumstances be used to pay for the costs of baseload generation using diesel when such baseload generation arises due to low water conditions. This happened, for example, in a number of months of 1999, when diesel was not considered to be on the margin (due to low grid load levels hydro should have been able to supply all baseload requirements) but extremely low water led to the need for baseload diesel generation. In practice, the distinction between normal peaking operation and true baseload diesel has been set in the past on WAF at 250 MW.h/month for calculation purposes[2].

Diesel has not been on the margin since the Faro mine closed in 1998. Diesel was not forecast to be on the margin in the 2009 GRA. No DCF determinations have been made subsequent to the 2009 GRA.

The Fund was established for the WAF system when the Faro mine was operating and diesel was on the margin for that system, (i.e., diesel was needed to provide baseload grid energy beyond peaking periods, reserve or emergency conditions). The DCF has been generally inactive since the Faro mine closed. More specifically, the Fund is inactive when hydro generation surplus conditions exist and diesel is not on the margin.

The Fund is to operate outside of rate base but an annual report detailing additions and deletions to the Fund is to be filed with the Board so that the Board may oversee the Fund's activities. The Board will direct the Companies on the additions and deletions to the Fund. The annual report to the Board will also include a forecast of available water for the year.

On March 29, 2010, Yukon Energy filed its 2008 Diesel Contingency Fund Filing and noted the potential need to update methods of operation of the DCF. It was noted that the DCF operating rules would require attention in the future to address a number of new circumstances, including updating long-term average hydro generation values, fund triggers, and potentially a means to address secondary sales. Today, following connection of the WAF and Mayo Dawson grids, it is also necessary to adjust the DCF to deal with more than only WAF hydro generation. Until the necessary changes in operating rules are addressed and reviewed and approved by the YUB, Yukon Energy stated that it did not anticipate that it would trigger operation of the DCF fund.

Separate from the YEC WAF grid DCF applications, imputed diesel generation savings or excess related to the YECL Fish Lake hydro facility were calculated in the past when the DCF was operating[3]. In Order

[2] Even in cases where diesel generation exceeded 250 MW.h but the generation was for peaking requirement, the DCF has not been charged – for example, December 2008.

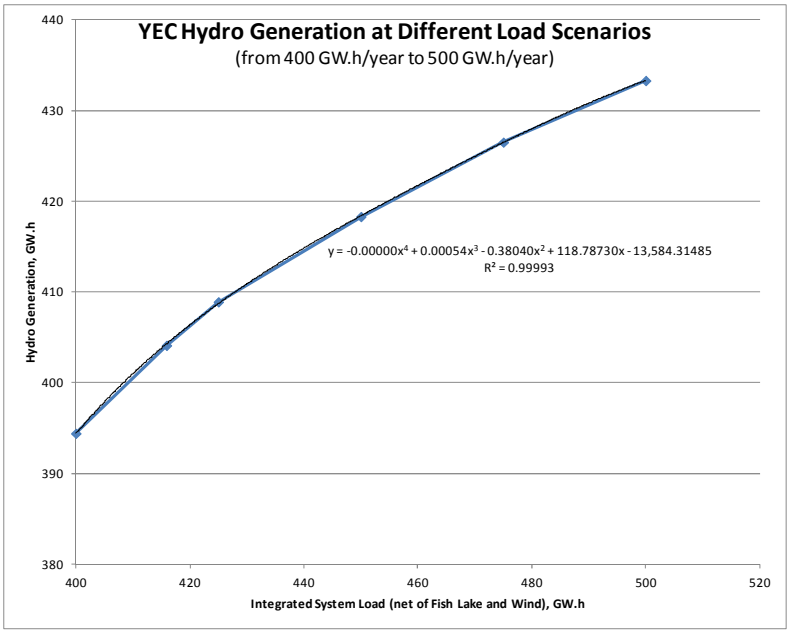
[3] Actual Fish lake generation was compared with the long term average Fish Lake generation forecast per the 1996/97 GRA filing (10 GW.h/year); and imputed diesel cost savings or excess for YECL were calculated assuming the YEC WAF diesel generation standard efficiency and fuel prices.

2009-2 following the 2008/2009 YECL GRA, the Board determined 8.73 GW.h to be a reasonable long-term average hydro generation number for Fish Lake (which was lower than what the DCF assumed in the 1996/97 GRA); however, subsequent to Order 2009-2, Unit #1 at Fish Lake has been shut down and is not currently expected to be replaced until January 2013. Changes in Fish Lake average hydro are beyond Yukon Energy's scope; accordingly, any updates to DCF rules related to YECL's Fish Lake plant are not addressed by Yukon Energy in this attachment.

Updated Long-Term Average Hydro Generation

The following figure provides estimated long-term average YEC hydro generation capability over a range from 400 to 500 GW.h/year of Integrated System grid loads (net of wind and Fish Lake generation), based on current installed hydro generation and licences/permits and the 2012 GRA loads with the Minto and Alexco mine loads. Table 3.2-1 (Attachment 3.2) shows the resulting estimates of hydro and diesel generation at 5 GW.h/year grid load increments. Extensions of this model can be provided for higher grid loads - but such extensions would require modified formula to address both the higher load range and any expected shift in annual load shape at such higher grid loads.

Figure 3.2-1
YEC Hydro Generation at Different Load Scenarios



Long-term average hydro generation at any specific grid load will vary slightly when new mines are added that modify the annual load shape. Table 3.2-2 (Attachment 3.2) shows the slightly modified estimates of long-term average hydro and diesel generation at 5.0 GW.h/year grid load increments,

based on current installed hydro generation and licences/permits and the 2013 GRA loads with the addition of the Whitehorse Copper Tailings mine load.

Hydro generation in any one year can vary a great deal from the long-term average estimated in the above figure. By way of example, at grid loads forecast for 2013 of 430.4 GW.h/year and based on water year records currently included in the relevant water models:

- Long-term average hydro generation (net of wind at 0.2 GW.h) capability approximates 412.0 GW.h, with expected diesel generation (long-term average) approximating 18.2 GW.h.
- In extreme high water years increased hydro generation capability could lead to almost no baseload diesel generation; and
- In extreme low water years reduced hydro generation capability could require diesel generation exceeding 100.0 GW.h/year.

DCF Term Sheet re: Recommended DCF Updates for YEC Grid

Attachment 3.2 to this appendix includes a DCF Term Sheet that sets out the current provisions of the DCF and recommended adjustments to update the DCF for the YEC grid and address current circumstances on the Integrated Grid.

ATTACHMENT 3.2: DCF TERM SHEET: UPDATES FOR YEC GRID

PURPOSE & FUNCTION: The DCF operates to smooth customer rate changes and changes in forecast diesel costs due to variability in existing grid hydro generation. The Fund is only to be used for these purposes and is not to be accessed for other reasons without prior YUB approval, including government subsidy of rates. Historically, the DCF has operated to offset diesel generation cost changes only for the WAF system[1] caused solely by variances from long-term average levels of WAF system hydro and wind generation.

UPDATE: *For the purposes of updating the Fund to address circumstances in 2012, the following additional adjustments are required: (1) the Fund needs to be amended to address the new interconnected system (i.e., not reference only "WAF" system generation and instead reference all interconnected grid hydro operated by YEC); (2) the Fund needs to be amended to address incremental costs for any fossil fuel used to displace diesel fuel (e.g., liquefied natural gas or LNG, as well as incremental costs for diesel fuel).*

LONG-TERM AVERAGE: The Fund currently assumes that the quantum of diesel generation costs in rates is determined using the long-term average water expected to be available for generation.

The last approved long-term average hydro and wind on the YEC WAF grid for the DCF as established in the 1996/97 GRA is set out below[2]:

1. Aishihik Facility - 105 GWh/yr
2. Whitehorse Rapids - 246 GWh/yr
3. YEC wind generation - 0.3 GWh/yr

UPDATE: *The previous approach of setting a single value for the long-term average hydro is not suited to today's system. At the range of grid loads relevant today and current hydro capabilities, it is necessary to recognize that long-term average hydro capability varies with variations in annual grid loads. Additional*

[1] After UKHM closed prior to 1990, surplus hydro conditions existed in Mayo system.
[2] The 2008/2009 GRA noted 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, approximated 351 GW.h per year.

variation can occur regarding month-by-month estimates of long-term average hydro and wind generation in years when, for at least some months, diesel is not on the margin.

The following changes are required:

1. ***Updates based on changes to grid system***

    a. *Mayo facility long-term average hydro updated to include existing conditions and licences with regards to Mayo A and Mayo B.*

    b. *Aishihik facility long-term average hydro based on existing conditions and licences, including Aishihik Third Turbine.*

    c. *Wind generation as forecast in the last approved GRA.*

2. ***Formulaic approach*** *– determine expected diesel generation based on long-term average water-based hydro generation that is forecast using a formulaic relationship to load in each year (including non-test years) rather than a fixed value as historically done[3]:*

    a. *Table 3.2-1 is adopted at this time to determine annual expected diesel generation prior to any new mine connections based on long-term average hydro generation at grid loads (net of wind and Fish Lake generation) ranging from 400 to 500 GW.h/year.*

    b. *The summary below (Example 3.2-1) provides an example of the determination of expected diesel generation at a grid load of 447 GW.h (net of wind and Fish Lake generation).*

[3] Long term average hydro generation under any set of assumed grid generation load and grid generation capacity and licence conditions is determined based on power benefit model calculations based on 28 years of water record for the interconnected grid. As load grows a portion of the load growth is currently served (on average) by increased hydro output and the remainder by increased average diesel. This same analysis would apply to LNG if it replaces diesel on the grid.

Example 3.2-1: Expected Diesel Generation Example for the Load at 447 GW.h (net of Wind and Fish Lake)

Step 1. Find the closest load from Column A that is less than 447 GW.h = 445 GW.h (Line 10).

Step 2. Find the diesel generation from Column C = 28.4 GW.h (Line 10).

Step 3. Find the difference between the given load (447 GW.h) and load from Step 1 (445 GW.h) = 2 GW.h

Step 4. Apply the percentage from Column F (64%) to the difference from Step 3 (2 GW.h) = 1.27 GW.h

Step 5. Add numbers from Step 2 (28.4 GW.h) and Step 4 (1.27 GW.h) = 29.67 GW.h

The expected diesel generation at 447 GW.h load is 29.67 GW.h.

Note: The load assumed the maximum load at 500 GW.h and the minimum load at 400 GW.h

c. Table 3.2-2 is adopted at this time to determine annual expected diesel generation in 2013 after such time as the Whitehorse Copper Tailings mine load is connected, based on long-term average hydro generation at grid loads (net of wind and Fish Lake generation) ranging from 400 to 500 GW.h/year and the annual load shape forecast with this new mine.

d. Yukon Energy will provide an update to Table 3.2-2 when required in future to address material changes in long-term average hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

3. Monthly reporting – *ensure the account can be managed on a monthly basis to permit financial reporting through use of a simple pre-determined monthly percentage distribution. Due to imprecision in forecast long-term average hydro monthly distributions it is possible that inappropriate values may arise during monthly estimating but these will not be part of final annual DCF calculations. Monthly calculations will be a placeholder with ultimate final calculations performed only on the annual values[4].*

DCF DIESEL SAVINGS (COSTS):

Diesel generation savings (excess) for the DCF related to changes in non-diesel generation for YEC is calculated to remove the effects for hydro-wind generation variances in total WAF generation for YEC. Diesel cost savings (excess) are

[4] There are limits to the ability to permit each month to have its own formula or polynomial, and differing monthly distributions may permit occasional odd values that resolve themselves in annual calculations. This same factor applied in the DCF calculations in the past.

calculated based on the approved forecasts for YEC WAF diesel generation costs per kWh based on GRA approved fuel prices, average diesel unit fuel efficiency, and average diesel unit incremental O&M costs per kWh[5].

UPDATE: *The relevant diesel fuel prices, unit fuel efficiency and incremental O&M costs are updated in each YEC GRA. In principle, the same approach would also apply regarding any other fossil fuel, i.e., these cost parameters are not limited only to diesel. To become operational for a fossil fuel other than diesel, this would require a GRA to approve related non-diesel fuel costs and engine efficiencies.*

DIESEL

ON THE MARGIN: Historically, the DCF was to be used only for offsetting baseload diesel generation changes due to the hydro/wind variances from long-term forecasts reflected in rates set in a GRA, and the DCF was only active when diesel was on the margin. The 1996 evidence presumed diesel generation was not on the margin for the WAF system when the Faro mine was closed.

UPDATE: *Under the proposed updated approach, the Fund would be permanently switched "on" through a formulaic approach that, subject to YUB review at each GRA, automatically adjusts forecast long-term hydro generation and related diesel (or other non-diesel fossil fuel) generation to reflect actual grid generation load. Accordingly, there would no longer be a diesel on the margin test for activating the DCF.*

With the diesel on the margin test discontinued for the DCF, there is need to consider other related items that would be affected (i.e., RS 42 with the related ERA requires that diesel on the margin be defined).

- *Effective the same date that the updated DCF approach becomes effective (i.e., recommended January 1, 2012), for the purpose of RS 42 it is necessary to recognize that diesel is on the margin, and that any required ERA determinations be made based on YEC costs incurred for actual diesel generation and/or DCF-related payments, i.e., based on the DCF as updated, YEC costs related to grid loads (and grid load changes) would be determined as provided for in the updated DCF.*

[5] Forecast from 1996/97 GRA were as follows: standard efficiency at 3.71 kWh/litre of fuel and YEC average WAF diesel fuel price forecast at approximately 29.60 cents/litre. Variable O&M costs per kWh of diesel fuel were assumed at 1.6 cents per litre, as assumed for the approved 1996/97 GRA retail runoff rates calculations for WAF.

QUANTUM & CAP:

The initial Fund was determined based on funds available as at December 31, 1995[6]. The cap on the Fund is currently set at the initial contribution level ($4,040,046). The "negative cap" is currently ($-4,040,046). If the Fund accumulates revenues in excess of the cap, the surplus balance at the end of the year is to be refunded by way of a rate-rider rebate to customers over the following two years. If the Fund falls below the equivalent negative cap level, a rate-rider increasing customer bills will occur to maintain the fund within the positive and negative cap levels.

UPDATE: *When diesel remains the marginal source of supply, major adjustments to the cap will need to be considered to adequately address the material potential swings related to diesel generation (e.g., potential for greater than +/- $20 million swings)[7]. However, it is not apparent that an excessively high cap would either (a) be able to be fully financed by YEC in the event it was a negative DCF balance; or (b) would yield the best outcome in terms of rate stability. In this respect, when diesel remains the marginal source of supply, one possibility is that the Fund have a very high cap for positive funding (perhaps up to $20 to 30 million reflecting the degree of possible drought today; funds which would be externally invested, or available to be "borrowed" by YEC as short term capital) but a much lower cap in terms of negative balances that must be financed by YEC (including potentially no larger than the $4 million presently approved).*

With potential shift to LNG with incremental fuel costs that are much lower than diesel costs, the current +/- $4 million threshold may continue to be relevant and feasible as a +/- cap.

Given that the Fund is ultimately in place to provide rate stability for ratepayers, Yukon Energy has not developed a specific recommendation at this time to modify the current quantum and cap for the Fund.

[6] The opening balance as at January 1, 1996 was $4,040,046.

[7] As noted at page 3.2-4, under forecast potential loads in 2013 potential annual diesel generation due to hydro fluctuations could exceed 100 GW,h/year, or over 80 GW.h higher than the applicable annual long-term average, reflecting a potential swing in annual diesel generation costs exceeding $20 million in extreme conditions.

SECONDARY

SALES: The Fund does not currently deal with secondary sales conditions or revenues, since the Fund only is active when diesel is on the margin (i.e., when secondary sales are not allowed).

UPDATE: *Secondary revenues remain highly variable component of YEC's income structure and fundamentally are made feasible from time to time based on water flows. For this reason a logical connection exists to the updated DCF and the overall objective of facilitating rate stability. In order to have stability in GRA rate revenues it is proposed that YEC will forecast 0 GWh of secondary sales in any GRA for the purposes of setting rates whenever annual long-term average hydro forecasts indicate the need for forecast baseload diesel/gas generation costs to be included in rates. In the event secondary sales arise secondary revenues will then be credited directly to the DCF (without any Rider F related adjustment or impact for price changes), thereby helping to fund the long-term risks related to hydro generation water condition fluctuation.*

INTEREST: The Fund is to attract interest based upon the short/intermediate term bond rates in which the Companies may invest the Fund and any negative balances would only attract interest at the lowest short term borrowing rate available to the Companies through a line of credit.

UPDATE: *No change is recommended to the current mechanism for interest.*

Table 3.2-1: Expected Diesel Generation Based on Long-Term Average Hydro Generation (Assumes Only Minto & Alexco Mine Loads)

Line Number	Grid Load (GWh)	Hydro Generation (GW.h)	Diesel Generation (GWh)	Increase in Load (GWh)	Increase in Diesel Generation (GWh)	Diesel as % of Increased Load
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	400	394.4	5.6			
2	405	397.8	7.2	5.0	1.5	30%
3	410	401.0	9.0	5.0	1.9	38%
4	415	403.8	11.2	5.0	2.2	44%
5	420	406.4	13.6	5.0	2.4	49%
6	425	408.7	16.3	5.0	2.7	53%
7	430	410.9	19.1	5.0	2.8	57%
8	435	412.9	22.1	5.0	3.0	59%
9	440	414.8	25.2	5.0	3.1	62%
10	445	416.6	28.4	5.0	3.2	64%
11	450	418.4	31.6	5.0	3.3	65%
12	455	420.1	34.9	5.0	3.3	66%
13	460	421.7	38.3	5.0	3.3	67%
14	465	423.3	41.7	5.0	3.4	68%
15	470	424.9	45.1	5.0	3.4	68%
16	475	426.5	48.5	5.0	3.5	69%
17	480	428.0	52.0	5.0	3.5	70%
18	485	429.4	55.6	5.0	3.5	71%
19	490	430.8	59.2	5.0	3.6	72%
20	495	432.1	62.9	5.0	3.7	74%
21	500	433.3	66.7	5.0	3.8	76%

Notes:

1. "Grid Load" is annual generation load on the Integrated Grid, excluding Fish Lake and Wind generation.

2. The diesel generation an increase for the added load are based on polynomial equations derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.

3. The simulation model develops expected hydro plant capabilities for each load scenario. It reviews, by week, 28 "water years" of record (1981-2008) and 20 "load years" (each examines a different hypothetical scenario to reflect different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this deletes cases where starting or ending year volumes can distort results). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.

4. The simulation model outputs for this table are based on Aishihik operation rule at 10-year rolling average spring elevation no lower than 913.7 m and current Mayo Lake operation rule (no additional storage); Mayo B and Aishihik 3rd Turbine are included.

5. The simulation model outputs are based on 2012 forecast load distributions and requires modifications when new mines are connected to the grid.

6. This table assumes maximum load at 500 GW.h and minimum load at 400 GW.h. If the load exceeds these limits, then the table needs to be updated.

Table 3.2-2: Expected Diesel Generation Based on Long-Term Average Hydro Generation (Assumes Minto, Alexco & Whitehorse Copper Tailings Mine Loads)

Line Number	Grid Load (GWh)	Hydro Generation (GW.h)	Diesel Generation (GWh)	Increase in Load (GWh)	Increase in Diesel Generation (GWh)	Diesel as % of Increased Load
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	400	395.1	4.9			
2	405	398.7	6.3	5.0	1.4	29%
3	410	401.8	8.2	5.0	1.8	36%
4	415	404.7	10.3	5.0	2.1	43%
5	420	407.3	12.7	5.0	2.4	48%
6	425	409.7	15.3	5.0	2.6	52%
7	430	411.9	18.1	5.0	2.8	56%
8	435	414.0	21.0	5.0	2.9	59%
9	440	415.9	24.1	5.0	3.1	61%
10	445	417.8	27.2	5.0	3.1	63%
11	450	419.5	30.5	5.0	3.2	64%
12	455	421.3	33.7	5.0	3.3	65%
13	460	423.0	37.0	5.0	3.3	66%
14	465	424.6	40.4	5.0	3.3	67%
15	470	426.2	43.8	5.0	3.4	68%
16	475	427.8	47.2	5.0	3.4	69%
17	480	429.3	50.7	5.0	3.5	70%
18	485	430.7	54.3	5.0	3.6	71%
19	490	432.1	57.9	5.0	3.7	73%
20	495	433.3	61.7	5.0	3.8	75%
21	500	434.4	65.6	5.0	3.9	78%

Notes:

1. "Grid Load" is annual generation load on the Integrated Grid, excluding Fish Lake and Wind generation.

2. The diesel generation an increase for the added load are based on polynomial equations derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.

3. The simulation model develops expected hydro plant capabilities for each load scenario. It reviews, by week, 28 "water years" of record (1981-2008) and 20 "load years" (each examines a different hypothetical scenario to reflect different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this deletes cases where starting or ending year volumes can distort results). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.

4. The simulation model outputs for this table are based on Aishihik operation rule at 10-year rolling average spring elevation no lower than 913.7 m and current Mayo Lake operation rule (no additional storage); Mayo B and Aishihik 3rd Turbine are included.

5. The simulation model outputs are based on 2012 forecast load distributions and requires modifications when new mines are connected to the grid.

6. This table assumes maximum load at 500 GW.h and minimum load at 400 GW.h. If the load exceeds these limits, then the table needs to be updated.

TAB 4
RATES

4.0 RATES

This tab reviews Yukon Energy's existing rates and sets out the changes to those rates proposed in this Application.

This tab consists of the following items:

- Summary of Proposed Rate Changes;
- Overview;
- Secondary Energy Rate Design;
- Major Industrial Firm Rates;
- Non-Industrial Firm Retail Rates; and
- Wholesale Rates.

4.1 SUMMARY OF PROPOSED RATE CHANGES

The key rate changes sought in this Application are[1]:

- **Rate Schedule 42** – Regarding the Energy Reconciliation Adjustment provision to take into account that the test years forecast indicate that diesel is now on the margin.
- **Rider J** – 2012 Yukon Energy Revenue Shortfall Rider applicable to all YEC and YECL firm retail rates (all YECL recoveries from this rider would flow through to YEC) and industrial rates. As noted below, interim refundable rates at the Rider J rate levels for retail and industrial customers are sought effective July 1, 2012.
- **Rider R** – 2013 Yukon Energy Revenue Shortfall Rider applicable, starting January 1, 2013, to all YEC and YECL firm retail and industrial rates, including Rider J (all YECL recoveries from this rider would flow through to YEC).

The rates arising from the final order in this GRA will not be in place until late 2012, or early 2013, given current timing estimates. As outlined in Section 4.5, interim refundable rates at the Rider J rate level are

sought effective July 1, 2012. This approach will mean that any required 2012 "true-up" will be part of the YUB's final order setting rates arising from this Application.

4.2 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 ($0.184 million in each test year) received by Yukon Energy[2]. In 2012, the revenue requirement is $39.857 million, and in 2013 is $45.641 million. Yukon Energy's forecast revenue requirement from firm electrical rates is $39.673 million in 2012 and $45.457 million in 2013.

Yukon Energy's revenue earned from rates is collected from charges for firm power and for secondary (interruptible or surplus) sales. Given that diesel is forecast to be on the margin in the test years YEC is forecasting 0 GW.h of secondary sales. However, as noted in Tab 3 (and in Appendix 3.2) and as described further below, in the event secondary sales arise, YEC is proposing that any resulting secondary revenues be credited directly to the DCF.

As set out in Table 4.1, assuming the sales forecasts set out in Tab 2, the current level of existing firm rates would result in a $3.455 million rate revenue shortfall in 2012, and a $7.685 million rate revenue shortfall in 2013 compared to revenue requirements set out in Tab 3. These shortfalls form the basis for the proposed rate increases in this Application.

[1] Blacklined rate schedules are provided in Appendix 4.1.
[2] Including items such as pole rentals, connection charges, and other facility rentals.

Table 4.1
Yukon Energy Revenue Required from Rates
($000s)

	2012	2013
Revenue Requirement (from Table 3.1)	$39,857	$45,641
Less: Non-rate Revenues	$184	$184
Revenue Required from Firm Rates	$39,673	$45,457
Less: Revenues from Firm Sales at Existing Rates (including "Fixed" component of industrial Rider F)	$36,218	$37,772
Firm Rate Increase Proposed	$3,455	$7,685

4.3 SECONDARY ENERGY RATE DESIGN

Yukon Energy's secondary rate offering provides interruptible power to customers of Yukon Energy or Yukon Electrical 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 Yukon Electrical as retailer, with Yukon Energy selling the equivalent quantity of power on a wholesale secondary basis to Yukon Electrical 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.

4.3.1 Retail Secondary Sales Rates (Rate Schedule 32)

In 2005, the Yukon Utilities Board 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/Yukon Electrical rate rider.

In the 2008/2009 GRA, Yukon Energy noted that with the increased utilization of surplus hydro generation in coming years, the existing opportunity to sell secondary energy on an interruptible basis would be basically eliminated; however, limited quantities of secondary energy may remain available in summer months during off-peak hours over the following years. At the time it was noted that in the test years secondary sales were forecast to be maintained through most hours of the year, but during cold winter periods there would be increased use of diesel generation for firm load peaking requirements and consequently greater forecast interruptions of secondary sales than in previous years.

After the 2008/2009 test years, secondary sales were suspended for a prolonged period of time due to low water[4]. As a result of this suspension of service a number of secondary sales customers converted to primary supply for their electric heating loads.

As previously noted in Tab 3, and Attachment 3.2 to Appendix 3.2, due to the variability of secondary sales and the direct relationship between such sales and water availability, Yukon Energy is forecasting 0 GW.h of secondary sales for the purposes of setting rates in the test years. In the event secondary sales arise, secondary revenues will be credited directly to the DCF (without any Rider F related adjustment or impact for price changes), thereby helping to fund the long-term risks related to hydro generation water condition fluctuation, and not affecting Yukon Energy's revenue or income. This treatment maintains a logical connection to the updated DCF and is intended to support rate stability going forward. Assigning secondary sales revenues to the DCF ensures that all such temporary revenues from surplus hydro conditions will go to funding future fossil fuel generation due to below average water conditions.

[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%.
[4] Except for the period from September 1, 2010 until September 1, 2011 when they were temporarily resumed due to high water in Aishihik Lake.

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

The PPA with Minto Explorations included as Schedule D, Rate Schedule 35, 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 Yukon Utilities Board and intervenors during the PPA hearing process, and was approved by the Board 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[5]. 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.

To date, the Yukon Utilities Board prerequisites for Rate Schedule 35 have not been met. In addition, YEC is not forecasting Rate Schedule 32 secondary sales to be available during the test years; in the event that Rate Schedule 32 sales were to become available, the forecast quantities of power available for Rate Schedule 35 (if the YUB prerequisites were to have been met) would still be very limited[6]. As with Rate Schedule 32 secondary sales, it is proposed in this Application that any future sales under Rate Schedule 35 would go to the DCF.

4.4 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 applies to the Minto mine, Alexco mine and Whitehorse Copper Tailings.

[5] See Board Order 2007-5.
[6] This rate is to be served at a lower priority than Rate Schedule 32 secondary sales. Accordingly, in the event that Rate Schedule 32 sales were to become available, no material energy is expected to be further "surplus" to Rate Schedule 32 needs for service under Rate Schedule 35, except possibly 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) at that time provided 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[7]. Subsequently, as provided for in OIC 2007/94, Board Order 2011-04 approved a 2.8% increase in Rate Schedule 39 demand and energy rates effective January 1, 2011 and Board Order 2011-14 approved a further 3.4% increase in Rate Schedule 39 demand and energy rates effective January 1, 2012[8].

Section 6(3) provided in OIC 2007/94 was replaced in April 2012 with a new OIC direction – OIC 2012/68. This new direction in effect requires that Rate Schedule 39 as approved in Board Order 2011-14 continue until December 31, 2013[9], except as follows:

1. If rates charged to retail customers for all or any part of 2012 are to be increased, then for that same period the greater of that increase and the percentage increase approved in Board Order 2011-14 [i.e., 3.4%] is to apply to the class of major industrial customers; and

2. The Board must otherwise ensure until December 31, 2013 that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers.

[7] Rate Schedule 39 as approved by Order 2008-13 included a demand charge of $15.00/kV.A.of billing demand per month and an energy charge of 7.60 cents/kW.h for all energy used. The last Rate Schedule 39 approved prior to Order 2008-13 (i.e., the rate schedule approved for 1997 by Order 1996-08) had a demand charge of $18.60/kV.A of billing demand per month and an energy charge of 5.03 cents/kW.h for all energy used (the option existed for customers with a Base Load Energy amount to have an energy charge of 4.728 cents/kW.h for energy that does not exceed the Base Load plus 10.45 cents/kW.h for all energy consumed in excess of the Base Load). Assuming an average load factor exceeding about 80%, the 2008 average charge was approximately 20% higher than the 1997 average charge.

[8] Order-in-Council 2007/94 (OIC) provided for escalation of demand and energy charges, once per 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. On December 5, 2011, Yukon Energy Corporation filed an application with the Yukon Utilities Board seeking an Order from the Board for approval of amendments to Rate Schedule 39, and in Order 2011-14 the Board approved escalating the demand and energy charges for Rate Schedule 39 by 3.4%, for rates effective January 1, 2012. The current rates include a demand charge of $15.94/kV.A of billing demand per month plus an energy charge of 8.08 cents/kW.h for all energy used and a fixed Rider F charge of 0.211 cents/kW.h charged only to Rate Schedule 39 customers (for fuel price escalation between November 2006 and 2009).

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

The Application conforms to the latest OIC direction provided by OIC 2012/68 and provides that Rider J and Rider R will apply to major industrial customers as follows:

- Rider J (2012 Yukon Energy Revenue Shortfall Rider, with an interim rate to start July 1, 2012) provides for a rate increase of 6.4% for all retail customer classes and a rate increase of 2.90% for major industrial class customers (when combined with the 3.4% increase in Board Order 2011-14, the cumulative 2012 increase of 6.4% is equal to the rate increase charged to retail customers). The Rider J increase applies to all major industrial rates then in effect pursuant to Order 2011-14, including the fixed Rider F charge of 0.211 cents/kW.h.

- Rider R (2013 Yukon Energy Revenue Shortfall Rider) provides for a rate increase of 6.5% effective January 1, 2013 for all retail customer classes and for major industrial class customers. The Rider R increase applies to all major industrial rate then in effect, including Rider J and the fixed Rider F charge.

4.5 NON-INDUSTRIAL FIRM RETAIL RATES

Firm retail non-industrial rates within each non-government retail customer class (i.e., rates for residential, general service and lighting customer classes) are required by OIC 1995/90 to be equal throughout Yukon for both Yukon Energy and Yukon Electrical customers, subject to allowed variation for run-off rates to reflect incremental costs that differ for different rate zones.

On October 3, 2008, the Yukon Government enacted OIC 2008/149 amending OIC 1995/90 to add the following immediately after Section 2 the following direction to be in effect until December 31, 2012:

> 2.1(1) the Board must ensure that rate adjustments for all retail customers apply equally, when measured as percentages, to all classes of retail customers.

Section 2.1 provided in OIC 2008/149 was replaced in April 2012 with OIC 2012/68. Insofar as it affects all classes of retail customers, this new direction in effect extends the earlier section 2.1(1) direction until December 31, 2013, and ensures that the same percentage rate adjustments will also apply to the class of major industrial customers (subject to provisions noted in Section 4.4 of this Application).

In accordance with OIC 2012/68, the Application proposes that the Yukon Energy revenue shortfall for 2012 and 2013 as shown in Table 4.1 be recovered through Revenue Shortfall Riders applied across the board to all firm retail and industrial rates in 2012 and in 2013 as follows (see Section 4.4 of this Application for details regarding how these rider also apply to industrial rates):

- **2012:** An across the board Rider J of 6.40% applied on an ongoing basis to all firm retail customer rates and 2.90% applied on an ongoing basis to all firm major industrial customer rates (i.e., excludes customers served under Rate Schedule 32 and Rate Schedule 35); if applied throughout 2012, this Rider J would provide the 2012 revenue shortfall, as shown in Table 4.2. The calculation of the 2012 revenue shortfall and the required 6.4% increase in firm retail rates and 2.90% increase in firm industrial rates are set out in Table 4.2 below.
    - Table 4.2 indicates consolidated YEC and YECL forecast 2012 retail sales revenues of $51.19 million at existing firm rates, forecast industrial sales revenues of $6.18 million (after the 3.40% increase in the demand and energy charge effective January 1, 2012 pursuant to Order 2011-14), for a total consolidated YEC and YECL firm retail and industrial rate revenue at existing rates of $57.37 million.
    - The 2012 Yukon Energy revenue shortfall (based on Table 4.1) at existing rates is $3.46 million. The following are required to recover this shortfall through rate riders that yield equal rate percentage increases for all retail customer classes and the major industrial customer class:
        - Non-industrial rate increase of 6.40% of the forecast 2012 consolidated retail revenues at existing rates (forecast $3.28 million added rate revenue from non-industrial customers for 2012 sales);
        - Industrial rate increase of 2.90% of the forecast 2012 industrial revenues at existing rates (after the 3.40% increase effective January 1, 2012, cumulative compound increase of 6.40% in 2012; forecast $0.18 million added rate revenue from industrial customers for 2012 sales).
    - With the above rate increases applied, total consolidated YEC and YECL firm retail and industrial rate revenues at proposed 2012 rates and 2012 forecast sales are $60.82 million.
- **2013:** An across the board Rider R of 6.50% applied, on an ongoing basis, to all firm retail and industrial customer rates, including Rider J, starting January 1, 2013 (i.e., excludes customers

served under Rate Schedule 32 and Rate Schedule 35). The calculation of the 2013 revenue shortfall and the required 6.50% increase in firm retail and industrial rates is set out in Table 4.2 below:

- Table 4.2 indicates total consolidated YEC and YECL forecast retail and industrial sales revenues at existing firm rates of $59.78 million.
- With 2012 firm rates (including the proposed Rider J), total consolidated YEC and YECL forecast retail and industrial sales revenues are $63.34 million.
- The 2013 Yukon Energy revenue shortfall (based on Table 4.1) at existing rates is $7.68 million; $3.57 million of this revenue shortfall at existing rates is forecast to be recovered via the proposed 2012 Rider J rate increase applied to rate revenues, leaving a $4.12 million shortfall to be recovered through the proposed 6.50% Rider R applied to all firm retail and industrial forecast rate revenues (including Rider J) of $63.34 million. Total consolidated YEC and YECL firm retail and industrial rate revenues at proposed 2013 rates and 2013 forecast sales are $67.46 million.

It is proposed that Rider J be applied initially as of July 1, 2012 as an interim refundable rate rider. This proposal recognizes that rates arising from the final order in this GRA will not be in place until late 2012 or early 2013 given current timing estimates, and that any required 2012 "true-up" will be part of the YUB's final order setting rates arising from this Application.

Table 4.2
Calculation of Required 2012 and 2013 Riders (Rider J & Rider R)

Line #			Forecast 2012	Forecast 2013
1	Total Consolidated Retail Revenues at existing rates	$million	51.19	52.39
2	Industrial Revenues at existing rates	$million	6.18	7.38
3=1+2	**Total Consolidated Revenues at existing rates**	$million	57.37	59.78
4=Table 4.1	Retail Revenue increase required in 2012	$million	3.46	
5	*- from non-industrial*	*$million*	*3.28*	
6	*- from industrial*	*$million*	*0.18*	
7=5/1	Rider J *(for non-industrial)*	%	6.40%	
8=6/2	Rider J *(for industrial)*	%	2.90%	
9=1+1*7	Total Consolidated Retail Revenues at 2012 rates (incl Rider J)	$million	54.46	55.75
10=2+2*8	Industrial Revenues	$million	6.36	7.60
11=9+10	**Total Consolidated Retail Revenues at 2012 rates**	$million	60.82	63.34
12=Table 4.1	Total Revenue increase required in 2013	$million		7.68
13=11-3	Recovered from Rider J	$million		3.57
14=12-13	Total Revenue net increase required in 2013	$million		4.12
15=14/11	Rider R	%		6.50%
16=9+9*15	Total Consolidated Retail Revenues at 2013 rates	$million		59.37
17=10+10*15	Industrial Revenues	$million		8.09
18=16+17	**Total Consolidated Retail Revenues at 2013 rates**	$million		67.46

Notes:
1. Total Consolidated Retail Revenues at existing rates in Line 1 includes revenues from YEC and YECL's residential, general service and streetlight sales.
2. Industrial revenue forecasts in Line 2 are based on rates as of January 1, 2012 (YUB 2011-14).

Appendix 4.2 includes bill comparisons related to non government residential and commercial customers, indicating how Yukon rates compare with those in other jurisdictions and impacts of the Application on monthly rate charges and bills for a residential customer using 1000 kW.h per month and a general service customer using 2000 kW.h/month.

4.6 WHOLESALE RATES

Yukon Energy's firm rate revenues today primarily arise from the wholesale rate charged to Yukon Electrical. Except as indicated below, wholesale rates are not proposed to be changed as a result of the Application.

The structure of the wholesale rate to Yukon Electrical must meet the criteria of OIC 1995/90. Specifically, the 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.

1. When the WAF system does not have diesel on the margin, as was deemed to be the case in the 2008/2009 GRA, the rate for all primary power supplied to YECL is at a single rate (currently 8.298 cents/kW.h). The proposed Rider J (2012 Yukon Energy Revenue Shortfall Rider) and Rider R (2013 Yukon Energy Revenue Shortfall Rider) will apply to and be collected from all Yukon Energy and Yukon Electrical customers as specified, and, as has been implemented in the past for similar rate riders, all Yukon Electrical recoveries from these Yukon Energy riders will flow through to Yukon Energy. On this basis, the wholesale rate (Rate Schedule 42) will not need to be adjusted at this time in order to implement the proposed Rider J and Rider R rate increases.

2. 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[10]. 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 at long term average water flows) driven by increases in the volume of wholesale sales, and second to ensure that Yukon Energy is able to recover its costs (as required by OIC 1995/90 section 7(b)) when diesel generation is on the margin. The current ERA as last approved by the Board for the 2008/2009 GRA[11] provides specifically as follows:

> Charges to YECL will be adjusted on a monthly basis to reconcile actual wholesale purchases to test year forecast purchases during the months when diesel generation in the Hydro zone is on the margin at long term average water

[10] See Order 1999-4.
[11] See Order 2011-6.

> flows. 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 the Hydro zone incremental cost of diesel of 32.74 cents per kW.h as approved by the Board in Order 2010-13. Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10% of the forecast wholesale purchases in any period.

Attachment 3.2 to Appendix 3.2 of Tab 3 responds to the Board's Direction in Order 2011-15 to address all DCF issues in the next GRA, including any changes necessary in the operating rules, administration and revised revenue requirements pertaining to the DCF and to provide a specific definition of the term 'diesel on the margin'.

In relation to the DCF, Attachment 3.2 to Appendix 3.2 notes that under the proposed updated approach, the DCF would be permanently switched "on" through use of a formulaic approach that, subject to Yukon Utilities Board review at each GRA, automatically adjusts forecast long-term hydro generation and related diesel (or other non-diesel fossil fuel) generation to reflect actual grid generation load. Consequently, based on Yukon Energy's DCF proposal there will no longer be a diesel on the margin test for activating the DCF.

In relation to the ERA, given that diesel will be on the margin on an ongoing basis effective January 1, 2012, Yukon Energy proposes that the ERA provisions in Rate Schedule 42 be similarly triggered on an ongoing basis effective January 1, 2012. On this basis, charges to Yukon Electrical will be adjusted when changes in actual Yukon Electrical wholesale purchases (relative to Yukon Energy's most recent test year forecast for such purchases) result in changes to Yukon Energy costs incurred for diesel generation, whether such costs are incurred through adjustments in actual diesel generation or through adjustments in DCF payments or recoveries[12].

Accordingly, Yukon Energy proposes that the wording for the ERA in Rate Schedule 42 be changed effective January 1, 2012 as follows [proposed changes in ***bold***]:[13]

[12] As noted in Appendix 3.2 in Tab 3 it is proposed that any required ERA determinations be made based on Yukon Energy costs incurred for actual diesel generation and/or DCF payments, i.e., based on the DCF as updated, Yukon Energy diesel costs related to grid loads (and grid load changes) will be determined using the formulaic approach proposed to be included in the updated DCF.
[13] The proposed adjustment automatically takes into consideration the DCF provisions and diesel fuel prices as approved by the Board from time to time.

Charges to YECL will be adjusted on a monthly basis to reconcile actual wholesale purchases to ***Yukon Energy's most recent*** test year forecast purchases during the months ***when Yukon Energy diesel generation cost is modified by such variances in wholesale purchases.*** To the extent that actual wholesale purchases fall short or exceed ***Yukon Energy's most recent test year*** forecast wholesale purchases, an adjustment to the YECL bills will be made ***based on the variance in diesel generation costs incurred by Yukon Energy as a direct result of actual wholesale purchases falling short or exceeding forecast wholesale purchases***. Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10% of the forecast wholesale purchases in any period.

APPENDIX 4.1
RATE SCHEDULES

Effective: ~~2011~~ 2012 ~~07~~ 016 01
Supercedes: ~~1997~~ 2011 ~~01~~ 07 01

RATE SCHEDULE - 42

WHOLESALE PRIMARY (YEC)

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 8.298¢ per kW.h

Energy Reconciliation Adjustment

Charges to YECL will be adjusted on a monthly basis to reconcile actual wholesale purchases to Yukon Energy's most recent test year forecast purchases during the months when Yukon Energy diesel generation is modified by such variances in wholesale purchases. ~~diesel generation in the Hydro zone is on the margin at long term average water flows.~~ To the extent that actual wholesale purchases fall short or exceed Yukon Energy's most recent test year forecast wholesale purchases, an adjustment to the YECL bills will be made based on the variance in diesel generation costs incurred by Yukon Energy as a direct result of actual wholesale purchases falling short or exceeding forecast wholesale purchases. ~~at a rate equal to the Hydro zone incremental cost of diesel of 32.74 cents per kW.h as approved by the Board in Order 2010-13.~~ Such adjustment for shortfalls in actual wholesale purchases will be limited to minus 10% of the forecast wholesale purchases in any period.

TERMS AND CONDITIONS OF SERVICE: The Company's Terms and Conditions of Service 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 Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

RIDER J

2012 YUKON ENERGY REVENUE SHORTFALL 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 42 and Rate Schedule 43.

RATE: A 6.4% surcharge applicable to the base rates of the following rate classes with all Yukon Electrical Company Limited recoveries from this rider to flow through to the Yukon Energy Corporation:

Residential Non Gov.
Residential Gov
General Service Non Gov.
General Service Municipal Gov.
General Service Gov. Fed. and Terr.
Street and Sentinel Lighting

A 2.9% surcharge applicable to the base rates (including the energy charge, fixed Rider F and demand charge) of the following rate classes:

Industrial

NOTE: Rider J does not apply to Rate Schedule 32, Rate Schedule 35, Rate Schedule 42 and Rate Schedule 43.

RIDER R

2013 YUKON ENERGY REVENUE SHORTFALL 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 42 and Rate Schedule 43.

RATE: A 6.5% surcharge applicable to the base rates, after application of Rider J where applicable, of the following rate classes with all Yukon Electrical Company Limited recoveries from this rider to flow through to the Yukon Energy Corporation:

Residential Non Gov.
Residential Gov
General Service Non Gov.
General Service Municipal Gov.
General Service Gov. Fed. and Terr.
Street and Sentinel Lighting
Industrial

NOTE: Rider R does not apply to Rate Schedule 32, Rate Schedule 35, Rate Schedule 42 and Rate Schedule 43.

APPENDIX 4.2
RATE CHARGES AND BILL IMPACTS FOR YUKON RESIDENTIAL AND GENERAL SERVICE NON-GOVERNMENT CUSTOMER

APPENDIX 4.2: BILL IMPACTS FOR YUKON RESIDENTIAL NON-GOVERNMENT AND GENERAL SERVICE NON-GOVERNMENT CUSTOMERS

The tables and figures below show bill impacts for the Yukon Residential Non-Goverment and General Service Non-Government customers.

- **Table 4.2A-1** compares Yukon Residential bills at 1,000 kW.h monthly consumption to other cities across Canada. The Yukon Residential bills are competitive with other jurisdictions, as the bills in nine other cities are higher than the existing Yukon Residential bills. At 2013 proposed rates Yukon Residential bills still would be less than six other cities shown in Table 4.2A-1, including less than all other northern city customers.
    - **Note:** NWT rates are as of January 2012. NWT filed GRA on March 23, 2012 with proposed rate increases of 7% for the first 3 years (2012/13, 2013/14, 2014/15) and 5% in year 4 (2015/16).
- **Figure 4.2A-1** compares northern residential bills to Yukon residential bills - Yukon is lowest.
- **Figure 4.2A-2** compares residential bills in 15 cities across Canada.
- **Table 4.2A-2** compares Yukon small General Service bills at 2,000 kW.h monthly consumption to other northern cities. The table shows that Yukon businesses in this group pay less for electricity than similar businesses in other northern cities.
- **Figure 4.2A-3** compares northern small commercial bills.
- **Table 4.2A-3** shows recent historical changes in Yukon Residential Non-Government rates and rate riders to July 2011 prior to consideration of subsidies, rebates and taxes.
- **Table 4.2A-4** compares existing Yukon Residential Non-Government rates and bills to the proposed rate changes for 2012 and 2013 prior to consideration of subsidies, rebates and taxes.
- **Table 4.2A-5** shows recent historical changes in Yukon General Service rates and rate riders to July 2011 prior to consideration of subsidies, rebates and taxes.
- **Table 4.2A-6** compares existing General Service Non-Government rates and bills to the proposed rate changes for 2012 and 2013 prior to consideration of subsidies, rebates and taxes.

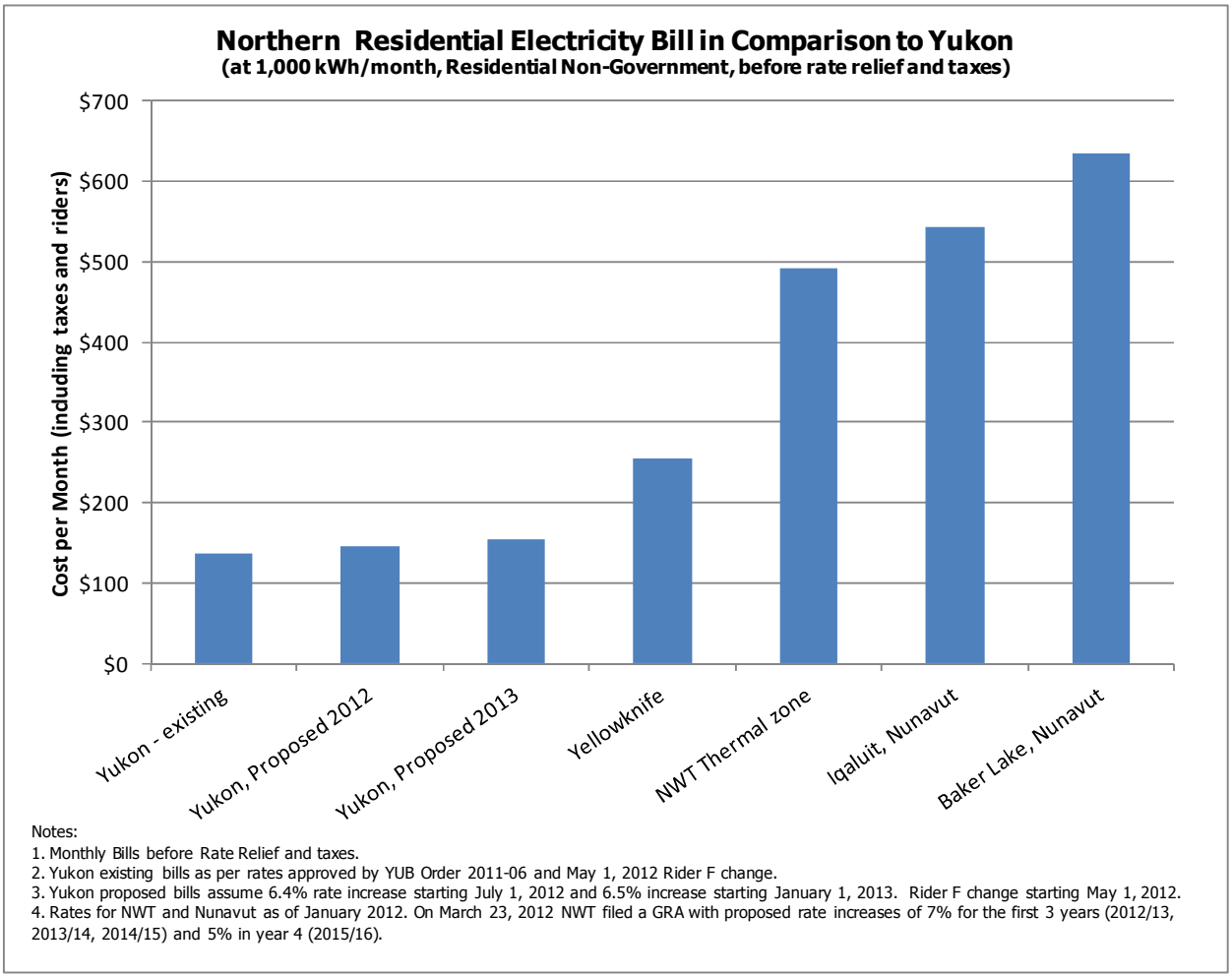
Table 4.2A-1
Residential Electricity Bills in Comparison to Yukon
(1000 kWh/month consumption, Residential Non-Government, $)

		Monthly Bills before rate relief and taxes
1	Yukon - existing	$136.05
2	Yukon, Proposed 2012	$144.76
3	Yukon, Proposed 2013	$154.17
4	Yellowknife	$254.29
5	NWT Thermal zone	$491.90
6	Iqaluit, Nunavut	$541.90
7	Baker Lake, Nunavut	$635.50
8	Winnipeg	$73.05
9	St. John's	$109.86
10	Toronto	$129.01
11	Halifax	$136.23
12	Regina	$137.92
13	Charlottetown	$145.07
14	Edmonton	$164.04
15	Calgary	$174.69

Notes:

1. Monthly Bills are before Rate Relief and taxes.
2. Yukon existing bills as per rates approved by YUB Order 2011-06 and May 1, 2012 Rider F change.
3. Yukon proposed bills assume 6.4% rate increase starting July 1, 2012 and 6.5% increase starting January 1, 2013. Rider F change starting May 1, 2012.
4. Rates for NWT and Nunavut as of January 2012. On March 23, 2012 NWT filed a GRA with proposed rate increases of 7% for the first 3 years (2012/13, 2013/14, 2014/15) and 5% in year 4 (2015/16).
5. Rates for the other cities as of April 2011 (Source: Hydro Quebec).

Figure 4.2A-1
Northern Residential Electricity Bill in Comparison to Yukon



Notes:
1. Monthly Bills before Rate Relief and taxes.
2. Yukon existing bills as per rates approved by YUB Order 2011-06 and May 1, 2012 Rider F change.
3. Yukon proposed bills assume 6.4% rate increase starting July 1, 2012 and 6.5% increase starting January 1, 2013. Rider F change starting May 1, 2012.
4. Rates for NWT and Nunavut as of January 2012. On March 23, 2012 NWT filed a GRA with proposed rate increases of 7% for the first 3 years (2012/13, 2013/14, 2014/15) and 5% in year 4 (2015/16).

Figure 4.2A-2
Residential Electricity Bill in Comparison to Yukon

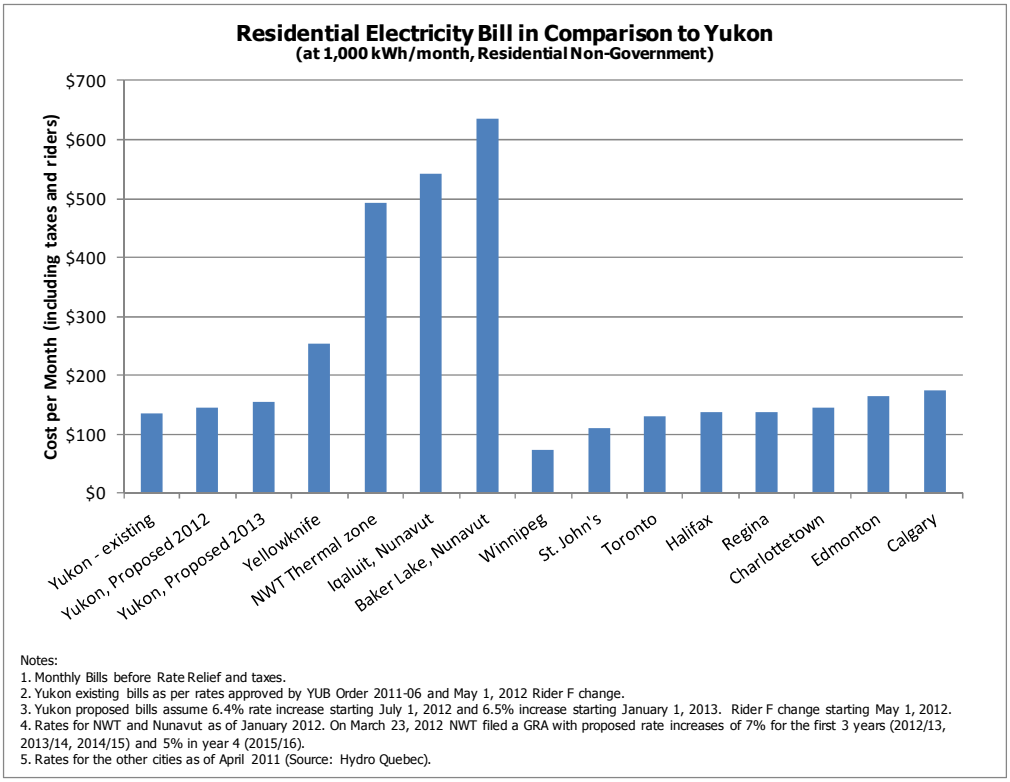


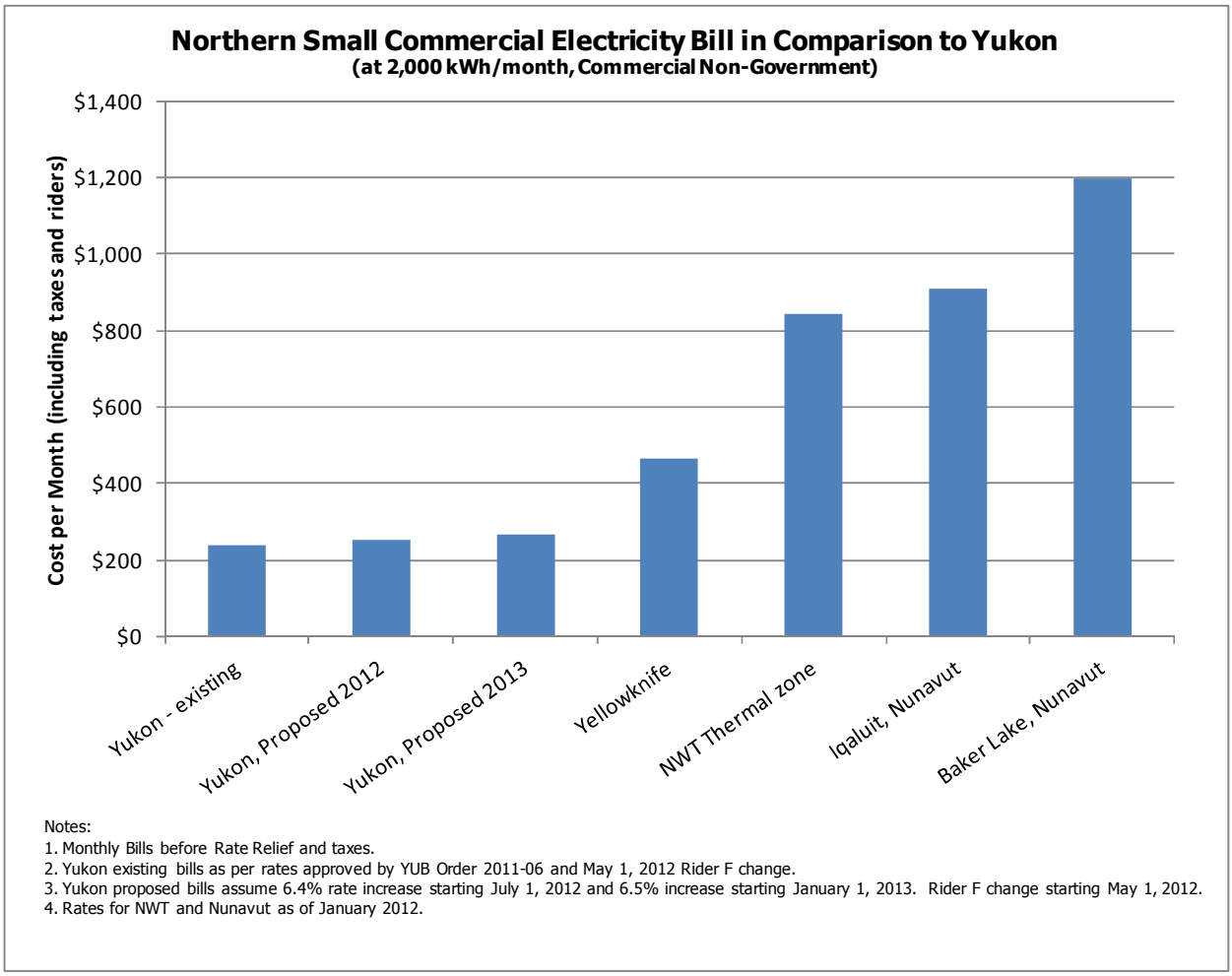
Table 4.2A-2
Small Commercial Electricity Bills in Comparison to Yukon
(2000 kWh/month consumption, Commercial Non-Government, $)

		Monthly Bills before rate relief and taxes
1	Yukon - existing	$236.95
2	Yukon, Proposed 2012	$252.11
3	Yukon, Proposed 2013	$268.50
4	Yellowknife	$464.93
5	NWT Thermal zone	$844.00
6	Iqaluit, Nunavut	$908.30
7	Baker Lake, Nunavut	$1,196.20

Notes:

1. Monthly Bills are before Rate Relief and taxes.
2. Yukon existing bills as per rates approved by YUB Order 2011-06 and May 1, 2012 Rider F change.
3. Yukon proposed bills assume 6.4% rate increase starting July 1, 2012 and 6.5% increase starting January 1, 2013. Rider F change starting May 1, 2012.
4. Rates for NWT and Nunavut as of January 2012. On March 23, 2012 NWT filed a GRA with proposed rate increases of 7% for the first 3 years (2012/13, 2013/14, 2014/15) and 5% in year 4 (2015/16).

Figure 4.2A-3
Northern Small Commercial Electricity Bill in Comparison to Yukon



Notes:
1. Monthly Bills before Rate Relief and taxes.
2. Yukon existing bills as per rates approved by YUB Order 2011-06 and May 1, 2012 Rider F change.
3. Yukon proposed bills assume 6.4% rate increase starting July 1, 2012 and 6.5% increase starting January 1, 2013. Rider F change starting May 1, 2012.
4. Rates for NWT and Nunavut as of January 2012.

Table 4.2A-3
Yukon Bills - Recent Historical Comparisons - Non-Government Residential
(prior to consideration of subsidies, rebates and taxes)

Line #	First Block Energy Use - Customer Use per month: 1,000 kWh	Rates in place at															
		Before May 2008		May-08 Rider F increase		Aug-08 YECL Rate Increase & Rider F increase		Dec-08 YEC Rate Decrease (interim Rider J)		Jun-09 Rider F, Rider G and Rider R change		Dec-09 Rider F		Jan-10 Rider F, Rider G and Rider R change		Jul-10 Rider F change		Jul-11 2009 Phase II GRA rates	
		Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																		
1	Customer Charge (per month)	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$11.90	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	$0.0986	$98.60	$0.0986	$98.60	$0.0986	$98.60	$0.0986	$98.60	$0.0986	$98.60	$0.0986	$98.60	$0.0986	$98.60	$0.0986	$98.60	$0.1214	$121.40
3=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]	$0.009638	$9.64	$0.0123	$12.30	$0.0186	$18.60	$0.0186	$18.60		$0.00	-$0.0039	-$3.90	-$0.0035	-$3.54	-$0.0009	-$0.90	$0.0035	$3.52
4=(1+2)*Rider G rate	Rider G (%)									4.15%	$4.58	4.15%	$4.58						
5=(1+2)*Rider J rate	Rider J (%)	14.93%	$16.50	14.93%	$16.50	14.93%	$16.50	11.45%	$12.65	11.45%	$12.65	11.45%	$12.65	12.46%	$13.77	12.46%	$13.77		
6=(1+2)*Rider R rate	Rider R (%)					5.00%	$5.53	5.00%	$5.53		$0.00		$0.00	10.53%	$11.63	10.53%	$11.63		$0.00
7=(1+2)*Rider J rate	Proposed Rider J (%)																		
8=(1+2)*Rider R rate	Proposed Rider R (%)																		
9=Sum(1:8)	Total Before Tax Rebate, RSF/IER, GST		$136.64		$139.30		$151.12		$147.28		$127.73		$123.83		$132.36		$135.00		$139.57
	Total Rate Charges excluding Rider F																		
9A=9-3	Total Rate Charges excluding Rider F		$127.00		$127.00		$132.52		$128.68		$127.73		$127.73		$135.90		$135.90		$136.05
	Change from last rate				*$0.00*		*$5.52*		*$3.85*		*$0.94*		*$0.00*		*$8.17*		*$0.00*		*$0.15*
					0.0%		*4.4%*		*-2.9%*		*-0.7%*		*0.0%*		*6.4%*		*0.0%*		*0.1%*

Table 4.2A-4
Yukon Bills– Existing vs. Proposed - Non-Government Residential
(prior to consideration of subsidies, rebates and taxes)

Line #	First Block Energy Use - Customer Use per month:	1,000 kWh	Rates in place at Jul-11		Proposed May-12		Proposed (GRA) Jul-12		Proposed (GRA) Jan-13	
			2009 Phase II GRA rates		Rider F		2012 Proposed Rates		2013 Proposed Rates	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates									
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)		$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		$0.0035	$3.52	$0.0042	$4.20	$0.0042	$4.20	$0.0042	$4.20
4=(1+2)*Rider G rate	Rider G (%)									
5=(1+2)*Rider J rate	Rider J (%)									
6=(1+2)*Rider R rate	Rider R (%)			$0.00		$0.00				
7=(1+2)*Rider J rate	Proposed Rider J (%)						6.40%	$8.71	6.40%	$8.71
8=(1+2)*Rider R rate	Proposed Rider R (%)								6.50%	$9.41
9=Sum(1:8)	Total Before Tax Rebate, RSF/IER, GST			$139.57		$140.25		$148.96		$158.37
	Total Rate Charges excluding Rider F									
9A=9-3	Total Rate Charges excluding Rider F			$136.05		$136.05		$144.76		$154.17
	Change from last rate			*$0.15*		*$0.00*		*$8.71*		*$9.41*
				0.1%		*0.0%*		*6.4%*		*6.5%*

Table 4.2A-5
Yukon Bills - Recent Historical Comparisons - Non-Government General Service
(prior to consideration of subsidies, rebates and taxes)

Line #	First Block Energy Use - Customer Use per month:	2,000 kWh	Rates in place at															
			Before May 2008		May-08		Aug-08		Dec-08		Jun-09		Dec-09		Jan-10		Jul-10		Jul-11	
		5 kW			Rider F increase		YECL Rate Increase & Rider F increase		YEC Rate Decrease (interim Rider J)		Rider F, Rider G and Rider R change		Rider F		Rider F, Rider G and Rider R change		Rider F change		2009 Phase II GRA rates	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																			
1	Demand Charge (per kW per month)		$6.00	$30.00	$6.00	$30.00	$6.00	$30.00	$6.00	$30.00	$6.00	$30.00	$6.00	$30.00	$6.00	$30.00	$6.00	$30.00	$7.39	$36.95
2=KWh*Base rate	First Block Energy (kWh)		$0.0831	$166.20	$0.0831	$166.20	$0.0831	$166.20	$0.0831	$166.20	$0.0831	$166.20	$0.0831	$166.20	$0.0831	$166.20	$0.0831	$166.20	$0.1000	$200.00
3=KWh*Rider F rate	Rider F (kW.h)		$0.009638	$19.28	$0.0123	$24.60	$0.0186	$37.20	$0.0186	$37.20		$0.00	-$0.0039	-$7.80	-$0.0035	-$7.00	-$0.0009	-$1.80	$0.0035	$7.04
4=(1+2)*Rider G rate	Rider G (%)										4.15%	$8.13	4.15%							
5=(1+2)*Rider J rate	Rider J (%)		14.93%	$29.29	14.93%	$29.29	14.93%	$29.29	11.45%	$22.46	11.45%	$22.46	11.45%	$22.46	12.46%	$24.45	12.46%	$24.45		
6=(1+2)*Rider R rate	Rider R (%)						5.00%	$9.81	5.00%	$9.81		$0.00		$0.00	10.53%	$20.65	10.53%	$20.65		
7=(1+2)*Rider J rate	Proposed Rider J (%)																			
8=(1+2)*Rider R rate	Proposed Rider R (%)																	0.00		$0.00
9=Sum(1:8)	Total Before Tax Rebate, RSF, GST			$244.77		$250.09		$272.50		$265.67		$226.80		$210.86		$234.30		$239.50		$243.99
	Total Before Tax Rebate, RSF, GST (excluding Rider F)			$225.49		$225.49		$235.30		$228.47		$226.80		$218.66		$241.30		$241.30		$236.95
	Change from last rate					*$0.00*		*$9.81*		*$6.83*		*$1.68*		*$0.00*		*$22.63*		*$0.00*		*$4.35*
						0.0%		*4.4%*		*-2.9%*		*-0.7%*		*0.0%*		*10.4%*		*0.0%*		*-1.8%*

Note:
1. Rates for 2008-2010 are for Rate Schedule 2160, General-Service Hydro.

Table 4.2A-6
Yukon Bills– Existing vs. Proposed - Non-Government General Service
(prior to consideration of subsidies, rebates and taxes)

Line #	First Block Energy Use - Customer Use per month:	2,000 kWh	Rates in place at		Proposed		Proposed			
			Jul-11		May-12		Jul-12		Jan-13	
		5 kW	2009 Phase II GRA rates		Rider F		2012 Proposed Rates		2013 Proposed Rates	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates									
1	Demand Charge (per kW per month)		$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95
2=KWh*Base rate	First Block Energy (kWh)		$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00
3=KWh*Rider F rate	Rider F (kW.h)		$0.0035	$7.04	$0.0042	$8.40	$0.0042	$8.40	$0.0042	$8.40
4=(1+2)*Rider G rate	Rider G (%)									
5=(1+2)*Rider J rate	Rider J (%)									
6=(1+2)*Rider R rate	Rider R (%)									
7=(1+2)*Rider J rate	Proposed Rider J (%)						6.40%	$15.16	6.40%	$15.16
8=(1+2)*Rider R rate	Proposed Rider R (%)			$0.00		$0.00		$0.00	6.50%	$16.39
9=Sum(1:8)	Total Before Tax Rebate, RSF, GST			$243.99		$245.35		$260.51		$276.90
	Total Before Tax Rebate, RSF, GST (excluding Rider F)			$236.95		$236.95		$252.11		$268.50
	Change from last rate			*$4.35*		*$0.00*		*$15.16*		*$16.39*
				-1.8%		*0.0%*		*6.4%*		*6.5%*

TAB 5
CAPITAL PROJECTS

5.0 CAPITAL PROJECTS

The largest component of Yukon Energy's rate base is investment in capital works (property, plants and equipment), planning and study (feasibility) costs, and relicensing costs. This section provides an overview of Yukon Energy's actual capital spending since the 2008/2009 General Rate Application, as well as forecast capital spending for 2012 and 2013.

- **Overview of Capital Spending:** Provide a summary of the spending planned by Yukon Energy in the test years and beyond.

- **Capital Works:** Reviews the capital spending on property, plant and equipment, including a detailed discussion of the major projects over $1 million (undertaken from 2009 to 2011, and forecast to be undertaken in 2012 and 2013). Descriptions for projects in excess of $100,000 and up to $1 million forecast to occur in 2012 and 2013 are also provided.

- **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 2009 to 2013. Detailed descriptions for the major projects over $1 million are provided along with general descriptions of projects between $100,000 and up to $1 million.

5.1 OVERVIEW OF CAPITAL SPENDING

Yukon Energy's capital spending from 2009 through 2013 aligns with load growth and the need to re-invest in existing infrastructure.

As forecast in the 2008/2009 General Rate Application (GRA) and the Mayo Hydro Enhancement Project (Mayo B) Part 3 Application, Yukon Energy has had record levels of capital spending since 2009. Major legacy initiatives have been carried out to connect the WAF and MD grids and to enhance renewable hydro capability on the new integrated grid. This has resulted in the completion in 2011 of three major projects (Carmacks-Stewart Transmission Project (CSTP) Stage 2, Aishihik Third Turbine and Mayo B.

Coordinated with these initiatives, Yukon Energy has also completed projects to enhance safety and reliability at the existing Mayo, Aishihik and Whitehorse hydro facilities. As forecast, deferred cost expenditures also increased and included costs to assess Demand Side Management (DSM) planning,

update the 2006 Resource Plan, and identify and examine potential new near-term renewable and other generation development options to displace costly diesel generation that would otherwise be required to meet load growth after 2013.

In the test years, 74% of Yukon Energy projected spending on capital works ($47.6 million) is on major projects over $1 million ($35.1 million).

Yukon Energy's level of "normal" or ongoing spending on capital works, outside of such major projects, over the period 2009 (actual) to 2013 (forecast) varies from a low of approximately $5.4 million (2012) to a high of $10.5 million (2010) averaging $7.26 million per year. The average is higher than the average ongoing capital spending reports in the 2008/2009 General Rate Application hearing, which was approximately $5.1 million over the 2005 to 2009 period.

Deferred cost expenditures averaged just over $9.4 million per year from 2009 to 2011, and are projected at $9.7 million for 2012 and $6.9 million for 2013. The Application includes, for approval by the Yukon Utilities Board (YUB), several policies relating to deferring capital expenditures including Yukon Energy's Planning Cost Accounting Policy (Appendix 5.1) and its DSM Accounting Policy (Appendix 5.2).

5.2 CAPITAL WORKS

This section reviews (a) major capital works projects (projects over $1 million) undertaken by Yukon Energy since the 2008/2009 GRA hearing and planned for 2012 and 2013, and (b) ongoing capital projects costing between $100,000 and $1 million forecast to occur in the 2012 and 2013 period.

5.2.1 Major Projects Over $1 Million

Significant investment in new infrastructure and re-investment in existing infrastructure have been undertaken over the period since 2009 to ensure that Yukon Energy can continue to meet Yukon load growth in a safe and reliable manner. Major legacy initiatives have been carried out to connect the WAF and MD grids and to enhance renewable hydro capability on the new integrated grid (CSTP Stage 2, Aishihik Third Turbine and Mayo B). The current Application indicates an approximate $32.05 million growth in mid-year net rate base from 2009 approved to 2011 preliminary actual, with additional growth forecast of $61.7 million by end of 2013 (see Tab 7, Schedule 1). This is considerably lower than the gross rate base related to total assets added to the system over this same period of approximately $213 million (see Tab 7, Schedule 1). Notably, the three major projects (Mayo B, CSTP Stage 2 and Aishihik

Third Turbine) included approximately $128.5 million of third party contributions that reduced the overall impact on ratepayers.

Coordinated with these legacy development initiatives, Yukon Energy has also completed projects needed to enhance safety and reliability at the existing Mayo, Aishihik and Whitehorse hydro facilities.

Each major project is reviewed separately below (see also Tables 5.1 and 5.2 at the end of Tab 5):

- **Major near-term projects subject to prior major YUB review processes** - Net Rate Base increase of approximately $43.8 million related to approximately $172.3 million capital costs (approximately $128.5 million of government/YDC contributions) for projects in-service prior to December 31, 2011:
    - Carmacks-Stewart Transmission Line Stage 2 (net rate base cost forecast at zero as project costs of approximately $41.9 million are forecast to be offset entirely by federal and Yukon Government/YDC contributions).
    - Mayo Hydro Enhancement Project (Mayo B) Construction (net rate base cost forecast at $35 million as forecast project costs of approximately $116.6 million are forecast to be offset by federal and Yukon Government/YDC contributions of approximately $81.6 million).
    - Aishihik Third Turbine Construction (net rate base cost forecast at approximately $8.8 million, after $5 million Yukon Government contribution).
- **Major projects required to ensure system safety and reliability -** Net Rate Base increase of approximately $19.1 million:
    - Mayo Hydro – Substation Enhancements (forecast cost of approximately $10.15 million, to be completed in 2012).
    - Mayo Head Gate Repairs (forecast cost of $1.3 million, to be completed in 2012).
    - Aishihik Generation Station Redundancy (forecast cost of approximately $6.4 million, completion in 2011).
    - Whitehorse Spillway Improvements (forecast cost of $1.25 million).

- **Other major projects not related to mine grid connections** - Net Rate Base increase of $3.2 million related to Enterprise System (JDE):
    - Enterprise System (JDE) (forecast cost of $3.2 million, including JDE and Enterprise System Enhancement projects, to be completed in 2013).
    - Whistle Bend Subdivision Supply (forecast total spending of $5.23 million in the end of 2013, this project will not be in service before 2014 and therefore will not impact rates in the test years).
- **Mine grid connections to be offset by customer contributions** - No Net Rate Base Cost Impact ($10.0 million of capital cost offset fully by customer contributions).
    - Victoria Gold – Grid Connection (forecast cost of $9.0 million, to be fully offset by customer contributions).
    - Western Copper – Grid Connection (forecast cost of $1.0 million, to be fully offset by customer contributions).

5.2.1.1 Carmacks-Stewart Transmission Project – Stage 2

The Carmacks-Stewart Transmission Project was developed to connect the 138 kV Whitehorse-Aishihik-Faro (WAF) and the 69 kV Mayo Dawson electricity grids. It involved the construction of a new 138 kV transmission line between the WAF grid at Carmacks and the Mayo Dawson grid at Stewart Crossing and was undertaken in two stages.

- Stage 1 was completed and in service in October 2008, and costs the included in rate base were reviewed as part of the 2008/2009 General Rate Application.

- Stage 2 was planned on the basis of securing contributions sufficient to offset all capital costs, such that the project's capital cost would have no impact on Yukon Energy's rate base. Its justification and need (including related risks) were fully addressed in prior regulatory reviews before the YUB[1] including the 2007 CSTP Part 3 hearing.

In discussing this Project at the 2008/2009 GRA Yukon Energy noted the final engineering design, costing and tendering activities for CSTP Stage 2 were 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. A business case for the

project was requested during interrogatories and provided in response to YECL-YEC-1-8 REVISED. At the time it was noted that based on preliminary engineering done in 2007 the updated project capital cost estimate was $40 million (subject to risks related to final engineering requirements and receipt of construction contract tenders).

In 2009, on confirmation of federal and territorial funding, Yukon Energy commenced the planning activities necessary to construct the project in accordance with funding deadlines. The forecast cost was to be fully funded by a combination of federal and YDC contributions.

Update on Completion and Costs

The project was energized on June 16, 2011.

Project costs are not yet final. The present estimates of the final completion cots are approximately $41.9 million. The full $41.9 million is funded by the federal and Yukon government contributions and, accordingly, there is no impact to rate base and no impact on rates.

5.2.1.2 Mayo Hydro Enhancement Project (Mayo B)

The Mayo B Project involves enhancements to the existing Yukon Energy Mayo hydroelectric facilities in order to increase hydro generation capacity installed on the Mayo River from approximately 5 MW to approximately 15 MW, including the construction of a new powerhouse downstream of the existing powerhouse and the construction of related facilities, as well as adjustments to the management of water on the Mayo River system downstream of the existing Wareham Dam. The justification and need for the Mayo B project, including related risks and alternatives, has been fully addressed in prior submissions to the YUB[2].

In December 2009, Yukon Energy filed a Part 3 Application for Mayo B. The Application addressed all matters related to project description, economic analysis (including engineering and contractor cost estimates), discussion of alternatives and risks, and an outline of all relevant assumptions included in the business case, including description of the committed federal and territorial funding for this project. The

[1] CSTP Stage 2 was reviewed as a major near-term opportunity project in the 2006 20-Year Resource Plan. It was also reviewed by the Board in the 2006 20-Year Resource Plan, and the Minto mine Power Purchase Agreement hearings.
[2] Mayo B has been subject to numerous prior regulatory reviews. Supporting information regarding the project is available in the Mayo Hydro Enhancement Project (Mayo B) Proposal Submission filed with YESAB in February 2009. This project was also reviewed as one of a suite of available hydro enhancements in the 2006 20-Year Resource Plan (see Appendix B of that document), and was subject to more rigorous review as part of the 2008/2009 General Rate Application.

benefits of the Mayo B project were fully described in terms of forecast net generation (diesel displacement) under various grid load assumptions; commitments for YDC to provide flexible debt financing were also described to mitigate risks to ratepayers related to forecast grid loads.

At the time of the 2008/2009 GRA no final decision to proceed with the Project had been undertaken. Yukon Energy was in the midst of planning, consultation, environmental, engineering and other related activities to obtain authorizations and approvals necessary to allow for a decision to commence construction of the Project in 2010. During the interrogatory process a detailed business case for Mayo B was provided in response to YECL-YEC-1-5 REVISED.

Update on Completion Costs

The Mayo B project proceeded to construction in June 2010 following the Board's recommendation to the Minister arising from the Part 3 Application. The budget cost for the Mayo B project was $120 million (including $1.5 million for the Mayo Lake project licensing), with a forecast net rate base cost of $36.5 million after Yukon and federal government contributions.

The project was commissioned ahead of schedule in December 2011.

The project's completed cost is forecast at approximately $116.6 million (excluding the Mayo Lake project), or $1.9 million less than $118.5 million budget (excluding Mayo Lake project costs). The net rate base cost is forecast at $35 million, as project costs are forecast to be offset by federal and Yukon Government/YDC contributions of approximately $81.6 million.

As previously committed, flexible debt long-term financing has been secured by Yukon Energy from YDC to mitigate ratepayer risks related to costs exceeding 11 cents per kW.h (2012$) in any year for diesel generation displaced (see Attachment 5.3 of Appendix 5.3 for a review of this financing and a copy of the relevant Note).

5.2.1.3 Aishihik Third Turbine Construction

The Aishihik Third Turbine Construction Project adds a new 7 MW turbine at the existing Aishihik Generation facility. This new turbine provides added peaking capability and additional annual long-term average hydro energy supply at the existing Aishihik generation station through efficiency gains.

The Project was initially reviewed in the 1992 YUB Resource Plan hearing. Yukon Territorial Water Board and environmental approvals for the project were received in the Aishihik Water Licence (approved in 2002). The project was subject to further review in the 2006 Resource Plan and in the 2007 CSTP Part 3 Application. These prior regulatory reviews extensively evaluated the justification and need for the Aishihik Project, including related risks and alternatives and determined it to be an economically justified project that would provide net benefits to ratepayers[3].

The Yukon Utilities Board Recommendations to the Minister of Justice in its the 20-Year 2006 Resource Plan Report noted that the addition of the third turbine was considered a requirement driven strictly by economic reasons, i.e., to offset future diesel generation (and not a capacity requirement determined by the planning criteria).

Subsequently, on March 30, 2007, Canada announced $5 million 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 would be used for the Aishihik Project. In recommendations to the Minister of Justice following the Carmacks-Stewart Transmission Project Part 3 proceeding, it was noted 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"[4].

Accordingly, these new government funds allowed the project to proceed on an accelerated basis to provide net ratepayer benefits without waiting for new mine connection arrangements to be confirmed.

Update on Completion Costs

In May 2007, a Supplemental Filing to the Resource Plan updated preliminary cost estimates to $7.155 million (in 2005$) for a projected 2010 in service (it was noted that the estimate remained a projection without benefit of tendered prices).

In 2008/2009, as a result of a tendered process Yukon Energy retained AECOM Engineering (AECOM) to provide general engineering services to Yukon Energy. One of the first projects AECOM became involved

[3] This project was reviewed as a major near-term opportunity project in the 2006 20-Year Resource Plan and reviewed by the Yukon Utilities Board during the 2006 20-Year Resource Plan and each of the Minto mine Power Purchase Agreement and the Carmacks-Stewart Transmission Line Part 3 hearings. PV savings were estimated in Appendix C of the 2006 Resource Plan Report, and updated in the CSTP Part 3 hearing (Exhibit B-9).

[4] The Board recommended that "any government funding for the Aishihik Third Turbine be applied directly to rate base before consideration of any cost overruns or potential disallowances from the Board" and noted, "this view and recommendation is consistent with the view expressed by the Board in its 20-Year Resource Plan Report."

in was the Aishihik Project. AECOM provided a suite of project management services for the Aishihik Project, including design, overall project management and management of the tendering processes.

At the request of Yukon Energy AECOM prepared a preliminary cost estimate for budgeting purposes. Based on AECOM's estimate in August 2009 Yukon Energy set a budget of $8.810 million.

AECOM then prepared the relevant documents and issued separate tenders for rock removal, the turbine and the construction related work.

In February 2010, the construction related work was tendered and all bids came in at prices materially higher than the original estimate provided by AECOM. In discussion with AECOM – after an in depth review of the bids – AECOM acknowledged they had significantly underestimated the costs of the Project, and the bids more accurately reflected the magnitude of the Aishihik Project costs.

As a result of the high bids the tender process was cancelled. Instead, in conjunction with AECOM, Yukon Energy had discussion with two separate contractors in an attempt to refine the project scope and achieve lower costs. These discussions, however, did not materially alter the estimated project costs. Yukon Energy then had a separate discussion with Peter Kiewit to see if better pricing could be obtained but once again Peter Kiewit's pricing was not materially different than the original bids.

As a result of the higher estimated Aishihik Project costs, Yukon Energy undertook a review of the Project's feasibility. As a result of that review it was clear that the Project was still a beneficial project and accordingly a decision to proceed was made. In August 2010, the budget was adjusted upwards by $4.003 million to $12.813 million to reflect the more up to date project cost estimate.

The delays in securing a construction contractor for the project pushed back the start date by several months. As a result, in order to reduce increased cost impacts from extended fall/winter outages the construction schedule was split between 2010 and 2011.

The revised schedule also added risks of overlaps with outages planned for Mayo B in summer 2011. To minimize these risks and related cost impacts the Aishihik outages were coordinated with construction of the Mayo B project. Accordingly, the major penstock work and electrical tie ins were scheduled to occur in June 2011 with remaining electrical and commissioning work scheduled for completion following the Mayo outage work in October 2011.

After the turbine and construction related contracts were in place project scope changes had to be done to address additional design considerations identified by AECOM (i.e., add cooling facilities to the generator hall) and to address unforeseen adverse site conditions (i.e., higher rock excavation costs) that were more difficult than anticipated in the tender package. Issues were also experienced because the original runner supplied by the manufacturer was defective and a new runner had to be designed and fabricated.

As a result of all of these issues, YEC needed to commit considerable internal and external resources to keep the electrical work on track to ensure that the overall schedule for both Aishihik and Mayo B outages was not compromised.

The project came into service in December 2011.

Project costs are not yet final, however, the forecast completion budget cost as at the end of 2011 is approximately $13.8 million. Yukon Energy is still attempting to resolve a number of issues including final deficiency work with the contractor which may impact costs but after the $5 million contribution from the Yukon Government, the present estimate of the net rate base cost is approximately $8.8 million.

Despite higher overall costs than the original estimates, the project remains very attractive compared to the cost of diesel generation with overall NPV benefits to ratepayers as well as added benefits of securing a new major asset that increases the operating efficiency of the Aishihik facility. The project was forecast to be feasible with the Minto mine load and CSTP Stage 1 loads, which have both materialized. At the revised forecast net capital cost and a wide range of grid loads (i.e., 450 GW.h/year and higher) the levelized cost of energy (LCOE) for the project on its own approximates 9 to 11 cents/kW.h over an assumed 65 year economic life[5].

5.2.1.4 Mayo Hydro – Substation Enhancements

The Mayo Substation Enhancements project was undertaken to ensure system reliability and safety and to accommodate forecast loads.

[5] Assumed net capital cost of $8.8 million, and average cost of capital of 6.51%/year, with 8.77% cost of equity and 5.0% cost of debt; assumed O&M cost of $6/MW.h. Diesel displacement under long term average hydro availability exceed 4 GW.h/year over this range with no Mayo B (i.e., the Aishihik Project was committed prior to Mayo B being committed).

The Mayo Substation at 50 years old was in need of major refurbishment and upgrades to continue operating in a safe and reliable manner. The project addresses amongst other things the outstanding concerns documented in the June 2004 BC Hydro Engineering Report No Es94 and ensures that an appropriate level of service is maintained for Mayo 1 and 2 generators, Dawson and Elsa Transmission Line and the local Mayo town distribution.

Added to the requirement to refurbish the substation, many ongoing external changes on the Yukon grid required material re-investment be done to the Mayo substation to ensure that it is equipped and fully capable of addressing the fundamental changes to the grid system at this time, including:

- Interconnection of the Whitehorse-Aishihik-Faro grid and the Mayo Dawson grid through the completion of the Carmacks Stewart Transmission Project - Stage 2;
- Addition of a new generation station and generating capacity at Mayo (i.e., Mayo B)[6]; and
- Additional new industrial loads in 2010 (i.e., Alexco mine) and anticipated potential future loads (e.g., Victoria Gold).

Given the requirement to refurbish the substation, and impending new requirements on the system there was no option but to proceed with this project at this time.

Coordination with the various consultants and personnel working on the Mayo Substation, Mayo B and CSTP Stage 2 was undertaken to secure overall efficiencies for the project. This included coordination with BBA re: Mayo Hydro – Substation Enhancements, Wardrop on CSTP Stage 2, KGS on Mayo B, and Hatch on the system electrical study. This provided cost savings in design, equipment specifications and procurement.

A three year schedule for the project was designed to take advantage of outages required for the Mayo B Project and the future availability of Mayo B to eliminate further outages and associated diesel costs:

- Design completed in 2010/11;

[6] The Mayo B Part 3 Application noted that due to the range of non-Mayo B material planning considerations and requirements associated with this substation, engineering and construction for the substation was being addressed separately from the Mayo B Project (the Mayo B capital cost budget included a set assignment of $0.6 million towards the substation project to cover costs for a least cost Mayo B connection option involving a simple single tap to the bus with appropriate disconnects for isolation).

- Construction for the Mayo B intertie with the necessary 69 kV line work and all civil work completed in 2011; and
- Remaining substation work and ring bus to be completed in 2012, including new transformers for Mayo town feeder and transmission line to Dawson.

The spending profile over the three year period is projected to total $10.15 million:

- $0.163 million in 2010;
- $3.647 million in 2011(net of $0.750 million cost assigned to Mayo B Project); and
- $6.342 million in 2012.

5.2.1.5 Mayo Head Gate Repairs

The Mayo Head Gate Repairs project was undertaken to ensure plant reliability and safety.

The existing reinforced concrete intake at Mayo Generating Station was constructed in the 1950's[7]. In order to ensure continued safe and reliable operation it needed replacement and upgrading to address ongoing deterioration of the existing structure and to ensure the intake gate is brought into compliance with current standards.

An inspection of the intake gate in 2009 determined the following:

- The existing gate presented a safety concern and was not fit to provide continued safe access to the intake tunnel for inspections[8].
- There was extensive corrosion due to biological growth and submersion and considerable build up of debris within the gate members that would require replacement and upgrading of the gate, gate guides, and hoist.
- The existing gate design did not meet today's standards. Specifically, the existing gate was not capable of emergency closure under full plant flow, which is not desirable for existing Mayo GS

[7] The Wareham Lake intake structure controls flows into the Mayo Generating Station. The existing reinforced concrete intake at Mayo Generating Station was constructed in the 1950's and includes a trash rack and a steel bulkhead gate with timber slides operated using an overhead wire rope hoist within embedded and heated vertical steel gate guides. The gate is roughly 3.4 metres by 3.4 metres and is normally suspended below water level from the top of the concrete intake.

operation and not in accordance with CDA dam safety criteria required for the construction of the new Mayo B plant[9].

Accordingly, a new stoplog system was designed and fabricated during winter of 2009/10 and installed in spring 2010 to facilitate a detailed dewatered inspection of the intake gate guides and intake structure and tunnel. No other options were available to resolve the intake structure issue – as the only way to hold back water from the headgate while maintenance is underway is to install a stop log system. A headgate designed for no-flow conditions (i.e., to act as an isolation point) was not considered an option because it would not meet current design safety standards[10].

After the inspection a comparison of available options for an emergency closure system was reviewed and a preferred option selected. The gate has been designed, constructed and delivered to site; installation will occur during summer 2012.

In addition to addressing the intake gate issues identified above, it was recognized that failure to proceed with recommended work on the intake structure would delay YEC's ability to advance the Mayo B project on schedule, i.e., the need to meet appropriate safety standards for the work to tie in the Mayo B penstock to the existing intake.

Assessment of Options & Preferred Alternative

Four permanent head and head gate system options were selected for detailed examination by the project engineer. Evaluation criteria included performance, constructability, schedule impact, anticipated cost and construction and operational risk. The amount of underwater construction and reliance on unknown geometry were also significant factors.

The base case option provided a new slide type head gate, with a double acting hoist, operating on upgraded gate guides installed on the existing guides at the location of the existing gate to provide an enhanced level of service over the existing intake with the addition of emergency closure capabilities. This option had the lowest anticipated cost, posed the least amount of risk during construction and

[8] Historically, the gate has been used to facilitate inspection of the tunnel.
[9] This structure does not have a gate capable of closing in emergency conditions, and there are no stop logs or other means of shutting off flows other than a single bulkhead gate or the turbine inlet valves located in the penstocks immediately upstream of the Mayo powerhouse.
[10] Water retaining structures are required to be certified single block or double block and bleed arrangements.

required the shortest outage period[11]. Preliminary costs for this option including design and contingencies (but excluding any energy outage costs), were in the order of $1.2 million[12].

The base case was selected as the preferred option over the more complex two gate stoplog options[13] and more costly roller gate option[14]. It was concluded that the single gate would meet YEC's needs for construction isolation and emergency closure at a significantly lower cost than the other options.

Within the base case option, two alternatives were evaluated: a slide gate with a hydraulic hoist and a roller gate with wire rope hoists. Two fabricators were engaged to assist with the option definition and pricing.

Project Schedule Considerations & Impact on Project Scope

The project schedule required work to be undertaken during the period when Mayo A was shutdown to undertake the Mayo B intake tie-in. Further, because installation of the intake gate required extensive underwater work, concerns were raised by the Mayo B construction contractor that delays in the installation of the gate would result in increased shutdown time and possible delays to the overall schedule, resulting in increased diesel costs and a later completion date.

To address material concerns related to delay in Mayo B tunnel tie-in work and prolonged Mayo Plant shutdowns (and added diesel cost requirements) a temporary bulkhead gate was fabricated to facilitate the shutdown of work (consequently, this work could be undertaken without the new permanent intake gate in place and the intake gate work could be deferred until later in 2011 or 2012). This temporary bulkhead gate was placed in the existing slots with the wicket gates closed without any work required to the guides. The guide work was removed from the critical path in the fall of 2011 or in 2012, without risk to the overall coordinated schedule. The additional cost for the bulkhead was estimated to be approximately $200,000.

[11] The base option did not provide for dewatered in-place inspection of the entire intake gate, but would permit dewatered inspection of the downstream face. The entire gate can be periodically removed for a dewatered inspection at the surface.
[12] Other options considered were more complex and higher cost. This included two options that used a new stoplog system and a new roller-type head gate and wire-rope hoist at the existing gate locations, and an option that provided for a new roller-type head gate and wire top hoist downstream of the existing gate at the existing ventilation shaft and a new bulkhead gate in the existing head gate guides.
[13] A design check of the intake piers, walls and base slab indicated the existing reinforcement in portions of the intake was not adequate to withstand the full dewatered hydrostatic pressure that would arise with stoplogs installed as provided and as a result implementation of these options would require additional reinforcement by drilling the full height of the intake and grouting new bars into the piers and that the floor slab be core drilled for drains and later anchored to the ground using rock bolts.
[14] The implementation costs for Option 3 including design and contingencies (but excluding any energy outage costs) were in the order of $2 million.

The temporary bulkhead will be replaced with the updated gate and controls in 2012.

Assessment of Completion Costs

A placeholder value of $1 million was initially provided in September 2009 based on a very preliminary estimate provided by the engineer. The base option selected for implementation was estimated to be in the order of $1.2 million (with implementation costs, including design and contingencies (but excluding any energy outage costs). In order to mitigate schedule (and added costs risks related to additional diesel generation) a temporary bulkhead gate was added to the scope of the project with an estimated cost of $200,000.

Final costs for the project are currently expected to be $1.33 million (with $0.694 million spent before the end of 2011 and $0.640 million spent in 2012).

5.2.1.6 Aishihik Generation Station Redundancy

The Aishihik Generating Station is a key operating unit for YEC, being the largest winter producer and the only multi-year water (energy) storage for the Corporation. The Aishihik Generation Station Redundancy project was undertaken to rectify a very serious system reliability issue relating to redundancy identified as a result of a major system outage on January 29, 2006. This project became a top priority for the Company.

The January 29, 2006 event identified very serious security of supply issues to Whitehorse during peak winter times that needed to be addressed. The following is noted in this regard:

- On January 29, 2006 a major Whitehorse area blackout occurred when the outgoing feeder at the underground Aishihik powerhouse tripped off causing Aishihik Unit 2 to then trip off. This set of events resulted in the loss of both Aishihik units which were supplying 49% of the total WAF generation at the time. The loss of one or more units during periods of higher grid loads on the WAF system (i.e., winter) would be expected to result in a grid blackout[15].

[15] In the April 11, 2009 letter to the YUB re: January 29, 2006 outage response and reliability plans it was noted that loss of any one or more generating units on WAF can cause a grid black out when such individual generating units are supplying between 14% and 37% of the total grid generation (as occurred on January 29).

- The January 29 outage lasted approximately 3 hours (with some areas being without power for up to 15 hours)[16]. Additional diesel was required on WAF until February 6, 2006 and secondary sales were shut of until February 8. The Aishihik plant was synchronized to the system on January 31 at a derated output (of 19 MW) and fully restored by February 21.

- The cause of the fault at the Aishihik plant was determined to be a short in one of the power cables running from the underground powerhouse to the surface substation and there was no alternate route for power from the Aishihik station to be delivered to the transmission system.

- The main transformer (T1) also did not have isolation switches and in the event of a failure, the transformer could not be taken out of service quickly.

To address the material concerns raised by the 2006 outage, AECOM, in consultation with Yukon Energy management, designed the Aishihik Generation Redundancy Project.

The project provides for redundant electrical supply to the main power transformers, improves the protection for each transformer and results in installation of redundant power cables from the generating floor to the surface building. Now in the case of a cable failure in the main supply cables from the generating floor to the surface (as occurred in 2006), Yukon Energy can switch to the new cables and restart the station immediately. The project also ensures that a failed main transformer can be switched out to minimize the downtime of the station.

The design required a new 7 unit switchgear lineup[17] (able to quickly switch to the other set of cables) to be installed in a new building beside the existing service building at the surface[18]. A second run of cables was installed from the generator hall to the surface along with a new switch around power transformer T1. A bushing on transformer T3 was at end of life and was also replaced. A PT transformer and a set reactor cables at end of life were also replaced. The switchgear is up to date and able to provide more reliable protection of the generators and powerhouse system. A new Remote Terminal Unit was also installed and will provide the SCC operator with better visibility and control of the units.

This project was planned to be constructed on the same general timeline as the Aishihik Third Turbine installation.

[16] In the event of a problem, the main transformer at Aishihik Generating station must be physically disconnected which can take about three hours to complete. The installation of isolation switches contemplated by this project will reduce this time to minutes.
[17] The lineup includes a spare breaker and cubicle (not in the existing station).
[18] A new building was required to be built due to lack of available space in the generator hall.

In August 2009, based on AECOM preliminary estimates Yukon Energy set its preliminary budget at $2.9 million. However, when the construction contract was tendered, the bid prices came in materially higher than AECOM's preliminary estimates. The tender process was cancelled and direct discussions were held with individual contractors to determine if the project scope could be refined to reduce the cost of the project. This was not possible and as a result of these discussions the estimate had to be materially increased.

Some of the material challenges that caused difficulties in AECOM estimating the costs included necessary changes to the building location and design, additional grading and related costs for a retaining wall (to address contaminated soil and soil integrity), and changes in base metal prices which increased the cost of cables and cable tray. Further, due to the complexity and importance of electrical work additional Yukon Energy resources had to be committed to the project to advise, plan and lead the work.

With all relevant cost information now compiled, the forecast project cost estimate is now $6.356 million.

5.2.1.7 Whitehorse Spillway Improvements

Project History-Business Case

The Whitehorse Spillway Improvements project was undertaken to ensure plant reliability and safety.

The Whitehorse Dam, including the spillway and spill gates, over 50 years old and absent refurbishment/ upgrades in identified areas, the gates were becoming less reliable and more prone to failure. In an outage (or any other time Yukon Energy is required to spill large quantities of water), loss of control of the gates may cause overtopping of the dam.

The spillway and spillway gates were originally installed to act as an emergency release mechanism for occasional high water levels. Since the construction of the WH4 plant in 1985, which removed the spillway weir, these gates have become the primary lake level control device. As these gates were not built to regulate water flows on the Yukon River, 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. Consequently, the gates and surrounding structure is in need of refurbishment in several key areas to allow them to continue in their role as lake level and river flow control.

In May 2011, an external advisor was retained to prepare a condition assessment of the gates and identify areas where the spill gates need to be upgraded and related budgetary costs. In August 2011

spending was approved for a total budget of $1.350 million for activities to occur between 2011 and 2013. The total estimated cost for construction work was $0.096 million in 2011, $0.575 million in 2012 and $0.575 million in 2013.

The key areas where critical work was identified in order to correct deficiencies are as follows:

- Repair work related to the embedded sills on the spillway and the corresponding sill sealing surfaces at the bottom of the gates, as well as the sill heaters – Extensive replacement and repair work was recommended to keep water from leaking through the sills and causing further damaged to the sills and gate superstructure[19].

- Repair work related to heating within the gates to ensure the gains, rollers and gate surfaces remains free of ice for operation during the winter[20] – This work was recommended to reduce stresses on the gates and it was noted that if the work was not undertake there was risk of loss of control of the gates. It was recommended that Yukon Energy install water resistant heaters on the sides for gain heat and install double the amount of force fan heaters in the compartment to increase air flow and install additional venting[21].

- Improved bubbler systems on the upstream side of the gates to create an ice-free zone for the upstream gate surfaces – It was recommended that to increase surface turbulence and prevent ice buildup the air bubbler system be upgraded by installing a high volume system to create an insulation curtain in front of the gate[22].

- Improvements to the VFDs and gate close controls/switches, to ensure that the gates will close in a decelerating and controlled manner[23] – Extra stresses upon the gates and the superstructure, could result in loss of control of the gate and raise concerns related to reliability. To alleviate these concerns it was recommended that the gate weight be calculated with appropriate measures, the VFDs be set up so the gates can decelerate and close softly and that the cutoff jam switches be rewired so the gate cannot over torque upon closing[24].

[19] Budget Cost for this portion of work – ($20,000 for east gate and $15,000 for west gate).
[20] The side heat for the gains inside both the East and West gate is not working and the radiant heaters are no longer functional due to water damage.
[21] Budgeted cost for this portion of work – $200,000 for east gate and $200,000 for west gate.
[22] The bubbler system would also likely result in decreased heating costs for the gate's internal heater. Budgeted cost for this portion of work – $50,000 for east gate and $50,000 for west gate.
[23] The VFD's require setting up to the gate size to allow the gate to come down to a soft close in both manual as well as remote control. The jam switch also needs to be set up at the same time and its operation retested for correct protection of the gates.
[24] Budgeted cost for this portion of work – $15,000 for east gate and $15,000 for west gate.

- Replacement of the stainless steel staunching rods with brass or bronze rods to improve the sealing down the sides of the gates – Due to increased wear on the sealing surfaces it was recommended that the existing stainless steel staunching rods be replaced with softer material that will not damage the sealing surfaces[25]. Maintaining current conditions for the gate would allow water to keep leaking out the gate and cause further damage[26].

- Improvements to the gate structures themselves – The mechanical structure on both the east and west gates requires repair, including insulation work, work on corroded areas, and work to compartment end seams to improve the water tight integrity of the gates. If repair work is not undertaken water will continue to leak into the compartments causing further long-term damage, a shorter gate life and failure in service[27].

- General miscellaneous work including protective log booms, water deflectors and other small work[28].

The current forecast capital cost for this project as provided in Table 5.2 is approximately $1.25 million, slightly less than the $1.3 million budget approved in August 2011.

5.2.1.8 Whistle Bend Subdivision Supply

With the development of a major new subdivision in Whitehorse (Whistle Bend Subdivision) Yukon Energy has undertaken, in collaboration with YECL and the developer, a review of how Whistle Bend should be connected to the system to ensure adequate supply and overall system reliability and protection. Preliminary review indicates this will be a major capital project costing upwards of $12 million depending on system reinforcement requirements. This project will not be in service before 2014 and therefore will not impact rates in the test years. Further review of the issues (including the need for developer or customer contributions), and a refinement of project costing is planned for 2012 with project construction forecast to commence in 2013. Although more refined estimates will be available after the 2012 review is completed, spending on this project is forecast at $50,000 in 2012 and $5 million in 2013.

[25] It was also recommended that new manufactured staunching rods be purchased and the sealing surfaces on the gate gains be repaired to ensure a good seal.
[26] Budgeted cost for this portion of work – $80,000 for east gate and $80,000 for west gate. Water losses through the gate system will also result in less hydro generation and greater diesel generation requirements.
[27] Budgeted cost for this portion of work is $250,000 for the east gate and $190,000 for the west gate.
[28] Budget cost for this portion of work is $20,000 for the east gate and $20,000 for the west gate.

5.2.1.9 Enterprise System (JDE)

Overview

The project encompasses the replacement of Yukon Energy's current JDE enterprise business system (on which Yukon Energy's financials, inventory management and procurement functions are operating)[29] with an integrated system that includes a computerized maintenance management system (CMMS) module for Operations which is currently operating manually.

The supplier has stopped support for the existing system and since 2002, Management has not re-invested in large scale upgrades, recognizing that a more comprehensive solution is required and system replacement is necessary in the near-term[30,31].

In sum, the current system is at its end of life[32] and not adequate to address the ongoing operational and management challenges facing Yukon Energy during this period of development and growth in Yukon[33]. Further, an additional level of detail for bookkeeping practices will also be required by the adoption of International Financial Reporting Standards. Implementing the new system at this time will accommodate the new requirements at set-up, as opposed to a more-complicated retrofit of the existing database.

History of Information before YUB

In 2008, a Financial Information System (FIS) project was established to source a replacement system for the current JDE system. A business case supporting the decision to replace the JD Edwards system was provided in the 2008/2009 General Rate Application in response to YECL-YEC-1-35 REVISED.

Yukon Energy included in the 2008/2009 GRA provision for Financial Systems Software Replacement [$125,000 (2008) and $450,000 (2009) and $425,000 (2010) (Competed in 2010)]. The replacement system was planned to be owned by Yukon Energy, with Yukon Energy providing YDC with accounting

[29] The JD Edwards Financial software package was originally installed in 1999 (at a total cost of approximately $1.413 million). See response to YECL-YEC-1-35(a) REVISED provided during the 2008/2009 GRA. The response to YECL-YEC-1-33 from the same hearing indicated approximately $10,000 per year is spent on JD Edwards licensing for the finance department.
[30] A Business Impact Assessment, dated January 2006 noted the JD Edwards financial system is not fully utilized, and as a result of failed attempts by YEC to modify the system to fit its operations, YEC finds itself with a sub-optimal JD Edwards configuration and the system is not used for the tasks required of it.
[31] See YECL-YEC-1-35(b) REVISED provided during the 2008/2009 GRA.
[32] Since the initial install, numerous issues with the software configuration have prevented optimum functionality, and system capabilities are minimally used and supported with manual processes for validations, reconciliations and the compilation of reports.
[33] For example, the current system that has been in use for many years for Maintenance is based on verbal instructions and undocumented expert knowledge and experience of certain key operations personnel. Adhoc files/spreadsheets are maintained by

services on a cost recovery basis, including use of the replacement financial software package[34]. It was noted that Management planned to complete a replacement system needs assessment and a product review, and present recommendations with implementation to commence in 2009 and completion by mid-2009.

Product Selection Process

The FIS project team commenced with a "current and future state" study, by interviewing key users from various business areas on current processes, deficiencies and issues including expected improvements to establish the 'future' state. Prior to the RFP, an Expression of Interest (EOI) document was issued to survey the marketplace for potential solutions. Subsequently the RFP was issued to 11 vendors of which 4 software product proposals were received.

The proposals were reviewed on product fit, price, vendor reputation, availability of support and compliance to YEC's current technology platform. One was eliminated due to non-compliance with YEC's technology platform. One was eliminated on price as it was deemed an expensive solution with a lot more built-in functionality than what YEC needs. The product fit and price point was deemed acceptable for both Microsoft Dynamics GP and Oracle's EnterpriseOne and these were shortlisted to proceed with product demonstrations. From the demonstrations, Microsoft Dynamics GP scored favorably over Oracle. Reference checks were subsequently conducted on the products chosen and the feedback in general was positive.

As a result of the FIS system sourcing project, the recommended solution was to replace the current JDE system with a combination of projects from Microsoft Dynamics and the Wennsoft suite of projects. Notably, the Wennsoft suite of projects is tightly and seamlessly integrated to dynamics GP which meets YEC's system objective of an integrated business system.

Total cost of the selection process was approximately $300,000.

Determination to Proceed with Replacement of Enterprise Business System Roll Out #1

Costs to the end of 2010 were $0.4 million.

individuals to facilitate their own work. A register of all the company's assets at a level of detail conducive to maintenance is non-existent.

[34] Per IR PWP-YEC-1-31 from 2008/2009 GRA.

In December 2010, Yukon Energy approved the purchase and implementation of a replacement financial information system and complementary computerized maintenance management system with a budget of $2,143,774. The budget was for Roll-out #1 (related to implementation of the GP Financial Modules which include General Ledger, Accounts Payable, Accounts Receivable (non-CIS), Fixed Assets, Procurement and Inventory Management, Wennsoft Modules for Job Cost and two plants for Maintenance tracking and scheduling).

Roll-out 1 is now estimated to take approximately 10 months with the post-2010 budget of approximately $2.83 million (total projected cost, including costs to the end of 2010, is $3.24 million). Installation of software has been completed, maintenance and core financial test review was conducted in August 2011 with completion of Roll-Out #1 expected to be completed by April 2012. The timing and scope of subsequent roll-outs will be dependent, in part on the work done in Roll-Out #1 and will be brought forward separately.

5.2.1.10 Victoria Gold – Grid Connection & PPA - $2 Million (2012) and $7 Million (2013) Offset by Matching Contributions

The Project Proposal filed with YESAB (December 2010) to develop the Eagle Gold [Dublin Gulch] property (near the McQueston River) includes a grid connection and expected in service date in late 2014. In order to connect the mine to the Integrated Grid, planning, permitting, design and construction for a 69 kV connection from L250 transmission line near Elsa to Eagle Gold property must be undertaken. The length of the power line is expected to be between 30 to 45 km, depending on the route selected, with a substation at the mine site.

The scope or the project includes negotiating a Power Purchase Agreement (PPA) with Victoria Gold, design and permitting of line and substations and construction of grid connection. Based on the system extension policy for industrial customers the customer contribution will fully cover all costs for these activities.

Preliminary engineering activities were undertaken during 2011 to identify connection alternatives and upgrades required to the L250 line in order to supply Victoria Gold. Anticipated costs to develop this grid connection include: (1) preliminary assessment of power line route options, permitting and design standards; and (2) costs of developing and negotiating a PPA with Victoria Gold. Assuming the project proceeds these costs will be fully recovered from the mine pursuant to the system extension policy

approved by Order 2010-13 and implemented regarding prior industrial connections (Minto mine and Alexco mine). If the mine does not proceed, these costs will be written off as feasibility costs.

Yukon Energy has signed a Letter of Intent (LOI) with Victoria Gold (dated February 1, 2011) that sets out the essential elements of the PPA and other agreements to be negotiated, executed and delivered between YEC and Victoria Gold for supply of electricity by YEC to Victoria Gold at the mine. The PPA with Victoria Gold will set out terms and conditions for Victoria Gold to pay YEC for all of YEC's costs (net of any contributions or approved YUB recovery from ratepayers) related to planning, ownership, installation, maintenance, operation and (to extent required) decommissioning. Electricity provided by YEC through the grid connection to Victoria Gold will be charged to Victoria Gold in accordance with applicable Rate Schedules.

5.2.1.11 Western Copper Grid Connection & PPA - $1 Million (2013) Offset by Customer Contribution of $1 Million (2013)

Western Copper has requested a grid connection from the CSTP Stage One to its planned mining project at the Carmacks Copper mine site. In order to connect the Carmacks Copper mine to the Integrated System, a new spur line connecting the mine with the CSTP Stage One will need to be licenced and constructed, and Yukon Energy will need to have concluded a PPA with Copper North Mining Corp. that is then reviewed and approved by the Yukon Utilities Board. Funds budgeted for 2013 will be used for the necessary planning, engineering, permitting/YESAA review and negotiation of a PPA. Based on the system extension policy for industrial customers the customer contribution will fully cover all costs for these activities.

5.2.2 Projects $100,000 to $1 Million

Growth in net rate base reflects an ongoing need to refurbish old assets and improve grid reliability. Significant re-investment in existing infrastructure has been undertaken since 2009 to ensure that the Yukon integrated grid can continue to meet the unprecedented level of growth on the system in a safe and reliable manner

Total spending on property, plant and equipment from 2009 to 2011 for projects less than $1 million averaged $7.9 million. The ongoing capital works spending on property, plant and equipment is forecast at $5.426 million, for projects added to rate base in 2012 and $7.107 million for 2013, as set out in

Table 5.1 (with details in Table 5.2); forecast customer contributions related to these capital works is $0.4 million (excluding contributions for major projects) for each test year.

- **Generation Projects** ($2.416 million in 2012 and $3.012 million in 2013) - Generation project expenditures forecast in 2012 and 2013 include small projects under $100,000 (totaling $0.085 million in 2012 and $0.175 million in 2013). Spending on generation projects is focused primarily on needed reliability improvements (to upgrade or replace deteriorated infrastructure required for continued safe and reliable operation of the existing hydro and diesel plants) and business improvements (to enhance operation of the generation plant through upgrade or replacement of deteriorated infrastructure).

  There was approximately $10.778 million in spending on generation projects $100,000 to $1 million prior to 2012 (2009 to 2011) with $6.571 million spent on reliability improvements and $2.539 million spent on business improvements. The balance of other spending prior to 2012 included spending on projects to ensure safety, demand and other.

  Approximately $1.215 million of total forecast spending in 2012 is required for reliability purposes while approximately $2.387 million of total forecast spending in 2013 is required for reliability purposes. The balance of spending in the test years is focused on business improvements: approximately $0.965 million in 2012 and approximately $0.300 million in 2013. Key areas of spending were as follows:

  - **Hydro Plant** – Improvements undertaken at all hydro facilities include installation of new oil filtration systems on the hydro governor to reduce wear and tear; installation of hydro unit platforms for working in draft tubes to provide a safe working surface; and dam water barriers to ensure public safety.

    - **Mayo Hydro facility and Wareham dam reliability and business improvements** – At Wareham Dam, improvements required to upgrade the Wareham spillway gates; at Mayo Hydro plant, improvements to install jackscrews on the spill gates to ensure continued reliable operation.

    - **Aishihik business improvements** – Include provision for icing studies and mitigation work to address effects of Aishihik operation on infrastructure downstream.

- **Whitehorse reliability and business improvements** – Replacement of deteriorated gear boxes better able to tolerate the manner in which the plant is operated; rebuild of the P 125 track rack and trash rack heating system that is at end of life; and replacement of end of life commutator at WH1 and WH2.

o **Diesel Plant**

- **Faro** – Extensive reliability and other improvements are to be undertaken on the Faro diesels in the test years to replace damaged equipment or to modernize and upgrade existing equipment to ensure that the diesel generation units can be run more efficiently to provide reliable back up generation on the integrated grid. This includes improvements to facilitate load sharing and to facilitate remote control capability.

- **Whitehorse** – Improvements at the Whitehorse diesel facility includes replacement of fuel tank and base at the plant to avoid potential failure and improve storage capacity.

- **Mayo** – Spending in the test years includes SCADA connection to allow units to be run remotely in order to provide required back up generation on the integrated grid.

- **Transmission Projects** ($1.248 million in 2012 and $1.170 million in 2013) - Transmission project expenditures forecast in 2012 and 2013 include routine spending on projects under $100,000 (none in 2012 and $0.020 million in 2013).

There was approximately $4.266 million spent on transmission projects $100,000 to $1 million prior to 2012 (2009-2011), with nearly 80% of such spending required for reliability purposes (other spending included business improvements and legal/regulatory compliance requirements).

Spending on transmission projects in the test years is focused almost exclusively on reliability. Spending in the test years includes ongoing programs to identify and replace poles, cross arms and insulators that are in the worst condition on the WAF and MD grids as well as ongoing transmission pole test and treat program. Other transmission improvements include a stubbing program on L 171, L 172 and L 169, a line switch replacement on L 172 and improvements to the Dawson P158 T1/T2 transformer. A review of all substation protection and control systems is also being undertaken to ensure a consistent standard is applied for continued operations (specific improvements are also being undertaken at Little Salmon PT substation).

- **Distribution Projects** ($0.720 million in 2012 and $1.025 million in 2013) - Distribution project expenditures forecast in 2012 and 2013 include no routine spending on small projects under $100,000.

  There was approximately $1.69 million in spending on distribution projects $100,000 to $1 million prior to 2012 (2009-2011). The majority of spending was to meet service requirements with the balance of spending on reliability and business improvements.

  Distribution projects in the test years needed to meet continued service requirements are forecast at approximately $0.475 million of spending in each test year (with $0.400 million customer contributions in each test year). Distribution projects in the test years also include the Faro mine connection (for the site abandonment plan, with costs expected to be offset by customer contribution), a new three phase distribution line at Dawson Dome, ongoing work to secure easements for distribution lines, and requirements for new customer extensions.

- **General Plant and Equipment Projects** ($1.043 million for 2012 and $1.900 million for 2013) - General plant and equipment project expenditures forecast in 2012 and 2013 include small projects under $100,000 in each year (totaling $0.578 million in 2012 and $0.265 million in 2013).

  There was approximately $3.427 million in spending on general plant and equipment projects $100,000 to $1 million prior to 2012 (2009-2011). Approximately 85% of this amount was for business improvements with the balance of spending on reliability, legal/regulatory compliance requirements, and safety.

  Spending in the range $100,000 to $1 million on general plant and equipment in the test years is focused on business improvements, with $0.465 million forecast spending in 2012 and $1.635 million forecast spending in 2013. Projects undertaken in the test years include improvements at the Lewes Control structure to upgrade the fish ladder and boat lock (which are at end of life) and installation of a repeater in the Tintina trench area to improvement communications for YEC staff. Other business improvements include an interactive safety and environmental video and online orientation and compliance process, a disaster recovery plan and business continuity development plan, electronic document management system, network improvements, security risk management and vehicle purchases. Safety improvements include installation of fall restraint or arrest systems for all facilities.

Appendix 5.4 provides a description (including need for and justification) of each of the projects in property, plant and equipment with spending greater than $100,000 million and less than $1 million total cost to be included in rate base in the test years.

5.3 DEFERRED COSTS

This section reviews (a) major deferred cost projects (projects over $1 million) and (b) other deferred cost projects between $100,000 and $1 million, undertaken by Yukon Energy since the 2009 General Rate Application, focusing on the 2012 and 2013 period.

Deferred costs during the 2009 to 2013 period reflect Yukon Energy's work to identify and examine potential new near-term renewable and other generation development options to displace future diesel generation that would otherwise be required to meet load growth.

Deferred costs include activities to examine major new generation options (e.g., feasibility studies regarding Marsh Lake Storage and Gladstone Diversion hydro projects, wind at Ferry Hill, waste-to-energy and district heating options, and LNG), continued relicensing work on the Mayo Lake Storage Enhancement Project (Mayo Lake Relicensing), rate case work on DSM and the update to the 2006 Resource Plan. Ongoing deferred cost activities are also included to address other rate case, relicensing, deferred overhauls, and feasibility study costs.

The Application includes, as Appendices to this section for approval by the YUB, Yukon Energy's Planning Cost Accounting Policy (Appendix 5.1) and DSM Accounting Policy (Appendix 5.2) to address amortization of these costs for regulated revenue requirement purposes.

5.3.1 Major Projects Over $1 Million

Yukon Energy must continue to plan to meet potential future loads (both expected near-term developments as well as over the longer term) in a cost effective manner that ensures continued reliable and low cost supply that is also environmentally responsible. In this respect, Yukon Energy cannot wait until loads develop with full certainty before commencing the required planning and studies work to develop new sources of supply, but must advance such work to ensure projects can be developed on timelines sufficient to meet new loads or are "shelf ready" (i.e., planning and studies work completed and licences obtained) such that a final decision to proceed can be made and construction commence when new loads are committed.

In order to ensure sufficient generation and transmission capability to meet growing power requirements on the integrated grid, without relying only on high cost diesel generation, Yukon Energy has carried out extensive feasibility and planning work to assess potential options for reducing diesel generation that would otherwise be required to supply future load growth. The nine major deferred cost projects (excluding 2012-2013 GRA rate case deferred costs) undertaken by Yukon Energy since 2009, each with costs in excess of $1 million over the period 2009 (actual) to 2013 (forecast), have total projected costs of approximately $23.91 million by the end of 2013. Projected third party contributions offset $1.48 million of these costs. Each major project is reviewed separately below (see also Tables 5.3-5.7).

Progression through the planning process on each major deferred cost project has been carefully monitored and controlled by staged approvals for expenditures that apply to each project phase. In effect, each phase requires an approval to define the scope of work and the deliverable to be completed before progressing to the next stage. During the planning phase ongoing assessment may determine that a project is not economic based on current conditions – in the event that a project is deemed uneconomic at the end of a planning phase, work would be delayed until suitable conditions arise and the project is considered economically feasible. If, and when, a project successfully progresses through the planning and feasibility phase and procures necessary regulatory approvals it will advance (where appropriate, and subject to final tenders and other required approvals) to the construction stage.

Due to the unprecedented levels of planning costs incurred since 2009, a new planning cost accounting policy (provided in Appendix 5.1 to Tab 5) is included in this Application to ensure that these costs are addressed and included in rates in a manner that moderates near-term rate impacts for ratepayers.

Deferred cost projects over $1 million are divided into the following types of projects:

- Planning & Feasibility, Relicensing and Rate Case projects related to future diesel generation displacement, including:
    - **Hydro Enhancements (identified in 2006 Resource Plan)** – Since 2006, Yukon Energy has continued to focus on cost effective projects to enhance output of existing hydro generation facilities at Aishihik, Whitehorse and in certain cases, Mayo. During the 2008/2009 General Rate Application Marsh Lake was described as one of a number of potential hydro enhancements that could be developed at an attractive cost compared to developing new greenfield hydro (or other) supply options. Notably, the key risk associated with development of small hydro enhancement projects in Yukon Energy's

inventory relates not to the economic justification for the project, but to the schedule risks related to planning and licensing requirements.

For the current test years approximately $13.55 million in deferred cost is forecast to go into rate base by the end of 2013 for the following hydro enhancement projects:

- **Marsh Lake ($4.8 million)** – Spending to end of 2011 of $3.23 million with forecast spending in 2012 of $0.800 million; amounts deferred to the end of 2012 will be closed and amortized over 10 years starting in 2013. Spending in 2013 to go into rate base is forecast to be $0.800 million.

- **Gladstone ($4.4 million)** – Spending to end of 2011 of $3.69 million with forecast spending in 2012 of $0.200 million; amounts deferred to the end of 2012 will be closed and amortized over 10 years starting in 2013. Spending in 2013 to go into rate base is forecast to be $0.500 million.

- **Atlin ($2.2 million)** – Spending to end of 2011 of $2.23 million with no further forecast spending; amounts deferred to the end of 2011 will be closed and costs amortized over 10 years starting in 2012.

- **Mayo Lake ($2.1 million)** – Spending to end of 2011 of $1.46 million on relicensing with forecast spending in 2012 of $0.66 million. The project is forecast to be completed by the end of 2012 or early 2013 and will be amortized over the term of the Mayo Generation Facility Water Use Licence.

o **Other Near-term Generation Options** – $6.81 million of net spending (after contributions) is forecast to go into rate base by the end of 2013 on other potential near-term opportunities that are being explored as potential options to meet near-term grid load diesel displacement (a further $1.7 million of related deferred costs are forecast to go into WIP during this period).

- **Demand Side Management (DSM) ($3.746 million less $0.735 million contributions)** – Spending to end of 2011 of $1.037 million (offset with $0.735 contribution), forecast spending in 2012 of $1.074 million and forecast spending in 2013 to go into rate base of 1.635 million. Amounts each year are forecast to be closed at end of year and amortized over ten years pursuant to the DSM Accounting Policy provided as Appendix 5.2.

- **Waste to Energy/Biomass ($1.853 million less $0.225 million contributions)** – Spending to end of 2011 of $0.741 million with $0.113 million offsetting contributions and forecast spending in 2012 of $0.613 million with $0.113 million offsetting contributions; amounts deferred to the end of 2012 will be closed and amortized over 10 years starting in 2013. Spending in 2013 to go into rate base is forecast to be $0.500 million.

- **District Heating ($1.03 million less $0.53 million contributions)** – Spending to end of 2011 of $0.070 million (with $0.53 million contribution) with forecast spending in 2012 of $0.460 million and spending in 2013 forecast to be $0.50 million (to be closed and amortized over 5 years starting in 2014 pursuant to the Planning Cost Accounting Policy).

- **LNG ($1.669 million)** – Spending to end of 2011 of $0.169 million with forecast spending in 2012 of $1.500 million. It is expected that this project will meet reasonable assurance before the end of 2012, with costs then carried in fixed assets WIP beyond 2012 (Table 5.2 forecast in 2013 shows a further $1.0 million expenditure in 2013 plus transfer of $1.669 million from feasibility study costs).

o **Long-Term Generation Options** – $2.6 million of forecast spending to go into rate base by the end of 2013 is focused on appropriate planning activities required over the near-term to protect the ability to proceed with potential longer-term legacy resource development options when loads are sufficient to justify proceeding.

- **Geothermal ($2.6 million)** – Spending to end of 2011 of $1.95 million (with amounts deferred to the end of 2011 closed and amortized over 10 years starting in 2012) and forecast spending in 2012 of $0.386 million (with amounts closed out at end of 2012 and amortized over ten years), and forecast spending in 2013 of $0.30 million (to be closed and amortized over 5 years).

• Expense related to costs for the 2012-2013 GRA regulatory review processes including reimbursement of related intervenor and YUB costs.

o **GRA Phase 1 Review** – An estimated placeholder expense of $1.100 million related to costs for the current GRA Application, anticipated to be incurred over 2012 and 2013 for

preparation and review of the Application and reimbursement of related intervenor and YUB costs, to be amortized over the 2 test years (2012 and 2013).

The justifications for deferred amounts to be included in rate base over the test years are reviewed below.

5.3.1.1 Marsh Lake Storage – Total Deferred Costs of $4.830 Million to end of 2013

The Marsh Lake Storage Project is a cost effective means of enhancing winter capacity and energy available to the Whitehorse Rapids Generation Station in order to displace higher cost diesel generation that would otherwise be required.

The business case for the Marsh Lake Fall/Winter Storage Project (then estimated at about 1.6 MW; 7.7 GW.h/year) was reviewed as part of the 2006 20-Year Resource Plan[35]. In its report and recommendations to the Minister of Justice regarding the 2006 20-Year Resource Plan, the YUB noted that, "[it] sees some viability to this project in terms of either displacing diesel generation or delaying future capacity additions" and recommended the project be retained in the Resource Plan but removed as a near-term project (i.e., at that time "near-term" referred to commitments by 2009 to meet loads out to 2012)[36].

Project Concept and Changes since 2006 Review

Yukon Energy currently has a control structure at the outlet of Marsh Lake to hold back water in the fall. The Marsh Lake Storage concept involves capital improvements on the Lewes Lake control structure and an amendment to Yukon Energy's current water licence in order to hold back up to an additional 0.3 m of water in Marsh Lake in the fall and withdraw the water over the winter time. This will provide additional winter generation and an increase of winter hydro capacity at the Whitehorse Hydro facility.

On November 9, 2006, YEC provided an update to its Resource Plan and withdrew the Marsh Lake Fall/Winter Storage project. Local resistance, shoreline erosion, high fall water-level impacts in low lying

[35] As scoped during the 2006 Resource Plan, the project involved seeking changes to the Whitehorse Rapids water licence to allow Yukon Energy to reduce the amount of water it releases from Marsh Lake in non-flood years from August 15 to the end of September, to allow that water to be used instead during the peak winter generation period (during flood years, no change would be made during August and September, until after flood levels subside). In all cases, the water levels would remain within the lake level limits currently experienced (i.e., the peak controlled level would be below the natural high water levels experienced in the lake). No new physical works were expected to be required.

areas, and related impacts to the environment were reasons given for the withdrawal. YEC felt that these concerns could not be addressed in the near-term. However, Yukon Energy continued to consult with the residents of Marsh Lake to develop a further understanding of the natural causes of high water levels on Marsh Lake,[37] and by the 2008/2009 GRA work on the project had proceeded again with forecast spending in the 2008/2009 Test years[38].

As currently understood, the main changes in the project since the 2006 Resource Plan review are slight reductions in expected project benefits (i.e., now forecast up to 6.7 GW.h/year of increased winter hydro generation, based on long-term average hydro, and approximately 1 MW of added winter hydro capacity) and materially higher forecast project costs (primarily due to forecast mitigation measures as reviewed below).

Project Risks, Costs and Benefits

A tender process was undertaken in 2009 to engage a third party consultant to provide project management services and integrated engineering, environmental/socio-economic and related technical consulting services for all three southern lakes projects (Marsh Lake Storage, Atlin Storage and Gladstone Diversion). It was expected that having one consultant firm providing bundled planning and assessment services that included project management, engineering and assessment would simplify and streamline the feasibility and assessment process and also provide for economies of scale (e.g., site investigations and other work for all projects could be carried out in an efficient and coordinated manner).

Planning and feasibility costs to the end of 2011 are $3.231 million with forecast spending over the test years of $1.6 million (total projected deferred cost of $4.83 million, with $4.03 million into rate base at the end of 2012 to be amortized over 10 years, and the balance of these costs to be incurred in 2013). The third party engineering, environmental assessment and project management components of the project comprise the majority of the project costs to date (approximately $2.9 million of the total $3.2 million to date). Specific activities that make up the costs incurred to date include:

[36] "Near-term" requirements in the 2006 Resource Plan were defined as "Yukon Energy generation and transmission commitments required before 2009 for major investments with anticipated costs of $3 million or more. Given the time needed for possible construction, the assessment examines possible in-service needs to meet loads out to 2012".
[37] Local residents of Marsh Lake also indicated what bio-physical aspects of Marsh Lake may need to be studied in order to assess the environmental and socio-economic effects of storing more water in the fall of each year after the peak water levels start to drop.
[38] See response to PWP/HML-YEC-1-40 from the 2008/2009 GRA.

- **Public Consultation** – Due to the significant public concern Yukon Energy engaged extensively with the local residents of Marsh Lake and the local First Nation in order to keep them informed on issues of concern and on progress with the project. This included meetings with individuals, public meetings and two separate workshops to review in detail issues of concern raised by local residents. Yukon Energy also brought in knowledge experts to explain the effects of the project on lake levels.

- **Extensive work on shoreline erosion and groundwater issues** – Due to identified public concern a significant amount of environmental studies have been undertaken to understand the effects of shoreline erosion and groundwater issues. This included extensive mapping of most of the shoreline of Marsh Lake and Tagish Lake, installation of piezometers around the lake and comprehensive work to define areas susceptible to erosion.

- **Hydraulic modeling** – Of southern lakes was undertaken in order to understand the relationships between the lakes and the water flows between the lakes.

It is not expected that there would be significant physical or environmental effects due to the project; however, given notable public concern regarding the project it is expected that the planning and permitting processes will be complex with potential for delay in the regulatory review and permitting process and risks related to increased regulatory costs (including mitigation cost requirements beyond those currently estimated).

In summary, spending on planning and feasibility activities over the 2009 to 2013 period relates to work required for engineering and environmental studies, with subsequent expenditures on planning and permitting activities (to address YESAA, YUB and YWB review and permitting processes).

It is currently expected that a YESAB project proposal can be filed in early 2013 (with a Designated Office level review). Once the Designated Office review is completed and decision documents issued a Yukon Water Board application would be filed to amend the current water licence. It is currently expected that these review processes could be completed before the end of 2013 or early in 2014. Mitigation work would be undertaken in the summer of 2014 and the earliest in service date would be the fall of 2014. Spending in 2012 and 2013 is expected to relate to completion of baseline work, effects assessment and mitigation design and preparation and filing of the YESAB DO submission. The 2013 budget will cover the YESAB review process and water licence amendment hearing process.

By the end of 2012 it is anticipated that a decision will be made on proceeding with the project (i.e., whether to proceed to secure licensing and approvals, and then commence construction). The forecast cost to complete the project is currently estimated at $10.5 million with mitigation design (shoreline erosion and surface water) expected to comprise about one-half of this total cost. However, at this time the actual costs for mitigation cannot be known with any certainty. It is also expected that if the project proceeds that construction costs will be incurred to revise the control structure at Lewes Bridge and to cover mitigation costs (to address shoreline erosion and higher groundwater levels anticipated due to higher water levels during fall months).

Full Utilization LCOE (2010$) is estimated at 8.5 cents per kW.h, assuming a capital cost (2010$) of $10.5 million, annual generation of 6.4 GW.h on average over a 65 year life, focused in winter months at current Whitehorse plant, and annual operating cost (2010$) of $8/MW.h. Marsh Lake Storage is assumed to provide 1 MW of added reliable peak winter capacity.

5.3.1.2 Gladstone - Total Deferred Costs of $4.394 Million

This hydro enhancement project is a cost effective means of increasing the amount of water available in winter months for hydroelectric generation at the Aishihik hydro facility in order to displace higher cost diesel generation that would otherwise be required.

Project Concept

The project proposes to divert water from the headwaters of Gladstone Creek into the Aishihik Lake system and would increase the amount of water available for hydroelectric generation at the Aishihik hydro facility. The project concept includes two diversion structures to divert the headwaters of Gladstone Creek into Isaac Creek which flows in Sekulmun Lake (the primary storage reservoir of Yukon Energy's Aishihik 37 MW Hydro facility). The project is forecast to provide sufficient water for up to an additional 36.6 GW.h (on average) of production from the Aishihik facility, focused in the winter months.

Assessment and permitting will be required under Yukon and Federal regimes. The project is within the traditional territory of the Champagne Aishihik First Nations. Kluane First Nation and White River First Nation also have interests in the vicinity of the project on or near Gladstone Creek near Kluane Lake.

Project Risks, Costs and Benefits

A tender process was undertaken in 2009 to engage a third party consultant to provide project management services and integrated engineering, environmental/socio-economic and related technical consulting services for all three southern lakes projects (Marsh Lake Storage, Atlin Storage and Gladstone Diversion). It was expected that having one consultant firm providing bundled planning and assessment services that included project management, engineering and assessment would simplify and streamline the feasibility and assessment process and also provide for economies of scale (e.g., site investigations and other work for all projects could be carried out in an efficient and coordinated manner).

Feasibility studies are required to assess the design and environmental licensing requirements, forecast costs and potential benefits. Planning and feasibility costs to the end of 2011 are $3.694 million with forecast spending over the test years of $0.700 million. Third party environmental assessment, engineering and project management costs comprise approximately 90% of the project costs to date. Environmental and engineering feasibility costs are higher for Gladstone diversion than for other southern lakes projects being assessed due to the remote location, i.e., in order to complete baseline work personnel and equipment were required to be flown to the site by helicopter. The diversion concept also requires extensive fisheries work, including undertaking pathogen and parasite testing.

Based on feasibility studies to date, project cost was estimated at $40 million (2010$) and LCOE over the 65 year project life estimated at 6.3 c/kW.h (assuming full utilization of added energy generation of up to 36.6 GW.h/year during the winter months at the current Aishihik plant and YEC blended capital cost averaging 6.56%/year). Earliest potential in-service for this project has been estimated to be late 2017[39].

The project's potential very positive benefit has been confirmed by the feasibility and planning studies to date, i.e., this hydro enhancement opportunity continues to offer higher potential long-term diesel displacement (well over 30 GW.h/year) than any other identified current enhancement option, with projected LCOE at less than 10 cents per kW.h.

The ongoing risks and uncertainties for this project continue to relate to regulatory risks and the need to resolve arrangements with the local First Nation. Activities during 2012 are directed at addressing and

[39] Reflects time needed for YESAA, FAA and other permit processes and YWB licensing plus two construction seasons; the YESAA and FAA applications are assumed to be delayed due to need for up to two years of further pathogen studies required by DFO and delays until YEC can resolve arrangements with the local First Nation.

resolving these risks, and ongoing expenditures and activities beyond 2012 will be dependent on success in this regard.

Forecast feasibility study costs to the end of 2012 (approximately $3.9 million) are assumed to be closed at the end of 2012 and amortized over 10 years starting in 2013. A further $0.5 million of feasibility study costs are forecast in 2013, to be amortized starting in 2014.

5.3.1.3 Atlin Lake Storage – Close out of Approximately $2.2 Million of Feasibility Study Costs in 2011 after Decision not to Proceed with Further Work at this time

This hydro enhancement project was examined as a cost effective means of enhancing winter capacity and energy available to the Whitehorse Rapids Generation Station in order to displace higher cost diesel generation that would otherwise be required.

Project Concept

The Atlin Lake outlet is located in Northern BC near the community of Atlin. The outflows from Atlin Lake make up approximately 40% of the total annual inflows to the Yukon River system and are used to generate electricity at the Whitehorse Hydro Facility[40]. Construction of a modest control structure on the Atlin River to regulate the outflow of Atlin Lake would hold back water in the fall and increase winter flows in the Atlin River, increasing the winter power generation available downstream at the Whitehorse Rapids Generating Station.

It is estimated that an additional 9 GW.h/year of added hydro energy could be generated at Whitehorse with regulation of the outflows of Atlin Lake within its natural range of lake levels. If 0.4 m of drawdown below the natural lake level was permitted it is estimated that a total of up to 18 GW.h/year could be generated. This project would also increase the winter hydro capacity of the Whitehorse facility by 1-2 MW.

The control structure would need to be located entirely within British Columbia and consequently would be assessed and permitted under BC and Federal Regimes.

[40] The flows from Atlin Lake pass down the 2.5 km long Atlin River into Tagish Lake, onto Marsh Lake then into Schwatka Lake.

Project Risks, Costs and Benefits

A tender process was undertaken in 2009 to engage a third party consultant to provide project management services and integrated engineering, environmental/socio-economic and related technical consulting services for all three southern lakes projects (Marsh Lake Storage, Atlin Storage and Gladstone Diversion). It was expected that having one consultant firm providing bundled planning and assessment services that included project management, engineering and assessment would simplify and streamline the feasibility and assessment process and also provide for economies of scale (e.g., site investigations and other work for all projects could be carried out in an efficient and coordinated manner).

Feasibility studies to date were conducted to assess the design and environmental licensing requirements, forecast costs and potential benefits. Based on these studies, project cost was estimated at $30 million (2010$)_and LCOE over the 65 year project life estimated at 10.5 c/kW.h (assuming full utilization of added energy generation and YEC blended capital cost averaging 6.56%/year).

The inter-jurisdictional nature of the project (need for BC approvals) and challenges by local residents presented material challenges to proceeding with this project. With the material risk that this project would be delayed or not proceed in the near-term, progression through the planning process was carefully monitored and controlled by staged approvals for expenditure applied to each project phase. In 2011, when the BC Government designated Atlin River as a Class A park (with expectation that the designated park would include the river), a decision was made by Yukon Energy to discontinue work on the Atlin Storage project.

Feasibility study costs to date of approximately $2.2 million will be amortized over 10 years, starting in 2012. Third party environmental assessment and project management costs comprised over 90% of the project costs to date. Due to public concern in the local community, Yukon Energy also engaged in extensive public consultation with the local residents and the local First Nation. This included incurring modest costs for rental of office space in Atlin and provision over a month long period for one Yukon Energy representative to go to the community one day a week to meet with local residents.

5.3.1.4 Mayo Lake Enhanced Storage – Total Deferred Costs of $2.1 Million

This hydro enhancement relicensing project will amend the current Mayo Generation Station Water Use Licence to provide for up to an additional 1 metre of draw down that will increase renewable power

generation capability of the Mayo hydro facility and displace diesel generation that would otherwise be required[41].

Project Concept

The Mayo Lake Enhanced Storage project seeks to amend the Mayo Generation Station Water Use Licence at Mayo Lake to secure additional storage through 1 metre of added drawdown by changing the existing licenced controlled storage range of 2.59 metres (663.25 to 665.84 metres) to a new licenced controlled range of 3.59 metres (662.25 to 665.84 metres). The project will also require Fisheries Act Authorization, but will require no physical works for water storage beyond those already in-service for the existing Mayo generation. The added 1 m of storage will increase the long-term average hydro generation potential of the Yukon grid system by approximately 4 GW.h (the specific yearly benefit will depend on the overall load level and flow conditions throughout Yukon).

The Mayo Lake Enhanced Storage project was originally included as a component of the Mayo Hydro Enhancement Project proposal. During the 2009 adequacy review process, YESAB informed Yukon Energy that the proposal was adequate with the exception of the Mayo Lake storage component. As a result, YEC made the decision to withdraw the Mayo Lake storage component from the original project proposal and file the Mayo Lake Enhanced Storage Project as a separate project at a later date.

Yukon Energy subsequently completed a Project Agreement with the local First Nation (Nacho Nyak Dun First Nation) regarding the Mayo B and Mayo Lake projects.

Following the Mayo B Part 3 hearing, the Yukon Utilities Board's (in its report to the Minister of Justice) recommended that YEC pursue the additional metre drawdown at Mayo Lake, noting positive effects that added draw down of Mayo Lake would have on the economics of Mayo B and associated positive impacts on rates.

A Project Proposal is currently being prepared and is expected to be filed with the relevant YESAB Designated Office in 2012. In order to address the information requirements identified by YESAB during the 2009 Mayo B adequacy review process, additional environmental and socio-economic fieldwork was conducted 2008 through 2011, including the following:

[41] The operating range of Mayo Lake will be increased by up to 1 metre from the existing licenced controlled range of 2.59 metres (663.25 to 665.84 metres) to a new licenced controlled range of 3.59 metres (662.25 to 665.84 metres).

- **Environmental and Socio-Economic Fieldwork Activities:** *Aquatic studies* – Index netting survey, lake trout/whitefish sampling, aquatic macrophyte study, lake trout spawning and incubation study, ice thickness study, bathymetry of Mayo Lake, ice assessment (2010); additional substrate cleaning (2011). *Wetland studies* – Water gauge study, Roop Lake backwater study, Roop Lake wetland health assessment (2010). *Terrestrial* – aquatic inventory. *Heritage* – (2010) visitation of two heritage sites, NND heritage.

- **Analysis and Assessment:** This involved ongoing meetings between YEC and NND to discuss and plan various topics related to the project. (2010 – Present).

- **Project Proposal (ongoing):** Gathering of materials and drafting of YESAA Designated Office.

- **Engineering Support (2010):** Hydraulic model and wetland flood mapping.

- **Public Consultation (Mayo and Whitehorse):** Round One (June-July 2011) – regulators (Yukon Government, YESAB, and DFO), Community dinner and information session, Canadian Wildlife Services and Yukon Conservation Society. Round Two (October 2011) – MDRRC, NND resource users' workshop, community dinner and open house, local placer miners and Yukon Conservation Society.

Project Risks, Costs and Benefits

The present value of total project costs over the project life (i.e., the life of Mayo B project) are estimated at $5.4 million ($2012) (including mitigation and monitoring costs) with an LCOE of 6.3 c/kW.h for approximately 4 GW.h/year of added average hydro grid energy with 1 m of added storage at Mayo Lake.

Earliest potential in-service for this project is estimated to be during 2013. The main risks related to the project are regulatory risks, including delays and/or mitigation, monitoring or other regulatory requirements that may restrict the effective drawdown range and benefits expected from the project.

Permitting and licensing costs (undiscounted) included in this cost by 2013 are estimated at $2.1 million, with spending to the end of 2011 at $1.43 million and forecast spending in the test years of $0.660 million. In the event that the project is approved, these costs are assumed to be amortized over the remaining term of the Mayo licence (13 years).

5.3.1.5 Demand Side Management (DSM) - $3.012 Million (net of contributions)

Demand side management (DSM) is widely recognized in utility resource planning (e.g., BC Hydro Power Smart program, similar programs by Manitoba Hydro and other major utilities) to be feasible at relatively low cost (Full Utilization LCOE on average likely less than 10 c/kW.h) for ongoing implementation with non-industrial and industrial customers.

Key context setting factors are noted:

- The Energy Strategy for Yukon strongly supports conservation measures such as DSM as a means of addressing growing demand (and related diesel generation requirements) in Yukon.
- The Yukon Utilities Board (with encouragement and support from intervenors) has directed that Yukon Energy and Yukon Electrical (Order 2009-2 and Order 2009-8) consult with stakeholders and jointly develop a DSM policy paper (Plan) to be presented as part of the next generation rate application.
- Generally, there is widespread public acceptance and support for DSM programming and energy conservation; this broad public support was evident at the Yukon Energy Charrette where DSM was considered the most favored option for YEC to proceed with in the near-term.

DSM is consequently considered to be a supply option where there is a clear commitment to proceed (albeit the specified programs would depend on the results of a conservation potential review underway and supporting economic and regulatory analysis). However, DSM requires some lead time before energy savings can be translated into electrical energy available and the amount of lead time varies by initiative. Typical DSM programs are implemented over a three to five year period at which time they are usually evaluated and modified based on the results of that evaluation.

Project Concept

A significant amount of DSM related planning and consultation work has been undertaken by Yukon Energy individually and by Yukon Energy in coordination with Yukon Government, Yukon Development Corporation and Yukon Electrical in order to implement a robust and aggressive DSM/SSE program, and to meet the Yukon Utilities Board directive.

- Yukon Energy continues to lead the joint working group (with YECL and Yukon Government) to develop a DSM plan with intentions to file the plan with the YUB in 2012.

- As part of the joint development of a demand side management plan, YEC, in cooperation with YG and YECL, proceeded with a detailed conservation potential review study [completed in December 2011]. This comprehensive analysis of energy use by customer class and electrical zone will form the basis of the DSM plan to be prepared after the fall of 2012 by establishing a reference case for future electrical use and then identifying the low, medium and high achievable (and cost-effective) DSM potential for different non-industrial customer classes. The review will also determine which DSM technologies are most appropriate for the Yukon in the short and medium term including the potential integration of customer generation (net metering).

- Work in 2011 also included the development and implementation of several pilot programs and the continued engagement of the Yukon public in the development of the DSM plan.

Yukon Energy is also actively considering DSM programming as part of its resource planning work and DSM is being considered as a key supply option to help address near-term and longer-term energy requirements.

- Yukon Energy has undertaken and continues to review the range of programs being offered in other jurisdictions to assess the adaptability to the Yukon context.

- In 2011, Yukon Energy consulted extensively on DSM and included it as a supply option for review and discussion during the March 2011 Energy Charrette. A background paper was prepared and is available for review on Yukon Energy's website. Yukon Energy also plans to have a workshop focused on DSM as a supply option in spring 2012.

- Yukon Energy as part of its resource planning processes has continued with baseline research and pilot projects. Pilot projects undertaken or currently under way include an LED Streetlight[42] project, an energy audit of Alexco mine, basic energy management training[43], an education event for children[44], an online energy calculator, public education and an energy audit of Yukon Energy's own buildings.

Project Cost

Planning and feasibility costs to the end of 2011 are $1.037 million – however, with offsetting contributions, net costs in 2011 are $0.303 million. Offsetting contributions in 2011 total $0.735 million

[42] YEC pilot project undertaken with input from ESC. Yukon Electrical has also undertaken its own pilot program.
[43] Dollars to Sense course offered twice in 2011 undertaken in partnership with NRCan in both instances and Yukon Electrical (one session).
[44] Conservation Kids program undertaken in partnership with YCS.

and are comprised of the following: $0.500 million from YDC for program development, $0.090 million from Yukon Government for the Conservation Potential Review, and a total of $0.145 million from Yukon Electrical ($0.087 for Conservation Potential Review, $0.052 million for community tour and $0.005 million for $$ to Sense workshop). Forecast spending over the test years is $2.709 million.

A material portion of DSM costs incurred to date, and expected to be incurred in the test years, relate to internal DSM within YEC. This includes feasibility, study, planning and implementation of conservation improvements at Yukon Energy's existing buildings and facilities. In 2011, Yukon Energy retained a third party consultant to conduct an energy audit of 25 of its buildings to determine significant areas where energy reductions could be made (of this, 6 were selected based on ease of access and opportunities for savings). Specific internal DSM activities will be undertaken in the test years and may include lighting upgrades, upgrades to building envelope and replacement of fixed pumps with variable speed pumps. The benefit of this form of DSM is that since Yukon Energy is carrying out the changes there is assurance that the activities will be undertaken and targeted savings achieved.

Other material costs incurred to date relate to Yukon Energy's contributions towards the Conservation Potential Review Study, which included material third party consultant costs as well as costs for other related activities (including a residential end use survey in 2011 and two separate workshops), and ongoing management of DSM research, pilot programs and policy/plan development.

Pursuant to the DSM Accounting Policy provided in Appendix 5.2 project related DSM costs will be closed out and amortized each year over a ten year period.

5.3.1.6 Waste-to-Energy/Biomass/Biogas – Total Deferred Costs of $1.629 million (net of contributions)

Project Concept

In assessing potential future supply options Yukon Energy has looked beyond diesel and hydro resources that have formed a significant portion of its supply portfolio to date and has also considered generation options that could be locally developed (based on local sources of supply) and that would provide firm, reliable power. These thermal biomass resources can be developed with conventional technology but require development of relatively more capital intensive high pressure steam generation plants that would typically be intended for year round operation in order to secure cost efficient use of the facilities. Accordingly, such options are potentially relevant under increased grid loads that provide sufficient opportunity for the biomass generation to displace default diesel generation. Such options have been considered at a pre-feasibility stage (where there is no decision to proceed with the project).

Specific studies to date have centred on determining feasibility of two specific thermal sources of supply: Waste-to-Energy and Wood Biomass.

- **Waste to Energy** – Feasibility work and studies to date have considered various options for a potential waste to energy thermal plant located in Whitehorse that would use municipal solid waste to produce both electricity and heat (for potential district heating in Whitehorse). Such work has considered a 2.2 MW plant (at a capital cost of $17.73 million/MW in 2010$) that would use 25,000 ODT/year of MSW feedstock plus a small amount of wood biomass (3,800 ODT/year at an assumed cost of $75/ODT). Potential district heat net revenues, tipping fees and other revenues of $3.3 million/year (2010$), and O&M costs excluding wood biomass of $2.7 million/year (2010$).

- **Wood biomass** – With a longstanding interest in possible fuel uses of deadfall from spruce beetle infestation in the Haines Junction area Yukon Energy has reviewed feasibility of thermal generation options that involve a high pressure steam thermal generating plant using wood to provide heat energy. A preliminary evaluation of opportunities to generate electricity in Yukon using wood biomass was undertaken and a draft letter report provided in June 2011. This included a feedstock assessment and estimates for electricity production and heat utilization for a 25 MW wood biomass thermal plant in Whitehorse (the report notes, from previous studies, that capital and operating costs per unit of production rise steeply when generation capacity falls below 20 MW)[45].

These options were publically reviewed as part of the 2011 Energy Charrette and in late 2011, Yukon Energy also held two separate public workshops to get input and share information. In this regard, the following feasibility work is available on Yukon Energy's website:

- Waste to Energy Summary Report – September 2011[46];
- Waste to Energy Technical Report – September 2011[47]; and
- Preliminary Yukon Biomass Energy Evaluation[48].

[45] Assuming conventional combustion technology combined with a Rankine cycle, the report estimates that a 25 MW facility will utilize approximately 140,000 ODT (approximately 308,000 cm) of biomass feedstock per year to generate approximately 197,000 MW.h/year (0.7 ODT per MW.h; 90% plant annual capacity factor).
[46] Available on Yuko Energy's website:
http://www.yukonenergy.ca/downloads/db/1074_WTE%20Summary%20Report%20Final%20Sept%206_11.pdf.
[47] Available on Yukon Energy's website:
http://www.yukonenergy.ca/downloads/db/1073_WTE%20Technical%20Report%20%20Final%20Sept%206_11.pdf.
[48] http://www.yukonenergy.ca/downloads/db/1081_Biomass%20Report%20Final%20Sept%2013_2011_DM.pdf.

Project Risks, Costs and Benefits

Current municipal waste to energy studies estimate that a 2.2 MW plant generating 17.1 GW.h/year (89% annual capacity factor) for a 25 year life would have an LCOE in 2010$ of 13.5 cents/kW.h if energy generated from the plant could be fully utilized 100% of the time and with assumed other revenues (i.e., district heat revenues and tipping fees). Absent revenues from district heat the LCOE would be 23.7 cents/kW.h), and absent district heat revenues and tipping fees the LCOE would likely be in the range of 31.4 cents/kW.h. Full winter peak capacity benefits are assumed for this plant. Based on the small plant scale, it is expected that most of the plant's annual generation could be utilized to displace diesel generation.

With regard to wood biomass feasibility studies to date, capital and operating costs (not including feedstock costs) for a 25 MW plant are estimated at $100 million ($4 million per MW) and $4 million per year respectively. Assuming feedstock cost at $150 per ODT ($105 per MW.h), overall electricity cost are estimated at $168 per MW.h[49]. District heat revenue potential is estimated at only $1.53 million per year (a reduction in net cost of about $7.77 per MW.h), reflecting the relatively small demand for heat energy in potentially feasible Whitehorse District Energy applications[50].

Based on a wood biomass plant of 25 MW, resource planning estimates indicate that only slightly over 50% of the plant's 197 GW.h/year generation would be utilized on average to displace diesel generation based on loads forecast for the Yukon grid with connection of the Victoria Gold mine (without such mine loads, a much lower share of the annual generation would on average be used to displace diesel generation). On this basis, wood biomass on this scale would not offer cost effective displacement of diesel generation at this time.

In addition, the Morrison Hershfield report on wood biomass plant feasibility identified lack of feedstock supply security as a significant project risk that will require mitigation prior to project development. The report provides recommendations to address project risks and uncertainties and facilitate advancement of the project into a detailed planning stage, including: promote the development of a Yukon Bioenergy Policy; incorporate biomass energy option in YEC public consultation; investigate and confirm feedstock availability and costs; assess options for integrating municipal solid waste within a biomass facility; confirm capital and operating costs; and initiate preliminary site investigations.

[49] Capital costs at $42.48/MW.h assuming 5.5% real cost of capital amortized over 20 years; non-fuel O&M cost at $20.30/MW.h.
[50] Estimates based on Stantec study (2010), zones 1 to 3 (potential heating demand equal to 29,900 MW.h/year.

Total forecast feasibility costs to the end of 2012 are $1.383 million with a $0.225 million offsetting contribution from CANNOR (50% of total $0.225 million contribution applied to each of 2011 and 2012). Forecast feasibility study costs included in rate base at the end of 2012 are approximately $1.128 million, net of contributions and these costs are assumed to be closed and amortized over 10 years starting in 2013. Costs to date have been incurred primarily for third party engineering consultants to undertake specific pre-feasibility work regarding this supply option. Other costs include costs for public consultation processes (Charrette and specific Waste to Energy, Biomass and Biogas workshops held in November/December 2011).

Spending in 2013 is forecast at $0.5 million. Costs expected to be incurred in the test years include environmental baseline work and data collection required for a feasibility level of assessment.

5.3.1.7 District Heating – Total Deferred Costs of $0.500 Million (net of contributions)

Yukon Energy is currently exploring various thermal supply options that produce waste heat, including liquefied natural gas, biomass and waste to energy. For these projects, a developed district heating market in Whitehorse may provide added value through generation of additional revenues that may lower costs for thermal supply options and consequently reduce impacts on ratepayers. Very preliminary findings to date indicate promising market potential of 3 to 4 MW of district heat applications within the core areas of Whitehorse.

The results from the District Energy System (DES) Pre-feasibility Study for Whitehorse (Stantec, 2010) indicate that a DES in Whitehorse is technically and economically feasible in some areas of Whitehorse. It was recommended to proceed to a full feasibility study. The purpose of this project is to determine whether a district energy system is feasible in the City of Whitehorse. It will include identifying potential customers, a preliminary design basis document, business case and infrastructure funding opportunities. Project work will build on the recommendation and findings of the study prepared in partnership with the Energy Solutions Centre, Property Management, Yukon Government and City of Whitehorse. Feasibility work will also be carried out in partnership with the City of Whitehorse and Yukon Government. Both governments will contribute financially and technically; and participate in a Project Steering Committee.

The feasibility study will consider the thermal generation feasibility work (biomass, liquid natural gas and waste to energy) currently being carried out by Yukon Energy in regards to examining a potential heat supply for a proposed system. Based on thermal options and locations being considered, district heating market potential will be assessed along with the feasibility of potential implementation plans.

Total spending on feasibility to date has been $1.03 million ($0.07 million in 2011, $0.46 million in 2012 and $0.500 million in 2013). However, total spending in 2011 and 2012 has been offset by $0.53 million in matching contributions in 2011[51]. Deferred costs are forecast to be closed and amortized over 5 years starting in 2014 pursuant to the Planning Cost Accounting Policy.

5.3.1.8 Liquified Natural Gas (LNG) – Total Deferred Costs of $1.669 Million

The feasibility of thermal generation using LNG is being considered by Yukon Energy for near-term development (i.e., before 2015) as it is expected to provide a reliable, abundant, low cost, and flexible source of supply with reduced greenhouse gas emissions and costs compared to using existing diesel generation.

Work in 2011 was undertaken by Yukon Energy to assess the feasibility of LNG for power generation in Yukon to determine if it is a viable near-term supply option to be included in near-term resource planning. Initial feasibility study activities were $0.169 million in 2011 and included high level engineering conceptual work performed by KGS and delivery of a LNG Feasibility Study conducted by Braemar Wavespec (a Houston based LNG consultation). The LNG Feasibility Study assessed supply chain alternatives, studied the costs, benefits and risks associated with sourcing LNG from BC sources and from local sources at Eagle Plain. The Braemar Wavespec report was cost-shared between Western Copper & Gold (WC&G) and YEC.

In order to pursue the LNG option for near-term development for power generation, further feasibility work is required to determine the optimum way to secure the LNG, the required timing and all related costs (including assessment of potential options for LNG supply chain development jointly with other interests to meet broader near and longer term Yukon opportunities). Feasibility work is also required to optimize the specific Yukon Energy generation capacity and technology for power generation using LNG (including assessment of the optimum combination of combined cycle and simple cycle units in response to different potential load scenarios).

A public workshop was held January 18, 2012 that reviewed this specific resource option. Materials available included a Background paper available on the Yukon Energy website[52].

[51] Contributions included $500,000 from YDC; $0.010 million from Yukon Government; $0.005 million from City of Whitehorse and $0.015 million from ESC.
[52] http://www.yukonenergy.ca/downloads/db/1102_LNG%20Background%20Paper%20January%202012.pdf.

Forecast feasibility study costs are approximately $1.7 million to the end of 2012. The Table 5.2 forecast in 2013 shows a further $1.0 million expenditure in fixed assets in 2013, plus transfer of $1.669 million from feasibility study costs. It is expected that this project will meet reasonable assurance before the end of 2012, and that the costs to date (and ongoing costs) will be included in construction WIP as the project is developed. Earliest in service for this project is forecast to be in late 2014.

5.3.1.9 Geothermal – Total Deferred Costs of $2.633 Million

Geothermal opportunities offer future potential to provide significant low cost, clean, and reliable long-term electricity supply in Yukon if successful exploration can define appropriate opportunities close to the grid.

Due to the potential significant benefits of this resource, geothermal opportunities in Yukon have been subject to high level review since the 2008/2009 GRA in order to ascertain geologic and economic potential for development for heat and electricity production at the following locations: Haines Junction, Volcano Mountain, Whitehorse, McArthur, Nash Creek and Larson Creek.

A preliminary resource assessment and prioritization of sites was subsequently undertaken for Yukon Energy by Borealis Geopower. This assessment indicates that, while unconfirmed, there is clearly a material and significant potential at the sites identified. Whitehorse is identified as a site with highest priority ranking compared to other sites[53], with its main advantage being proximity to power infrastructure and markets. The report indicates however that all sites have some level of exploration risk, and that the information collected to date is insufficient to substantiate a finding of the inferred geothermal resources at any of the six sites.

Future consideration of geothermal is dependent on successful exploration that defines appropriate opportunities close to the grid.

Industry standards indicate that exploration activities typically comprise approximately 10% of the total capital cost of a geothermal project.

Planning and feasibility costs to the end of 2011 are $1.95 million with forecast spending over the test years of $0.686 million. The majority of costs to date have been spent on studies undertaken by third

party consultants (EBA and Borealis). Efforts until 2011 focused screening of various sites across Yukon in order to identify and gain a preliminary understanding of geological context and origin of the hydrothermal fluids of various geothermal surface expressions, e.g., Jarvis Creek, Volcano Mountain, Whitehorse, McArthur, Nash Creek and Larson Creek. Drilling activities were initiated on one site of potential interest – however, technical difficulties prevented further work at the site.

Forecast feasibility study costs of $1.95 million to the end of 2011 are closed and amortized over 10 years starting in 2012. A further $0.38 million of feasibility study costs are forecast in 2012 and $0.30 million in 2013, to be amortized over 5 years.

This work is expected to focus on targeted studies in the Whitehorse area that have a geological context favourable to the development of a geothermal resource. In this regard, 2012 work will follow the recommendations of the Borealis report (i.e., confirm temperature gradient and water quality and potentially some geophysical survey work). If results of 2012 studies are favourable and there is sufficient geophysical data plans for an exploratory drilling program would be developed and undertaken to confirm heat resources.

Additional baseline studies and permitting work are expected to total $1 million to $1.5 million while costs for exploration and drilling would increase to $5 million.

5.3.1.10 GRA Phase 1 Revenue Requirement Review – $1.1 million

This spending addresses the costs of preparing and filing a 2012/2013 Phase I GRA, as well as a full regulatory review. Any joint YEC/YECL cost of service and rate design filing is to be undertaken at a future date to be determined, and is not included in this projected cost.

5.3.2 Projects between $100,000 and $1 Million

The projected total 2012 and 2013 spending on deferred cost activities outside of major projects over $1 million (as described in Section 5.3.1) totals $2.89 in 2012, as set out in detail in Table 5.6, and a total of $2.7 million for 2013 as set out in detail in Table 5.7. Spending in 2012 and 2013 on each deferred cost activity between $100,000 and $1 million is summarized below (totaling $2.61 million for 2012 and $2.60

[53] Estimates of potential capacity and cost per kW.h for the Whitehorse site ranged from 30-45 MW and 9.3 to 12.6 cents/kW.h. Other sites had lower potential capacity estimates and higher potential cost estimates (except for Larson Creek, located in the far southeast corner of Yukon, which had the same cost range as Whitehorse).

million for 2013), with key areas of spending including feasibility studies, deferred overhauls, relicensing, dam safety, and rate case.

- **Feasibility** (spending from 2009 to 2011 of $3.02 million, and with $1.13 million in 2012 and $1.0 million in 2013).
    - Studies undertaken to determine feasibility of potential supply options to displace diesel include Aishihik Hydro re-runnering feasibility, wind feasibility – Ferry Hill, Atlin Grid connection feasibility, and Large Hydro (potential future greenfield hydro projects). Other studies related to demand included a Climate Change Study to develop a plan for the Corporation to mitigate and adapt to potential climate change effects on existing and future assets.
    - Studies undertaken to ensure continued reliability or determine requirement for business improvements for existing assets include:
        - The System Stability Review to ensure the electrical system remains stable with any power quality issues identified and addressed with the best economic solution.
        - The Condition Assessment of Selected Assets to determine practical remaining life and study of ice processes in the Mayo River to address YEC's concern regarding surface water and icing issues in 2010/11.
        - The Study of Ice Processes in the Mayo River (undertaken to better understand icing and hydraulic issues and better understand potential impacts on the Mayo diesel facilities).
        - The Wareham Spillway Hoist upgrade to meet current reliability and safety standards.
        - The WH4 Rotor Investigation undertaken to understand root causes of poor performance and provide long-term solutions.
    - Studies undertaken for legal or regulatory compliance reasons include the International Financial Reporting Standards.
- **Deferred Overhauls** (spending from 2009 to 2011 of $0.18 million, and with $1.28 million in 2012 and $1.60 million in 2013) – Both hydro and diesel unit overhauls are required during the test years to ensure continued reliability.

- **Hydro Overhauls** – To improve reliability and reduce risk of a component failure, spending in the test years includes standard ten year tear down and overhaul of AH1, AH2 and WH3 units to inspect worn bushings and bearings and make corrective repairs that are not identifiable on a running unit.

- **Diesel Overhauls** – DD-2, DD-3 and DD-5 will each require a total engine overall in the test years to maintain the unit's availability without decreasing engine life and reliability.

- **Relicensing and Dam Safety Review** (spending from 2009 to 2011 of $0.51 million (excluding Mayo Lake Enhanced Storage project), and with $0.087 million in 2012 for renewal of the Air Emission Licence.

- **Rate Case** (from 2009 to 2011 of $1.02 million (excluding GRA reviews), and with an additional $0.23 million in 2012) – spending in the test years is focused on the preparation of the 2011 Resource Plan Update required to facilitate decision making on major infrastructure projects by providing new an additional information on load forecasts, generation and transmission options as well as an assessment of alternatives.

Appendix 5.5 provides a description (including need for and justification) of each of the deferred cost projects with spending greater than $100,000 million and less than $1 million in each of the test years.

YUKON ENERGY CORPORATION **Table 5.1**
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT - SUMMARY **April 2012**
($000S)

Description	Actual 2009	Actual 2010	FYF 2011	BP 2012	BP 2013
SUMMARY - RECONCILIATION OF PROPERTY, PLANT AND EQUIPMENT					
Work in Progress (WIP), Beginning of Year	4,340	20,898	91,851	7,892	6,199
Total Major Projects	15,616	71,661	90,109	18,494	16,606
Ongoing Capital					
Total Transmission	1,449	1,574	1,483	1,248	1,170
Total Distribution	356	921	414	720	1,025
Total Generation	2,988	6,504	2,801	2,416	3,012
Total General Plant & Equipment	2,803	1,497	1,002	1,043	1,900
Subtotal Ongoing Capital	7,596	10,496	5,700	5,426	7,107
Total Expenditures	23,213	82,157	95,809	23,921	23,713
Transfer to RFSR	-150	-243			
Transfers (Income Statement, Feasibility and other)	-92	-18	-816		
ES&G difference	-146	-68	6		
Total WIP Adjustments and Transfers	-389	-329	-810	0	0
Transfer to Ratebase	-6,266	-10,874	-178,959	-25,613	-10,114
WIP end of year	**20,898**	**91,851**	**7,892**	**6,199**	**19,798**
Opening PPE in-service	270,928	276,364	286,319	465,125	490,739
Net transfer from WIP	6,266	10,874	178,959	25,613	10,114
Retirements and other adjustments	-831	-918	-153		
Closing PPE in-service	**276,364**	**286,319**	**465,125**	**490,739**	**500,853**
Opening Total PPE (in-service plus WIP)	275,268	297,261	378,171	473,017	496,938
Change to total PPE	21,993	80,909	94,846	23,921	23,713
Closing total PPE	**297,261**	**378,171**	**473,017**	**496,938**	**520,651**
RECONCILIATION OF CUSTOMER CONTRIBUTIONS					
Opening Customer Contributions WIP	897	6,932	90,238	120	2,000
Customer Contributions Received	8,188	83,488	35,333	6,123	8,900
Adjustments	-13		-8		
less: transfer to Rate Base	-2,140	-181	-125,442	-4,243	-400
Customer Contributions WIP end of year	6,932	90,238	120	2,000	10,500
Opening Gross Customer Contributions in Service	48,336	50,477	50,658	176,100	180,344
Transfers from WIP	2,140	181	125,442	4,243	400
Retirements, Disposals and Adjustments					
Closing Gross Customer Contributions in Service	50,477	50,658	176,100	180,344	180,744
Opening Total Contribution (in-service plus WIP)	49,233	57,408	140,896	176,220	182,343
Change to total Contribution	8,175	83,488	35,324	6,123	8,900
Closing total Contribution	**57,408**	**140,896**	**176,220**	**182,343**	**191,243**

Notes:
1. 2011 transfers include Mayo Lake project cost of $0.662 million transferred to Relicensing.

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

Table 5.2
April 2012

Description	Actual 2009	Actual 2010	FYF 2011	BP 2012	BP 2013
Major Projects					
Mayo B - Construction	7,441	41,200	60,721	7,226	
Carmacks Stewart Transmission Line Stage 2	3,836	24,424	13,652		
Aishihik Third Turbine Construction	4,074	4,742	5,000		
Whistle Bend Subdivision Supply			68	50	5,112
Mayo Hydro - Substation Enhancements		163	3,648	6,342	
Victoria Gold - Grid Connection			14	2,000	7,000
Aishihik Generation Station Redundancy	102	706	5,300	257	
Enterprise System	102	221	1,180	1,404	250
LNG (Liquified Natural Gas)			0	0	2,669
Mayo Head Gate Repairs	62	204	428	640	
Whitehorse Spillway Improvements			96	575	575
Western Copper - Grid Connection					1,000
Total Major Projects	**15,616**	**71,661**	**90,109**	**18,494**	**16,606**
Generation					
Wareham Intake Rock Scaling		759	126		
Wareham Spillway Upgrades			75	700	0
FD1 Engine Overhaul	555	214			
WD3 Rebuild - Parts	564	146			
Aishihik River Icing Study Mitigation - Bridge				665	
Mayo Lake Project		662			
WH West Gate Gearboxes and VFD					600
Faro Switchgear FD3, FD5, FD7			0	0	587
Mayo Lake Control Structure		583			
Wareham Bridge		574			
Wareham Dam Core Raise & Improvements			571		0
WH East Gate Gearboxes	102	435			
WD3 Rebuild	452	83			
WD1-7 Load Sharing	79	423			
Minto Mine Diesel Upgrades and SCADA	0	333	157	0	
Aishihik River Icing Study - Berm			455	0	0
Mayo Diesel SCADA Connection				0	450
P125 Bulkhead Gate (Stop Logs)		66	362		
Aishihik Elevator Modernization Project		97	301		
WH4 Governor Sys Hydraulic Upgrade	89	300			
Aishihik 3rd Turbine Spare Parts	153	198	17		
Hydro Unit Platforms for Working in Draft Tubes				150	150
Lewes Gate Structure - SCADA		276			
Install Jack Screws on Mayo Spill Gates			0	0	250
Faro FD7 Local Engine Control PLC				250	0
Faro Plant Remote Control Automation Upgrades			0		250
FD1 Testing & Commission (ACTC)	10	233			
Kidney Loop Filter System				100	100
Dam Water Barriers				200	0
Assessment/Replacement of Fuel Tank at Whitehorse				0	200
BPE FD1 Engine Controls	111	84			
Dawson Diesel #1 Overhaul	169	1			
Faro FD0 Load Sharing				0	150
MH2 Upper Guide Bearing Replacement		50	91		0
Mayo Gate House Rock Removal		136			
WD7 PLC Replacement	120				
FD1 Balance of Plant Mechanical & Civil	35	75			
Mayo Stoplog Hoist Upgade	110				
P125 Trash Racks and Heaters Rebuild		21	21	65	
WH4 Spillgate PLC & RTU Upgrade		103			
Aishihik GS Environmental Remediation		103			
EMD's Actuator Upgrade			102	0	0
WH1 Commutator Upgrade				100	
WH2 Commutator Upgrade					100
FD1 Valve Cage Cooling				100	0
Other projects under $100K	441	551	523	85	175
Total Generation	**2,988**	**6,504**	**2,801**	**2,416**	**3,012**

YUKON ENERGY CORPORATION **Table 5.2**
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT **April 2012**
($000S)

Description	Actual 2009	Actual 2010	FYF 2011	BP 2012	BP 2013
Transmission					
WAF Transmission Upgrades	273	331	392	350	350
Minto Landing 138kV Shunt Reactor		424	402	0	
Transmission Pole Test and Treat	216	245	171	248	250
L250 Transmission Line Upgrades	82	131	146	150	150
Minto Landing & Carmacks Substation	371	69			
Little Salmon PT Substation		80	20	200	
Substation Protection and Control Minor Upgrades			73	100	100
Minto Mine Substation Upgrade	183	37	26	0	
L172 Switch Replacement			0	200	0
Dawson P158 T1/T2 Transformer				0	200
CSTP - Legal Survey	199				
Replace Obsolete SEL 321 Relays		139	18	0	0
Aishihik Substation Upgrades	66	71			
RTU Upgrade S164 (Takhini)			101		
Transmission Stubbing Program				0	100
Other projects under $100K	60	47	133	0	20
Total Transmission	**1,449**	**1,574**	**1,483**	**1,248**	**1,170**
Distribution					
Faro Mine Connection					500
Alexco Keno 69KV Spur Line		368	22		
Land Management & Easement Project	104	38	9	25	50
Dawson Dome Distribution Extension			7	220	
Downtown Distribution Upgrades			168		
Hatchery Waterline Relocation		121			
Dawson Northwestel Cellular Tower		120			
Other Customer Extensions Projects	252	275	208	475	475
Total Distribution	**356**	**921**	**414**	**720**	**1,025**
General Plant & Equipment					
CSTP Communications & Control	619	39			
Auger Equipped Truck		484			
Vehicle Purchases		452	242	125	125
Nodwell Purchase	421				
Fish Ladder Replacement					400
DRP/BCP Plan Development			0		325
Network Improvements		53	108	50	50
Boat Lock Upgrade at Lewes Control Structure			0		250
YEC Fall Arrest Systems			82	75	75
Main Office Sprinkler System	208				
Server Replacements	160	19			
WH3 Digital Governor Retrofit	149	0			
Plant Security	129	0			
Tintina Trench Repeater				125	0
WH4 Digital Governor Retrofit	121	0			
Interactive Safety and Environmental Orientation Video					120
Computer Replacements	86	25			
Security Risk Management			6	50	50
Safety Improvements			25	40	40
Fish Ladder Lewes Control Structure			0		100
Electronic Document Management					100
Other projects under $100K	910	426	540	578	265
Total General PPE	**2,803**	**1,497**	**1,002**	**1,043**	**1,900**
TOTAL	**23,212**	**82,156**	**95,809**	**23,921**	**23,713**

Notes:
1. Numbers include AFUDC where applicable.
2. Numbers incude tranfers from planning and study cost and transfers from other projects where the capital expenditures may not be in the year shown.
3. Mayo Lake project cost of $0.662 million transfered to Relicensing in 2011.

YUKON ENERGY CORPORATION **Table 5.3**
Continuity Schedule of Deferred Costs (2009) **April 2012**
($000S)

	Total expenditures					Accumulated Amortization		
	Dec 31	Act 2009		Actual	Amortization Rate and Method	Dec 31	Act 2009	Actual
	2008	Additions	Transfers/ Write-offs	2009		2008	expenses	2009
Feasibility Study								
Completed projects:								
Infrastructure Plan Study Ph 1	48,806			48,806	SL-10 years	37,418	4,881	42,299
Generation Asset Assessment	61,848			61,848	SL-10 years	47,417	6,185	53,602
Transmission Line Assessment	81,988			81,988	SL-10 years	62,857	8,199	71,056
Carmacks/Stewart Feasibility	2,392			2,392	SL-5 years	2,113	279	2,392
WAF Power Flow Study	81,567			81,567	SL-5 years	58,457	16,314	74,770
Secondary Sales Technical Standard	28,392			28,392	SL-5 years	20,348	5,678	26,026
Substation Asset Assessment	84,589			84,589	SL-10 years	43,704	8,459	52,163
Infrastructure Plan (Phase2)	125,100			125,100	SL-10 years	64,635	12,510	77,145
Fishway Redevelopment	15,026			15,026	SL-5 years	10,268	3,005	13,273
Transmission Extension	84,762			84,762	SL-10 years	40,968	8,476	49,445
Powerline Easement Assessment	25,729			25,729	SL-5 years	17,152	5,146	22,298
WH4 Intake Seismic Assessment	42,967			42,967	SL-5 years	27,852	8,569	36,422
Infrastructure Plan Final Report	31,034			31,034	SL-5 years	20,820	6,207	27,026
Atlin/Jakes Corner Grid Extension	32,716			32,716	SL-5 years	19,630	6,543	26,173
WH4 Static Exciter Assessment	21,259			21,259	SL-5 years	12,756	4,252	17,007
Transmission Small Load Stepdown	23,058			23,058	SL-5 years	13,835	4,612	18,446
Mayo Dam Service Life Assessment	17,888			17,888	SL-5 years	10,435	3,578	14,012
Resource Plan Phase 1	205,329			205,329	SL-5 years	106,538	41,066	147,604
Fish Screen Assessment	909			909	SL-5 years	424	182	606
Infrastructure Plan Peer Review	187,754			187,754	SL-5 years	84,489	(23,469)	61,020
Insulation Coordination Study	20,806			20,806	SL-5 years	8,322	4,161	12,484
P126 Balance of Plant Assessment	53,775			53,775	SL-5 years	21,510	10,755	32,265
Resource Plan Phase 2	228,570			228,570	SL-5 years	45,714	45,714	91,428
L170 Line Assessment	213,987			213,987	SL-5 years	42,797	42,797	85,595
2006 Dam Safety Upgrades	27,141			27,141	SL-5 years	5,428	5,428	10,856
Wareham Spillway Wall Raise	8,588			8,588	SL-5 years	1,718	1,718	3,435
Marsh Lake Fall Storage	62,578			62,578	SL-5 years	12,516	12,516	25,031
2006 Yukon River Downstream Icing	146,612			146,612	SL-5 years	29,322	29,322	58,645
Customer Billing System Replacement	51,724			51,724	SL-5 years	10,345	10,345	20,690
Minto Mine PPA	769,057			769,057	SL-12 years	5,341	64,088	69,429
2006 Dam Safety Upgrades	110,244			110,244	SL-5 years	11,024	22,049	33,073
Hydro Storage & Generation Pre-Feasibility	409,335			409,335	SL-5 years	34,111	81,867	115,978
Mayo/Wareham Liquefaction Analysis	72,876			72,876	SL-5 years	4,858	14,575	19,434
Wareham Liquefaction Assessment	37,904			37,904	SL-5 years	-	7,581	7,581
Southern Lakes Hydrology Study	170,243			170,243	SL-5 years	-	34,049	34,049
Hydro Storage & Generation Pre-Feasibilty	185,082			185,082	SL-5 years	-	37,016	37,016
L170 Trx Line Assessment Carmacks	206,721			206,721	SL-5 years	-	41,344	41,344
Wareham Liquefaction Assessment		3,021		3,021	SL-5 years		497	497
Wareham Dam Reliability		21,365		21,365	SL-5 years		2,849	2,849
Aishihik Unit Up-rate Study		5,454		5,454	SL-5 years		727	727
Wareham Rock Face Feasibility Phase 2		55,902		55,902	SL-5 years		7,454	7,454
Mayo Lake Structure Integrity Assessment		25,467		25,467	SL-5 years		-	-
Wareham Liquefaction Assessment		22,117		22,117	SL-5 years		-	-
Wareham Spillway Hoist Upgrade		41,617		41,617	SL-5 years		-	-
Metering Audit 2009		30,510		30,510	SL-5 years		-	-
Protection Event Collection System		28,154		28,154	SL-5 years		-	-
Total Feasibility Study Closed	3,978,357	233,606		4,211,963		935,123	607,522	1,542,646
Work in Progress								
Aerial Photo Mapping & Route Selection	25,200	5,033		30,233				
Aishihik River Icing	27,114	42,901		70,015				
International Financial Reporting Standards	18,823	236,283		255,107				
Geothermal	208,443	1,099,142		1,307,584				
Power Benefit Model Development		1,724		1,724				
Wareham Consequence Category Assessment		50,375		50,375				
AH0 Deluge System		22,863		22,863				
WAF/MD Modeling and Stability		215,203		215,203				
Hydro Unit Performance Test		251,777		251,777				
Study P126 Heating System		4,228		4,228				
Metering Audit 2009		35		35				
Alexco Resource Corporation PPA		39,989		39,989				
Marsh Lake Storage		447,167		447,167				
Atlin Storage		446,195		446,195				
Gladstone		1,011,999		1,011,999				
Large Hydro		331,863		331,863				
Mayo B	1,880,211	5,560,658	7,440,869	-				
CSTP2	847,510		847,510	-				
Total Feasibility Study WIP	3,007,301	9,767,437	8,288,379	4,486,358		-	-	-
Total Feasibility	6,985,658	10,001,042	8,288,379	8,698,321		935,123	607,522	1,542,646

YUKON ENERGY CORPORATION **Table 5.3**
Continuity Schedule of Deferred Costs (2009) **April 2012**
($000S)

	Total expenditures					Accumulated Amortization		
	Dec 31	Act 2009		Actual	Amortization Rate and Method	Dec 31	Act 2009	Actual
	2008	Additions	Transfers/ Write-offs	2009		2008	expenses	2009
Rate Case								
Completed projects:								
YUB 2007-7 & 9 - Resource Plan	642,853			642,853	SL-10 years		64,285	64,285
YUB 2007-7 & 9 - PPA Review	243,045			243,045	SL-12 years		20,254	20,254
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years		4,111	4,111
2008/2009 GRA Phase 1 Revenue Review	276,686	644,064		920,750	Note 2		920,750	920,750
Total Rate Case Closed	1,347,595	644,064	-	1,991,659		-	1,009,401	1,009,401
Work in Progress								
2008/2009 GRA Phase 2	27,686	63,595		91,281				
Total Rate Case	1,375,281	707,659		2,082,940		-	1,009,401	1,009,401
Relicensing								
Completed projects:								
Aishihik Relicensing	8,691,961	78,954		8,770,915		3,416,441	479,592	3,896,034
Whitehorse Relicensing	96,499			96,499		38,856	3,391	42,247
Mayo Relicensing	27,848			27,848		13,048	871	13,918
Air Emission Licence Renewal		200,359		200,359			21,076	21,076
Total Relicensing Closed	8,816,308	279,312	-	9,095,620		3,468,345	504,929	3,973,275
Work in Progress								
Aishihik FAA Agreement Negotiations		70,379		70,379				
Aishihik Heritage Mitigation-Update		28,520		28,520				
Total Relicensing WIP	-	98,899	-	98,899				
Total Relicensing	8,816,308	378,211	-	9,194,519		3,468,345	504,929	3,973,275
Dam Safety Review								
Completed projects	212,862			212,862		199,566	13,297	212,862
Deferred Overhauls								
Completed projects								
Total Deferred Costs	**17,390,110**	**11,086,912**	**8,288,379**	**20,188,643**		**4,603,034**	**2,135,149**	**6,738,183**
Closed				**15,512,104**				
WIP				**4,676,538**				
Net Deferred Costs (excluding WIP)								**8,773,921**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.
2. 2008/2009 GRA Phase 1 Revenue Review cost amortized over 2008 and 2009 as per YUB 2009-11.

YUKON ENERGY CORPORATION **Table 5.4**
Continuity Schedule of Deferred Costs (2010) **April 2012**
($000S)

	Total expenditures					Accumulated Amortization		
	Dec 31	Act 2010		Actual	Amortization Rate and Method	Dec 31	Act 2010	Actual
	2009	Additions	Transfers/ Write-offs	2010		2009	expenses	2010
Feasibility Study								
Completed projects-feasibility:								
Infrastructure Plan Study Phase 1	48,806			48,806	SL-10 years	42,299	4,881	47,179
Generation Asset Assessment	61,848			61,848	SL-10 years	53,602	6,185	59,786
Transmission Line Assessment	81,988			81,988	SL-10 years	71,056	8,199	79,255
WAF Power Flow Study	81,567			81,567	SL-5 years	74,770	6,797	81,567
Secondary Sales Technical Standard	28,392			28,392	SL-5 years	26,026	2,366	28,392
Substation Asset Assessment	84,589			84,589	SL-10 years	52,163	8,459	60,622
Infrastructure Plan (Phase2)	125,100			125,100	SL-10 years	77,145	12,510	89,655
Fishway Redevelopment	15,026			15,026	SL-5 years	13,273	1,753	15,026
Transmission Extension	84,762			84,762	SL-10 years	49,445	8,476	57,921
Powerline Easement Assessment	25,729			25,729	SL-5 years	22,298	3,431	25,729
WH4 Intake Seismic Assessment	42,967			42,967	SL-5 years	36,422	6,545	42,967
Infrastructure Plan Final Rprt	31,034			31,034	SL-5 years	27,026	4,007	31,034
Atlin/Jakes Corner Grid Ext	32,716			32,716	SL-5 years	26,173	6,543	32,716
WH4 Static Exciter Assessment	21,259			21,259	SL-5 years	17,007	4,252	21,259
Transmission Small Load Stepdown	23,058			23,058	SL-5 years	18,446	4,612	23,058
Mayo Dam Service Life Assessment	17,888			17,888	SL-5 years	14,012	3,578	17,590
Resource Plan Phase 1	205,329			205,329	SL-5 years	147,604	40,615	188,218
Fish Screen Assessment	909			909	SL-5 years	606	182	788
Infrastructure Plan Peer Review	187,754			187,754	SL-5 years	61,020	37,551	98,571
Insulation Coordination Study	20,806			20,806	SL-5 years	12,484	4,161	16,645
P126 Balance of Plant Assessment	53,775			53,775	SL-5 years	32,265	10,755	43,020
Resource Plan Phase 2	228,570			228,570	SL-5 years	91,428	45,714	137,142
L170 Line Assessment	213,987			213,987	SL-5 years	85,595	42,797	128,392
2006 Dam Safety Upgrades	27,141			27,141	SL-5 years	10,856	5,428	16,285
Wareham Spillway Wall Raise	8,588			8,588	SL-5 years	3,435	1,718	5,153
Marsh Lake Fall Storage	62,578			62,578	SL-5 years	25,031	12,516	37,547
2006 Yukon River Downstream Icing	146,612			146,612	SL-5 years	58,645	29,322	87,967
Customer Billing System Replacement	51,724			51,724	SL-5 years	20,690	10,345	31,035
Minto Mine PPA	769,057			769,057	SL-12 years	69,429	64,088	133,517
2006 Dam Safety Upgrades	110,244			110,244	SL-5 years	33,073	22,049	55,122
Hydro Storage & Generation Pre-Feasibilty	409,335			409,335	SL-5 years	115,978	81,867	197,846
Mayo/Wareham Liquefaction Analysis	72,876			72,876	SL-5 years	19,434	14,575	34,009
Wareham Liquefaction Assessment	37,904			37,904	SL-5 years	7,581	7,581	15,162
Southern Lakes Hydrology Study	170,243			170,243	SL-5 years	34,049	34,049	68,097
Hydro Storage & Generation Pre-Feasibility	185,082			185,082	SL-5 years	37,016	37,016	74,033
L170 Trx Line Assessment Carmacks	206,721			206,721	SL-5 years	41,344	41,344	82,688
Wareham Liquefaction Assessment	3,021			3,021	SL-5 years	497	611	1,108
Wareham Dam Reliability	21,365			21,365	SL-5 years	2,849	4,273	7,122
Aishihik Unit Up-rate Study	5,454			5,454	SL-5 years	727	1,091	1,818
Wareham Rock Face Feasibility Phase 2	55,902			55,902	SL-5 years	7,454	11,180	18,634
Mayo Lake Structure Integrity Assessment	25,467			25,467	SL-5 years	-	5,093	5,093
Wareham Liquefaction Assessment	22,117			22,117	SL-5 years	-	4,424	4,424
Wareham Spillway Hoist Upgrade	41,617			41,617	SL-5 years	-	8,323	8,323
Metering Audit 2009	30,510			30,510	SL-5 years	-	6,102	6,102
Protection Event Collection System	28,154	33		28,187	SL-5 years	-	5,637	5,637
AH0 Deluge System	22,863	2,656		25,519	SL-5 years			-
P125 Headgates Single Point		50,419		50,419	SL-5 years			-
Total Feasibility Study Closed	4,232,434	53,108		4,285,543		1,540,254	683,000	2,223,254
WORK IN PROGRESS								
Aerial Photo Mapping & Route Selection	30,233			30,233				
Aishihik River Icing	70,015	18,042		88,057				
International Financial Reporting Standards	255,107	178,841		433,948				
Geothermal	1,307,584	278,341		1,585,925				
Power Benefit Model Development	1,724	(1,724)						
Wareham Consequence Category Assessment	50,375	11,955	62,330	-				
WAF/MD Modeling and Stability	215,203	261,918		477,121				
Hydro Unit Performance Test	251,777	65,219		316,996				
Study P126 Heating System	4,228	49	4,276	-				
Metering Audit 2009	35	(35)		-				
Alexco Resource Corporation PPA	39,989	6,702	46,691	-				
Wind Feasibility- Ferry Hill		36,124		36,124				
Mayo/Wareham Geotechnical Investigation		44,565		44,565				
WH4 (Rotor) Investigation		28,771		28,771				
Waste To Energy		235,777		235,777				
Communications Stategy Study		16,684		16,684				
P125/126 Hydrocarbon Containment		26,396		26,396				
Study of Ice Processes in the Mayo River at Mayo		12,067		12,067				
Marsh Lake Storage	447,167	1,035,711		1,482,879				
Atlin Storage	446,195	1,616,254		2,062,448				
Gladstone	1,011,999	2,077,573		3,089,572				
Large Hydro	331,863	149,042		480,905				
Mayo B	-	2,422,837	2,431,581	(8,744)				
Mayo Lake Project		613,764	613,764	-				
Total Feasibility Study WIP	4,463,495	9,134,872	3,158,642	10,439,725				
Total Feasibility	8,695,930	9,187,981	3,158,642	14,725,268		1,540,254	683,000	2,223,254

YUKON ENERGY CORPORATION **Table 5.4**
Continuity Schedule of Deferred Costs (2010) **April 2012**
($000S)

	Total expenditures					Accumulated Amortization		
	Dec 31	Act 2010		Actual	Amortization Rate and Method	Dec 31	Act 2010	Actual
	2009	Additions	Transfers/ Write-offs	2010		2009	expenses	2010
Rate Case								
Completed projects:								
YUB 2007-7 & 9 - Resource Plan	642,853			642,853	SL-10 years	64,285	128,571	192,856
YUB 2007-7 & 9 - PPA Review	243,045			243,045	SL-12 years	20,254	40,507	60,761
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years	4,111	8,223	12,334
Reserve for Injuries & Damages - Study		42,500		42,500	SL-2 years			
Total Rate Case Closed	1,070,909	42,500	-	1,113,409		88,650	177,301	265,951
Work in Progress								
2008/2009 GRA Phase 2	91,281	315,859		407,141				
Brushing & ROW Vegetation Management		129,778		129,778				
Alexco PPA Regulatory Costs		25,272		25,272				
DSM		49,779		49,779				
Resource Plan Update		175,097		175,097				
Total Rate Case WIP	91,281	695,786	-	787,067				
Total Rate Case	1,162,190	738,286	-	1,900,476		88,650	177,301	265,951
Relicensing								
Completed projects:								
Aishihik Relicensing	8,770,915			8,770,915		3,896,034	486,172	4,382,206
Whitehorse Relicensing	96,499			96,499		42,247	3,391	45,638
Mayo Relicensing	27,848			27,848		13,918	871	14,789
Air Emission Licence Renewal	200,359			200,359		21,076	57,091	78,167
Total Relicensing Closed	9,095,620	-		9,095,620		3,973,275	547,525	4,520,800
Work in Progress								
Aishihik FAA Agreement Negotiations	70,379	31,674		102,053				
Aishihik Heritage Mitigation-Update	28,520	(2,193)	26,327	-				
Aishihik Fish Monitoring 2010		67,732	67,732	-				
Aishihik Licence Annual Payments		25,000	25,000	-				
Total Relicensing WIP	98,899	122,213	119,059	102,053	-	-	-	-
Total Relicensing	9,194,519	122,213	119,059	9,197,673		3,973,275	547,525	4,520,800
Dam Safety Review								
Completed projects	212,862	118,734		331,597		212,862		212,862
Deferred Overhauls								
Completed projects								
Total Deferred Costs	**19,265,501**	**10,167,214**	**3,277,701**	**26,155,013**		**5,815,041**	**1,407,826**	**7,222,868**
Closed				**14,826,168**				
WIP				**11,328,845**				
Net Deferred Costs (excluding WIP)								**7,603,301**

Note: This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION **Table 5.5**
Continuity Schedule of Deferred Costs (2011) **April 2012**
($000S)

	Total expenditures					Accumulated Amortization		
	Dec 31 2010	Actual 2011 Additions	Actual 2011 Transfers/Write-offs	Actual 2011	Amortization Rate and Method	Dec 31 2010	2011 expenses	Actual 2011
Feasibility Study								
Completed projects-feasibility:								
Infrastructure Plan Study Phase 1	48,806			48,806	SL-10 years	47,179	1,627	48,806
Generation Asset Assessment	61,848			61,848	SL-10 years	59,786	2,062	61,848
Transmission Line Assessment	81,988			81,988	SL-10 years	79,255	2,733	81,988
Substation Asset Assessment	84,589			84,589	SL-10 years	60,622	8,459	69,081
Infrastructure Plan (Phase2)	125,100			125,100	SL-10 years	89,655	12,510	102,165
Transmission Extension	84,762			84,762	SL-10 years	57,921	8,476	66,397
Mayo Dam Service Life Assessment	17,888			17,888	SL-5 years	17,590	298	17,888
Resource Plan Phase 1	205,329			205,329	SL-5 years	188,218	17,111	205,329
Fish Screen Assessment	909			909	SL-5 years	788	121	909
Infrastructure Plan Peer Review	187,754			187,754	SL-5 years	98,571	89,183	187,754
Insulation Coordination Study	20,806			20,806	SL-5 years	16,645	4,161	20,806
P126 Balance of Plant Assessment	53,775			53,775	SL-5 years	43,020	10,755	53,775
Resource Plan Phase 2	228,570			228,570	SL-5 years	137,142	45,714	182,856
L170 Line Assessment	213,987			213,987	SL-5 years	128,392	42,797	171,190
2006 Dam Safety Upgrades	27,141			27,141	SL-5 years	16,285	5,428	21,713
Wareham Spillway Wall Raise	8,588			8,588	SL-5 years	5,153	1,718	6,871
Marsh Lake Fall Storage	62,578			62,578	SL-5 years	37,547	12,516	50,063
2006 Yukon River Downstream Icing	146,612			146,612	SL-5 years	87,967	29,322	117,290
Customer Billing System Replacement	51,724			51,724	SL-5 years	31,035	10,345	41,379
Minto Mine PPA	769,057			769,057	SL-12 years	133,517	64,088	197,605
2006 Dam Safety Upgrades	110,244			110,244	SL-5 years	55,122	22,049	77,171
Hydro Storage & Gen Pre-Feasibility	409,335			409,335	SL-5 years	197,846	81,867	279,713
Mayo/Wareham Liquefaction Analysis	72,876			72,876	SL-5 years	34,009	14,575	48,584
Wareham Liquefaction Assessment	37,904			37,904	SL-5 years	15,162	7,581	22,742
Southern Lakes Hydrology Study	170,243			170,243	SL-5 years	68,097	34,049	102,146
Hydro Storage & Generation Pre-Feasibilty	185,082			185,082	SL-5 years	74,033	37,016	111,049
L170 Trx Line Assessment Carmacks	206,721			206,721	SL-5 years	82,688	41,344	124,032
Wareham Liquefaction Assessment	3,021			3,021	SL-5 years	1,108	604	1,712
Wareham Dam Reliability	21,365			21,365	SL-5 years	7,122	4,273	11,395
Aishihik Unit Up-rate Study	5,454			5,454	SL-5 years	1,818	1,091	2,909
Wareham Rock Face Feasibilty Phase 2	55,902			55,902	SL-5 years	18,634	11,180	29,814
Mayo Lake Structure Integrity Assessment	25,467			25,467	SL-5 years	5,093	5,093	10,187
Wareham Liquefaction Assessment	22,117			22,117	SL-5 years	4,424	4,423	8,847
Wareham Spillway Hoist Upgrade	41,617			41,617	SL-5 years	8,323	8,323	16,647
Metering Audit 2009	30,510			30,510	SL-5 years	6,102	6,102	12,204
Protection Event Collection System	28,187			28,187	SL-5 years	5,637	5,637	11,275
AH0 Deluge System	25,519			25,519	SL-5 years	-	5,104	5,104
P125 Headgates Single Point	50,419			50,419	SL-5 years	-	10,084	10,084
Wareham Consequence Category Assessment		62,882		62,882	SL-5 years		18,865	18,865
Mayo/Wareham Geotechnical Investigation	44,565	(3)		44,562	SL-5 years		8,912	8,912
Geothermal - Preliminary Eng & Env Studies	1,585,925	361,485		1,947,410	SL-10 years			-
WAF/MD Modeling and Stability	477,121	(29,585)		447,536	SL-5 years		52,213	52,213
Hydro Unit Performance Test	316,996	23,204		340,200	SL-5 years		34,020	34,020
WH4 (Rotor) Investigation	28,771	69,196		97,967	SL-5 years			-
Communications Strategy Study	16,684	63,892		80,576	SL-5 years			-
P125/126 Hydrocarbon Containment	26,396	1,176		27,572	SL-5 years		3,676	3,676
Study of Ice Processes in the Mayo River at Mayo	12,067	167,197		179,265	SL-5 years			-
IT Security Audit		38,071		38,071	SL-5 years			-
Mayo River Salmon Enhancement		7,212		7,212	SL-5 years			-
Mayo Lake Control Structure - Fish Passage		2,569		2,569	SL-5 years			-
Atlin Storage	2,062,448	168,204		2,230,652	SL-10 years			-
Wind Feasibility- Ferry Hill	35,700	391,917		427,617	SL-5 years			-
International Financial Reporting Standards	433,948	131,821		565,769	SL-5 years			-
System Stability Review		99,961		99,961	SL-5 years			-
Western Copper - Aerial Photo Mapping & Route Selection	30,233			30,233	SL-5 years			-
Short Term Energy Storage Feasibility		44,200		44,200	SL-5 years			-
Atlin Grid Connection Feasibility Study		109,941		109,941	SL-5 years			-
Mayo Lake Outlet Channel Bathymetry & Water Output Analysis		13,250		13,250	SL-5 years			-
Climate Change Study		106,659		106,659	SL-5 years			-
Large Hydro	480,905	190,852		671,757	SL-5 years			-
Total Feasibility Study Closed	9,535,555	2,024,101		11,559,656		1,921,506	787,506	2,709,012
WORK IN PROGRESS								
Aishihik River Icing - Berm	88,057	10,829	98,886	-				-
District Heating		70,449		70,449				
District Heating - Contributions		(530,000)		(530,000)				
Waste to Energy	235,777	505,226		741,003				
Waste to Energy - Contributions		(112,500)		(112,500)				
LNG (Liquified Natural Gas)		168,905		168,905				
Mayo B	(8,744)		(8,744)	-				
Marsh Lake Storage	1,482,879	1,748,029		3,230,907				
Gladstone	3,089,572	604,052		3,693,624				
Total Feasibility Study WIP	4,896,285	2,464,990	98,886	7,262,389		-	-	-
Total Feasibility	14,431,840	4,489,091	98,886	18,822,044		1,921,506	787,506	2,709,012

YUKON ENERGY CORPORATION **Table 5.5**
Continuity Schedule of Deferred Costs (2011) **April 2012**
($000S)

	Total expenditures					Accumulated Amortization		
	Dec 31 2010	Actual 2011 Additions	Actual 2011 Transfers/Write-offs	Actual 2011	Amortization Rate and Method	Dec 31 2010	2011 expenses	Actual 2011
Rate Case								
Completed projects:								
YUB 2007-7 & 9 - Resource Plan	642,853			642,853	SL-10 years	192,856	64,285	257,141
YUB 2007-7 & 9 - PPA Review	243,045			243,045	SL-12 years	60,761	20,254	81,015
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years	12,334	4,111	16,445
Reserve for Injuries & Damages - Study	42,500			42,500	SL-2 years			-
2008/2009 GRA Phase 2	407,141	143,577	238,181	312,537	SL-2 years			-
Brushing & ROW Vegetation Management	129,778	43,449		173,227	SL-2 years			-
Alexco PPA Regulatory Costs	25,272	36,672	8,090	53,854	SL-5 years			-
DSM	49,779	1,133,238	145,838	1,037,179	SL-10 years			-
DSM Contributions		(734,554)		(734,554)	SL-10 years			-
Rate Schedule 39 Inflation Update		27,659	1,968	25,691	SL-2 years			-
Rider F Policy Review		31,535		31,535	SL-2 years			-
Total Rate Case Closed	1,725,378	681,576	394,077	2,012,878		265,951	88,650	354,601
Work in Progress								
Resource Plan Update	175,097	633,906	175,097	633,906				
Total Rate Case	1,900,476	1,315,482	569,174	2,646,784		265,951	88,650	354,601
Relicensing								
Completed projects:								
Aishihik Relicensing	8,770,915	106,692		8,877,606		4,382,206	486,172	4,868,378
Whitehorse Relicensing	96,499			96,499		45,638	3,391	49,028
Mayo Relicensing	27,848			27,848		14,789	871	15,660
Air Emission Licence Renewal	200,359			200,359		78,167	57,091	135,258
Lewes Control Evaluation		70,786		70,786				
Total Relicensing Closed	9,095,620	177,478		9,273,098		4,520,800	547,525	5,068,324
Work in Progress								
Air Emission Licence Renewal		89,429		89,429				
Mayo Lake		1,434,000		1,434,000				
Total Relicensing WIP	-	1,523,429	-	1,523,429	-	-	-	-
Total Relicensing	9,095,620	1,700,907	-	10,796,527		4,520,800	547,525	5,068,324
Dam Safety Review								
Completed projects	331,597			331,597		212,862	23,747	236,609
Deferred Overhauls								
WIP								
DD2 Engine Overhaul		178,786		178,786				
Total Deferred Costs	**25,759,532**	**7,684,265**	**668,060**	**32,775,737**		**6,921,119**	**1,447,427**	**8,368,547**
Closed (includes Rate Case WIP)				**23,811,134**				
WIP (excludes Rate Case WIP)				**8,964,603**				
Net Deferred Costs (excluding WIP)								**15,442,587**

Note: This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION **Table 5.6**
Continuity Schedule of Deferred Costs (2012) **April 2012**
($000S)

	Total expenditures					Accumulated Amortization		
	Dec 31	Forecast 2012		Forecast	Amortization Rate and Method	Dec 31	2012 Forecast	Forecast
	2011	Additions	Transfers/ Write-offs	2012		2011	expenses	2012
Feasibility Study								
Completed projects-feasibility:								
Substation Asset Assessment	84,589			84,589	SL-10 years	69,081	8,459	77,540
Infrastructure Plan (Phase2)	125,100			125,100	SL-10 years	102,165	12,510	114,675
Transmission Extension	84,762			84,762	SL-10 years	66,397	8,476	74,873
Resource Plan Phase 2	228,570			228,570	SL-5 years	182,856	45,714	228,571
L170 Line Assessment	213,987			213,987	SL-5 years	171,190	42,797	213,987
2006 Dam Safety Upgrades	27,141			27,141	SL-5 years	21,713	5,428	27,141
Wareham Spillway Wall Raise	8,588			8,588	SL-5 years	6,871	1,718	8,588
Marsh Lake Fall Storage	62,578			62,578	SL-5 years	50,063	12,516	62,578
2006 Yukon River Downstream Icing	146,612			146,612	SL-5 years	117,290	29,322	146,612
Customer Billing System Replacement	51,724			51,724	SL-5 years	41,379	10,345	51,724
Minto Mine PPA	769,057			769,057	SL-12 years	197,605	64,088	261,693
2006 Dam Safety Upgrades	110,244			110,244	SL-5 years	77,171	22,049	99,220
Hydro Storage & Generation Pre-Feasibility	409,335			409,335	SL-5 years	279,713	81,867	361,580
Mayo/Wareham Liquefaction Analysis	72,876			72,876	SL-5 years	48,584	14,575	63,159
Wareham Liquefaction Assessment	37,904			37,904	SL-5 years	22,742	7,581	30,323
Southern Lakes Hydrology Study	170,243			170,243	SL-5 years	102,146	34,049	136,194
Hydro Storage & Generation Pre-Feasibility	185,082			185,082	SL-5 years	111,049	37,016	148,066
L170 Trx Line Assessment Carmacks	206,721			206,721	SL-5 years	124,032	41,344	165,376
Wareham Liquefaction Assessment	3,021			3,021	SL-5 years	1,712	604	2,316
Wareham Dam Reliability	21,365			21,365	SL-5 years	11,395	4,273	15,668
Aishihik Unit Up-rate Study	5,454			5,454	SL-5 years	2,909	1,091	3,999
Wareham Rock Face Feasibilty Phase 2	55,902			55,902	SL-5 years	29,814	11,180	40,995
Mayo Lake Structure Integrity Assessment	25,467			25,467	SL-5 years	10,187	5,093	15,280
Wareham Liquefaction Assessment	22,117			22,117	SL-5 years	8,847	4,423	13,270
Wareham Spillway Hoist Upgrade	41,617			41,617	SL-5 years	16,647	8,323	24,970
Metering Audit 2009	30,510			30,510	SL-5 years	12,204	6,102	18,306
Protection Event Collection System	28,187			28,187	SL-5 years	11,275	5,637	16,912
AH0 Deluge System	25,519			25,519	SL-5 years	5,104	5,104	10,208
P125 Headgates Single Point	50,419			50,419	SL-5 years	10,084	10,084	20,168
Wareham Consequence Category Assessment	62,882			62,882	SL-5 years	18,865	12,576	31,441
Mayo/Wareham Geotechnical Investigation	44,562			44,562	SL-5 years	8,912	8,912	17,825
Geothermal - Preliminary Eng & Env Studies	1,947,410	385,755		2,333,165	Note 2	-	194,741	194,741
WAF/MD Modeling and Stability	447,536			447,536	SL-5 years	52,213	89,507	141,720
Hydro Unit Performance Test	340,200			340,200	SL-5 years	34,020	68,040	102,060
WH4 (Rotor) Investigation	97,967	175,310		273,277	SL-5 years	-	19,593	19,593
Communications Stategy Study	80,576			80,576	SL-5 years	-	16,115	16,115
P125/126 Hydrocarbon Containment	27,572			27,572	SL-5 years	3,676	5,514	9,191
Study of Ice Processes in the Mayo River at Mayo	179,265	50,000		229,265	SL-5 years	-	35,853	35,853
IT Security Audit	38,071			38,071	SL-5 years	-	7,614	7,614
Mayo River Salmon Enhancement	7,212			7,212	SL-5 years	-	1,442	1,442
Mayo Lake Control Structure - Fish Passage	2,569			2,569	SL-5 years	-	514	514
District Heating	70,449	460,000		530,449	SL-5 years	-		
District Heating - Contributions	(530,000)			(530,000)	SL-5 years	-		
Atlin Storage	2,230,652			2,230,652	SL-10 years	-	223,065	223,065
Western Copper - Aerial Photo Mapping & Route Selection	30,233			30,233	SL-5 years	-	6,047	6,047
Large Hydro	671,757	200,000		871,757	SL-5 years	-	134,352	134,352
Short Term Energy Storage Feasibility	44,200			44,200	SL-5 years	-	8,840	8,840
International Financial Reporting Standards	565,769	101,307		667,076	SL-5 years	-	113,154	113,154
Atlin Grid Connection Feasibility Study	109,941	50,000		159,941	SL-5 years	-	21,988	21,988
Mayo Lake Outlet Channel Bathymetry & Water Output	13,250	55,500		68,750	SL-5 years	-	2,650	2,650
Climate Change Study	106,659	50,000		156,659	SL-5 years	-	21,332	21,332
Wind Feasibility- Ferry Hill	427,617	100,000		527,617	SL-5 years	-	85,523	85,523
System Stability Review	99,961	150,000		249,961	SL-5 years	-	19,992	19,992
Waste to Energy	741,003	612,500		1,353,503	SL-10 years			
Waste to Energy - Contributions	(112,500)	(112,500)		(225,000)				
Aishihik Hydro - Turbine-rerunnering		150,000		150,000	SL-5 years			
Faro FD1 Mirrlees Generator Assessment Rad Repair		50,000		50,000	SL-5 years			
Hydraulic Wood Removal System for Spill Gates at WH		75,000		75,000	SL-5 years			
Wareham Spillway Hoist Upgrade		100,000		100,000	SL-5 years			
Whitehorse Dam Break and Mapping		80,000		80,000	SL-5 years			
Marsh Lake Storage	3,230,907	800,000		4,030,907	SL-10 years			
Gladstone	3,693,624	200,000		3,893,624	SL-10 years			
Total Feasibility Study Closed	17,974,036	3,732,872		21,706,908		2,029,909	1,639,136	3,669,045
WORK IN PROGRESS								
LNG (Liquified Natural Gas)	168,905	1,500,000		1,668,905				
Total Feasibility	18,142,941	5,232,872	-	23,375,813		2,029,909	1,639,136	3,669,045

YUKON ENERGY CORPORATION **Table 5.6**
Continuity Schedule of Deferred Costs (2012) **April 2012**
($000S)

	Total expenditures					Accumulated Amortization		
	Dec 31 2011	Forecast 2012 Additions	Transfers/ Write-offs	Forecast 2012	Amortization Rate and Method	Dec 31 2011	2012 Forecast expenses	Forecast 2012
Rate Case								
Completed projects:								
YUB 2007-7 & 9 - Resource Plan	642,853			642,853	SL-10 years	257,141	64,285	321,427
YUB 2007-7 & 9 - PPA Review	243,045			243,045	SL-12 years	81,015	20,254	101,269
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years	16,445	4,111	20,557
Reserve for Injuries & Damages - Study	42,500			42,500	SL-2 years		21,250	21,250
2008/2009 GRA Phase 2	312,537			312,537	SL-2 years		156,269	156,269
Brushing & ROW Vegetation Management	173,227			173,227	SL-2 years		86,614	86,614
Alexco PPA Regulatory Costs	53,854			53,854	SL-5 years		10,771	10,771
DSM	1,037,179	1,074,000		2,111,179	SL-10 years		30,262	30,262
DSM Contributions	(734,554)			(734,554)	included in above			
Rate Schedule 39 Inflation Update	25,691			25,691	SL-2 years		12,846	12,846
Rider F Policy Review	31,535			31,535	SL-2 years		15,768	15,768
Resource Plan Update	633,906	225,000		858,906	SL-5 years		-	-
2012/2013 GRA Phase I		1,100,000		1,100,000	SL-2 years		550,000	550,000
Total Rate Case Closed	2,646,784	2,399,000	-	5,045,784		354,601	972,429	1,327,030
Relicensing								
Completed projects:								
Aishihik Relicensing	8,877,606			8,877,606		4,868,378	495,063	5,363,441
Whitehorse Relicensing	96,499			96,499		49,028	3,391	52,419
Mayo Relicensing	1,461,848	660,000		2,121,848		15,660	871	16,530
Air Emission Licence Renewal	289,788	87,403		377,191		135,258	57,091	192,350
Lewes Control Evaluation	70,786	22,123		92,909			5,899	5,899
Total Relicensing Closed	10,796,527	769,526		11,566,053		5,068,324	562,315	5,630,639
Dam Safety Review								
Completed projects	331,597			331,597		236,609	23,747	260,356
Deferred Overhauls								
Completed projects:								
DD2 Engine Overhaul	178,786	135,850		314,636	SL-5 years			
AH1 Ten Year Overhaul		325,000		325,000	SL-10 years			
AH2 Ten Year Overhaul		325,000		325,000	SL-10 years			
Total Closed	178,786	785,850	-	964,636				
WIP								
DD5 Bottom End Overhaul		500,000		500,000				
Total Deferred Overhauls	178,786	1,285,850	-	1,464,636				
Total Deferred Costs	**32,096,634**	**9,687,248**	**0**	**41,783,882**		**7,689,444**	**3,197,627**	**10,887,070**
Closed				**39,614,977**				
WIP				**2,168,905**				
Net Deferred Costs (excluding WIP)								**28,727,907**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.
2. Per paragraph 4.2 (a) of the proposed Planning Accounting Policy the 2011 major WIP projects that close out with costs exceeding $1 million amortizes over 10 years. The costs incurred in 2012 amortizes over 5 years (based on paragraph 2.3 of the mentioned Policy).

YUKON ENERGY CORPORATION **Table 5.7**
Continuity Schedule of Deferred Costs (2013) **April 2012**
($000S)

	Total Expenditures					Accumulated Amortization		
	Dec 31	Forecast 2013		Forecast	Amortization Rate and Method	Dec 31	2013 Forecast	Forecast
	2012	Additions	Transfers/ Write-offs	2013		2012	expenses	2013
Feasibility Study								
Completed projects-feasibility:								
Substation Asset Assessment	84,589			84,589	SL-10 years	77,540	7,049	84,589
Infrastructure Plan (Phase2)	125,100			125,100	SL-10 years	114,675	10,425	125,100
Transmission Extension	84,762			84,762	SL-10 years	74,873	8,476	83,349
Minto Mine PPA	769,057			769,057	SL-12 years	261,693	64,088	325,781
2006 Dam Safety Upgrades	110,244			110,244	SL-5 years	99,220	11,024	110,245
Hydro Storage & Generation Pre-Feasibility	409,335			409,335	SL-5 years	361,580	47,756	409,336
Mayo/Wareham Liquefaction Analysis	72,876			72,876	SL-5 years	63,159	9,717	72,876
Wareham Liquefaction Assessment	37,904			37,904	SL-5 years	30,323	7,581	37,904
Southern Lakes Hydrology Study	170,243			170,243	SL-5 years	136,194	34,049	170,243
Hydro Storage & Generation Pre-Feasibility	185,082			185,082	SL-5 years	148,066	37,016	185,082
L170 Trx Line Assessment Carmacks	206,721			206,721	SL-5 years	165,376	41,344	206,720
Wareham Liquefaction Assessment	3,021			3,021	SL-5 years	2,316	604	2,920
Wareham Dam Reliability	21,365			21,365	SL-5 years	15,668	4,273	19,941
Aishihik Unit Up-rate Study	5,454			5,454	SL-5 years	3,999	1,091	5,090
Wareham Rock Face Feasibility Phase 2	55,902			55,902	SL-5 years	40,995	11,180	52,175
Mayo Lake Structure Integrity Assessment	25,467			25,467	SL-5 years	15,280	5,093	20,373
Wareham Liquefaction Assessment	22,117			22,117	SL-5 years	13,270	4,423	17,693
Wareham Spillway Hoist Upgrade	41,617			41,617	SL-5 years	24,970	8,323	33,293
Metering Audit 2009	30,510			30,510	SL-5 years	18,306	6,102	24,408
Protection Event Collection System	28,187			28,187	SL-5 years	16,912	5,637	22,549
AH0 Deluge System	25,519			25,519	SL-5 years	10,208	5,104	15,312
P125 Headgates Single Point	50,419			50,419	SL-5 years	20,168	10,084	30,252
Wareham Consequence Category Assessment	62,882			62,882	SL-5 years	31,441	12,576	44,017
Mayo/Wareham Geotechnical Investigation	44,562			44,562	SL-5 years	17,825	8,912	26,737
Geothermal - Preliminary Eng & Env Studies	2,333,165	300,000		2,633,165	Note 2	194,741	271,892	466,633
WAF/MD Modeling and Stability	447,536			447,536	SL-5 years	141,720	89,507	231,227
Hydro Unit Performance Test	340,200			340,200	SL-5 years	102,060	68,040	170,100
WH4 (Rotor) Investigation	273,277			273,277	SL-5 years	19,593	54,655	74,249
Communications Strategy Study	80,576			80,576	SL-5 years	16,115	16,115	32,230
P125/126 Hydrocarbon Containment	27,572			27,572	SL-5 years	9,191	5,514	14,705
Study of Ice Processes in the Mayo River at Mayo	229,265			229,265	SL-5 years	35,853	45,853	81,706
IT Security Audit	38,071			38,071	SL-5 years	7,614	7,614	15,228
Mayo River Salmon Enhancement	7,212			7,212	SL-5 years	1,442	1,442	2,885
Mayo Lake Control Structure - Fish Passage	2,569			2,569	SL-5 years	514	514	1,028
District Heating	530,449	500,000		1,030,449	SL-5 years	-	90	90
District Heating - Contributions	(530,000)			(530,000)	included in above			
Atlin Storage	2,230,652			2,230,652	SL-10 years	223,065	223,065	446,130
Western Copper - Aerial Photo Mapping & Route Selection	30,233			30,233	SL-5 years	6,047	6,047	12,093
Large Hydro	871,757	100,000		971,757	SL-5 years	134,352	174,351	308,703
Short Term Energy Storage Feasibility	44,200			44,200	SL-5 years	8,840	8,840	17,680
International Financial Reporting Standards	667,076			667,076	SL-5 years	113,154	133,415	246,569
Atlin Grid Connection Feasibility Study	159,941			159,941	SL-5 years	21,988	31,988	53,976
Mayo Lake Outlet Channel Bathymetry & Water Output	68,750			68,750	SL-5 years	2,650	13,750	16,400
Climate Change Study	156,659			156,659	SL-5 years	21,332	31,332	52,664
Wind Feasibility- Ferry Hill	527,617	100,000		627,617	SL-5 years	85,523	105,523	191,047
System Stability Review	249,961			249,961	SL-5 years	19,992	49,992	69,984
Waste to Energy	1,353,503	500,000		1,853,503	Note 3	-	112,850	112,850
Waste to Energy - Contributions	(225,000)			(225,000)	included in above			
Aishihik Hydro - Turbine-rerunnering	150,000			150,000	SL-5 years	-	30,000	30,000
Faro FD1 Mirrlees Generator Assessment Radiator Repair	50,000			50,000	SL-5 years	-	10,000	10,000
Hydraulic Wood Removal System for Spill Gates at WH	75,000			75,000	SL-5 years	-	15,000	15,000
Wareham Spillway Hoist Upgrade	100,000	650,000		750,000	SL-5 years	-	20,000	20,000
Whitehorse Dam Break and Mapping	80,000			80,000	SL-5 years	-	16,000	16,000
Marsh Lake Storage	4,030,907	800,000		4,830,907	Note 3	-	403,091	403,091
Gladstone	3,893,624	500,000		4,393,624	Note 3	-	389,362	389,362
Condition Assessment of Selected YEC Assets		150,000		150,000	SL-5 years			-
VOIP Assessment		35,000		35,000	SL-5 years			-
Diesel Seismic Study - Dawson, Whitehorse, Faro		70,000		70,000	SL-5 years			-
Total Feasibility Study Closed	20,967,706	3,705,000	-	24,672,706		2,929,843	2,697,774	5,627,617
WORK IN PROGRESS								
LNG (Liquified Natural Gas)	1,668,905		1,668,905	-				
Total Feasibility Study WIP	1,668,905	-	1,668,905	-				
Total Feasibility	22,636,611	3,705,000	1,668,905	24,672,706		2,929,843	2,697,774	5,627,617

YUKON ENERGY CORPORATION **Table 5.7**
Continuity Schedule of Deferred Costs (2013) **April 2012**
($000S)

	Total Expenditures					Accumulated Amortization		
	Dec 31	Forecast 2013		Forecast	Amortization Rate and Method	Dec 31	2013 Forecast	Forecast
	2012	Additions	Transfers/ Write-offs	2013		2012	expenses	2013
Rate Case								
Completed projects:								
YUB 2007-7 & 9 - Resource Plan	642,853			642,853	SL-10 years	321,427	64,285	385,712
YUB 2007-7 & 9 - PPA Review	243,045			243,045	SL-12 years	101,269	20,254	121,522
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years	20,557	4,111	24,668
Reserve for Injuries & Damages - Study	42,500			42,500	SL-2 years	21,250	21,250	42,500
2008/2009 GRA Phase 2	312,537			312,537	SL-2 years	156,269	156,269	312,537
Brushing & ROW Veg Management	173,227			173,227	SL-2 years	86,614	86,614	173,227
Alexco PPA Regulatory Costs	53,854			53,854	SL-5 years	10,771	10,771	21,541
DSM	2,111,179	1,635,000		3,746,179	SL-10 years	30,262	137,662	167,925
DSM Contributions	(734,554)			(734,554)	included in above			
Rate Schedule 39 Inflation Update	25,691			25,691	SL-2 years	12,846	12,846	25,691
Rider F Policy Review	31,535			31,535	SL-2 years	15,768	15,768	31,535
Resource Plan Update	858,906			858,906	SL-5 years	-	171,781	171,781
2012/2013 GRA Phase I	1,100,000			1,100,000	SL-2 years	550,000	550,000	1,100,000
Total Rate Case Closed	5,045,784	1,635,000	-	6,680,784		1,327,030	1,251,610	2,578,640
Relicensing								
Completed projects:								
Aishihik Relicensing	8,877,606			8,877,606		5,363,441	495,063	5,858,504
Whitehorse Relicensing	96,499			96,499		52,419	3,391	55,810
Mayo Relicensing	2,121,848			2,121,848		16,530	161,948	178,478
Air Emission Licence Renewal	377,191			377,191		192,350	89,306	281,656
Lewes Control Evaluation	92,909			92,909		5,899	7,910	13,809
Total Relicensing Closed	11,566,053	-	-	11,566,053		5,630,639	757,617	6,388,257
Dam Safety Review								
Completed projects	331,597			331,597		260,356	23,747	284,103
Deferred Overhauls								
Completed projects:								
DD2 Engine Overhaul	314,636			314,636	SL-5 years		62,927	62,927
AH1 Ten Year Overhaul	325,000	300,000		625,000	SL-10 years		32,500	32,500
AH2 Ten Year Overhaul	325,000	300,000		625,000	SL-10 years		32,500	32,500
DD5 Bottom End Overhaul	500,000	150,000		650,000	SL-5 years			
DD3 Engine Overhaul - Complete		350,000		350,000	SL-5 years			
WH3 Ten Year Overhaul		500,000		500,000	SL-10 years			
Total Closed	1,464,636	1,600,000	-	3,064,636		-	127,927	127,927
Total Deferred Costs	**41,044,681**	**6,940,000**	**1,668,905**	**46,315,776**		**10,147,869**	**4,858,675**	**15,006,544**
Closed				**46,315,776**				
WIP				**0**				
Net Deferred Costs (excluding WIP)								**31,309,231**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.
2. Per paragraph 4.2 (a) of the proposed Planning Accounting Policy the 2011 major WIP projects that close out with costs exceeding $1 million amortizes over 10 years. The costs incurred in 2012 amortizes over 5 years (based on paragraph 2.3 of the mentioned Policy).
3. Per paragraph 4.2 (b) of the proposed Planning Accounting Policy the 2011 major WIP projects where the close outs delayed until end of 2012 with total costs exceeding $1 million amortizes over 10 years. The costs incurred in 2013 amortizes over 5 years (based on paragraph 2.3 of the mentioned Policy).

APPENDIX 5.1
PLANNING POLICY

YUKON ENERGY	FINANCE POLICY FA-016	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Chief Financial Officer	Planning Accounting
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2012	February 2015	President & CEO

1.0 Purpose

1.1 The purpose of this policy is to outline the accounting policy for costs incurred in relation to Planning activities.

1.2 Planning and study costs include, but are not limited to, the following:
- Generation planning;
- Pre-feasibility and feasibility;
- Environmental;
- Water management;
- Fisheries;
- Reconnaissance;
- Survey and investigation; and
- Water license renewal studies

2.0 Policy

2.1

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

2.2 Planning costs deferred without amortization must meet a "Reasonable Assurance Test":
a. Future expenditures will not be recognized as work-in-progress assets[1] until such time as there is reasonable assurance that a Corporation commitment to construction will be made.[2]
b. In the event a project is abandoned after this step, accrued costs will be amortized over 10 years.

2.3 Planning costs incurred in relation to major projects that do not meet Reasonable Assurance will promptly be closed out in annual stages, and amortized over 5 years[3]:

[1] That is, carried beyond each year end as a deferred cost without amortization.
[2] Such assurance would be consistent with a decision by YEC to define a specific project location, approach, technology, etc, and/or to prepare and file a YESAB Project Proposal, enter into substantive negotiations with First Nations or project partners, preparation of engineering designs and tender materials, and arrange project financing where needed (i.e., the YEC "Commitment to Proceed" test).
[3] This approach is adopted primarily for rate stability reasons, and is relevant for YUB regulation but not necessarily for internal IFRS accounting.

a. Costs will not be carried/deferred beyond periods of approximately 12 months and all costs incurred within the 12 month period will be closed out and amortized over 5 years.
b. All projects will be scrutinized as part of the year-end financial review to ensure the requirement for annual milestones and close-outs is being met.
   i. Tangible products or reports shall be required within the deferral period in order to demonstrate a useful "asset".
   ii. If there is no demonstrable tangible product or report, the costs incurred to date will be closed out and the balances will be written off to income in that year.

2.4 Planning and study costs related to water license renewals shall be deferred and amortized over the term of the renewed license.

3.0 Application

3.1 Management should use its best judgment in determining which of the above categories each specific study applies to.

4.0 Transition Policy for 2012 & 2013 Test Years

4.1 A one-time special transition approach for costs presently in WIP is to be implemented over 2012 and 2013 test years. Transition measures are intended to mitigate rate impacts from 5-year amortization of existing WIP costs incurred prior to Reasonable Assurance and that have climbed to over $1 million in the past few years.

4.2 Where appropriate, current balances for Major Projects in WIP will be crystallized and amortized over 10 years as follows:
a. Allow 10-year amortization for current (2011) major WIP projects that close out with costs exceeding $1 million[4]; and
b. Allow delay of close out until end of 2012 for eligible projects with ongoing costs assumed in 2012[5].

[4] This includes Marsh Lake Storage, Atlin Storage, Gladstone, Geothermal, and Waste to Energy WIP projects, including 2012 forecast spending for the major projects close-out delayed until end of 2012..
[5] The following projects are assumed to have close out delayed until the end of 2012: Marsh Lake Storage, Gladstone and Waste to Energy.

APPENDIX 5.2
DSM POLICY

YUKON ENERGY	FINANCE POLICY FA-015	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Chief Financial Officer	Demand Side Management Accounting
		ISSUED:	REVIEW DATE:	APPROVED BY:
		March 2012	February 2015	President & CEO

1.0 Purpose

1.1 The purpose of this policy is to outline the accounting policy for costs incurred in relation to Demand Side Management (DSM) activities.

1.2 DSM is defined as "options available to electric utilities to alter the volume and pattern of electricity end-use, so as to improve or increase the efficiency of electricity production and system performance". This includes any improvements in Corporation "end use" such as insulation in its buildings, but does not include Supply Side Enhancements that the Corporation does to improve efficiency of generation and transmission activities**.**

1.3 The intent of DSM programming is to implement programs or rate structures designed to influence electricity consumption patterns by reducing and/or shifting loads. The primary benefits of DSM for the Yukon were seen to be lower costs of providing electrical service and enhanced customer relations.

2.0 Policy

2.1 Costs associated with specific DSM programs will be deferred and amortized on a straight-line basis:

a. DSM program expenditures will be deferred where a specific program is defined and is expected to proceed to the development stage and is expected to achieve net benefits. The following conditions may be relevant to this determination:
   i. A defined plan, product or program has been identified.
   ii. The technical feasibility of the defined plan product or program and its benefits have been established, a future market is defined and adequate financial resources are expected to be available to complete the plan, product or program.
   iii. Management has indicated its intention to proceed with the program.

b. Research related activities not associated with a specific program will be expensed in the year incurred.

2.2 The following DSM-related costs shall be expensed as incurred:

a. Administrative and other general overhead expenditures are expensed unless the expenditure can be directly attributed to a specific DSM program.
b. Expenditures related to information programs and advertising unless directly attributed to a specific DSM program.
c. Expenditures on training staff shall be expensed.

2.3 The amortization period for deferred DSM expenditures shall be ten years.

a. Over each year eligible DSM program expenditures will be deferred.

b. At the end of each year eligible deferred DSM program expenditures will be closed out and amortized over the following ten years.

APPENDIX 5.3
MAYO B FLEXIBLE NOTE

APPENDIX 5.3: MAYO B FLEXIBLE NOTE

PRIOR COMMITMENTS

Yukon Energy, when seeking approval to proceed with the Mayo B Project, committed in the Mayo B Part 3 Application that it would secure (via Yukon Development Corporation [YDC]) flexible debt financing for the Mayo B Project (i.e., measures to reduce overall return on rate base in order to mitigate specific near-term rate impact concerns), and at that time outlined as follows the rationale and broad approach for this financing.

The Mayo B flexible debt will allow the interest rate on the debt to change, based on the IS [Integrated System] grid generation load, as required to prevent, in any fiscal year during the short-term, the cost of Mayo B net generation used to displace diesel generation from exceeding a 10 to 11 c/kW.h range (2012$). [YEC's Mayo B Project Part 3 Application, page 45].

Additional commitments for this flexible debt included in the Mayo B Part 3 Application (page 45) were as follows:

- YDC funding at no cost to YEC for the additional interest rate reductions (including cash injections through 'negative' interest rate payments) required in this regard (i.e., to prevent net generation cost from exceeding the stipulated unit cost range) to mitigate any delays in connecting the Carmacks Copper mine load to the grid – these no cost arrangements for YEC were to apply in the short-term for years before the Carmacks Copper assumed operating load of approximately 50 GW.h/year was to be supplied from the grid.

- The face interest for this flexible debt (i.e., the rate charges when no interest rate reductions apply) will be set above YEC's then applicable long-term borrowing costs in order to enable YDC an opportunity to earn an overall return on the load over its life equal to YDC's long-term borrowing costs when the flexible debt is established.

The specific methodology for implementation of the above financing was not developed at the time of the Part 3 hearing. The YUB noted in its Report and Recommendations to the Minister following the Mayo B hearing (page 45) that it expects "...the complete details of the flexible debt financing with YDC and illustrative examples of how the flexible debt financing works will be provided by YEC in its next GRA."

OVERVIEW OF FLEXIBLE DEBT NOTE

The YDC Mayo B Flexible Debt (long-term promissory note – the "Note") with YEC for $21.9 million[1] that was concluded effective December 31, 2011 is attached at Attachment 5.3. Illustrative examples of how the flexible debt financing works are provided in Schedule 2 of the Note.

[1] The budget for the Mayo B project is $120 million. The majority of the financing for the Mayo B project is derived from other sources (Federal Infrastructure Fund payments of $53.35 million and Yukon Government Contributions of $30.15 million), resulting in this project being expected to add $36.5 million to YEC's asset base. In keeping with the 60:40 debt:equity structure, this asset addition requires a debt component of $21.9 million (60% of $36.5 million). At the time that the Note was concluded in November/December 2011, commissioning of Mayo B was scheduled for completion during December, 2011, and this Note was therefore required to be in place by December 31, 2011.

Simplified terms for the Mayo B Flexible Debt have been established that in summary reflect the following. The simplified terms and other revisions are summarized below:

- **Debt Amount** – The Note is for the full $21.9 million, assuming that the ultimate net rate base for Mayo B is $36.5 million.

- **Term** – 40 years (reflects maximum term of other flexible debt in the past for YDC with YEC). The following are noted with regard to the Term:

    - Flexible interest terms extend to the Expiry Date, which is January 1, 2021 if the Mayo Lake Project is in service, and otherwise is January 1, 2023.

    - Annual principal repayment is calculated based on an assumed 65 year project life (depreciation), with a balloon payment for the outstanding balance at the end of the Term.

- **Interest Rate** – The 5.46% annual rate was determined as the rate estimated to achieve a forecast interest IRR of 5% over the Term, taking into account forecast Maximum Interest Payable under grid loads as currently forecast by YEC assuming connection of Victoria Gold by late 2014, and assuming connection to the grid at a minimum of at least 52 GW.h/year of new mine load (compared to forecast Minto and Alexco loads) at the start of 2012 and remaining for six years (i.e., to the end of 2017).

- **Simplified Approach to determine Maximum Interest Payable Prior to the Expiry Date** – The simplified approach follows the Canada Flexible Debt mechanics that rely on readily available grid generation records, and avoids the complexities of requiring annual reviews of actual YEC costs and estimates of annual net generation used to displace diesel or other fossil fuel generation on the grid.

    - The simplified approach assumes a ceiling on interest payments in any year at 11 cents/kW.h in 2012$ (adjusted after 2012 by annual Yukon CPI escalation) times the estimated grid diesel generation displaced by Mayo B based on the actual grid generation load and long term average annual grid hydro generation at that load assuming renewable generation capability in place and as licensed in December 2012, i.e., no Mayo Lake project and Aishihik FAA as at this time[2].

    - "Actual Grid Generation" is to be determined for this purpose after adding back the estimated reduction, if any, in grid generation in that years due to DSM/SSE (as defined in the Note) undertaken since December 31, 2012[3].

    - The assessments of maximum and minimum grid loads adopted in the simplified approach (Schedule 1 attached) were calibrated and tested using detailed model calculations of the applicable **maximum grid load** (i.e., load at which full interest payable) and **minimum grid load** (i.e., load at which no interest payable) based on

[2] The Note is not varied in the event that new renewable generation is added to the grid, or the existing licences are modified, after December 31, 2012, i.e., the assistance that was committed related solely to load-related risk affecting diesel displacement by Mayo B and was independent of impacts on such diesel displacement as a result of subsequently approved new generation projects.
[3] The Note is not varied by the impacts of DSM/SSE, i.e., the assistance that was committed related solely to load-related risk independent of impacts of DSM/SSE.

forecast annual Mayo B operating and maintenance costs, 65 year depreciation of the assumed $36.5 million net rate base cost, and equity at 40% of rate base with an allowed ROE of 8.49%/year.

- Figures 5.3A-1 and 5.3A-2 provide further information on this analysis.

Figure 5.3-1

Mayo B Grid Load at Full Interest, at 5%, no more than 11 cents/kW.h in $2012

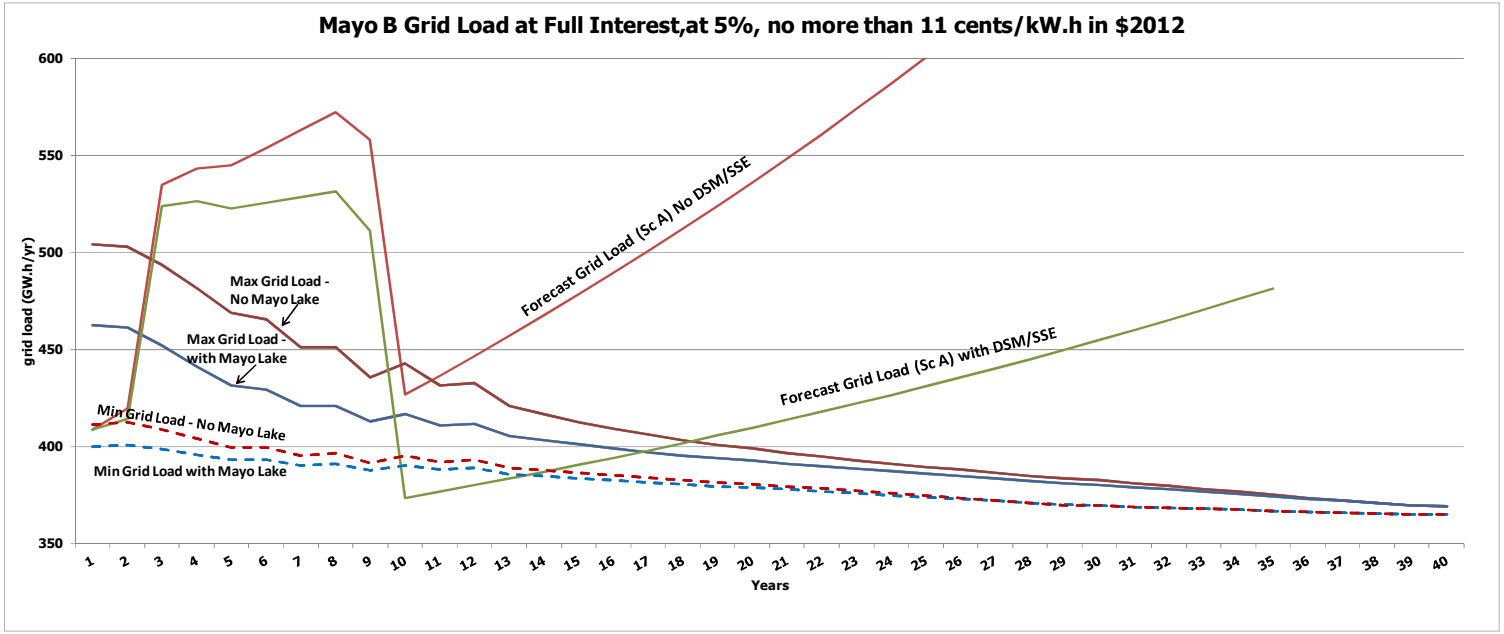


Figure 5.3A-1 shows detailed calculated estimates (i.e., not using the simplified approach) by year (year 1=2012) of **Maximum Grid Load** (at and above this level full interest is paid) and **Minimum Grid Load** (at this level zero interest is paid, and below this level negative interest is paid), assuming interest is constrained as required to ensure Mayo B annual costs do not exceed 11 cents per kW.h (2012$) of net generation (diesel displaced) by Mayo B, and based on assumed forecast annual Mayo B costs for O&M, depreciation and return on equity. Max and Min Grid Loads are shown by year both (a) with no Mayo Lake Project and (b) with Mayo Lake Project enhanced storage (1 metre lower bottom storage) – including the Mayo Lake Project reduces the Max and Min Grid Loads. Figure 5.3-1 also shows forecast grid loads by year, indicating years when full interest is expected to be paid versus years when interest is expected to be reduced. Current [as at November/February 2011] forecast loads are shown for the first two years (2012 and 2013); after 2013, the forecast shows the currentt [as at November/February 2011] longer-term planning YEC grid generation forecast with Victoria Gold. Separate grid load forecasts are provided with no DSM/SSE, as well as the lower loads with maximum DSM/SSE as assumed in current long-term resource planning forecasts.

In summary, Figure 5.3A-1 shows that full interest would be paid each year that Victoria Gold is on the grid, as well as each year after 2021 with only non-industrial forecast grid loads, i.e., no mines connected to the grid, assuming no reductions for DSM/SSE are considered. Without Victoria Gold loads, however, only minimal interest would be paid for many years prior to 2022. Further, if DSM/SSE impacts materially reduce grid loads the period with no or reduced interest would be greatly extended in the absence of new mine loads and/or adjustment to remove the effects of DSM/SSE when determining Mayo B Flexible Debt interest payments.

The Mayo B Flexible Debt commitments were made based only on Mayo B and the grid resources and licences at the time of the Mayo B commitment, and are not intended to reflect changes due to subsequent resource investments such as DSM/SSE or new renewable generation resources on the grid.

Figure 5.3-2
Mayo B Grid Load at 40 Years Flex Term Debt (lump sum payment in year 40), 65 years depreciation, no more than 11 cents/kW.h in $2012

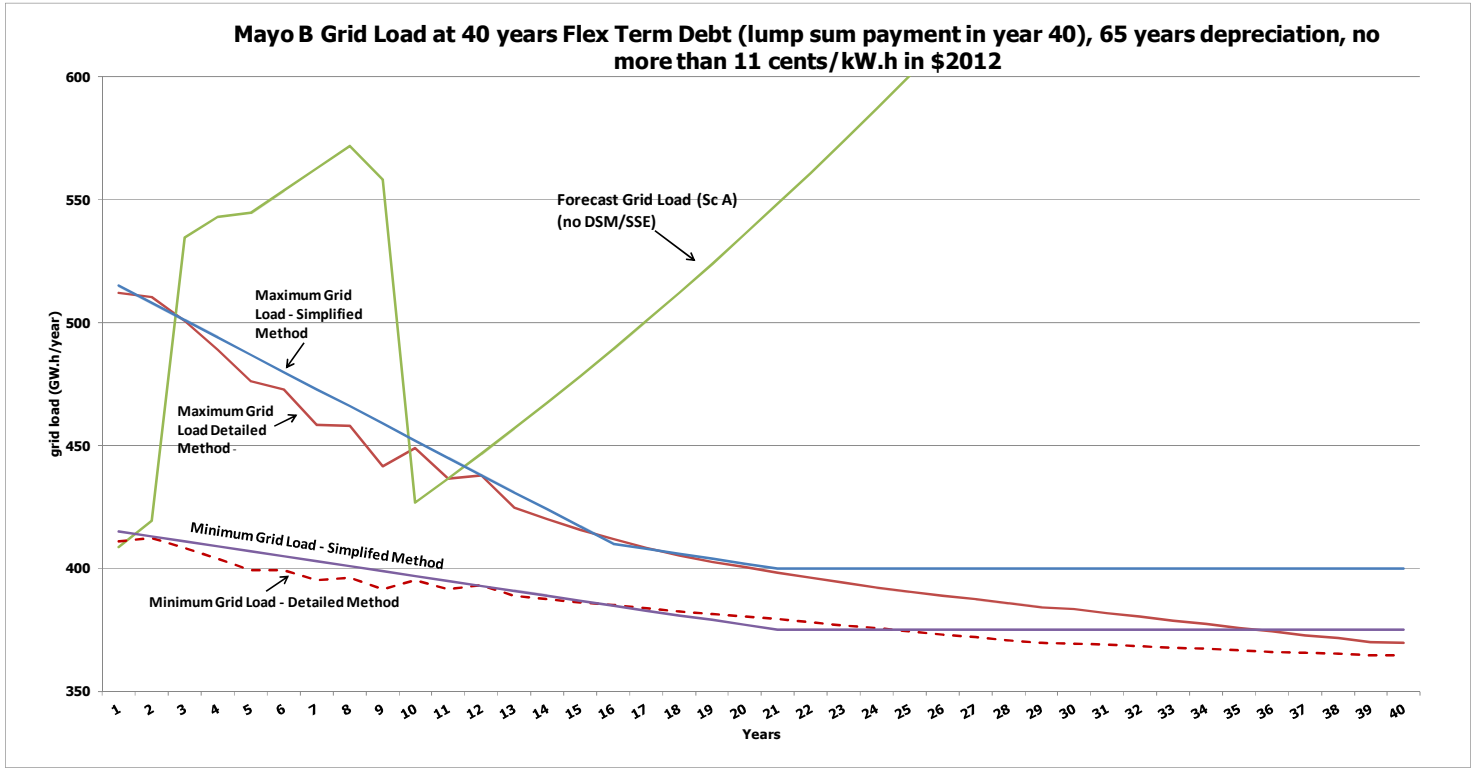


Figure 5.3-2 shows **Maximum Grid Load** (at and above this level full interest is paid) and **Minimum Grid Load** (at this level zero interest is paid, and below this level negative interest is paid), comparing the Simplified Method and the Detailed Calculation Method (see Figure 5.3-1). Forecast grid loads are also shown by year assuming no DSM/SSE (the current [as at November/February 2011] YEC forecast loads are shown for the first two years [2012 and 2013]; after 2013, the forecast shows the current [as at November/February 2011] long-term resource planning grid generation forecast with Victoria Gold).

Figure 5.3-2 shows that the Simplified Method in almost every year results in Max and Min Grid loads that are equal to or higher than those determined with the Detailed Calculation Method.

The Interest Rate of 5.46% was determined as the rate estimated to achieve a forecast interest IRR of 5% over the 40-year term, taking into account forecast Maximum Interest Payable under the grid loads shown in Figure 5.3-2 (with "Carmacks Copper" minimum loads assumed in 2012 and 2013 per commitments by YEC in the Part 3 proceeding, i.e., assuming connection to the grid at a minimum of at least 52 GW.h/year of new mine load [compared to forecast Minto and Alexco loads)]at the start of 2012 and remaining for six years [i.e., to the end of 2017]). In the event that the Mayo Lake Project is approved, Figure 5.3-1 demonstrates that the 11 cent per kW.h cost ceiling would be met by 2020/21 at grid loads with no mines connected.

ATTACHMENT 5.3: MAYO B PROMISSORY NOTE

December 31, 2011 $21,900,000
Due in installments

1. Promise to Pay

1.1 Effective as of December 31, 2011, in consideration of the advance by way of loan of the sum of $21,900,000 from Yukon Development Corporation ("**YDC**") to Yukon Energy Corporation ("**Yukon Energy**") Yukon Energy promises to pay to YDC, the principal amount of, and interest on, $21,900,000 in lawful money of Canada as follows:

(a) 40 equal annual installments of principal of $336,923.07 each, payable on December 31 of each calendar year commencing on December 31, 2012 and continuing up to and including December 31, 2051; and

(b) a final payment of principal of $8,423,078, payable on December 31, 2051;

(c) subject to Sections 1.2 below, interest at the Interest Rate, calculated annually, and not in advance, on the principal amount from time to time remaining unpaid as of December 31 of each calendar year of this Note prior to the payment of principal in that calendar year. Such interest is to accrue from January 1 to December 31 and include each calendar year of this Note. Interest is payable on December 31 of each calendar year commencing on December 31, 2012 up to and including December 31, 2051.

1.2 **Limitation on Interest.** Notwithstanding Section 1.1(c), prior to the Expiry Date, the amount of interest payable in each calendar year of this Note will not be more than the Maximum Interest Payable in that year (as defined below), determined as of December 31 of each calendar year of this Note. If the Interest Rate exceeds the Maximum Interest Payable in a calendar year then the terms set out in Section 3.1 will apply. For greater certainty, if the Maximum Interest Payable under this Note is a negative number then YDC will pay to Yukon Energy the positive dollar amount of that number on or before March 31 of the next calendar year.

1.3 **Application of Payments.** Payments received will be applied firstly in payment of unpaid interest and the balance, if any, in reduction of principal.

1.4 **Sample Calculation.** A sample calculation of the annual interest payment (Maximum Interest Payable) is attached to this Note as Schedule 2.

2. Definitions and Interpretation

2.1 **Definitions.** In this Note the following terms have the following meanings:

(a) **"Actual Grid Generation"** means in any calendar year commencing with 2012, the total GW.h in that year of Yukon Energy generation and purchased power on the electrical grid system connected with Mayo B based upon metered readings (or based upon reasonable estimates thereof consistently applied from year to year where it is unreasonable or impractical to base grid generation or purchased power upon metered readings), plus the estimated reduction, if any, in such grid generation in that year due to DSM/SSE undertaken since December 31, 2012;.

(b) **"Business Day"** means any day other than a Saturday, Sunday, or a statutory holiday in the Yukon Territory;

(c) "**DSM/SSE**" means the estimated amount by which Actual Grid Generation in any calendar year has been reduced due to demand side management and supply-side enhancement measures undertaken by the Yukon Territorial Government, Yukon Energy, or Yukon Electrical Company Limited since December 31, 2012, based on reasonable estimates thereof by Yukon Energy consistently applied from year to year; for this purpose,

(i) "**demand side management**" measures include any load reduction measures undertaken specifically by the Yukon Government, Yukon Energy or the Yukon Electrical Company Limited to reduce the electrical sales to customers required to be supplied by Yukon Energy or the Yukon Electrical Company Limited on the electrical grid system connected with Mayo B; and

(ii) "**supply-side enhancement**" measures include any generation or transmission efficiency improvement measures undertaken specifically by Yukon Energy or the Yukon Electrical Company Limited, other than demand side management measures, to reduce the electrical generation required to be supplied by Yukon Energy or the Yukon Electrical Company Limited on the electrical grid system connected with Mayo B;

(d) "**Expiry Date**" means the earlier of:

(i) if the Mayo Lake Project is in service, January 1, 2021; or

(ii) January 1, 2023.

(e) **"Interest Rate"** means in each calendar year of this Note that annual rate of interest equal to **[5.46%]**;

(f) "**Mayo Lake Project**" means the enhancement of the storage upstream of the Mayo B Project by adding additional drawdown to YEC's authorized storage

range at Mayo Lake beyond the storage range authorized as at December 31, 2011;

(g) **"Maximum Grid Load"** for each calendar year is as established in Schedule 1 to this Note;

(h) **"Maximum Interest Payable"** means for any calendar year:

(i) The Interest Rate if Actual Grid Generation for the calendar year is at or above the Maximum Grid Load established in Schedule 1 of this Note for that calendar year; or

(ii) If Actual Grid Generation for the calendar year is below the Maximum Grid Load established in Schedule 1 of this Note for that calendar year, an amount arrived at by applying the following formula for the Actual Grid Generation, Minimum Gird Load and Range values for that calendar year:

$$\frac{\text{(Interest Rate)} \times \text{(Actual Grid Generation} - \text{Minimum Grid Load)}}{\text{(Range)}}$$

(i) **"Maximum Interest Payable Statement"** has the meaning set out in Section 3.2;

(j) **"Mayo B"** means Yukon Energy's Mayo Hydro Enhancement Project;

(k) **"Minimum Grid Load"** for each calendar year is as established in Schedule 1 to this Note;

(l) **"Note"** means this Promissory Note;

(m) **"Parties"** means Yukon Energy and YDC and **"Party"** means any one of them;

(n) **"Range"** for each calendar year is as established in Schedule 1 to this Note; and

(o) **"YUB"** means the Yukon Utilities Board.

2.2 **Headings.** The headings are inserted for convenience of reference only and will not affect the construction or interpretation of this Note.

2.3 **Governing Law.** This Note will be governed by, and construed under the laws of the Yukon Territory.

2.4 **Invalidity of Any Provision.** If any covenant, obligation, or provision contained in this Note is invalid or unenforceable, the remainder of this Note will not be affected and each covenant, obligation, or provision of this Note will separately be valid and enforceable to the fullest extent permitted by law.

2.5 **Amendments.** This Note may only be amended from time to time in writing and any such amendment may be evidenced by a document signed by an authorized officer of each of the Parties.

2.6 **Included Words.** Whenever the singular or the masculine is used the same will be considered to include the plural or the feminine or the body corporate where the context or the Parties so require.

3. Maximum Interest Payable

3.1 **Interest Abatement.** The amount of interest, if any, which is payable under this Note as a result of the Interest Rate exceeding the Maximum Interest Payable will abate forever and will not be payable by Yukon Energy to YDC, it being the clear intention of the Parties that the amount of interest payable by Yukon Energy as a result of the Interest Rate payable by Yukon Energy to YDC will not exceed the Maximum Interest Payable.

3.2 **Maximum Interest Rate Statement.** Yukon Energy covenants and agrees to provide YDC on or before March 31 in each year of the Note commencing March 31, 2013 and continuing until the whole of the principal and interest under the Note is paid, with a statement (the "**Maximum Interest Payable Statement**") certified by the Chief Financial Officer of Yukon Energy as to the Maximum Interest Payable for the preceding calendar year, including explanation of any estimates (including any DSM/SSE estimates) used in the determination of the Maximum Interest Payable. If the Maximum Interest Payable Statement at March 31 of each year differs from the interest paid under Section 1.1 as at December 31 of the preceding calendar year, payment of the difference will be made forthwith by either YEC or YDC, as the case may be, together with simple interest at the Interest Rate computed from January 1 to the date of payment.

3.3 **Dispute.** If YDC does not object in writing to the Maximum Interest Payable Statement within 30 days of receipt of such statement from Yukon Energy the Maximum Interest Payable Statement will be final and binding on YDC. If YDC does object in writing to the Maximum Interest Rate Statement within such 30 days the Parties will negotiate in good faith a resolution to the dispute for a period of 15 days. If the dispute is not resolved by the Parties the matter will be referred to a single arbitrator under the *Arbitration Act* (Yukon Territory), whose decision will be final and binding on the Parties. If the arbitrator's decision differs from the Maximum Interest Rate Statement, payment of the difference will be made forthwith by either YDC or Yukon Energy, as the case may be, together with simple interest at the Interest Rate computed from January 1 to the date of payment.

3.4 **Access to Books and Records.** Yukon Energy will allow YDC and YDC's representatives access to the books, records, and other documents of Yukon Energy at all reasonable times for the purpose of verifying the Maximum Interest Payable.

4. General

4.1 **Disposition of Project.** If Yukon Energy sells, transfers, or otherwise disposes of Mayo B without the prior written approval of YDC, which may be arbitrarily withheld, then YDC may,

at any time thereafter, demand payment of the entire principal and interest owing under the Note, whereupon the entire principal and interest then remaining will become due and payable notwithstanding any other provision of this Note.

4.2 **Insurance Proceeds.** If there is damage to all or part of the Project for which insurance proceeds are paid to Yukon Energy and which are not used to repair or replace such damage within a reasonable time with work commencing within six months of the damage having occurred, Yukon Energy will be required to pay to YDC the amount of such proceeds first, in reduction of any outstanding interest under the Note and then in reduction of any outstanding principal under the Note.

4.3 **Prepayment.** The principal amount due under the Note may be paid by Yukon Energy in whole or in part with mutual agreement of the Parties on one year's written notice without bonus or penalty.

4.4 **Default.** Upon default in payment of any payment when due under this Note, the entire unpaid balance of the principal amount and accrued interest will become immediately due and payable without notice or demand and the undersigned covenants to pay interest on it and on subsequent overdue interest at the Interest Rate, both before and after judgment, until paid in full. The covenants to pay interest will not merge on the taking of a judgment or judgments with respect to any of the obligations stipulated for this Note.

4.5 ***Interest Act* of Canada.** For the purposes of the *Interest Act* (Canada), whenever any interest is calculated in respect of this Note on the basis of a period of time other than a calendar year, the annual rate of interest to which each rate of interest determined pursuant to such calculation is equivalent to such rate as so determined multiplied by the actual number of days in the calendar year in which the same is to be ascertained and divided by the number of days used in the basis for such determination.

4.6 **Notices.** In this Note:

(a) any notice or communication required or permitted to be given under this Note will be in writing and will be considered to have been given if delivered by hand, transmitted by facsimile transmission or mailed by prepaid registered post in Canada, to the address or facsimile transmission number of each Party set out below:

(i) if to YDC:

206A Lowe Street
Whitehorse, YT Y1A 1W6

Attention: President
Fax No.: 867-393-7071

(ii) if to Yukon Energy:

#2 Miles Canyon Road

Whitehorse, YT Y1A 6S7

Attention: President
Fax No.: 867-393-5323

or to such other address or facsimile transmission number as any Party may designate in the manner set out above; and

(b) notice or communication will be considered to have been received:

(i) if delivered by hand during business hours on a Business Day, upon receipt by a responsible representative of the receiver, and if not delivered during business hours, upon the commencement of business on the next Business Day;

(ii) if sent by facsimile transmission during business hours on a Business Day, upon the sender receiving confirmation of the transmission, and if not transmitted during business hours, upon the commencement of business on the next Business Day; and

(iii) if mailed by prepaid registered post in Canada, upon the fifth Business Day following posting; except that, in the case of a disruption or an impending or threatened disruption in postal services every notice or communication will be delivered by hand or sent by facsimile transmission.

4.7 **Assignment by Yukon Energy.** Yukon Energy may not to assign this Note, except with the prior written consent of YDC.

4.8 **Assignment by YDC.** YDC may assign this Note without the consent of Yukon Energy.

4.9 **Enurement.** This Note and all its provisions will enure to the benefit of and be binding upon the Parties, their successors and permitted assigns.

4.10 **Yukon Energy Waiver.** Yukon Energy waives demand and presentment for payment, notice of non-payment, protest, notice of protest, notice of dishonour, bringing of suit, and diligence in taking any action.

4.11 **Set-off.** Yukon Energy will not be entitled to set-off against any payments payable to YDC under this Note any amounts owing or alleged to be owing by YDC to Yukon Energy.

Executed at Whitehorse, Yukon Territory, on December _____, 2011.

YUKON ENERGY CORPORATION

Per:

_____

Authorized Signatory

_____

Authorized Signatory

YUKON DEVELOPMENT CORPORATION

Per:

_____

Authorized Signatory

_____

Authorized Signatory

SCHEDULE 1

	Year	Maximum Grid Load (GWh)	Minimum Grid Load (GWh)	Range
1	2012	515	415	100
2	2013	508	413	95
3	2014	501	411	90
4	2015	494	409	85
5	2016	487	407	80
6	2017	480	405	75
7	2018	473	403	70
8	2019	466	401	65
9	2020	459	399	60
10	2021	452	397	55
11	2022	445	395	50
12	2023	438	393	45
13	2024	431	391	40
14	2025	424	389	35
15	2026	417	387	30
16	2027	410	385	25
17	2028	408	383	25
18	2029	406	381	25
19	2030	404	379	25
20	2031	402	377	25
21	2032	400	375	25
22	2033	400	375	25
23	2034	400	375	25
24	2035	400	375	25
25	2036	400	375	25
26	2037	400	375	25
27	2038	400	375	25
28	2039	400	375	25
29	2040	400	375	25
30	2041	400	375	25
31	2042	400	375	25
32	2043	400	375	25
33	2044	400	375	25
34	2045	400	375	25
35	2046	400	375	25
36	2047	400	375	25
37	2048	400	375	25
38	2049	400	375	25
39	2050	400	375	25
40	2051	400	375	25

SCHEDULE 2 – EXAMPLE: RE ANNUAL INTEREST PAYMENT

Assume for 2012:

- Balance of debt outstanding at start of fiscal year $21.9 million
- Maximum Grid Load (Schedule 1) 515 GW.h
- Minimum Grid Load (Schedule 1) 415 GW.h
- Range (Schedule 1) 100 GW.h
- Maximum Interest Payable at different Actual Grid Loads:
    - Assume Actual Grid Load at 520 GW.h
        - Actual Grid Load>Max Grid Load
        - Maximum Interest Payable at 5.44% (full interest)
        - Amount Payable:
          $1,195,740.00=5.46% x $21.9 million (paid by YEC to YDC)
    - Assume Actual Grid Load at 450 GWh
        - Actual Grid Load<Max Grid Load
          Max Interest Rate = $\frac{\text{(Interest Rate) x (Actual Grid Generation – Minimum Grid Load)}}{\text{(Range for the year as established in Schedule 1)}}$
        - Maximum Interest Payable: 5.46%x(450-415)/100=0.35x5.46%=1.911%
        - Amount Payable
          $418,509.00 =1.911%x$21.9 million (paid by YEC to YDC)
    - Assume Actual Grid Load at 400GWh
        - Actual Grid Load<Max Grid Load
          Max Interest Rate = $\frac{\text{(Interest Rate) x (Actual Grid Generation – Minimum Grid Load)}}{\text{(Range for the year as established in Schedule 1)}}$
        - Maximum Interest Payable: 5.46%x(400-415)/100=-0.819%
        - Amount Payable
          -$179,361.00= -0.819%x$21.9 million (indicates YDC amount paid to YEC)

APPENDIX 5.4
CAPITAL PROJECTS BETWEEN $100,000 AND $ 1 MILLION

APPENDIX 5.4: CAPITAL PROJECTS BETWEEN $100,000 AND $ 1 MILLION

Appendix 5.4 provides descriptions for projects in excess of $100,000 and up to $1 million forecast to occur in 2012 and 2013. Capital spending on property, plant and equipment is described using the following categories:

1. **Reliability** – Projects which when applied to the existing system will improve dependability of service delivery to our customers. These projects may involve replacement of some or all of a component of an asset on the system, or the project could involve the introduction of a new component or technology that accomplishes the objective of improved reliability and/or quality of service.

2. **Business Improvements –** Upgrade or replacement of deteriorated or end of life infrastructure required for continued or improved efficiency of utility operations.

3. **Legal/Regulatory Compliance** – Projects that are required to be undertaken either as a result of a direct order from the regulator or a regulatory provision in a licence or permit (e.g. water licence, air emissions permit) or costs associated with projects required to amend or renew licences and permits.

4. **Safety** – Projects required to ensure safety of workers and/or third parties.

5. **Environment –** Projects required to ensure minimal damage to the natural environment due to a Yukon Energy project or activities.

6. **Demand** – Projects required to meet the energy and/or capacity requirements on the integrated grid.

7. **Other/Special –** Other types of special projects that do not fit into the above categories (e.g., Resource Plan Update).

Generation:

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
WH West Gate Gearboxes and VFD	Reliability	In 1982, the regulating gate at the spillway was converted to an intake for WH4, and the West spillway gate was operated to regulate flows even though they were not designed for this purpose. The spillway gates needed to be moved frequently to avoid freeze up, and this frequency of movement put exceptionally high demands on the entire lift system, resulting in the deterioration of all three gear boxes, and putting them at material risk of failure. To ensure continued reliable operation all three gear boxes must be replaced with new gear boxes that can tolerate additional loading and frequency of movement and are designed to fit into the existing installation. As well, installation of variable frequency drives will improve motor control and performance.			$600,000
Wareham Spillway Upgrades	Reliability	The Wareham spill gates system (and many of its components) is almost 60 years old. Specifically, the system requires a major re-fit and life extension to repair damage to the spill-gate gains. It also requires that the existing gain heaters be upsized and insulated, the concrete around the gains which has eroded over time be replaced and strengthened, and the J-seals and the stop logs (that are damaged or in a poor location on both spill gates) need to be replaced. This project is essential to ensure continued reliable and safe operation of the Wareham spill gates system and certified single point of isolation regulation.	$75,000	$700,000	
Install Jack Screws on Mayo Spill Gates	Reliability	The Mayo spill gates are operated by a cable hoist system that can only be operated locally. Installation of threaded stem or			$250,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		jacking screws in the spill gates will allow the gates to close under pressure and avoid the need to set up separate equipment to jack down and close the gates. This improvement will help ensure continued reliable operation of the Mayo spill gates and enhance SCADA control and monitoring of water levels.			
Kidney Loop Filter System	Business Improvement	The hydro governor oil system on the hydro units has no filtration system. A new oil filtration (or kidney loop filtering system) installed on the hydro governor oil units will prevent dirt from entering the system and reduce wear and tear. This will help ensure continued reliable option of the units.		$100,000	$100,000
WH1 Commutator Upgrade	Reliability	The commutator on WH1 is at its end of useful life and requires refurbishing to continue to provide reliable service.		$100,000	
WH2 Commutator Upgrade	Reliability	The commutator on WH2 is at its end of useful life and requires refurbishing to continue to provide reliable service.			$100,000
Faro D7 Local Engine Control PLC	Reliability	The engine controller for FD7 currently uses an IDEC controller that is outdated, no longer manufactured and installed in a poor location. Installation of a new and more up to date PLC based local engine controller will ensure that FD7 can load share with the entire plant (as in Whitehorse (planned) and Dawson). This will help ensure continued safe, reliable and efficient operation of Faro D7 and standardizes this equipment across the different plants on the system.		$250,000	
Faro FD0 Load Sharing	Reliability	With a rebuild of the FD1 Mirrlees, the Faro diesel plant is expected be used as a strategic generation site. However, the			$150,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		three CAT diesels in Faro currently do not have the ability to load share. To ensure that these units can be deployed as noted, it is necessary to ensure the ability to load share between the CATs for planned and unplanned outages and to improve response times in event of outages.			
Faro Plant Remote Control Automation Upgrades	Reliability	It is important for the efficient and reliable operation of the system that Yukon Energy has remote generation capability for its diesel plants. Consequently, related improvements are required to the remote control capability of the Faro Diesel plant to ensure continued safe and reliable operation of the Faro plant.			$250,000
FD1 Valve Cage Cooling	Reliability	The valve cage cooling system is not providing adequate cooling to run the engine at full output and the secondary water system is not providing sufficient cooling water to keep the valve cooling system at the appropriate temperature. In order to ensure continued reliable operation of the Faro FD1 unit, testing and analysis is required to determine why the system is not functioning correctly.		$100,000	
Mayo Diesel SCADA Connection	Reliability	The completion of the MD1 and MD2 SCADA connection will allow the units to be run remotely and ensure continued safe and reliable operation of the Mayo Diesel units and to improve response times in event of outages. The YM01 units would also be connected to SCADA at the same time.			$450,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Faro Switchgear FD3, FD5, FD7	Reliability	Switchgear equipment on these three units is at the end of its serviceable life. The FD0-89-1 switch was also destroyed in early 2009 in a switching accident. This equipment must be replaced as the disconnect functionality is an operational necessity.			$587,000
Hydro Unit Platforms for Working in Draft Tubes	Safety	When an inspection or work is required on the bottom end of the turbine a temporary platform is required in the draft tube to provide a stable working surface. However, temporary platforms have safety risks associated with their installation, and consequently, to ensure activities can be undertaken safely, a completely engineered platform must be designed and installed for all of the hydro units in service at Yukon Energy. Platforms will be removable to prevent water turbulence issues on running units.		$150,000	$150,000
Dam Water Barriers	Business Improvement/ Legal – regulatory compliance	The lack of sufficient barriers near the headwater of all of Yukon Energy's dams presents safety issues and concerns that with increased traffic on the lake there is greater potential that vehicles (boats, rafts, planes) that get too close to the dam will be caught in the current. To ensure public safety, a water barrier across the head waters of the dam is needed to warn boaters and other recreational lake users to remain a safe distance from the dam. The Mayo B Navigable Waters Act Authorization requires installation of water barriers at Wareham. It is expected that similar conditions would be required in future for the other dam facilities when applicable water licences are renewed. For Wareham dam installation of debris screens under the barriers is also needed to reduce the potential debris (i.e.,		$200,000	

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		trees) that may be caught in the intake valves.			
Assessment and Replacement of Fuel Tank at Whitehorse	Business Improvement	Whitehorse currently has a vertical 1948 vintage fuel tank. This style of tank has a history of failing at the bottom when water becomes trapped between the bottom of the tank and the base, and the current type of tank and berm setup also decreases fuel storage capacity as the bottom six feet of fuel cannot be collected. To avoid potential failure and increase fuel storage capacity, a study will be conducted to assess options for replacement.			$200,000
Aishihik River Icing Study Mitigation – Bridge	Business Improvement	Operation of Aishihik facility could potentially create icing in the vicinity of the Canyon Creek Heritage Bridge. Remediation on the heritage bridge is required to allow for the operation of all Aishihik hydro units without jeopardizing downstream infrastructure. Specifically, raising the Canyon Heritage Bridge downstream of the Aishihik Generating Station will allow sufficient freeboard for ice formation with all three Aishihik generating units in operation.		$665,000	
P125 Trash Racks and Heaters Rebuild	Reliability	The P125 trash rack and trash rack heating system must be rebuilt as it is at end of life and is beyond the point where repair is an option. The PWF 2x4 trash rack members are worn and broken. Trash racks are required to protect the turbine from damage due to debris entering the unit. The operational and financial consequences of frazil ice are potentially severe and the trash rack heat is required to guard against the consequences of frazil ice build-up before ice-cover on Schwatka lake. The extent of repair work was assessed in 2010 and included review of alternatives such as plastic gates which would not require heat.	$42,000	$65,000	

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		Yukon Energy has purchased a set of polymer gates and is testing them in 2012 to determine effectiveness. Also in 2012, Yukon Energy will refurbish one existing trash rack to ensure continuity of service.			

Transmission:

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
WAF Transmission Upgrades	Reliability	The WAF transmission system allows low cost hydro generation supplied from Aishihik or Whitehorse to other locations on the grid. A failure of a transmission line structure would interrupt this supply, potentially resulting in a wider grid collapse. Structures were built in the 1960s and 1970s, and to ensure continued system security and power quality, poles, cross arms and insulators that are in worst condition must be replaced as part of an ongoing replacement program to improve system reliability (and decrease the likelihood of a transmission line structure failing). If no action is taken, the transmission line structures or insulators will eventually fail and require emergency repair and this may result in wider grid outages and higher costs.	$996,000	$350,000	$350,000
L250 Transmission Line Upgrades	Reliability	Much of this line has been upgraded over the past several years, however, due to wet ground conditions, parts of the L250 transmission line from Mayo to Keno are in particular 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. As part of an ongoing replacement program to decrease the likelihood of a transmission line structure failing, and to improve the reliability of the network that feeds Elsa and Keno, poles, cross-arms and insulators that are in bad condition must be replaced.	$359,000	$150,000	$150,000
Transmission Stubbing Program	Reliability	The 'Test and Treat' of the transmission line to Aishihik has uncovered a number of poles that require structural support.			$100,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		To address identified deficiencies during the 2009 test and treat program of L171, L172 and L169, and ensure continued safe and reliable operation of the transmission system a number of poles must be reinforced or replaced at this time. These identified issues must continue to be actively managed to reduce risk at an appropriate level of cost.			
L172 Line Switch Replacement	Reliability	The 138 kV gang switches, originally installed by NCPC personnel approximately in 1970, are considered to be at end of life, are not load break capable and were mounted too low to the ground for safe operation by line personnel in the energized state. Age and pest infiltration have led to further structural weakness on the existing structures and supporting switches for L172 89-47 and L172 89-48 (S164 Takhini). As well, this switch suffered a failure during 2011 that necessitated a temporary fix. Continued use of the switches is an operational requirement for L172 and replacement of the switches with new ones that have load break capability will give YEC operational flexibility, reduce outage interval times and provide faster isolation times for L172 as well as increased reliability and enhanced safety for operational staff.		$200,000	
Transmission Pole Test and Treat	Reliability	To ensure continued reliable and safe operation of the transmission system, the test and treat program has undertaken repairs and improvements to the wood pole assets at all YEC substation, transmission and distribution lines. Specific, test and treat work scheduled for summer of 2012 includes test and treat of L356 from Faro to Ross River, test	$632,000	$248,000	$250,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		and treat of Vangorda Mine Feeder (extension of L170) from Faro to Vangorda Mine Substation, test and treat of walk-in sites not tested in previous years due to access difficulties, test only those poles on the L250 feeder from Mayo to Keno to identify critical poles to manage this line until it is replaced in the near futures, and a test and treat of Mayo Distribution Poles as budget permits.			
Substation Protection and Control Minor Upgrades	Reliability	Yukon Energy substations require a number of improvements to ensure continued safe and reliable service. Specifically, to ensure a more consistent standard for all Yukon Energy substations, substation protection and control systems will be reviewed to identify and address the following issues: indication of relay failure to SCC (this is often either non-existent or the flagging shares common failure modes with the relay itself); trip circuit monitoring scheme that are installed but do not indicate to SCADA at all; and incomplete backup protection.	$73,000	$100,000	$100,000
Dawson P158 T1/T2 Transformer	Reliability	To ensure continued safe and reliable operation of the Dawson P158 T1/T2 transformer, several liabilities in its current configuration must be corrected. • The fence around the transformer installation is about six feet high and is adjacent to public access. Clearances to ground of live conductors are too low, and underground cable connections across the street to the express feeder are recommended to address clearance issues. • The unit is rarely maintained due to the impact of taking the transformer out of service (increasing the likelihood of an unexpected equipment failure that would otherwise be			$200,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		prevented through routine maintenance and minor repairs). Reconfiguration of the transformers is required to protect the transformers and enable YEC to switch back and forth between them so maintenance can be performed safely without interrupting service.			
Little Salmon PT Substation	Reliability	An inspection of the Little Salmon PT Substation has determined that one of the poles at the existing substation is broken and the entire structure (built on a slope) is slipping down the hill. To ensure continued safe and reliable service, the existing Little Salmon PT substation must be replaced with a new PT substation at a different location to improve accessibility.	$100,000	$200,000	

Distribution:

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Faro Mine Connection [to be completed in 2014]	Demand	The Faro mine site abandonment plan administered by the Yukon Government has a forecast life in excess of 15 years. Earlier reports (2010) indicated that the plan would begin in 2013, at which time YEC annual sales to the mine site could increase significantly. The initial planning indicated that YEC must study customer requirements during 2010 to determine necessary equipment which will be purchased in 2011 and installed in 2012. It was indicated at that time that the majority of project costs will be funded by customer contributions, although some costs may be considered transmission improvements, and that permitting processes may delay the in service date. Current capital cost forecasts for this project during the test years provide for $0.5 million of costs in 2013 that will be offset by customer contributions.			$500,000
Dawson Dome Distribution Extension	Reliability	The existing single phase distribution line supplying the Dome in Dawson has a difference in loading between the winter and summer months and the ground fault protection is turned off at the diesel plant in winter to avoid repetitive outages due to imbalance in the feeder for the area. A new three phase distribution line at the Dawson Dome is required to address the load imbalances that occur in the winter so that ground fault protection can remain in-service at the diesel plant to protect the line. The project would also accommodate growth expected from the potential Dome Road subdivision (currently in planning stage of development with an estimated 100 lots).	$7,000	$220,000	

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Land Management & Easement Project	Legal - Regulatory Compliance	Having registered easements in place enhances customer relations and increases the efficiency of Yukon Energy's operations This program will continue to secure easements for Yukon Energy's distribution lines.	$151,000	$25,000	$50,000
Other Customer Extensions	Legal - Regulatory Compliance	Yukon Energy is required to provide service to new customers coming onto the system. Customer extensions are forecast and budgeted as capital items without identifying specific projects. Most costs of customer extensions are covered by customer contributions pursuant to the Electrical Service Regulations.	$735,000	$475,000; offset by Customer Extensions Customer Contribution - $400,000	$475,000; offset by Customer Extensions Customer Contribution - $400,000

General Plant and Equipment Projects:

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
YEC Fall Arrest Systems	Safety	To ensure a safe work environment for all of its workers, Yukon Energy is required to complete installation of fall restraint or arrest systems for all of its facilities.	$82,000	$75,000	$75,000
Fish Ladder Lewes Control Structure	Business Improvements	The Lewes River fish ladder is at end of life and continues to be degraded by ice contact. In order to extend its useful life the structure needs to be upgraded.			$100,000
Boat Lock Upgrade at Lewes Control Structure	Business Improvements	The existing boat lock at the Lewis Control Structure was built in 1970, is at end of life and needs to be upgraded and replaced. The existing wooden gates are warped and do not maintain a seal and need to be replaced with a simpler and lighter steel boat lock system that would be easier for the public to use.			$250,000
Interactive Safety and Environmental Orientation Video	Business Improvements	Yukon Energy's Safety and Environmental Orientation process has been overhauled and an orientation video and online orientation and compliance process developed to ensure required participation and ongoing compliance with safety policies, procedures and safe work practices for Yukon Energy employees and contractors throughout Yukon. Via this new process, Yukon Energy is better able to ensure that legal due diligence continues to be met. By offering an online version of the orientation, new employees and contractors can complete mandatory orientation(s) at their convenience prior to reporting to work.			$120,000
Vehicle Purchases	Business Improvement	Unit #36 has more than 200,000 km on it and maintenance costs are beginning to escalate. A service body trunk will be purchased in 2012 to replace unit #36.	$694,000	$125,000	$125,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		Occupational Health and Safety regulations set out that for any work where there are six or more workers on site, and where there is more than 20 minutes surface travel time to the hospital, an Emergency Transfer Vehicle (ETV) should be on site at all times. Yukon Energy has in the past rented an SUV – however, this is not an adequate long term solution considering ongoing work requirements at Aishihik and other sites will require the presence of an ETV over the next year. An ETV is consequently required in 2012.			
Tintina Trench Repeater	Business Improvement	Communication capabilities are not available in the area between Rock Creek to Gravel Lake. YEC service personnel are required to travel this area on a regular basis and in order to improve communication for YEC staff, a repeater will be installed in the Tintina trench area with a connection to Ferry Hill (Mayo/Stewart) and required local drops in the Dempster Corner and Rock Creek area.		$125,000	
Network Improvements	Business Improvement	To ensure best practices are maintained as well as continued network efficiency and productivity recommended network improvements from the 2009 Security Audit are being implemented. This includes cable management in the communications rooms to prevent safety risks and improve reliability and efficiency, separation of critical time-sensitive SCADA traffic from large data chunks being transferred during backups as more services converge on the corporate LAN, improving overall performance and knowledge of the system via advanced QOS training, implementing intrusion detection and prevention systems (IDP/IPS) for improved security, and ensuring documentation documentation, procedures and planning identified in the Disaster Recovery Plan/Business	$161,000	$50,000	$50,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		Continuity Plan.			
Disaster Recovery Plan/ Business Continuity Plan Development (DRP/BCP)	Business Improvement	Development of a disaster recovery and business continuity plan is an important part of an overall framework for identifying and managing risk. Yukon Energy is responsible for supplying its customers the essential service of electrical power and must be prepared to address the severe impacts of extended electrical power failure, fire, flood or other potential disasters.			$325,000
Fish Ladder Replacement	Business Improvement	The fish ladder at the Whitehorse hydro facility is over 50 years old and is at end of life and was constructed out of materials that are a health hazard. The structure needs to be replaced before it fails or is otherwise determined to be unfit for service.			$400,000
Electronic Document Management System	Business Improvement	Yukon Energy currently has no formal electronic document management system (EDMS). EDMS systems generally support a large variety of document formats and provide extensive access control and searching capabilities. The medium of business has moved from paper to electronic records and with new technologies and business formats. Areas of concern to be addressed in a EDMS include: (1) the requirement for a formal system to maintain, control and safeguard electronic records to ensure that they are easily accessible, correct versions can be proven to be authentic and reliable when required for legal proceedings or that they are destroyed in compliance with the Corporation's Retention Schedule, and (2) requirement for a classification system or retention schedule applied to electronic records.			$100,000
Security Risk	Business	An annual budget of $50,000 is required to cover security	$6,000	$50,000	$50,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Management	Improvement	issues that are brought forward to the Risk Management Committee. The security issues brought forward are intended to reduce the risk of physical loss of assets and/or to mitigate the potential for unauthorized people on YEC's property to either harm themselves or damage property. Due to such acute safety and security considerations, the identified security risk issues are required to be addressed on a timely basis and require immediate funding to be available. In the test years, the Risk Management Committee has identified the need for several cameras and other items to be added to decrease the risk to the corporation.			
Safety Improvements	Legal/ Regulatory Compliance	Safety issues are expected to arise that are required to be addressed on an immediate basis and capital funding must be available without undue delay. Certain safety related issues cannot be treated in the same manner as a capital project and waiting until the next capital budget year is not an option. A blanket PID was set up to enable funding to be allocated in 2008 and later years. This mechanism will allow safety issues requiring capital funding to be addressed in a timely manner.	$25,000	$40,000	$40,000

APPENDIX 5.5
DEFERRED PROJECTS BETWEEN $100,000 AND $1 MILLION

APPENDIX 5.5: DEFERRED PROJECTS BETWEEN $100,000 AND $ 1 MILLION

Appendix 5.5 provides descriptions for projects in excess of $100,000 and up to $1 million forecast to occur in 2012 and 2013. Spending on deferred cost projects is described using the following categories:

1. **Reliability –** Projects which when applied to the existing system will improve dependability of service delivery to our customers. These projects may involve replacement of some or all of a component of an asset on the system, or the project could involve the introduction of a new component or technology that accomplishes the objective of improved reliability and/or quality of service.

2. **Business Improvements –** Upgrade or replacement of deteriorated or end of life infrastructure required for continued or improved efficiency of utility operations.

3. **Legal/Regulatory Compliance –** Projects that are required to be undertaken either as a result of a direct order from the regulator or a regulatory provision in a licence or permit (e.g. water licence, air emissions permit) or costs associated with projects required to amend or renew licences and permits.

4. **Safety** – Projects required to ensure safety of workers and/or third parties.

5. **Environment –** Projects required to ensure minimal damage to the natural environment due to a Yukon Energy project or activities.

6. **Demand –** Projects required to meet the energy and/or capacity requirements on the integrated grid.

7. **Other/Special –** Other types of special projects that do not fit into the above categories (e.g., Resource Plan Update).

Feasibility:

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Aishihik Hydro Turbine Re-runnering feasibility	Demand	Hydro Turbine rerunnering is a potential, cost effective supply side enhancement opportunity that will install new turbine runners at the Aishihik plant and improve performance of the existing Aishihik Generation units, increasing the hydro generation available to displace more costly diesel generation. Preliminary studies and testing are required to determine whether it is feasible and cost effective to proceed with this potential major project (total estimated cost of $4 million). Water flow measurement and testing was undertaken in 2010 and 2011. In 2012, the data from these tests will be used to determine how much energy can be gained through re-runnering. This information will be combined with a runner condition assessment to determine whether it is feasible to undertake the re-runnering project.		$150,000	
Wind Feasibility Study – Ferry Hill	Demand	Alternative sources of renewable energy are a key component of Yukon Energy's strategic plan and 20 Year Resource Plan. Wind is a publically acceptable renewable resource option that Yukon Energy has experience with and that can be developed within relatively short timeframes with minimal regulatory risk and relatively slow planning and regulatory costs. The feasibility work and regulatory permits can be obtained and actual procurement of materials and construction deferred until loads are sufficient to justify material capital investments required for this renewable resource. Ferry Hill, located near Stewart Crossing and in close proximity to the Mayo Dawson line, has the highest average wind speed of all commercial wind sites monitored in Yukon by YEC. Feasibility work is required for Yukon Energy to confirm the viability of wind at this site. The scope of work to date includes sizing, location, effects of rime icing and connection to the grid.	$427,617	$100,000	$100,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Large Hydro Feasibility	Demand	There are in Yukon a range of Greenfield hydro resource project opportunities potentially available to start construction before 2021, subject to appropriate planning and development of loads sufficient to fully utilize these resources. Yukon is examining potential future hydro development options, including potential staged development of one or more hydro generating sites and reservoirs on the upper reaches of the Pelly River in the range of 20-40 MW and annual energy production of 150-175 GWh/year. These projects offer potential to establish sustainable lower cost electricity as well as low GHG emissions in a way similar to that secured by earlier legacy hydro developed in response to earlier major mines in Yukon. Development of such longer-term renewable resource options is subject to connecting new grid loads that could fully utilize the specific renewable resource options over 20-30 or more years. Protecting the option to start construction for such projects before 2021 is contingent upon sustaining sufficient site specific planning processes as required throughout the next five year period through 2015. Feasibility study costs to date have been to screen and update costs for potential developments. Hydro resource options would provide renewable energy with low GHG emissions. Subject to adequate grid loads to sustain high utilization for 30+ years, studies to date have identified 17 medium (11-60 MW) to large (>60 MW) hydro options that also offer low costs per kW.h (i.e., below 15 cents/kW.h Full Utilization LCOE) plus additional small hydro sites with costs below 25 cents per kW.h. Initial future feasibility study costs are to perform engineering, consultation and environmental studies with subsequent expenditures to address YESAA, YUB and water licence processes which, upon completion and approval could result in capital expenditures for construction.	$671,757	$200,000	$100,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Atlin Grid Connection Feasibility Study	Demand	A grid connection with the Pine Creek hydro facility near Atlin may provide for Yukon a potentially cost effective new source of renewable energy that could reduce costly diesel requirements over the longer-term. An assessment is being conducted to determine the technical and financial feasibility of connecting the Pine Creek hydro plant to the Yukon grid. The possibility of expanding the Pine Creek plant to maximize the amount of surplus power available from this facility will also be assessed.	$109,941	$50,000	
Climate Change Study	Demand	Climate change may potentially affect Yukon Energy's hydro watersheds and other major infrastructure. Consequently, a study was required to assess potential effects of climate change on Yukon Energy's infrastructure and determine any plan required to adapt to, and mitigate the potential climate change effects on existing and future assets. This includes an education component for key Yukon Energy staff on mitigation and adaptation to climate change effects that need to be considered by Yukon Energy.	$106,659	$50,000	
Condition Assessment of Selected YEC Assets	Reliability	There is a need for detailed engineering condition assessments to determine the practical remaining life of selected assets including spillways, substations, generation facilities, equipment, diesel and overhead facilities. An accurate assessment of the condition of key assets allows management to effectively target resources to ensure maximum reliability benefits to the system. The last time this work was done was in 2004 so it is timely to update this body of information. The output from this work will also allow us to add important condition information into the Computerized Maintenance Management System (CMMS) for these key assets.			$150,000
International Financial	Legal - Regulatory	In February 2008, the Canadian Accounting Standards Board	$565,769	$101,307	

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Reporting Standards (IFRS)	Compliance	confirmed that the Canadian Generally Accepted Accounting Principles (GAAP) would be changed to IFRS for all Canadian publicly accountable enterprises, including Yukon Energy. For rate regulated entities 2012 is the year that financial statements are required to become IFRS compliant. External consultants with experience in conversion to IFRS have been retained to assist Yukon Energy in compliance with this extensive conversion process.			
Study of Ice Processes in the Mayo River at Mayo	Business improvement	In the winter/spring of 2011 ice issues arose on the Mayo River at Mayo which resulted in surface water and icing behind the Mayo Dyke near the Yukon Energy diesel plant site in Mayo. YEC retained KGS Group to assist it in understanding the issues at hand. The study focused on ice related hydraulic investigations. Because of YEC's additional concerns regarding flooding near its diesel generation facilities - geotechnical and other preliminary site investigations related to the Mayo dyke were undertaken by KGS to facilitate further understanding of potential issues regarding Yukon Energy's diesel plant.	$179,265	$50,000	
System Stability Review	Reliability	Yukon Energy has completed, or is expecting in the near-term to undertake and complete, a number of major projects that will impact the integrated grid. A system stability review is required to ensure Yukon Energy's electrical system remains stable and that power quality issues are identified and addressed with the best economic solution selected. This requires assistance from a Systems Engineer consultant to engage with YEC personnel and to complete a review of system scenarios and analysis to ensure YEC is prepared to deal with system disturbances, which may result from the installation and completion of the following major new and potential future projects: CSTP Phase 2	$99,961	$150,000	

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
		Project (2011); Phase 1 of the Mayo A Substation Enhancement Project (2011); Installation of Mayo B and AH3 Generator Projects (2011); Phase 2 of Mayo A Substation Enhancement Project (2012); Carmacks Substation Expansion Project (2012); and Takhini Substation new Supply Source for the Whistle Bend subdivision.			
Wareham Spillway Hoist Upgrade	Business Improvement	The Wareham spillway hoist dates back to the early 1950s and was designed and installed during a period when the gates were allowed to freeze in and the spillway and hoist were not operated in the winter. Due to changes in operating requirements, the lifting capacity of the Wareham spillway hoist and the design configuration (i.e., using cables instead of screw lifts) must be upgraded to meet current safety and reliability standards. The project includes providing single point isolation using stop logs.		$100,000	$650,000
WH4 (Rotor) Investigation	Reliability	Stability performance of the WH4 generator is unsatisfactory and must be addressed to ensure continued safe and reliable operations of WH4. Previous system testing indicated that the WH3 and WH4 governors require tune-ups to improve performance as a possible and immediate improvement. For the governors, the long-term solution requires a broader investigation into the influences of turbine rough zone loading, hydraulic surging, fore-bay and tailrace levels, exciter tuning and the impact of the interconnected system load to the problem of the generator performance and stability. A root cause analysis will also be performed to determine why cracks are appearing in the rotor.	$97,967	$175,310	

Deferred Overhauls:

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
AH1 Ten Year Overhaul	Reliability	Ten year unit tear downs and overhauls are an industry standard. The tear down will inspect bushings and bearings and make corrective repairs that are not identifiable on a running unit. Proper maintenance management of this unit will support Yukon Energy's objectives and mission of improved reliability. If no action is taken the unit will be at an increase risk of component failure. This overhaul is due in 2016.		$325,000	$300,000
AH2 Ten Year Overhaul	Reliability	Ten year unit tear downs and overhauls are an industry standard. Proper maintenance management of this unit will support Yukon Energy's objectives and mission of improved reliability. The purpose of the tear down is to inspect worn bushings and bearings and to make corrective repairs that are not identifiable on a running unit. If no action is taken the unit will be at an increased risk of component failure.		$325,000	$300,000
Dawson Diesel 2 Engine Overhaul (DD-2), complete	Reliability	The DD-2 engine is nearing the required 12,000 hour overhaul. A complete overhaul must be conducted to maintain the engine's availability without compromising engine life and reliability. Without the overhaul, there is a high probability for component failure. The unit will require the engine block decking to be machined because fretting of the deck was evident during the last overhaul. The unit out be removed and sent out for the overhaul. The generator also requires service.	$178,786	$135,850	
Dawson Diesel 3 Engine Overhaul	Reliability	DD3 is close to its required 12,000 overhaul. A total engine overhaul is required in 2012 to maintain the engine's availability without decreasing engine life and reliability. Without the			$350,000

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
(DD-3), complete		overhaul, there is a high probability for component failure.			
Dawson Diesel 5 Engine Overhaul (DD-5), complete	Reliability	The DD-5 engine is 3,753 hours past the time to conduct a bottom-end overhaul. During the last overhaul, Yukon Energy decided to only complete an overhaul on the top end due to the number of hours that would run with the new line between Mayo and Dawson. With an increasing load, the bottom end of the overhaul is required before the unit is put into service.			$150,000
WH3 Ten Year Overhaul	Reliability	Ten year unit tear downs and overhauls are an industry standard. Proper maintenance management of this unit will support Yukon Energy's objectives and mission of improved reliability by increasing equipment availability, predictability, output from existing assets and reliability; as well as avoiding unnecessary capital replacement costs, accurately defining life cycle of assets and allowing better tracking of assets from a regulatory point of view. The purpose of the tear down is to inspect bushings and bearings and to make corrective repairs that are not identifiable on a running unit.			$500,000

Relicensing:

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Air Emissions Licence Renewal	Legal – Regulatory Compliance	The Yukon grid system requires diesel generation to provide reliable peaking capacity. Yukon Energy's diesel generation facilities require air emissions permit renewals every 3 years in order to continue to operate. In 2011, the three year period for all facilities was renewed and included stack dispersion testing work. Some work was not able to be completed in 2011 and was completed in 2012 with results to be filed with the regulator.	$289,788	$87,403	

Rate Case:

Project	Category	Description/Rationale	Prior to 2012	Forecast 2012	Forecast 2013
Resource Plan Update	Special/ Legal – regulatory compliance	In late 2005, Yukon Energy completed a 20-year Resource Plan for the years 2006-2025 and the Yukon Utilities Board recommended that YEC file an update to its resource plan within five years. An update was undertaken in 2011 to assist decision making on new infrastructure projects. This review assessed impacts on the integrated grid due to the addition of major new assets to the system, updated load forecasts and assessed new generation and transmission options for both the near-term (up to 2015) and longer-term (after 2015).	$633,906	$225,000	

TAB 6
BOARD DIRECTIVES

6.0 BOARD DIRECTIVES

This Tab reviews directives contained in Board Decisions since the submission of the 2008/2009 General Rate Application (GRA), and, where relevant, Yukon Energy's response.

6.1 BOARD ORDER 2009-2

On April 30, 2008, Yukon Electrical Company Limited (YECL) filed with the Yukon Utilities Board (YUB or Board) an Application, pursuant to the Public Utilities Act and Order-in-Council (OIC)1995/90, for approval of its forecast revenue requirements for the 2008 and 2009 test years and approval of certain deferral accounts. The Board approved the 2008 and 2009 revenue requirement for Yukon Electrical with the changes directed in the Reasons for Decision.

Order 2009-2 resulted in a number of specific Board directions for Yukon Electrical. However, the Board also addressed some of its directives to both Yukon Electrical and Yukon Energy – directives that were to both companies, and Yukon Energy's response to these directives, are noted below.

Directive #26

- ***The Board directs YECL, in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to IPPs to be included as part of YECL's and YEC's next GRA.***

The Government of Yukon's Energy Strategy for Yukon identifies the development of both an Independent Power Producer's (IPP) Policy and a Net Metering Policy as priority policy actions which support updating and developing a policy framework for electricity that emphasizes efficiency, conservation and renewable energy[1]. The following activities have been undertaken in this regard:

- A joint government/utilities working group, led by the government of Yukon, was established to develop IPP and net metering policy.
- A discussion paper on both IPP and net metering was released for a government led public consultation process between November 2009 and February 2010[2].

[1] Energy Strategy for Yukon, p. 15-16.
[2] See http://www.energy.gov.yk.ca/pdf/ipp_net_metering_discussion_paper_nov2009.pdf.

- A summary document of consultation responses was prepared in June 2010.

One of the key outcomes of that process was the decision to develop separate policies for IPP and net metering. Yukon Energy is providing input into both policies which are being developed following established Government of Yukon processes for public consultation and government policy approval.

The consultation period for the draft net metering policy ended April 29, 2011[3]. The policy is in the process of being finalized and approved by the Yukon Government. Yukon Energy is not directly involved with those approval processes and is not in a position to comment further on the timelines for release of the draft policy.

A draft IPP policy is still in the development stages and it is Yukon Energy's understanding that the Yukon Government will be providing the public with an opportunity to comment on that draft in the future. Again, while YEC is a participant in the policy development process, it is not in a position to comment further on government processes and/or timelines for moving the policy forward.

Directive #27

- ***The Board directs YECL in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to DSM initiatives and include this policy paper as part of YECL's and YEC's next GRA. To be clear, YEC and YECL are to jointly lead these processes and jointly submit the policy papers (IPP and DSM) in their next GRA. The DSM policy papers are to provide DSM initiatives developed through negotiations with Intervenors and communities in its service territory and YEC's service territory.***

Please see Yukon Energy's response to directive #3 in Board Order 2009-8 discussed below.

6.2 BOARD ORDER 2009-8

On October 6, 2008, Yukon Energy filed with the Yukon Utilities Board an Application pursuant to the *Public Utilities Act* and Order-In-Council 1995/90.

The 2008 and 2009 Revenue Requirements were approved subject to Board ordered adjustments, and Yukon Energy re-filed amended schedules as part of the compliance filing approved by the Board. Order 2009-8 resulted in a number of specific Board directions. Most of these directives related to 2008 and

[3] See http://netmetering.gov.yk.ca/Home/Documents.

2009 revenue requirements, and accordingly were incorporated into the revised re-filing approved in Order 2009-10. The remaining outstanding directives are noted below:

Directive #3

- ***Furthermore, the Board finds DSM to be a critical issue for all electric rate payers in Yukon. The Board directs YEC in conjunction with YECL, to consult with stakeholders and develop a policy paper with respect to DSM initiatives. YEC and YECL are to jointly lead this process and submit a policy paper (Plan) in their next GRA. Further the utilities are to be cognizant of and work with ESC where necessary so as not to duplicate efforts.***

A significant amount of Demand Side Management (DSM) related planning and consultation work has been undertaken by Yukon Energy individually and by Yukon Energy in coordination with Yukon Government (YG), Yukon Development Corporation (YDC) and Yukon Electrical in order to implement a robust and aggressive DSM program, and to meet the Yukon Utilities Board directive noted above.

As part of this work a comprehensive review process has been initiated to develop a Demand Side Management Plan and a joint policy paper. Details of work to date are noted below.

Collaborative Work Undertaken to Date

Yukon Government, Yukon Energy and Yukon Electrical are working together collaboratively in the development of a robust and aggressive Demand Side Management plan.

The plan will be based on the following principles:

- Measurable reduction in energy use and energy demand;
- Cost-effective for ratepayers compared to new infrastructure development;
- Equitable/ inclusive programming; and
- Promote partnerships and cooperation between utilities, governments and stakeholders.

As outlined further below, this process has included a thorough stakeholder and public consultation program (see below) as well as an extensive research project (Conservation Potential Review) detailing the potential for DSM across the Yukon Territory. It is expected that a policy document will be completed in early 2012 with specific DSM programming identified before the end of 2012.

The process for implementation of DSM programming includes the following stages:

1. Identification / Information Gathering (2010/11)

- Hosting of focus group session and subsequent public consultation related to potential DSM initiatives undertaken by Yukon Energy and Yukon Electrical.
    - A half-day focus group session was held January 13, 2011 to seek input on how stakeholders want to be involved in development of DSM programming and to provide stakeholders with an opportunity to identify key demand side management issues. This included 15 participants representing a broad selection of stakeholder and community agencies. A short background paper was provided for review in advance of the session and a follow up report was produced.
    - A community engagement tour was conducted by the OneChange Foundation on behalf of Yukon Energy and Yukon Electrical in June 2011 in order to inform communities and stakeholders and gather input on future DSM programming. A follow up community tour is planned for fall 2012.
- Residential End Use Survey (REUS)
    - A Residential End Use Survey was conducted by Aasman Brand Communications on behalf of Yukon Energy to analyze the type and intensity of electricity usage by residential customers in early 2011[4]. The survey objectives were as follows:
        - To determine the characteristics of energy consumption and efficiencies among residential/household users.
        - To determine the awareness of consumers as to the existence of regulatory agencies, and their perception of the agencies' effectiveness.
        - To provide data for the Conservation Potential Review (CPR).

      It is anticipated that a REUS will continue to be conducted on a bi-annual basis.
- Conservation Potential Review analysis of electrical consumption in Yukon (hydro and diesel communities) - Lack of customer end use data is an impediment to the development of an effective DSM program. In 2011, ICF Marbek was jointly retained by Yukon Government, Yukon Energy and Yukon Electrical to undertake a detailed energy Conservation Potential Review

(required to determine the specific extent and cost/implication plans for feasible DSM programs and provide a set of baseline date for developing a DSM program). Specifically, this analysis includes energy use by customer class and electrical zone that will inform future DSM programming by identifying low, medium and high achievable (and cost-effective) DSM potential for different customer classes. The review will also help determine which technologies are most appropriate for Yukon in short and medium term (including integration of customer generation (i.e., net metering).

The study includes the following components:

- Development of customer end use models using utility customer billing information; and
- Stakeholder consultation and customer surveys to ground truth model results. Stakeholder consultation included two public sessions held over the course of 2011.
    - **May 2011 Workshop** – A one day methodology workshop held May 3, 2011, to meet with ICF Marbek. The workshop included a session with representatives from Yukon Government, Yukon Electrical, Yukon Energy, NGO's and stakeholders, and separate technical sessions with smaller groups.
    - **November 2011 Workshop** – Three days of workshops were held from November 15-17, 2011 to discuss the findings of the ongoing Conservation Potential Review study undertaken by ICF Marbek. Each workshop focused on a facilitated discussion of a selection of energy efficiency technologies and measures for each sector. Working within a structured format, the discussion of each selected technology opportunity (e.g., cold climate heat pumps) included a short technical overview by the consultants, followed by a discussion designed to seek participants' views on:
        - The key market barriers and challenges that constrain customer implementation of the selected technology/measure.
        - A high level strategy for addressing the constraints (e.g., key influences, role of incentives, potential delivery partners, etc).
        - Estimates of potential customer participation rates under "Best Case" and "Business as Usual" conditions.

[4] The survey included results from 520 Yukoners, including a representative sample from the communities.

  - The results of the workshop were used to complete the study's estimates of the scope for achievable energy efficiency savings within each sector over the period 2012 to 2030.

- Meetings and interim reports to study participants (YEC/YECL/YG) – The reports will be public documents but the accompanying databases and/or models will only be available to joint owners of the study.

The complete Conservation Potential Review report is now finished and will be presented to the public in early Q2 2012. To follow up on the findings of the Conservation Potential Review, Yukon Energy and Yukon Electrical have engaged ICF Marbek to complete market characterization studies and detailed program design.

It is expected that a Conservation Potential Review will be conducted every five years using the databases provided in the 2011 study.

2. Policy Development / Pilot Projects (2012)

- Develop and file a DSM program for YUB approval to be delivered in stages based on data and stakeholder input. Program should include targets and evaluation criteria. The DSM working group meets monthly and often bi-weekly to discuss ongoing programs, project ideas, develop policy, plan and coordinate public education and communications.

3. 2012-2015 Program Implementation and Evaluation

- Staged implementation and annual evaluation by lead organizations.

In summary, a policy document will be completed in early Q2 2012 and it is anticipated that before the end of 2012 Yukon Energy in collaboration with others will have determined the specific DSM programs to be implemented in the near-term. The policy document and any further updates regarding DSM programming will be filed with the Board once available.

DSM Planning Work undertaken to Date by Yukon Energy

In addition to studies and policy development work coordinated with Yukon Electrical and Yukon Government, Yukon Energy is also actively considering DSM programming as part of its resource planning work currently underway, and DSM is also being considered as a key supply option to help address near term and longer term supply requirements.

- Yukon Energy has opened an Energy Conservation office and dedicated two full time employees to the management of research, pilot programs and policy/plan development. Through the Energy Conservation office Yukon Energy acts as Chair of the DSM working group and manages all contractors working on behalf of the partners.

- Yukon Energy continues to review the range of programs being offered in other jurisdictions to assess the adaptability to the Yukon context.

- Yukon Energy included DSM as a supply option for review and discussion during the March 2011 Energy Charrette. A background paper was prepared and is available for review on Yukon Energy's website. Yukon Energy and its partner also plan to have a workshop focused on DSM as a supply option in April 2012.

- Yukon Energy as part of its resource planning processes has continued with baseline research and pilot projects. Pilot projects currently under way include an LED Streetlight[5] project, an energy audit of Alexco mine, basic energy management training[6], an education event for children[7], an online energy calculator, public education and an energy audit of Yukon Energy's own buildings[8].

Until a full DSM plan is completed Yukon Energy continues to engage in public education and awareness activities. The Corporation routinely updates winter forecasts to let customers know when the corporation predicts diesel will be required for peak electricity demand. Yukon Energy also maintains a web based energy efficiency house on its website which can be used as a tool for households unsure of which areas/types of electrical infrastructure are higher electricity users.

Directive #4

- ***The Board finds the UCG and LE proposals for deferral accounts in support of the DSM initiatives acceptable and both YEC and YECL can propose appropriate treatment of these accounts at the time of their next GRA.***

Yukon Energy's accounting approach for deferral and amortization of DSM costs is provided in the DSM Accounting Policy provided as Appendix 5.2 to Tab 5.

[5] YEC pilot project undertaken with input from ESC. Yukon Electrical has also undertaken its own pilot program.
[6] Dollars to Sense course offered twice in 2011 undertaken in partnership with NRCan and Yukon Electrical (one session).
[7] Conservation Kids program undertaken in partnership with Yukon Conservation Society.
[8] For further information on DSM programming see Yukon Energy's website: http://yukonenergy.ca/energy/projects/dsm/.

Directive #7

- ***The Board therefore directs YEC to undertake a study into brushing activities of similar utilities and report its findings to the Board at the time of its next GRA. Further, the Board directs YEC in its report to include a written brushing policy that describes comprehensively YEC's approach and explains the manner in which the budget for any year is derived.***

In order to develop a comprehensive written brushing policy as directed by the Board, management decided it was prudent to first undertake an independent study of current brushing practices in order to identify opportunities to enhance program management, reliability and cost effectiveness. The relevant studies were undertaken in 2010. Yukon Energy is in the process of field testing the recommendations arising from the study in order to assess which recommendations work best. This testing is expected to be completed in 2012. In 2013, after this work is completed, Yukon Energy plans to develop a formal brushing policy. Further detail on the process to date is provided below.

Status of Work to Date

In Order 2009-8, the Board noted concerns regarding the lack of structure respecting Yukon Energy's brushing program, noting "a written policy that outlines the structure of the program and reasons for the structure would enable interveners and the Board to understand the inherent problems that YEC is facing in regard to brushing, as well as, the reasons underpinning the material increases or decreases that may occur with respect to brushing costs in future GRAs."

Yukon Energy's current practice is for all transmission lines to be inspected both from the air (annually) and on the ground (particular sections identified from the air). Brushing requirements and any other issues or problems, such as poles that need replacement, are identified. These inspections are then converted into work plans for the highest priority areas and issues. Yukon Energy's practice has been to isolate and effect repairs identified from these patrols. Danger trees are removed as soon as reasonably possible.

Yukon Energy retained CEATI International Inc. to undertake a study of brushing practices in other jurisdictions (provided as Appendix 12.1 to Tab 12).

In 2010, Yukon Energy also retained Environmental Consultants, Inc. (ECI) to complete a survey of its transmission/sub-transmission rights of way and a review of the vegetation management program in order to:

1. Assess the vegetation conditions on the Yukon Energy overhead transmission and sub-transmission system and note areas of immediate concern, recommend a long term maintenance schedule and development associated budgets to support this schedule; and

2. Conduct a high level assessment of the vegetation management program and identify general opportunities to enhance program management, reliability and cost effectiveness. Appendix D of the study provided a proposed work priority and recommended cycle options and estimated cost.

The study (provided as Appendix 12.2 to Tab 12) summarized the key strengths of Yukon Energy's vegetation management program as follows:

- Yukon Energy management is supportive of program improvements;
- The program is focused on reliability;
- A centralized management structure is in place;
- Right-of-way (ROW) conditions are inspected on an annual basis; and
- Budget has been increasing as kilometers of line increased.

The study also provided recommendations for Yukon Energy to consider implementing to enhance the quality of the vegetation management program based on industry best practices. Yukon Energy is currently in the process of field testing the ECI recommendations and plans to develop a brushing policy once this work is completed.

Directive #8

- ***The Board concludes that a policy outlining the criteria for charging items to the Reserve [for Injuries and Damages] is needed. The Board directs YEC to undertake a risk management study (Study) of other utilities. The Study should examine and provide results that among other things:***
    - ***Maximizes the benefits of tradeoffs between the deductible amounts proposed to be used on property insurance, the additional costs of making claims on its existing insurance and the size of uninsured claims; and***

- ***Outlines the criteria used to include an item in the Reserve, i.e. materiality threshold, probability of the event occurring, etc.***

Yukon Energy has also updated its current practice with regard to the annual appropriations to the Reserve for Injuries and Damages (RFID) and has developed a written policy for charging items to the reserve (the RFID policy is provided as Appendix 3.1 to Tab 3). A description of studies undertaken to respond to the Board's concerns and directions provided in Order 2009-8 as provided below.

- **Power and Utility Survey Results – Self Funding Vehicles (November 2010)** (provided as Appendix 12.3 to Tab 12) – This study was undertaken to respond to the Board's directive to undertake a risk management study of other utilities. The study was based on survey data collected in 2010 and captured perspectives of twelve[9] power and utility corporations across Canada in order to understand each corporation's tolerance for retaining risk, the maturity of their risk management processes and details on any self funding mechanisms in place. It was noted in the study that insight into a peer group may help a corporation benchmark their own decisions**.**

  The study provided the following insights:

  - Seventy-five percent of companies had performed a risk assessment and over 83% had performed some type of Enterprise Risk Management.

  - Seven of the 12 companies had developed some form of contingent reserve fund – and 63% of companies continue to use some form of contingent reserve today. Most government companies had a post funding mechanism that allowed for recovery of losses from the public through a consumer rate adjustment. Over 83% of companies surveyed had not conducted any formal study to determine the feasibility of the contingent reserve fund.

  - Of the 42% of the companies with pre-loss self funding mechanism it varied widely by company as to which department administered the funds. Companies that did not have a per loss self funding vehicle provided the following reasons: currently expensing losses, the decision was based on the current asset mix and geographic locations of facilities, government guarantees allow companies to collect losses from the ratepayers and not allowed by the commission to have a pre-loss funded vehicle.

[9] There were ten public utility companies and two publically traded companies included in the survey.

- There are various ways to determine the level of funding used by companies with pre-loss or post-loss contingency reserves, including historical costs and statistical information, post-loss reserves, loss adjusters and approval by the utility commission.

- Funds tend to be transferred into the reserve on an annual basis. The calculations of the amount transferred were performed by a variety of departments including internal finance staff, loss adjusters, the treasury department, legal and finance or the utility commission.

- It was noted that there was a wide variation in terms of the loss criteria required to access the funds from the reserve. The criteria varied from only liability claims, to any insured losses within the deductible, to all uninsured losses. Of the losses that qualified, the minimum threshold below which the loss is considered to be an operational risk included the following:
  - $1,000 based on a decision made by management;
  - $100,000 determined through historical loss records;
  - Anything under deductible as determined by an actuary; and
  - $1 million.

- Sixty-seven percent of companies surveyed considered a captive insurance company but for various reasons did not pursue it (including no tax savings, cost and no prior problems obtaining good coverage).

- **General Liability and Commercial Property Retention Analysis** (provided as Appendix 12.4 to Tab 12) – This study was undertaken to respond to the directive to examine approaches to maximize the benefits of tradeoffs between the deductible amounts proposed to be used on property insurance, the additional costs of making claims on its existing insurance and the size of uninsured claims. The study reviewed potential benefits that may arise by varying levels of retentions with respect to Yukon Energy's general liability and property program, evaluated Yukon Energy's current insurance program, and estimated the total cost of risk for the program and the expected retained losses at various retention levels. The study then determined the effects of retaining risk via an alternate retention program and made recommendations.

The key conclusions and recommendations of the analysis were:

- **With regard to the General Liability Program** – the study did not recommend altering the retention structure for the General Liability Program at this time.
- **With regard to the Property Program** – the study did not recommend altering the retention structure for property line at this time.

- **Actuarial valuation as at December 31, 2009** (provided as Appendix 12.5 to Tab 12) – The purpose of the study was to prepare an actuarial valuation of Yukon Energy's RFID as at December 31, 2009 – this was undertaken not in response to the particular Board directive, but to concerns raised by the Board and intervenors during the 2008/2009 General Rate Application regarding the justification for the annual appropriation to the reserve. The study reviewed historical losses and exposures for the program to evaluate Yukon Energy's RFID, estimate the ultimate losses as at December 30, 2009, and determine the annual provision for the reserve fund. The study estimated the annual provision for RFID, based on information as at December 31, 2009 as $195,048.

As noted, the above studies were undertaken to support the development of an RFID policy for Yukon Energy in order to respond to the Board's direction and to concerns raised by the Board and intervenors in the last GRA. This policy is provided as Appendix 3.1 to Tab 3.

Directive #12

- ***The Board is persuaded by the submissions of YECL and UCG with respect to KPIs. There is merit in reviewing KPIs for each of the three functions of YEC (generation, transmission, and distribution). At the time YEC files its next GRA, the Board directs YEC to file KPIs for each of the functions included in the application. The KPIs will be provided for the three years prior to the test years and a forecast of KPIs for the test years in that application. YECL should note that for its next GRA, the Board expects the same inclusion.***

KPIs are provided as Appendix 6.1 to Tab 6.

Directive #14

- ***To alleviate existing concerns regarding YEC's ability to estimate, the Board directs YEC, in future, to file any Part 3 applications before this Board only when preliminary***

engineering estimates are available and included as part of the application. Further, in future GRA applications, the Board directs YEC to include business cases for major capital items, including electronic models. Business cases will include:

- ***Descriptions of the project;***
- ***Economic analysis including preliminary engineering estimates;***
- ***Discussion of alternatives and how the chosen option was determined;***
- ***Discussion of the risks of proceeding with the chosen alternative;***
- ***Discussion of risks of not proceeding with the chosen alternative; and***
- ***Discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.***

The response to this directive is addressed in Tab 5 (Capital and Deferred Costs) for major projects (i.e., greater than $1 million).

Directive #15

- ***Therefore the Board is not satisfied that there is a need for the Minto units (based on the capacity planning criteria) and finds that YEC has not shown that the Minto units are the least cost option for YEC to pursue. The Board concludes that the Minto units are not to be included into rate base for this test period and directs YEC in its compliance filing to amend its revenue requirement and schedules accordingly. YEC may reapply in a future GRA when the need for the units is established through load growth and the units are proven to be the least cost option.***

In the compliance filing related to the 2008/2009 General Rate Application Yukon Energy noted that the Minto diesels were removed from ratebase and would remain in work-in-progress throughout the test years and consequently the Minto loan was also excluded from long term debt. Since the compliance filing, Yukon Energy has made a decision not to purchase the Minto diesel units.

Directive #16

- ***The Board is also aware of the numerous steps that are involved in bringing a project to fruition and the fine balance that exists between micro managing and allowing a***

utility to conduct its business. However, the Board finds intervenor comments regarding the lack of business cases for each the individual projects and hence the absence of significant and material information to be justifiable. Therefore, in future, for those costs which YEC wishes to include in its revenue requirement, the Board directs YEC to provide appropriate business cases to support those costs.

Please see response to Directive #14. Business cases for major projects over $1 million are reviewed in Tab 5.

Directive #17

- ***The evidence suggests that YEC has a review process in place wherein concerns are identified, tested and reviewed by YEC's Board of Directors. The Board considers that the review process itself should be documented more clearly what materials are actually reviewed and how decisions that affect the status of studies and projects are made. Therefore, the Board directs YEC to keep written documentation of any and all deferred cost project review meetings that occur (e.g. agendas, materials presented for discussion, minutes, etc.) and have available for review for those items YEC wishes to include in its revenue requirement.***

The major decision stages and management process for each project are fully addressed in Tab 5. Representatives from the Company who report to the Board will be witnesses at the oral hearing to answer any relevant and appropriate questions relating to these issues.

With regard to the review process undertaken by the Yukon Energy Board of Directors it is noted that for each major project the Board of Directors is continually provided with status updates throughout the planning and construction phases and until the project is completed and in service. For example, for Mayo B, after the decision to proceed toward securing approvals for the project (i.e., Yukon Energy management decision to proceed with YESAB filing and licencing activities), the Yukon Energy Board of Directors was updated at each Board meeting on key decision points (e.g., all key contracts and agreements were presented to and reviewed and approved by the Board of Directors) and, after start of construction, ongoing progress including costs, risks and other material issues of concern.

Directive #19

- ***The Board is satisfied with the explanations provided by YEC in respect to the concerns noted by YECL. In future applications when updates occur, the Board directs***

YEC to provide explanations of all variances (forecast to actual) 10% or greater and a brief explanation of why those variances were not captured in the original forecast.

Yukon Energy will provide such information at the time of any update filing during the course of this review process.

Directive #20

- ***The Board notes that IFRS does not come into effect until January 1, 2011 and that for comparison purposes, 2010 results will need to be reported in the IFRS format. As this is outside the current test period (although some transition costs may affect 2009), the Board sees this as an issue for 2010. Therefore, YEC is to include in its next GRA (Phase I) a section on how the transition to IFRS has affect the reporting of their results and provide a comparison on how the results would have been reported had there not been a transition to IFRS.***

The Accounting Standards Board of Canada has deferred until January 1, 2012 the requirement for rate regulated utilities to be IFRS compliant[10]. Due to this delay in implementation of IFRS accounting standards the comparison of results that would have been reported had there not been a transition to IFRS is not yet completed.

Appendix 6.2 to Tab 6 provides *A Summary of Yukon Energy Corporation's Transition from Canadian Generally Accepted Accounting Principles ("GAAP") to International Financial Reporting Standards ("IFRS").* This document provides an overview of Yukon Energy's required transition from Canadian GAAP to IFRS, including an update regarding the status of the conversion project and a summary of likely GAAP differences and expected impacts to opening transition statement of financial position under IFRS dated as of January 1, 2011.

6.3 ORDER 2010-13 – PHASE II RATE APPLICATION

On February 19, 2010, Yukon Electrical Company Limited and Yukon Energy Corporation (jointly, the Companies) filed with the Yukon Utilities Board, pursuant to the *Public Utilities Act* , and Order-In-Council 1995/90, the 2009 Phase II Rate Application.

[10] In March 2012, the Accounting Standards Board of Canada indicated that it would defer for a further year (until January 1, 2013) the requirement for rate regulated entities to be IFRS compliant. Yukon Energy is considering whether to take the additional deferral at this time.

In Order 2010-13, the Board directed the Companies to provide a compliance filing which was to include updated Rate Schedules, Bill Comparison Tables and Terms and Conditions of Service. The Companies provided the compliance filing, including revised Rate Schedule and Terms and Conditions of Service. The compliance filing was approved by Order 2011-05.

Order 2010-13 resulted in a number of specific Board directions. Most of these directives were incorporated into the compliance filing approved in Order 2011-05. The following directive was addressed in 2011:

Directive #18

- ***Given the large swings in the balance of the Rider F account, the Board directs the Companies to provide a written policy, for approval by the Board, on how Rider F is to be managed at the time of the next filing to adjust the rate for Rider F, or at the latest by June 30, 2011. Secondly, to allow all interested parties to monitor the balance in the Rider F account, the Companies are to provide to the Board quarterly acknowledgement filings stating the balance in the Rider F account and concurrently posting those filings on each company's website for easy public access.***

In response to this directive, the Companies filed a jointly on June 30, 2011 the *YEC & YECL Rider F – Fuel Adjustment Rider & Deferred Fuel Price Variance Policy* (the "Policy"). This written policy outlines the administration of the deferred fuel price variance account and sets out how Rider F changes are administered in Yukon based on well established past practice and specific order of the Yukon Government (OIC 1995/90). This policy was reviewed as part of a written process that occurred between August and November 2011 that included interrogatories, argument and reply argument. Order 2011-15 approved the policy as revised by directions as set out by Reasons for Decision (Appendix A attached to the Order). The Companies filed a revised Policy January 20, 2012 and the Board invited intervenor comments on the filing (due February 8, 2012). The matter remains under Board review at this time.

The Board also provided in Order 2010-13 a series of directives related to the Cost of Service Study as filed by the Companies noting that it "[did] not accept the COS study as filed by the Companies", "an updated COS study approved by the Board is essential to establishing a future rate restructuring process" and directed the Companies to "file a joint COS study within six months of the expiry of OIC 2008/149" that "incorporate[s] all findings and directions of the decision." The Board directives regarding Cost of Service and Rate Design consequently cannot be addressed until the next joint cost of service study is filed by the Companies. The latest OIC direction in April 2012 effectively provides that material rate

design changes that would result in rebalancing of rates between different customer classes cannot be undertaken until 2014 at the earliest.

In Order 2011-05 the Board noted that the Compliance Filing was consistent with the direction provided in Appendix A to Order 2010-13 and approved the rate schedules attached as Appendix A to Board Order 2011-05 and Terms and Conditions attached as Appendix B to Order 2011-05 effective June 1, 2011. The Board also noted that it was "*not persuaded with respect to the Cost of Service submissions of the Companies. Board Order 2010-13 stands with respect to Cost of Service; that is, the Board does not accept the COSS as filed by the Companies. The Board is of the view that any revenue-to-cost ratios derived from the application are without merit*."

The remaining outstanding directives to be addressed in the next joint cost of service and rate design application are noted below:

Directive #1

- ***The Board directs the Companies to file a joint cost of service study at the expiry of OIC 2008/149. The COS study must incorporate the directions in this Decision.***

Directive #2

- ***The Board finds there is no compelling evidence on the record of this proceeding to persuade it that the classification of the Aishihik plant should be changed to 100% energy from its present classification of 60% energy and 40% demand. The Board therefore denies the Companies' proposal to change the Aishihik plant classification to 100% energy. Furthermore, the Board directs the Companies to classify the Aishihik hydro plant 60% energy and 40% demand in the next COS study.***

Directive #3

- ***The Board can find no compelling evidence that justifies the reclassification of the Mayo hydro plant from 60% energy and 40% demand to 100% energy. The Board therefore denies the Companies' proposal to change the Aishihik plant classification to 100% energy. Accordingly, the Board directs the Companies to classify Mayo hydro plant 60% energy and 40% demand in the next COS study.***

Directive #4

- ***The Board accepts the view that transmission is "effectively an extension of the generation plant." Being that the Board directed that Yukon hydro plant be classified 60% energy and 40% demand, the Board finds that a Transmission Line classification of 60% energy and 40% demand to be reasonable. The Board denies the Companies' proposal to classification transmission lines 100% energy and directs the Companies to reflect a 60% energy and 40% demand Transmission Line classification in the next COS study.***

Directive#5

- ***The Board finds that secondary sales bear no relation to a cost-based standard in terms of the costs to the utilities to supply the service, but rather a value-of service concept based on the customer's avoided costs. Accordingly, the Board finds the Companies' proposal to be reasonable and directs the Companies in the next COS to use these secondary sales revenues to reduce the firm rate revenues required to be collected from all distribution connected rate classes.***

Directive #6

- ***In respect of the next COS study, the Board directs the Companies to collaborate to identify and select appropriate cost-effective measures that will effectively measure actual Yukon-specific customer loads so that the ATCO Alberta models can be calibrated to provide reliable Yukon-specific load information, and to implement these measures prior to the next Phase II Application.***

Directive #7

- ***The Companies are directed in the next Phase II Application to provide an explanation of and accompanying reasons as to why the measures are appropriate in calibrating the ATCO Alberta EDLA study in order to provide reliable Yukon-specific load information. This will enable Parties to the proceeding and the Board to examine the results of the EDLA study.***

Directive #8

- ***The Board directs the Companies to confirm the appropriateness of using the demand tables from REA Bulletin 45-2, and to affirm that the document has never been updated.***

Directive #9

- ***If the simplified model is used to provide EDLA results in the next COS study, the Board directs the companies to provide details regarding the differences and the impacts respecting the results of the EDLA. Further, in respect of losses, the Board directs the Companies to provide details that support the transmission line loss calculation in EDLA, considering the different transmission voltages in the Yukon (69kV and 138kV) and Alberta (144kV).***

Directive #10

- ***In respect of the creation of two General Service classes, the Board acknowledges and agrees with the Companies' proposal to separate "the nonhomogeneous general service class into two subclasses at a future date." The Board believes that a split General Service rate classes, i.e. small and large, may serve to explain the divergence of load factors since 1996/97 and contribute to the goal of allocating costs according to cost causation. The Board therefore directs the Companies to create and to incorporate two General Service rate classes, i.e. small and large General Service customer rate classes, into the next COS study.***

Directive #11

- ***The Board accepts the rates for energy blocks 2 and 4 as jointly agreed to by the Companies. The Board also recognizes that the fourth energy block may be an initial step toward the transition to a new Large General Service rate class which the Board directs the Companies to put forth in their next Phase II Application.***

Directive #12

- ***The Board accepts the rates for energy block 4 as jointly agreed to by the Companies. The Board also recognizes that the fourth energy block may be an initial step toward the transition to a new Large General Service rate class which the Board directs the Companies to put forth in their next Phase II Application.***

Directive #19

- ***The desire on the part of customers to get some understanding on the costs and benefits of seasonal rates has been noted by the Board. The Board also notes that all Parties recognize that seasonal rates cannot be offered at this time. To obtain further understanding on this issue, the Board directs the Companies to undertake a study of seasonal rates and report the results of that study to the Board at the time of the next Phase II Rate Application.***

6.4 ORDER 2010-14 – ALEXCO PPA APPLICATION

On September 28, 2010, Yukon Energy filed an application with the Yukon Utilities Board seeking an Order approving the Purchase Power Agreement (PPA) between YEC and Alexco. The Application stated that Alexco intended to develop mines and mills in the Mayo-Keno area and would be connected to the transmission facilities in early October. Also, Alexco intended to commence service as a major industrial customer, as defined in OIC 1995/90, by mid-October 2010.

The PPA included provisions for Alexco to pay YEC for the reasonably incurred costs related to the initial mine facilities spur, capital costs for any other mine facilities, costs to negotiate and conclude the PPA and decommissioning costs. Section 6.1 of the PPA also sought approval to issue only one bill totalling the Electric Demand and Electric Energy at the Points of Delivery. YEC also sought approval for the Alexco Fixed Charge of $7,289 per month as defined in Schedule A of the PPA.

In response, the Board issued Board Order 2010-14 that included the following direction:

Directive #1

- ***The Board denies the PPA as applied for. In order to approve the PPA, a change is required with respect to totalized metering as discussed in the attached Appendix A – Reasons for Decision. The Board directs YEC to revise the PPA based on the foregoing and file a revision with the Board by January 31, 2011. As guidance to YEC, the Board accepts all other terms included in the PPA.***

On January 11, 2011, YEC filed a letter in response to Board Order 2010-14. It explained that Section 6.1 of the PPA is the only section that pertains to totalized metering. It confirmed that Section 6.1 of the PPA provides for billing only as approved by the Board or permitted by the Electrical Services Regulations (ESRs or Terms and Conditions of Service). YEC noted that the Board did not approve totalized metering

and the current ESRs do not allow for totalized metering in the Alexco case because the multiple Points of Delivery are not within a half-mile radius of each other. Also, the Board directed in Board Order 2010-13 that the provision on totalized metering in the proposed Terms and Conditions of Service be revised to reflect the current provision respecting totalized metering. Therefore, YEC submitted that section 6.1 of the PPA provides for totalized billing as approved in Appendix A of Board Order 2010-14, Reasons for Decision. On this basis, YEC requested the approval of the PPA.

In Order 2011-1 the Board indicated that it was satisfied that YEC had clarified that section 6.1 of the PPA only applies to totalizing billing and approved the Alexco PPA (including the Fixed Charge as defined in Schedule A of the PPA, the customer contribution as provided in Section 5.1 and 5.2 of the PPA, the customer's obligation to pay decommissioning costs for mine facilities spurs as provided in Part 11 of the PPA and the issuance of totalized billing in accordance with Section 6.1 of the PPA where the energy and demand charges applicable to each point of delivery under the PPA are totalled and included in one bill).

6.5 ORDER 2010-15 & 2011-4 – RATE SCHEDULE 39 ESCALATION

On November 30, 2010, Yukon Energy filed an application with the Board seeking an Order from the Board for approval of amendments to Rate Schedule 39[11]. On December 23, 2010, the Board issued Order 2010-12 outlining a written process for a Rate Schedule 39 proceeding. On December 30, 2010, YEC requested that escalation of Demand and Energy charges in Rate Schedule 39 by 2.8%, as set out in its November 30, 2010 letter, be provided on an interim refundable basis effective January 1, 2011. This was approved by Order 2011-4.

6.6 ORDER 2011-15 – YEC & YECL RIDER F – FUEL ADJUSTMENT RIDER & DEFERRED FUEL PRICE VARIANCE POLICY

On June 30, 2011, Yukon Electrical and Yukon Energy Corporation filed a joint application with the Board seeking an Order from the Board for approval of the YEC & YECL Rider F — Fuel Adjustment Rider & Deferred Fuel Price Variance Policy (Policy). The Board in Order 2011-15 approved the Policy as revised by the directions set out in the Reasons for Decision (Appendix A attached to this Order) and directed the

[11] OIC 2007/94 provides for escalation of demand and energy charges, once per 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. The existing Rate Schedule 39 was approved in Board Order 2008-13, pursuant to OIC 2007/94. In the proceeding that resulted in that Board Order, YEC committed to file for approval of the Board any changes to this rate schedule arising from the escalation of demand and energy charges under the OIC.

Companies to provide a revised Rider F Policy, as an acknowledgement filing, within 30 days of the issuance of this Order, incorporating the changes directed.

Order 2011-15 resulted in a number of specific Board directions. Most of these directives were incorporated into the compliance filing filed with the Board on January 20, 2012.

The only Board directive not addressed in the compliance filing was provided to Yukon Energy specifically at page 9 of the Order:

- ***The Board accepts the commitment of YEC to address all DCF issues in the next GRA and directs YEC to address any changes necessary in the operating rules, administration and revised revenue requirements pertaining to the DCF in its next GRA. Also, the Board requires that YEC provide a specific definition of the term "diesel on the margin". The Board directs that YEC complete its review and bring the necessary changes before the Board at the earliest of its next GRA or July 1, 2012.***

YEC has completed its review of DCF issues. DCF updates and the updated definition of "diesel on the margin" are addressed in Tab 3 of the Application (specifically Appendix 3.2).

6.7 BOARD ORDERS 2009-11 (AND ERRATA), 2010-9, 2011-7 (AND ERRATA), 2011-8 AND 2011-9

Cost awards were determined subsequent to the Yukon Energy 2008/2009 General Rate Application, the Mayo B Part 3 hearing, the Rate Schedule 39 Escalation proceeding, the Phase II Rate Application and the Alexco PPA proceeding. The Board provided the following directives related to hearing cost awards for each of these proceedings:

- 2008/2009 General Rate Application (Order 2009-11 and errata to Order 2009-11);
    - "YEC shall pay the following amounts to the Intervenors identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing related costs over 2008 for $0.421 million and the balance in 2009, as set out in its GRA Application. YEC shall include in the Phase 2 application a proposal regarding the proper allocation of the costs in the account to the different rate classes".

- Mayo B Part 3 Application (Order 2010-9);
    - "YEC shall pay the following amounts to the Intervenors identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing related costs".
- Rate Schedule 39 Escalation Proceeding (Order 2011-7 and errata to Order 2011-7);
    - "YEC shall pay the following amounts to intervenors identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing-related costs".
- 2009 Phase II Rate Application (Order 2011-8);
    - "YECL and YEC shall pay each half of the following amounts to the Intervenors identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing-related costs. YECL may add its hearing costs in this proceeding to its hearing cost reserve account".
- Alexco PPA Application (Order 2011-9);
    - "YEC shall pay the following amounts to the Intervenors identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing-related costs".

In response to Board Orders 2009-11 (and errata), 2010-9, 2011-7 (and errata), 2011-8, 2011-9 and 2012-1 costs noted in Table 6.1 are to be amortized as set out in Tab 5, Tables 5.6 and 5.7. YEC amortized the 2008/2009 GRA costs over two years, Mayo B Part 3 Application costs are included in the Mayo B Project costs and will be amortized over the life of the asset, Rate Schedule 39 Escalation Proceeding costs over two years, 2009 Phase II Rate Application over two years and, Alexco PPA Application costs over five years as set out in Tab 5 (see Tables 5-3 to 5-7). At the time of preparation of the Application, the Order approving costs for the YEC & YECL Rider F – Fuel Adjustment Rider & Deferred Fuel Price Variance Policy had not yet been issued. Costs for this proceeding included in the Application are based on forecasts. Actual costs approved by Order 2012-1 will be incorporated in future updates and will be amortized over two years. 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 2009-11 (and errata), 2010-9, 2011-7 (and errata), 2011-8, 2011-9

	Yukon Energy 2008/09 GRA - Order 2009-11	Mayo B Part 3 Application - Order 2010-9	RS 39 Escalation - Order 2011-7	Phase II Rate Application - Order 2011-8	Alexco PPA Appilcation - Order 2011-9
Yukon Energy	$ 421,428.21	$ 99,696.45		$ 207,781.88	$ 18,924.91
YECL	$ 40,239.71			$ 55,286.97	
UCG	$ 28,861.25 [1]	$ 16,303.71	$ 1,582.00 [2]	$ 20,577.86	$ 2,394.47
City of Whitehorse	$ 67,840.89	$ 25,865.77		$ 49,821.24	
Leading Edge	$ 8,520.97		$ 358.31	$ 6,654.37	$ 643.12
Yukon Conservation Society		$ 1,820.00			
Government of Yukon	$ 75,263.12	$ 135,428.40	$ 23,950.00	$ 135,141.20	$ 31,891.02
Total	**$ 642,153.18**	**$ 279,114.33**	**$ 25,890.31**	**$475,263.52**	**$ 53,853.52**

1. Errata to Order 2009-11 adjusted UCG costs from $26,772.38 to $28,861.25 and total award from $640,065.28 to $642,153.18.

2. Errata to Order 2011-7 adjusted UCG costs from $1,544.20 to 1,582.00.

APPENDIX 6.1

KEY PERFORMANCE INDICATORS (KPIs)

INTRODUCTION

In Board Order 2009-8, the Yukon Utilities Board ("YUB" or the "Board") directed Yukon Energy to provide Key Performance Indicators ("KPIs") for each of the three functions of Yukon Energy (generation, transmission, and distribution) for the three years prior to the test years, as well as a forecast of for the test years in the next General Rate Application. Specifically, Directive #12 set out as follows:

> *The Board is persuaded by the submissions of YECL and UCG with respect to KPIs. There is merit in reviewing KPIs for each of the three functions of YEC (generation, transmission, and distribution). At the time YEC files its next GRA, the Board directs YEC to file KPIs for each of the functions included in the application. The KPIs will be provided for the three years prior to the test years and a forecast of KPIs for the test years in that application. YECL should note that for its next GRA, the Board expects the same inclusion.*

Yukon Energy has not historically tracked transmission KPIs separately from distribution KPIs, and transmission related outage incidents are included in distribution KPIs[1]. Since the 2008/2009 General Rate Application, Yukon Energy has added major new transmission infrastructure to the bulk power system and interconnected the WAF and Mayo Dawson grids. Now that these material changes to the system are complete, Yukon Energy will engage in work necessary to determine how best to track and report KPIs for transmission and will provide the Board with relative updated information once available.

This attachment reviews actual KPIs related to the generation and distribution functions for the 2009-2011 actual years and provides forecast KPIs for 2012 and 2013.

[1] For example, Yukon Energy has not tracked transmission line KPIs regarding the number of pole failures per 100km or equipment failures by equipment types similar to the type of information report in CEA Forced Outage Performance Transmission Equipment.

EXECUTIVE SUMMARY

As set out in Tab 2 of this GRA Application, Yukon Energy directly serves about two thousand 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 Integrated System through its wholesale sales to the Yukon Electrical Company Limited ("YECL"). Industrial sales under Primary Industrial Rate Schedule 39 currently include sales to the Capstone Mining Corp ("Minto mine") and Alexco Resource Corp. ("Alexco mine"); industrial sales to Eagle Industrial Minerals ("Whitehorse Copper Tailings" or "WHCT") are also forecast starting in 2013.

As shown in Table 1 below, the number of retail customers increased by 4.2% in 2011 over 2009, total firm sales increased by 3.8% in 2010 over 2009 and further 7.9% in 2011 over 2010. The overall increase in firm sales in 2011 over 2009 is 12%, 60% of this is due to increase in wholesales. Although, the sales in the system are growing the reliability index has remained higher than 99.9% (see Table 2.1 below).

Hydro generation remains the predominant source of generation forecast for the test year and is expected to be supplemented by diesel generation as required.

The hydro generation KPIs for 2009 and 2010 reflect normal operations compared to 2011 which shows lower Capacity, Availability and Operating factors due to interruptions in services caused by the Mayo B and Aishihik Third Turbine projects. Diesel generation increased in 2011 due to load increases on the system as well as planned outages at the Aishihik and Mayo hydro facilities as outlined in Generation KPIs section below.

In the past three years the Yukon Energy system experienced more outages than the CEA average (5-year average SAIFI index of 7.4 compared to 2.67 of CEA 5-year average), however, they were of a shorter duration (5-year average SAIDI index of 5.11 compared to 7.83 of CEA 5-year average; 5-year average CAIDI index of 0.71 compared to 2.89 of CEA 5-year average).

Table 1: Summary of Customers, Energy Sales and Generation

Line No.	Description		2009 Actual	2010 Actual	Preliminary 2011	Proposed Forecast 2012	Proposed Forecast 2013
	Residential						
1	Customers		1,457	1,472	1,515	1,526	1,536
2	Sales in MWh		11,676	11,386	12,710	12,325	12,408
3	MWh sales per customer		8.0	7.7	8.4	8.1	8.1
	General Service						
4	Customers		442	455	464	460	467
5	Sales in MWh		19,672	22,719	21,305	21,693	22,620
6	MWh sales per customer		44.5	50.0	45.9	47.1	48.5
	Industrial						
7	Sales in MWh		29,355	30,255	43,259	52,309	62,364
	Street lights						
8	Sales in MWh		496	283	283	279	279
	Space lights						
9	Sales in MWh		26	14	14	15	15
	Total - Firm Retail & Ind.						
10	Customers		1,899	1,927	1,979	1,986	2,003
11	Sales in MWh		61,225	64,658	77,571	86,621	97,685
	Wholesale sales						
12	Sales in MWh		267,229	276,345	290,541	296,000	298,228
	Total - Firm						
13	Sales in MWh		328,455	341,003	368,112	382,621	395,913
	Secondary						
14	Sales in MWh		17,384	10,489	552	0	0
	Total						
15	Sales in MWh		345,839	351,492	368,665	382,621	395,913
16	Losses - MWh		28,007	30,764	32,101	33,288	34,444
17	Losses - %		8.1%	8.8%	8.7%	8.7%	8.7%
18	Total Generation		373,846	382,255	400,766	415,909	430,357
	Source						
19	Hydro Generation		370,962	377,044	384,429	408,128	419,405
20		*% of total*	*99.2%*	*98.6%*	*95.9%*	*98.1%*	*97.5%*
21	Diesel Generation		2,645	5,127	15,935	7,542	10,714
22		*% of total*	*0.7%*	*1.3%*	*4.0%*	*1.8%*	*2.5%*
23	Wind Generation		238	85	402	239	238
24		*% of total*	*0.1%*	*0.0%*	*0.1%*	*0.1%*	*0.1%*

1.0 GENERATION KPIs

Operational Performance Indicators

The operational performance of generation units is gauged on the basis of Capacity Factor, Unit Availability Operating Factor and Forced Outage Rate.

Detailed definitions are as provided below:

- ***Capacity Factor*** – Defined as the actual energy produced by the generators, divided by the maximum possible energy production in a year. This indicator ignores the fact that there may not be sufficient fuel (e.g., water or wind) to run the generation unit at its maximum for 365 days. It is useful as an indication of the utilization of the generators as useful assets, especially in terms of providing energy (kWh's). The higher the percentage the more the units are being run at closer to their maximum capacity.

- ***Unit Availability*** – Defined as the actual number of hours the generators were available for use in the year, divided by the total number of hours in the years (8,760 except in a leap year). This number, expressed as a percentage, is useful in monitoring the overall reliability of the generators but does not consider whether the units were available when they were needed the most, (i.e., hydro in the summer and diesel in the winter).

- ***Operating Factor*** – Defined as the hours that the generators were on-line and generating power, divided by the total number of hours in the year. It is useful in assessing the value of the generation required on the grid.

- ***Forced Outage*** – Defined as the occurrence of a component failure or other condition which requires that the generation unit be removed from service immediately or up to and including the very next weekend. It represents the percentage of time that a unit is not available for operation due to an unscheduled removal from service.

The graphs and tables below provide results for hydro and diesel generation KPIs and display the Capacity Factor, Unit Availability, Operating Factor and Forced Outage rates for Yukon Energy owned hydro and diesel generators.

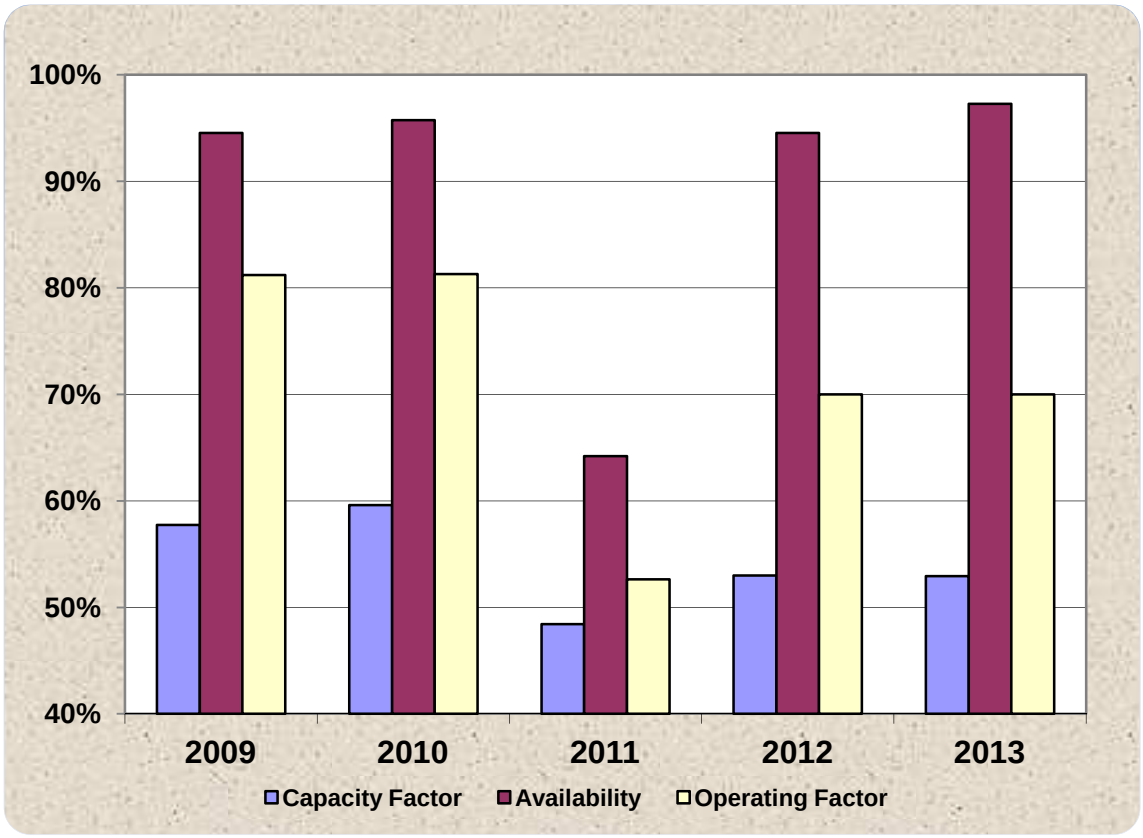
A Summary of Results for Hydro Generation KPI's

A summary of Hydro generation KPIs is provided in Table 1-1 and Figure 1-1 below:

Table 1-1: Hydro Generation KPI's

Year	Capacity Factor	Unit Availability	Operating Factor
2009	57.74%	94.54%	81.2%
2010	59.6%	95.73%	81.3%
2011	48.42%	64.19%	52.62%
F- 2012	52.98%	94.52%	70.0%
F- 2013	52.94%	97.26%	70.0%

Figure 1-1: Hydro Generation KPIs



The hydro generation KPIs for 2009 and 2010 reflect normal operation of the units without any capital project impact. The 2011 results were affected by the Mayo B and Aishihik Third Turbine projects which

required extended plant outages resulting in lower Unit Availability and a decreased Operating Factor as the units could not be run for as long of duration as in the prior years.

The 2012 and 2013 Capacity Factor is forecast to be lower due to increased capacity from the newly installed hydro generating units that went into service in December 2011 (7 MW new turbine at Aishihik and two 5 MW hydro turbines at Mayo B). This results in a reduction of Capacity Factor in the near term as less of the total capacity is being utilized.

Unit Availability will be lower in 2012 than in 2013 as capital projects are forecast for summer 2012 at both the Aishihik[2] and Mayo hydro facilities[3]. A lower Operating Factor (estimated) is also expected as fewer unit operating hours will be required at the Mayo hydro facility to generate the same amount of electricity. Some of this reduction will be offset by increased growth on the integrated grid in the future; in particular starting in 2014 when one or more industrial customers are expected to be connected and in-service.

Summary of Results for Diesel Generation KPIs

A summary of diesel generation KPIs is provided in Table 1-2 below:

Table 1-2: Diesel Generation KPI's

YEAR	Capacity Factor	Unit Availability	Operating Factor
2009	0.84%	89.53%	1.21%
2010	2.13%	89.88%	3.01%
2011	6.15%	95.84%	8.71%
F- 2012	2.03%	96.68%	4.11%
F- 2013	2.91%	97.37%	5.86%

The Capacity Factor for diesel generation remains low as it continues to fulfill the role of back-up generation. During 2011, it increased as diesel generation was required while the Aishihik and Mayo hydro facilities were scheduled out of service in order to construct the two new hydro projects and the inter-connection of the WAF and MD grids during 2011. The Capacity Factor is forecast to increases in 2012 and 2013 as more peaking diesel may be required for winter months.

[2] Required work at Aishihik generation plant in 2012 relates to scheduled overhauls of AH1 and AH2 which may make each unit unavailable for up to 8 weeks
[3] Mayo intake gate is scheduled in spring 2012. This work is expected to take between 4 to 6 weeks

The lower Unit Availability rates in 2009 and 2010 reflect the rebuild of diesel units in Faro and Whitehorse which rendered units unavailable for extended periods of time. Forecast preventative maintenance activities for diesel units during 2012 will result in lower availability than for 2013.

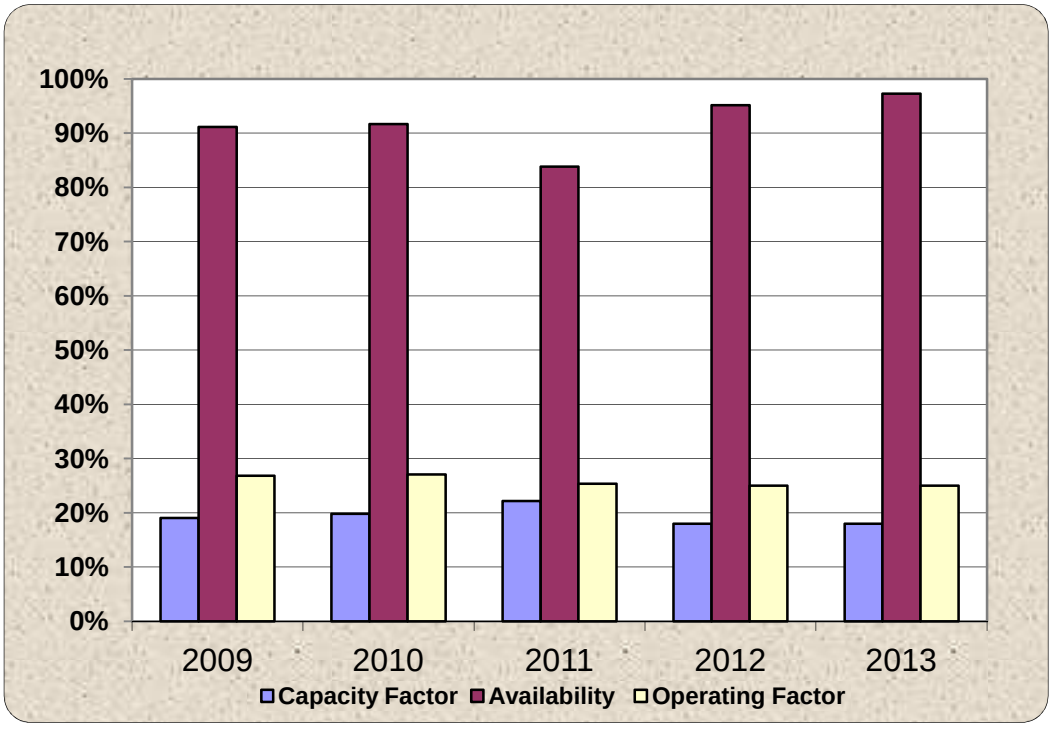
The Operating Factor is higher in 2011 when compared to 2009 and 2010 as diesel units ran for more hours due to hydro units not being available during the construction phase of the Aishihik Third Turbine and Mayo Hydro Enhancement (Mayo B) projects. The increased Operating Factor forecast in 2012 and 2013 versus 2009 and 2010 reflects a forecast increase in peaking diesel.

The only performance indicator determined for the wind turbines is Capacity Factor. The two wind turbines combined to produce a net Capacity Factor of 3.36% in 2009; 1.19% in 2010 and 5.67% in 2011.

Summary of Results for All Generation KPIs

A summary of all general KPIs for the period from 2009 to 2011 Actual is provided in Figure 1-2 below:

Figure 1-2: All Generation KPIs: 2009 to 2013



As observed in the hydro KPIs, the overall Unit Availability dips in 2011 due to reduced availability of hydro units during the Mayo B and Aishihik Third Turbine construction projects. YEC forecasts that 2012

Unit Availability will return to historical norms approaching +95% as capital programs affected Unit Availability in 2009 through 2011.

Table 1-3: Forced Outages

Forced Outage Rates by Generation			
	2009	2010	2011
Hydro	0.45%	0.38%	0.22%
Diesel	4.79%	0.85%	3.07%
Combined	3.40%	0.71%	1.99%

Forced Outages for hydro generation during 2009 through 2011 were the result of various minor occurrences all with short duration. Notable Diesel Forced Outages were a failed exciter unit on FD3 and post overhaul issues on WD3 in 2009 and a failed breaker on FD5 and a valve failure on WD6 in 2011.

2.0 DISTRIBUTION KPIs

Yukon Energy has been reporting distribution KPIs since 1998. There is no historical data prior to this date as it was tracked as part of the overall Yukon totals and not broken out separately. The reliability indices track distribution performance for the Yukon Energy service areas of Mayo, Dawson City and Faro.

Reliability Performance Indicators

Reliability of the distribution system is assessed based on the following indicators that define distribution performance:

- ***System Average Interruption Frequency Index (SAIFI) -*** SAIFI is the average number of interruptions per customer for the period (a year in this case). It is a measure of how many outages an "average" customer experienced throughout the year. SAIFI is calculated by taking the total number of customer interruptions divided by the total number of customers served.

- ***System Average Interruption Duration Index (SAIDI) -*** SAIDI is the system average interruption duration for customers served for the period (a year in this case). It is a measure of how long all customers were affected (i.e., the last customer to be restored power). SAIDI is calculated by totalling the customer hour interruptions and dividing by the total number of customers served.

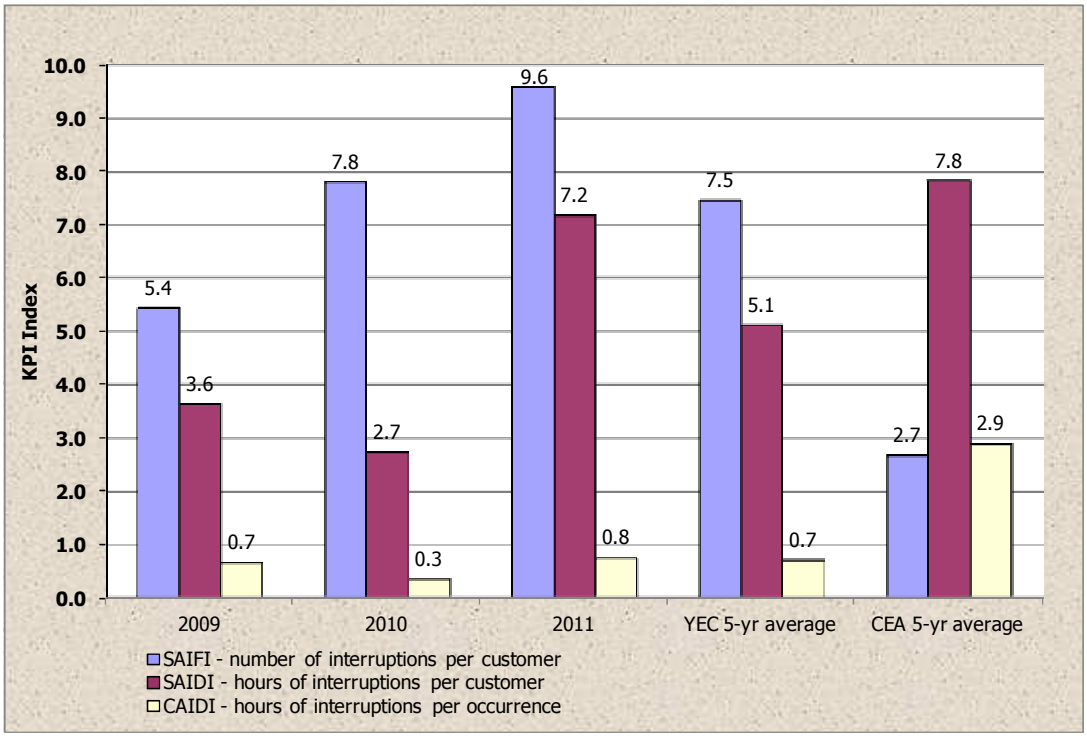
- ***Customer Average Interruption Duration Index (CAIDI) -*** CAIDI is the average customer interruption duration for customers interrupted. It is a measure of how long the "average" outage lasted for the customers affected. CAIDI is the total number of customer hour interruptions divided by the total number of customer interruptions.

- ***Index of Reliability (IOR) -*** IOR is the annual customer-hours that service is available measured as a percentage. It is determined by (8,760 hours/year – SAIDI) divided by 8,760 hours/year.

Summary of Results for Distribution KPIs

Figure 2-1 illustrates the reliability indicators using YEC data for 2009 through 2011 along with a 5-year average for YEC compared to the most current 5-year CEA average[4].

Figure 2-1: Yukon Energy Distribution KPIs: 2009 to 2011



The SAIFI index is consistent with a year by year increase in outages. Refer to the Classification of Distribution Outages section (below) for analysis and comment regarding causation of outages. As a small grid, YEC typically experiences a higher frequency rate than is reported by the CEA index. Some of

[4] The Canadian Electrical Association (CEA) compiles data from member utilities across the country which differentiates urban utilities (Region 1) from urban/rural (Region 2) utilities. For comparative purposes, Yukon Energy is more similar to Region 2 utilities. 5-year CEA averages are calculated based on 2006-2010 numbers as 2011 was not available.

the increased frequency is attributable to YEC's reporting standard of including all outages that affect a whole YEC service area or a YECL community receiving power from YEC or an industrial customer even though there may be fewer than 50 customers affected by the outage.

The SAIDI index is a function of the duration of the outages. The nature of the outage often affects the duration. For example, outage incidents caused by lightning and snow contribute most to the customer hour interruptions because they affect a larger portion of the grid than other types of more localized outages. Typically YEC customers experience fewer customer hour interruptions than the CEA average. Much of this is attributable to having diesel back-up in communities which is readily available when an outage occurs that impacts the transmission infrastructure.

The CAIDI Index is lower than the CEA average which reflects YEC's ability to restore power on its grid more quickly than southern grids resulting in shorter outage durations being experienced by its customers.

IOR is the annual customer-hours that service is available measured as a percentage. It is determined by (8,760 hours/year – SAIDI) divided by 8,760 hours/year. On a year-to-year and 5-year comparison basis YEC is equal to or higher than the CEA reporting utilities.

Table 2-1: Index of Reliability

Index Of Reliability				
2009	2010	2011	YEC 5 yr	CEA 5 Yr
99.96%	99.97%	99.92%	99.94%	99.91%

Classification of Distribution Outages

Yukon Energy classifies the primary cause of an interruption to match the CEA classification groups. A customer interruption has been defined in terms of the primary cause of the interruption. These causes have been assigned the following codes:

0 – Unknown/Other

Customer interruptions with no apparent cause or reason which could have contributed to the outage.

1 - Scheduled Outage

Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

2 – Loss of Supply

Customer interruptions due to problems in the bulk electricity supply system such as under frequency load shedding, transmission system transients, or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle.

3 – Tree Contacts

Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.

4 – Lightning

Customer interruptions due to lightning striking the Electrical System, resulting in an insulation breakdown and/or flashover.

5 – Defective Equipment

Customer interruptions resulting from equipment failure due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

6 – Adverse Weather

Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

7 – Adverse Environment

Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

8 – Human Element

Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage.

9 – Foreign Interference

Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage (by others) and foreign objects.

Causes of Distribution Outages

YEC reports all outages of any duration that affect more than 50 customers or a complete YEC service area or result in an interruption of service to a YECL community receiving power from YEC or an industrial customer.

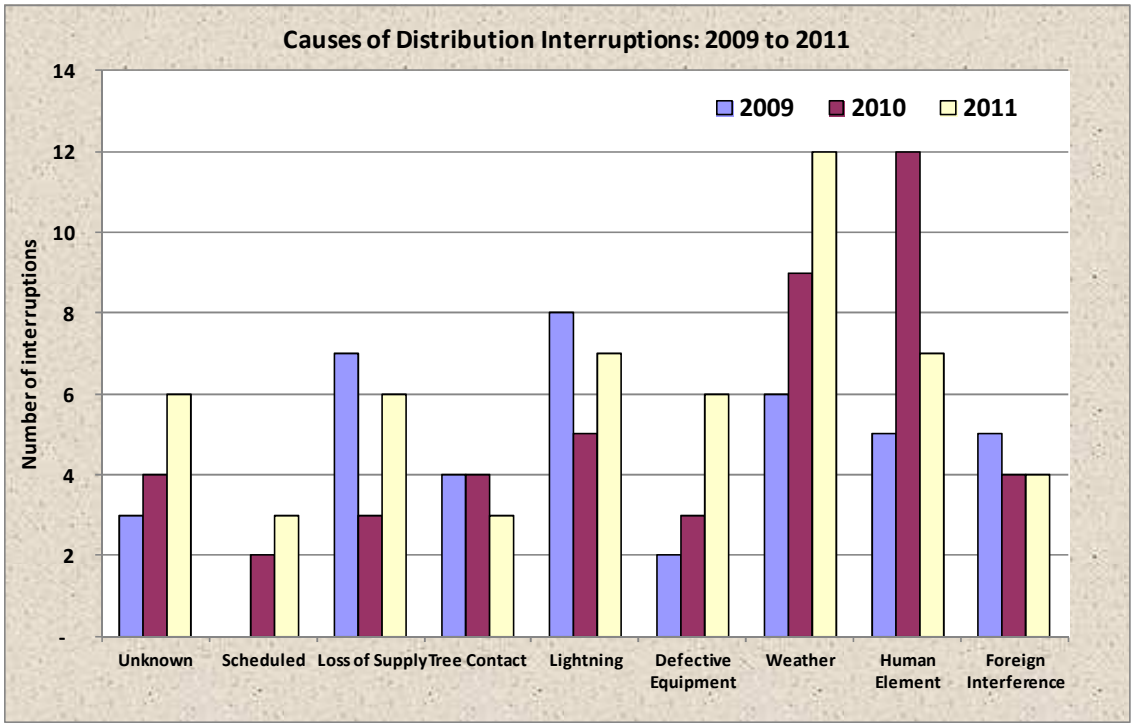
The Table 2-2 lists the number and causes of interruptions form 2009 to 2011.

Table 2-2: Cause of Interruption: 2009 to 2011

Cause of Interruption	2009	2010	2011
Unknown	3	4	6
Scheduled	-	2	3
Loss of Supply	7	3	6
Tree Contact	4	4	3
Lightning	8	5	7
Defective Equipment	2	3	6
Weather	6	9	12
Human Element	5	12	7
Foreign Interference	5	4	4
Total	40	46	54

Figure 2-2 below illustrates the number of distribution interruptions from 2009 to 2011.

Figure 2-2: Causes of Distribution Interruptions: 2009 to 2011



Unknown, Scheduled, Tree Contacts, Lightning, Weather and Foreign Interference contribute towards the majority of outages each year and are usually attributable to events beyond the immediate control of the utility. If the average for the past 8 years continues, YEC forecasts that it will encounter approximately 30 of these outages per year during 2012 and 2013.

Loss of Supply, Defective Equipment and Human Element are categories where the YEC attempts to reduce outages through preventative maintenance and training activities. For example, much of the spike in Human Element occurrences in 2010 was due to an incident where multiple attempts to reclose a switch resulted in a series of short outages on the same day – with each recorded as an interruption in service. Training and improved procedures can reduce occurrences of this type of outage.

As the SAIFI, SAIDI and CAIDI indices vary based on incidents and duration YEC has not attempted to forecast the indices but expects that the outcome for 2012 and 2013 will be slightly lower than the 5-year average attained in 2011.

APPENDIX 6.2
A SUMMARY OF YUKON ENERGY CORPORATION'S TRANSITION FROM CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (GAAP) TO INTERNATIONAL FINANCAL REPORTING STANDARDS (IFRS)

TABLE OF CONTENTS

1.0 INTRODUCTION

In Board Order 2009-8, the Yukon Utilities Board ("YUB") directed Yukon Energy Corporation ("Yukon Energy" or "YEC") to include in its next GRA "a section on how the transition to IFRS has affected the reporting of their results and provide a comparison on how the results would have been reported had there not been a transition to IFRS". Specifically, Directive #20 set out as follows:

> *The Board notes that IFRS does not come into effect until January 1, 2011 and that for comparison purposes, 2010 results will need to be reported in the IFRS format. As this is outside the current test period (although some transition costs may affect 2009), the Board sees this as an issue for 2010. Therefore, YEC is to include in its next GRA (Phase I).*

This document provides an overview of Yukon Energy's required transition from Canadian Generally Accepted Accounting Principles ("GAAP") to International Financial Reporting Standards ("IFRS"), and specifically addresses the following matters:

(1) An overview of Yukon Energy's required transition from CGAAP to IFRS;

(2) Current status of the IFRS conversion project; and

(3) A summary of the likely GAAP differences and expected impact to the opening transitional statement of financial position under IFRS dated as of January 1, 2011.

The effect of IFRS on Yukon Energy's accounting records is estimated at this time based on best available information and is subject to change until Yukon Energy's December 31, 2012 year end financial statements are issued. The implementation of IFRS (and how provisions are interpreted and applied) will evolve up to December 31, 2012. These and other factors may impact IFRS reporting requirements and Yukon Energy's identified IFRS differences and adjustments.

1.1 BACKGROUND

The financial accounting records of Yukon Energy are currently maintained in accordance with Canadian Generally Accepted Accounting Principles[1].

[1] *The Budget Transparency and Accountability Act* (BTAA) specifies that Government and government organizations conform to the set of standards and guidelines that comprise generally accepted accounting principles for senior governments in Canada, unless otherwise directed by Treasury Board.

Accounting standards for senior governments are understood to mean standards established by the Public Sector Accounting Board ('PSAB'). PSAB has directed Government Business Enterprises ('GBE') to follow the guidance applicable to publicly accountable enterprises, as issued by the Canadian Accounting Standards Board ('ASB').

The ASB, in turn, has required publicly accountable enterprises to adopt International Financial Reporting Standards ('IFRS'), as issued by the International Accounting Standards Board ('IASB') and adopted by the Canadian Institute of Chartered Accountants, for years beginning on or after January 1, 2011. Yukon Energy is classified as a GBE and consequently must adopt these new accounting standards.

Update on Progress

On October 1, 2010, the ASB allowed entities that meet the criteria for rate regulated activities to defer the transition to IFRS for one year, to years beginning on or after January 1, 2012, and to continue to apply CGAAP until that time[2]. Yukon Energy has elected to take this deferral option and will therefore report under IFRS for the first time in its year ended December 31, 2012.

Prior to fiscal year 2012, Yukon Energy prepared its consolidated financial statements in accordance CGAAP in effect for these periods. Comparative figures to Yukon Energy's year ended December 31, 2012 financial statements (i.e. year ended December 31, 2011) will be reported under IFRS. The first set of financial statements will include an additional balance sheet dated, January 1, 2011, as IFRS generally requires more extensive financial statement disclosures.

Summary of Expected Impacts of Transition on Yukon Energy

IFRS uses a conceptual framework similar to historical CGAAP, but there are significant differences in recognition, measurement and disclosures. The transition to reporting under IFRS is expected to impact Yukon Energy in the following ways:

(1) Transitional adjustments

The conversion to IFRS will result in adjustments to Yukon Energy's opening balances dated January 1, 2011, including adjustments to opening retained earnings.

(2) Ongoing adjustments and differences from Canadian GAAP

[2] In March 2012, the Accounting Standards Board of Canada indicated that it would defer for a further year (until January 1, 2013) the requirement for rate regulated entities to be IFRS compliant. Yukon Energy is considering whether to take the additional deferral at this time.

There will be ongoing differences from Canadian GAAP that may give rise to volatility in earnings compared to CGAAP. For example, differences in the timing of recognition of costs under IFRS when compared to CGAAP.

(3) Costs of conversion to IFRS

Additional costs are, and will, continue to be incurred with respect to the conversion to IFRS due to increased internal and external consulting time, IT system costs and additional audit and other compliance costs. Costs for this extensive conversion process are expected to total $667,076 by the end of 2012 and are addressed in greater detail in Tab 5 and Appendix 5.5 (Deferred Projects Between $100,000 and $ 1million).

2.0 IFRS CONVERSION PROJECT STATUS

Yukon Energy hired an advisor experienced with IFRS to assist in developing and executing its conversion to IFRS in order to ensure the following: (1) that differences between CGAAP and IFRS that affect Yukon Energy were identified; and (2) that any required changes to accounting processes and controls (including information technology systems) could be made in a timely manner.

Yukon Energy has a project manager leading the conversion to IFRS who is working with the advisor and senior management in order to execute the plan. Yukon Energy is also assessing and considering changes to its accounting policies, internal controls and procedures, and financial information systems, and is training staff on the implementation of the new standards.

Through 2012, the IFRS team will work through the affected topics and finalize position papers on the expected accounting treatment under IFRS. These position papers will be reviewed by senior management and external auditors prior to finalization.

3.0 ESTIMATED RECONCILIATION OF STATEMENT OF FINANCIAL POSITION AS OF JANUARY 1, 2011 FROM CANADIAN GAAP TO IFRS

The following unaudited consolidated balance sheet adjustments as at transition to IFRS (i.e. January 1, 2011) show the expected impacts of the noted differences between IFRS and CGAAP. It is anticipated that an update to the details of the annual expected adjustments will be provided in Yukon Energy's 2011 annual report in [June 2012].

3.1 EXPECTED IFRS 1 FIRST-TIME ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS - EXEMPTIONS AND ELECTIONS

First time adoption of IFRS generally requires a company to restate its previous GAAP accounting policies and report as if the Company's initial IFRS accounting policies had always been applied to the reporting entity. For most utilities, including Yukon Energy, this retrospective restatement would be extremely costly and time-consuming to do. Consequently, IFRS 1 contains a number of elections to the first time reporter under IFRS, so as to avoid retrospective restatements, as well as the disclosures required on conversion to IFRS.

Yukon Energy expects to apply the following exemptions and elections in its transition from Canadian GAAP to IFRS:

a) Employee Benefits

IFRS 1 provides the option to recognize all cumulative actuarial gains and losses (and also transitional balances) that exist at the date of transition (January 1, 2011) in opening retained earnings. Yukon Energy will take this optional election and an adjustment to reduce retained earnings by approximately $1.0 million is expected.

b) Capital Assets – Deemed Cost

For entities subject to rate regulation, IFRS 1 provides the option to elect the previous GAAP carrying value (i.e. CGAAP net book value) of property plant and equipment (PPE) and intangible assets at transition date to be the new 'deemed cost' under IFRS. It is acknowledged in IFRS 1 Appendix D8B that "The carrying amount of such items might include amounts that were determined under previous CGAAP but do not qualify for capitalization in accordance with IFRSs".

Pursuant to Appendix D8B of IFRS 1, the criteria for being subject to rate regulation is as follows:

> *If they provide goods or services to customers at prices (i.e. rates) established by an authorized body empowered to establish rates that bind the customers and that are designed to recover the specific costs the entity incurs in providing the regulated goods or services and to earn a specified return. The specified return could be a minimum or range and need not be a fixed or guaranteed return*.

Yukon Energy meets these criteria and has elected to take the deemed cost option; as such, no adjustment to retained earnings is expected as a result of this policy election.

3.2 EXPECTED APPLICABLE CANADIAN GAAP TO IFRS ACCOUNTING DIFFERENCES TO YUKON ENERGY

The principal adjustments expected to be made by Yukon Energy in restating its CGAAP consolidated statement of financial position as at January 1, 2011 (and expected also adjust its fiscal year 2011 financial statements) include:

a) Rate Regulated Assets and Liabilities

Canadian GAAP allows Yukon Energy, as a regulated utility, to recognize the effects of rate regulation as regulatory assets and liabilities on its balance sheet. These accounts, representing deferral accounts established by the regulator, allow the timing of costs incurred, and revenues received, to be matched and allocated over the period in which ratepayers will fund the costs. The use of these deferral accounts for rate-setting purposes reduces exposure to volatility in costs and rates and reduces the impact of actual variances on forecasted items the utility often has little control over. The recognition of these deferral accounts in the general purpose financial statements provides consistency between the external financial statements and those used for regulatory purposes.

IFRS does not currently contain any separate guidance related to the recognition of assets, liabilities, revenues and expenses that have arisen from rate regulation. If the assets and liabilities, represented by deferral accounts and other acceptable regulatory treatments, would not otherwise be recognized under current IFRS standards, such balances would not be recognized. IFRS generally requires that revenues and expenses be recognized as incurred and, at present, it is Yukon Energy's view that IFRS does not support recognition of deferral accounts on the balance sheet as assets and liabilities. This issue is still under review with IFRS advisors and auditors but the net effect of eliminating these deferral accounts would be to reduce Yukon Energy's retained earnings as at January 1, 2011 by approximately $870,000.

b) Asset Retirement Obligations

Under CGAAP, an asset retirement obligation is recorded if a utility has a legal obligation to incur an expenditure in the future associated with an asset currently in use.

Under IFRS, asset retirement obligations are recognized for both legal and constructive obligations at the best estimate to settle the obligation.

At this time, management expects the balance in the Reserve for Site Restoration to be a reasonable proxy for these legal and constructive obligations, negating the need for any adjustment to the balance

sheet. This is a preliminary assessment and requires further vetting by IFRS advisors and sign off by external auditors.

c) Property, plant and equipment

IFRS requires capital assets to be classified into their significant components and that such components be depreciated over their estimated economic lives, if material. To date, the effect of annual depreciation rates for this componentization is estimated not to be material, however, Yukon Energy will be re-evaluating this conclusion once it obtains the results of a depreciation study.

YEC is in the process of establishing its IFRS accounting policies for capital assets, including capitalization, depreciation and disposal accounting policies.

d) Overheads

Under the previous accounting policy, Yukon Energy applied a percentage of actual cost to each capital project as a provision for overhead costs. The percentage used could vary from 0.5% to 10% depending on the size and complexity of the job. Under IFRS, general overhead allocations are specifically not allowed on capital projects. Accordingly, Yukon Energy has eliminated the pooling of overhead expenses for general allocation. In lieu of this, management has directed staff to charge all capital related work to specific projects. As well, vehicle expenses that were previously included in the overhead pool are now charged to projects based on the driver's labour coding. This new treatment was adopted in 2011 – it is not expected that this change will have a material impact on the amount of overhead charged to capital.

e) Interest During Construction

In lieu of earning a rate of return on assets under construction, the utility charges WIP projects at the weighted average cost of capital during the period the asset is being constructed. Under IFRS, entities are not permitted to charge projects for equity returns; accordingly, Yukon Energy has amended this policy to use a debt-only rate for AFUDC (Allowance for Funds used during Construction) starting in 2011. At current rates, this will result in lower charges to capital[3].

4.0 CONCLUSION

YEC is required to adopt IFRS beginning with its 2012 fiscal year, including comparative figures for 2011. The transition to IFRS and its impact on Yukon Energy's financial reporting is still being determined at

[3] Average 2011 debt rate was approximately 4.5%, while the blended debt/equity rate is 6.1% using equity of 8.49%.

this time, but differences from CGAAP are expected and financial statement disclosures will be expanded under IFRS.

TAB 7
FINANCIAL SCHEDULES

Yukon Energy Corporation
April 2012

Schedule Index

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

Schedule 1
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	**Property, Plant and Equipment**									
2	Year end balance	S.3 L.5	286,660	297,262	378,171	473,017	496,938	496,938	520,651	520,651
	Deduct:									
3	Accumulated depreciation (note 1)	S.3 L.10	89,221	89,353	95,584	103,288	115,017	111,706	127,419	120,694
4	Construction-in-progress	S.3 L.11	8,686	20,898	91,851	7,892	6,199	6,199	19,798	19,798
5	Disallowed assets	S.3 L.12	200	200	200	200	200	200	200	200
6	Miscellaneous reserves	S.3 L.13	7,814	7,373	6,782	6,366	6,001	6,140	5,636	5,914
7	Total deductions		105,921	117,823	194,417	117,745	127,417	124,244	153,053	146,606
	Add:									
8	Deferred study costs (note 2)	S.3 L.15	22,451	12,374	17,328	22,115	26,760	27,178	25,466	27,207
9	Less: Studies in Progress	S.3 L.16	(14,526)	(4,584)	(10,543)	(8,965)	(2,169)	(2,169)	-	-
10	Other deferred costs	S.3 L.17	121	-	-	-	-	-	-	-
11	Accum. Disallowed depreciation	S.3 L.18	78	78	82	86	90	90	94	94
12	Total additions		8,124	7,868	6,867	13,236	24,681	25,099	25,560	27,301
	Net plant in Service									
13	Current year-end balance	S.3 L.20	188,863	187,306	190,621	368,508	394,202	397,792	393,158	401,346
14	Previous year-end balance		191,305	186,710	187,306	190,621	368,508	368,508	394,202	397,792
15	Total		380,168	374,016	377,927	559,129	762,710	766,301	787,360	799,138
16	Mid-year balance		190,084	187,008	188,963	279,564	381,355	383,150	393,680	399,569
18	Mid-year rate case expense		1,026	966	915	1,570	3,281	3,006	4,736	3,911
19	Working capital	S.2 L.8	3,193	3,594	3,822	4,150	4,014	4,118	4,218	4,280
20	**Gross Rate Base**		194,303	191,568	193,700	285,284	388,650	390,274	402,634	407,761
	Deduct:									
	Contributions for extensions									
21	Current year-end balance		55,366	57,408	140,896	176,220	182,343	182,343	191,243	191,243
22	Contributions in WIP		5,000	6,932	90,238	120	2,000	2,000	10,500	10,500
23	Current year-end balance in-service		50,366	50,476	50,658	176,100	180,343	180,343	180,743	180,743
24	Accumulated amortization of contributions		4,376	5,179	7,025	9,200	13,733	12,736	18,315	16,305
25	Net current year-end balance in-service		45,990	45,297	43,633	166,900	166,610	167,607	162,428	164,438
26	Previous year-end balance		46,680	45,077	45,297	43,633	166,900	166,900	166,610	167,607
27	Total		92,670	90,374	88,930	210,533	333,511	334,507	329,039	332,046
28	Mid-year balance		46,335	45,187	44,465	105,267	166,755	167,254	164,519	166,023
29	**Net Rate Base**	S.5 L.1	147,968	146,381	149,235	180,017	221,895	223,020	238,115	241,738

Note 1: Including Reserve for Future Removal and Site Restoration
Note 2: Planning and Study costs, Relicencing, Dam Safety costs and Deferred Overhauls. Net of contributions.

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

Schedule 2
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Operating and maintenance	S.5 L.5	13,403	14,765	15,219	18,377	17,681	19,241	19,779	21,026
2	Taxes other than income	S.5 L.6	256	288	291	297	312	312	326	326
3	Non-allowable expenses		(85)	(159)	(133)	(333)	(85)	(85)	(85)	(85)
4	Cash operating expenses		13,575	14,894	15,377	18,341	17,907	19,468	20,021	21,267
5	27/365 in 2009 GRA		1,004	1,102	1,137	1,357	1,325	1,440	1,481	1,573
6	Inventory (three year average)		2,279	2,574	2,644	2,731	2,770	2,770	2,830	2,830
7	GST Impact on working capital	S.2A L.11	(90)	(81)	41	62	(80)	(92)	(93)	(123)
8	Working capital	S.1 L.19	3,193	3,594	3,822	4,150	4,014	4,118	4,218	4,280

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

Schedule 2A
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Expenses subject to GST		25,921	30,134	95,658	111,287	41,519	43,079	38,801	40,047
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		1,296	1,507	4,783	5,564	2,076	2,154	1,940	2,002
4	Day Factor		14	14	14	14	14	14	14	14
5	Recoverable portion of GST impact		50	58	183	213	80	83	74	77
6	Revenue subject to GST		31,997	31,708	32,376	34,294	36,402	39,857	37,956	45,641
7	GST blended rate (2009 GRA)		4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%	4.58%
8	GST payable		1,465	1,452	1,482	1,570	1,667	1,825	1,738	2,090
9	Day factor		35	35	35	35	35	35	35	35
10	Payable portion of GST impact		140	139	142	151	160	175	167	200
11	Net impact of GST on working capital	S.2 L.7	(90)	(81)	41	62	(80)	(92)	(93)	(123)

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

Schedule 3
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	**Property, Plant and Equipment**									
2	Balance at beginning of year		277,842	275,268	297,262	378,171	473,017	473,017	496,938	496,938
3	Net Increases to PPE (Table 5.1)		9,078	22,824	81,827	95,000	23,921	23,921	23,713	23,713
4	Retirements, disposals and adjustments (note 1)		(260)	(831)	(918)	(153)	-	-	-	-
5	Balance at end of year	S.1 L.2	286,660	297,262	378,171	473,017	496,938	496,938	520,651	520,651
6	**Accumulated depreciation (including Future Removal Reserve)**									
7	Balance at beginning of year		82,955	83,107	89,353	95,584	103,288	103,288	115,017	111,706
8	Depreciation expense	S.6 L.7	6,526	7,214	7,369	7,902	11,730	8,418	12,402	8,989
9	Retirements, disposals and adjustments (note 1)		(260)	(969)	(1,137)	(199)	-	-	-	-
10	Balance at end of year		89,221	89,353	95,584	103,288	115,017	111,706	127,419	120,694
	Deduct:									
11	Construction-in-progress	S.1 L.4	8,686	20,898	91,851	7,892	6,199	6,199	19,798	19,798
12	Disallowed assets	S.1 L.5	200	200	200	200	200	200	200	200
13	Miscellaneous reserves (note 2)	S.1 L.6	7,814	7,373	6,782	6,366	6,001	6,140	5,636	5,914
14	Total		16,700	28,471	98,833	14,457	12,400	12,539	25,634	25,912
	Add:									
15	Deferred study costs (note 3)	S.1 L.8	22,451	12,374	17,328	22,115	26,760	27,178	25,466	27,207
16	Less: Studies in Progress	S.1 L.9	(14,526)	(4,584)	(10,543)	(8,965)	(2,169)	(2,169)	-	-
17	Other deferred costs	S.1 L.10	121	-	-	-	-	-	-	-
18	Accum. Disallowed depreciation	S.1 L.11	78	78	82	86	90	90	94	94
19	Total		8,124	7,868	6,867	13,236	24,681	25,099	25,560	27,301
20	Net Property, Plant and Equipment	S.1 L.13	188,863	187,306	190,621	368,508	394,202	397,792	393,158	401,346

Note 1: Largely relate to retirements and disposals, as well as charges against the Reserve for Future Removal and Restoration
Note 2: Includes Fire Insurance Reserve, Deferred Dewatering Revenues and the Reserve for Injuries and Damages
Note 3: Planning and Study costs, Relicencing, Dam Safety costs and Deferred Overhauls. Net of contributions.

Yukon Energy Corporation
Cost of Capital Calculation
2009 Approved and 2009-2010 Actual
($000s)

Schedule 4A
April 2012

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
	2009 Approved						
1	Long-Term debt	S.11 L.18	92,092	60.0%	88,781	6.15%	5,463
2	Common Stock	S.7 L. 8	61,385	40.0%	59,188	8.49%	5,025
3	Total	S.5 L.3	153,477	100.0%	147,969	7.09%	10,488
	2009 Actual						
4	Long-Term debt	S.11 L.18	91,288	60.0%	87,897	6.22%	5,464
5	Common Stock	S.7 L. 8	60,740	40.0%	58,483	7.92%	4,631
6	Total	S.5 L.3	152,028	100.0%	146,381	6.90%	10,095
	2010 Actual						
7	Long-Term debt	S.11 L.18	89,516	58.6%	87,400	6.38%	5,575
8	Common Stock	S.7 L. 8	63,332	41.4%	61,835	7.45%	4,610
9	Total	S.5 L.3	152,848	100.0%	149,235	6.82%	10,185

Yukon Energy Corporation
Cost of Capital Calculation
2011 Actual and 2012 Forecast
($000s)

Schedule 4B
April 2012

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
	2011 Preliminary Actual						
1	Long-Term debt	S.11 L.18	106,222	58.8%	105,825	3.61%	3,818
2	Common Stock	S.7 L. 8	74,471	41.2%	74,192	6.59%	4,886
3	Total	S.5 L.3	180,693	100.0%	180,017	4.84%	8,704
	Forecast for 2012 - Existing						
4	Long-Term debt	S.11 L.18	133,177	60.0%	133,137	3.40%	4,520
5	Common Stock	S.7 L. 8	88,786	40.0%	88,758	4.38%	3,886
6	Total	S.5 L.3	221,963	100.0%	221,895	3.79%	8,407
	Proposed 2012 - GRA						
7	Long-Term debt	S.11 L.18	133,821	60.0%	133,812	3.38%	4,521
8	Common Stock	S.7 L. 8	89,215	40.0%	89,209	8.77%	7,823
9	Total	S.5 L.3	223,036	100.0%	223,020	5.54%	12,345

Yukon Energy Corporation
Cost of Capital Calculation
2013 Forecast
($000s)

Schedule 4C
April 2012

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
	Forecast for 2013 - Existing						
1	Long-Term debt	S.11 L.18	142,807	60.0%	142,869	3.91%	5,586
2	Common Stock	S.7 L. 8	95,205	40.0%	95,246	-0.97%	-928
3	Total	S.5 L.3	238,013	100.0%	238,115	1.96%	4,658
	Proposed 2013 - GRA						
4	Long-Term debt	S.11 L.18	144,993	60.0%	145,043	3.90%	5,650
5	Common Stock	S.7 L. 8	96,662	40.0%	96,695	8.77%	8,480
6	Total	S.5 L.3	241,656	100.0%	241,738	5.85%	14,130

Yukon Energy Corporation
Utility Revenue Requirement
($000s)

Schedule 5
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Net rate base	S.1 L.30	147,968	146,381	149,235	180,017	221,895	223,020	238,115	241,738
2	Average Rate of return on rate base		7.09%	6.90%	6.82%	4.84%	3.79%	5.54%	1.96%	5.85%
3	Utility income	S.8 L.1	10,488	10,095	10,185	8,704	8,407	12,345	4,658	14,130
4	Utility expenses									
5	Operating and maintenance (note 1)	S.6 L.3	13,403	14,765	15,219	18,377	17,681	19,241	19,779	21,026
6	Taxes other than income	S.6 L.4	256	288	291	297	312	312	326	326
7	Amortization of deferred costs	S.6 L.5	1,707	1,735	1,407	1,447	3,065	3,198	5,632	4,859
8	Reserve for Injuries and Damages	S.6 L.6	100	100	100	100	100	231	100	231
9	Depreciation	S.6 L.7	6,526	7,214	7,369	7,902	11,730	8,418	12,402	8,989
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(1,361)	(2,166)	(2,116)	(2,445)	(4,803)	(3,798)	(4,852)	(3,831)
11	Disallowed depreciation		(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
12	Donations		(85)	(94)	(75)	(85)	(85)	(85)	(85)	(85)
13	Disallowed Expenses (note 2)			(224)						
14	Total utility expenses		20,544	21,614	22,191	25,590	27,995	27,512	33,298	31,511
15	Revenue Requirement	S.6 L.1	31,031	31,708	32,376	34,294	36,402	39,857	37,956	45,641

Note 1: Includes fuel expenses and purchased power.
Note 2: 2009 disallowed expenses with respect to 2008/2009 GRA Cost Awards Filing (YUB 2009-11). Other disallowed expenses are included in Regulatory gain/losses (Schedule 6, Line 13).

Yukon Energy Corporation
Statement of Earnings
($000s)

Schedule 6
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Revenues (note 1)	S.5 L.17	31,031	31,708	32,376	34,294	36,402	39,857	37,956	45,641
2	**Operating expenses**									
3	Operating and maintenance	S.10 L.15	13,403	14,765	15,219	18,377	17,681	19,241	19,779	21,026
4	Taxes other than income	S.5 L.6	256	288	291	297	312	312	326	326
5	Amortize deferred costs	S.5 L.7	1,707	1,735	1,407	1,447	3,065	3,198	5,632	4,859
6	Reserve for Injuries and Damages	S.5 L.8	100	100	100	100	100	231	100	231
7	Depreciation	S.3 L.8	6,526	7,214	7,369	7,902	11,730	8,418	12,402	8,989
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(1,361)	(2,166)	(2,116)	(2,445)	(4,803)	(3,798)	(4,852)	(3,831)
9	Total		20,632	21,936	22,270	25,679	28,084	27,601	33,387	31,600
10	**Operating income**		10,399	9,773	10,106	8,615	8,318	12,256	4,569	14,041
11	**Other income**									
12	Allowed for Funds Used	S.8 L.2	798	392	514	555	500	500	500	500
13	Miscellaneous (note 2)	S.8 L.3	(155)	1,099	1,163	61	(49)	(49)	(23)	(23)
14	Total		643	1,491	1,677	616	451	451	477	477
15	**Other expenses**									
16	Interest expense	S.8 L.4	5,665	6,893	7,006	4,278	4,522	4,522	5,584	5,648
17	Total		5,665	6,893	7,006	4,278	4,522	4,522	5,584	5,648
18	**Net earnings**	S.8 L.8	5,378	4,370	4,777	4,953	4,247	8,185	- 537	8,870

Note 1: Includes revenues from sales, non-operating revenues and other revenues. 2009 revenues also include the Faro Dewatering transfer.
Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

Yukon Energy Corporation
Statement of Retained Earnings
($000s)

Schedule 7
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Balance at beginning of year		22,048	21,536	21,943	26,720	29,621	29,621	40,750	41,609
	Add:									
2	Net earnings	S.6 L.18	5,378	4,370	4,777	4,953	4,247	8,185	(537)	8,870
3			27,426	25,906	26,720	31,674	33,867	37,805	40,213	50,480
	Less:									
4	Common Dividends/(Injection) (note 1)		4,704	3,963	-	2,053	(6,883)	(3,804)	(2,247)	5,964
5	Balance at end of year		22,722	21,943	26,720	29,621	40,750	41,609	42,460	44,516
	Shareholder's Equity									
6	Common shares		39,000	39,000	39,000	53,600	53,600	53,600	53,600	53,600
7	Retained earnings		22,722	21,943	26,720	29,621	40,750	41,609	42,460	44,516
8	Total		61,722	60,943	65,720	83,221	94,350	95,209	96,060	98,116

Note:
1. YDC equity injection required in order to maintain 60/40 debt to equity ratio.

Yukon Energy Corporation
Reconciliation of Utility Income to Net Earnings
($000s)

Schedule 8
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	Utility Income (Return on Rate Base)	S.5 L.3	10,488	10,095	10,185	8,704	8,407	12,345	4,658	14,130
	Add:									
2	Allowance for funds used	S.6 L.13	798	392	514	555	500	500	500	500
3	Other income (expenses)	S.6 L.14	(155)	1,099	1,163	61	(49)	(49)	(23)	(23)
			11,131	11,585	11,862	9,320	8,857	12,795	5,135	14,608
	Less:									
4	Interest - long-term	S.6 L.17	5,665	6,893	7,006	4,278	4,522	4,522	5,584	5,648
5	Donations	S.5 L.12	85	94	75	85	85	85	85	85
6	Disallowed costs	S.5 L.13	-	224	-	-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	4	4	4	4	4	4	4	4
			5,754	7,215	7,085	4,367	4,611	4,611	5,673	5,737
8	Net earnings	S.6 L.18	5,378	4,370	4,777	4,953	4,247	8,185	(537)	8,870
9	Adjustments to Net earnings (note 1)			(241)						
10	Net earnings per financial statements			4,129	4,777					

Note 1:
1. Adjustments to the net earnings reflect the impact of YUB 2009-8 ($0.375 million secondary sales revenues: decrease in 2009 and increase in 2008; $0.026 million transfer from deferred Dewatering revenues: decrease in 2009 and increase in 2008; $0.4 million rate case amortization expense: decrease in 2009 and increase in 2008; $0.05 million RFID: decrease in 2009 and increase in 2008; $0.192 million fuel cost: decrease in 2009 and increase in 2008)

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues
($000s)

Schedule 9
April 2012

Line No.	Description	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Proposed 2012	Proposed 2013
1	**Residential**						
2	Customers	1,432	1,457	1,472	1,515	1,526	1,536
3	Sales in MWh	11,183	11,676	11,386	12,710	12,325	12,408
4	MWh sales per customer	8	8	8	8	8	8
5	Revenue ($000s)	1,335	1,386	1,359	1,694	1,803	1,815
6	Cents per KWh	11.94	11.87	11.94	13.33	14.63	14.63
7	**General Service**						
8	Customers	457	442	455	464	460	467
9	Sales in MWh	19,543	19,672	22,719	21,305	21,693	22,620
10	MWh sales per customer	43	45	50	46	47	48
11	Revenue ($000s)	2,637	2,696	2,942	3,218	3,582	3,735
12	Cents per KWh	13.49	13.70	12.95	15.10	16.51	16.51
13	**Industrial**						
14	Sales in MWh	29,023	29,355	30,255	43,259	52,309	62,364
15	Revenue ($000s)	3,203	3,190	3,311	4,599	6,179	7,383
16	Cents per KWh	11	11	11	11	12	11.84
17	**Street lights**						
18	Sales in MWh	278	496	283	283	279	279
19	Revenue ($000s)	71	60	74	82	88	88
20	Cents per KWh	25.63	12.07	26.26	29.02	31.55	31.55
21	**Space lights**						
22	Sales in MWh	15	26	14	14	15	15
23	Revenue ($000s)	3	3	3	3	4	4
24	Cents per KWh	21.54	12.03	21.73	23.96	26.76	26.76
25	**Total Company - Firm Retail and Industrial**						
26	Customers	1,889	1,899	1,927	1,979	1,986	2,003
27	Sales in MWh	60,042	61,225	64,658	77,571	86,621	97,685
28	Revenue ($000s)	7,249	7,335	7,689	9,596	11,656	13,025
29	Cents per KWh	12.07	11.98	11.89	12.37	13.46	13.33
30	**Wholesale sales**						
31	Sales in MWh	267,747	267,229	276,345	290,541	296,000	298,228
32	Revenue ($000s)	18,314	18,279	18,902	21,940	24,562	24,747
33	Cents per KWh	6.84	6.84	6.84	7.55	8.30	8.30
34	**Total Company - Firm**						
35	Sales in MWh	327,789	328,455	341,003	368,112	382,621	395,913
36	Revenue ($000s)	25,563	25,613	26,591	31,535	36,218	37,772
37	Cents per KWh	7.80	7.80	7.80	8.57	9.47	9.54
38	**Secondary**						
39	Sales in MWh	7,584	17,384	10,489	552	0	0
40	Revenue ($000s)	470	1,066	644	46	0	0
41	Cents per KWh	6.20	6.13	6.14	8.30		
42	**Total Company**						
43	Sales in MWh	335,373	345,839	351,492	368,665	382,621	395,913
44	Revenue ($000s)	26,033	26,679	27,234	31,581	36,218	37,772
45	Cents per KWh	7.76	7.71	7.75	8.57	9.47	9.54
46	Rider J	4,518	4,493	4,944	2,466		
47	Post-GRA Reconcil Req'd	355	355				
48	GRA Increase Req'd					3,455	7,685
49	Total Sales of Power	30,906	31,527	32,178	34,047	39,673	45,457
50	Other Revenues	125	181	198	247	184	184
51	Total Revenues	31,031	31,708	32,376	34,294	39,857	45,641

Yukon Energy Corporation
Summary of Operating and Maintenance Expenses
($000s)

Schedule 10
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
1	**Utility operations**									
2	Production		2,977	3,759	4,179	4,472	4,452	4,452	4,494	4,494
3	Transmission and distribution		1,793	1,868	1,383	1,767	1,970	1,970	2,112	2,112
4	General		952	1,145	1,194	1,336	1,339	1,339	1,405	1,405
5	Administration and general		6,148	6,453	6,418	7,197	8,357	8,357	8,923	8,923
6	Insurance		952	787	787	774	835	835	895	895
7	Sub-total		12,822	14,012	13,962	15,547	16,953	16,953	17,828	17,828
8	Donations		85	94	75	85	85	85	85	85
9	Sub-total		85	94	75	85	85	85	85	85
10	O&M not including fuel and									
11	purchased power		12,907	14,106	14,037	15,632	17,038	17,038	17,913	17,913
12	Fuel		443	622	1,145	2,708	602	2,163	1,826	3,073
13	Purchased power		54	36	38	38	40	40	40	40
14	Sub-total		497	658	1,183	2,746	642	2,203	1,866	3,113
15	Total operating and maintenance	S.6 L.3	13,403	14,764	15,220	18,377	17,681	19,241	19,779	21,026
	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*	*100*	*100*	*231*	*100*	*231*
17	*Property Taxes*		*256*	*288*	*291*	*297*	*312*	*312*	*326*	*326*
18	*less: Donations*		*-85*	*-94*	*-75*	*-85*	*-85*	*-85*	*-85*	*-85*
19	*O&M per Table 3.3 (Tab 3)*		*13,178*	*14,401*	*14,353*	*15,943*	*17,365*	*17,496*	*18,254*	*18,385*

Note: 2009 actuals reflect the impact of YUB Order 2009-8 (Note 1, Schedule 8).

Yukon Energy Corporation
Summary of Cost of Long - Term Debt
($000s)

Schedule 11
April 2012

Line No.	Description	Cross Ref.	2009 Approved	Actual 2009	Actual 2010	Prelim. Actual 2011	Forecast Existing 2012	Forecast Proposed 2012	Forecast Existing 2013	Forecast Proposed 2013
	General Purpose Long-Term Debt Balance									
1	Canada Flexible Term Note		25,126	25,111	24,111					
2	TD Canada Trust		6,471	6,471	5,724	4,891	3,938	3,938	2,945	2,945
3	YDC Loan			59,836	57,779	78,891	75,891	75,891	72,891	72,891
4	Mayo B Flexible Term Note					21,900	21,563	21,563	21,226	21,226
5	New YDC Loan					19,148	18,510	18,510	17,871	17,871
6	New YDC Loan						21,623	22,911	20,902	22,147
7	New YDC Loan								8,254	10,093
8	YDC Loan #12 (5.88%)		22,493							
9	YDC Loan #13 (6.03%)		3,649							
10	YDC Loan #14 (5.40%)		2,841							
11	YDC Mayo-Dawson Note (6.55%)		15,157							
12	YDC Loan #15 (5.34%)		3,585							
13	YDC Loan #16 (5.28%)		4,251							
14	YDC Loan #17 (5.28%)		4,304							
15	YDC Loan #18 (5.28%)		4,704							
16	Current year-end balance		92,581	91,418	87,614	124,830	141,525	142,813	144,090	147,174
17	Previous year-end balance		91,602	91,159	91,418	87,614	124,830	124,830	141,525	142,813
18	Mid Year		92,092	91,288	89,516	106,222	133,177	133,821	142,807	144,993
	Interest Costs									
19	Canada Flexible Term Note		1,726	1,742	1,758					
20	TD Canada Trust		535	535	479	371	180	180	140	140
21	YDC Loan			3,398	3,473	3,461	3,371	3,371	3,225	3,225
22	Mayo B Flexible Term Note						11	11	212	212
23	New YDC Loan						960	960	925	925
24	New YDC Loan								1,081	1,146
25	New YDC Loan									
26	YDC Loan #12 (5.88%)		1,393							
27	YDC Loan #13 (6.03%)		220							
28	YDC Loan #14 (5.40%)		153							
29	YDC Mayo-Dawson Note (6.55%)		1,022							
30	YDC Loan #15 (5.34%)		191							
31	YDC Loan #16 (5.28%)		224							
32	YDC Loan #17 (5.28%)		200							
33	YDC Loan #18 (5.28%)									
34	Minto Diesel		155							
35	**Total Cost of Interest**		5,820	5,675	5,710	3,833	4,522	4,522	5,584	5,648
36	Mid-Year Cost of Debt		6.15%	6.22%	6.38%	3.61%	3.40%	3.38%	3.91%	3.90%

TAB 8
RETURN ON EQUITY

8.0 RETURN ON EQUITY

Tab 8 reviews the proposed basis for determining the return on equity allowed for Yukon Energy (YEC) in 2012 and 2013, including the following:

- Background; and
- Yukon Energy Fair ROE for 2012 and 2013.

8.1 BACKGROUND

Yukon Energy's rate base is financed by two main sources of capital: long-term debt and shareholder's equity. With respect to the equity component, Yukon Energy's rates are required to include "provision to recover a fair return on the Corporation's equity, less one-half of one per cent (0.5%)" per Order-in-Council (OIC) 1995/90 Section 2 and as amended by OIC 1998/32 Section 1 (see Tab 11 of this Application). In past General Rate Applications (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 Yukon Electrical (YECL), notwithstanding that Yukon Energy as a generation utility would typically be understood to face considerably higher risk levels than Yukon Electrical with its focus on distribution.

A number of approaches may be used to determine a fair level of return on equity. For Yukon Utilities Board (YUB or the Board) proceedings up to the 1996/97 GRA, Yukon Electrical 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 to the level set for Yukon Electrical.

For the 1998 rate revision[1], 2005 Required Revenues and Related Matters proceeding and 2008/2009 Yukon Energy General Rate Application, Yukon Energy proposed that the return on equity be set by reference to the British Columbia Utilities Commission (BCUC) formulaic approach[2]. Generally, under this "benchmark 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 additional risks of equity compared to debt

[1] Yukon Energy 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.

[2] In the 2005 proceeding, it was noted that several regulated jurisdictions across Canada had adopted similar "formulaic" approaches towards establishing ROE's, including British Columbia, Alberta, the National Energy Board, Manitoba, Ontario and Newfoundland.

(to yield a benchmark cost of equity for a low risk utility), and with further adjustments to reflect any specific added risks related to each specified utility that is not a low risk utility.

In the 2005 hearing, the Board determined that the requested rate of return and the application of the BCUC approach were 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. The Board agreed with Yukon Energy's assessment with respect to risk premiums relative to a low risk utility (i.e., that it fell somewhere between PNG-West at 65 basis points and Aquila, now FortisBC, at 40 basis points) given the level of risk experienced by Yukon Energy in relation to other utilities within its peer group.

In Yukon Energy's 2008/2009 GRA, Board Order 2009-08 in effect approved the same approach used in 1998 and 2005 for setting YEC's ROE based on the most recent BCUC generic benchmark ROE, adjusted as required for the risk specific to YEC (and using the same risk adjustment in this regard as had been previously approved for YEC based on BCUC decisions for similar risk utilities). Order 2009-08 also stated that the BCUC approach is the precedent for Yukon and will continue to be a precedent for this jurisdiction until otherwise ordered.

Since 2009, there has been a material shift in how return on equity is determined in British Columbia. In effect, the Terasen ROE decision (Order G-158-09) eliminated the automatic adjustment mechanism and ordered Terasen Gas Inc[3] to complete a study of alternative formulae for an automatic adjustment mechanism and report results to the BCUC by December 31, 2010[4]. However, the BCUC determined that the 2009 approved ROE for Terasen (9.5%) may continue to be used as the Benchmark ROE in establishing the ROE for rate-setting purposes for other BC utilities[5]. BC utilities continue to reference this benchmark and apply utility-specific risk premiums as approved by the BCUC. The BCUC has recently initiated a generic cost of capital proceeding; however, an up-to-date low risk benchmark is not expected before the end of 2012[6].

[3] As of March 2011, Terasen Gas Inc is now FortisBC Energy Inc.
[4] http://www.bcuc.com/ROE.aspx.
[5] See Order G-158-09. The BCUC approved a return on equity for TGI of 9.5%.
[6] A recent press release notes the BCUC has issued preliminary notification to all regulated entities including the FortisBC regulated utilities (FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc. and FortisBC Inc.; TSX:FTS) that it plans to initiate a Generic Cost of Capital proceeding in early 2012. The BCUC plans to address the following issues: (1) Setting the appropriate cost of capital for a benchmark low-risk utility; (2) establishing a return on equity automatic adjustment mechanism; (3) establishing a deemed capital structure and deemed cost of capital methodology particularly for those utilities without third party debt. See: http://www.fortisbc.com/MediaCentre/NewsReleases/2011/Pages/Generic-cost-of-capital-review-for-BC-utilities.aspx.

8.2 YUKON ENERGY FAIR ROE FOR 2012 AND 2013

Use of a benchmark approach (i.e., reference to a benchmark return on equity for a low risk utility, with adjustments to reflect any specific added risks related to Yukon Energy) provides for continuity with prior Yukon proceedings and practice, and offers a simple, transparent and cost effective method to determine a consistent and fair return for Yukon utilities[7].

In past proceedings, Yukon Energy relied upon the BCUC low risk utility benchmark ROE updated annually pursuant to a Board approved formula. As noted, this formulaic approach to update the benchmark ROE annually is no longer used by the BCUC and the low risk benchmark currently relied upon to determine fair ROE for other BC utilities has not been updated since 2009. The BCUC is currently engaged in a review process; however, until this review is completed, a more up-to-date low risk benchmark is required for the purposes of determining fair ROE for the test years. Aside from using a more up-to-date benchmark ROE for a low risk utility, Yukon Energy intends to maintain the approved practice adopted for previous applications (i.e., the approved adjustment to reflect any specific added risks related to Yukon Energy).

Yukon Energy has reviewed recent ROE decisions from other jurisdictions. Based on this review, the Application proposes to use the most recent low risk utility benchmark ROE established in Canada set by the Alberta Utilities Commission (AUC) in December 2011 (Decision 2011-474[8]) in order to determine a fair ROE for the test years. This would modify the benchmarking approach used since 1998 by referencing the Alberta Utilities Commission generic ROE rather than the BCUC generic ROE before applying the previously approved utility-specific risk premium of 52 basis points[9].

[7] The precedent of relying on a benchmarking mechanism for determining the return on equity for a single application extends beyond the 2005 and 2008/2009 proceedings. The YUB used this approach to a limited extent in determining Yukon Energy's fair return on equity during the 1998 hearing, where the 1998 ROE was set based on adjusting the approved 1997 ROE by an approach similar to the BCUC approach (except that 100% of the change in Long Canada bonds was applied rather than the 80% sliding scale factor used by the BCUC).

[8] On November 2009 (Decision 2009-216) the AUC discontinued its annual adjustment formula for establishing a generic return on equity for Alberta regulated utilities. The AUC in 2009 and in 2011 has determined a generic ROE for Alberta utility with consideration of Capital Asset Pricing Model ROE estimates, Discounted Cash Flow ROE, changes in financial environment and expert witness evidence provided by intervenors. Once a generic ROE is adopted, differences in risk between utilities are recognized through adjustments to each utilities' capital structure.

[9] A 52 basis point risk premium was approved for Yukon Energy in Order 2005-12 and 2009-8.

As in prior proceedings, Yukon Energy is not proposing an automatic ongoing adjustment of the ROE beyond the test years. An overview of the proposed approach is as follows:

- **Step 1 – Determine Low-Risk Utility Benchmark ROE based on AUC determination for 2012:** The low risk utility benchmark ROE for Yukon for 2012 and 2013 will be set equal to the AUC Generic ROE for 2011 of 8.75% as provided in Decision 2011-474.

- **Step 2 – Apply Yukon Energy Fair Return on Equity by incorporating the risk premium for Yukon Energy:** The established approach in Yukon requires that the appropriate ROE in 2012 and 2013 for individual utilities will incorporate the risk premium that the Board has previously determined for each utility relative to the low-risk utility benchmark allowed ROE. In Order 2005-12, the Board approved a proposed Yukon Energy fair return on equity set equal to 52 basis points above the low-risk utility benchmark ROE to reflect the specific conditions of Yukon Energy. This was confirmed as reasonable in Order 2009-2 and Order 2009-8. The same 52 basis points risk premium is adopted for this Application.

- **Step 3 – Determine Yukon Energy allowed ROE by deducting 50 basis points from the Yukon Energy Fair Return on Equity:** For test years 2012 and 2013, the Yukon Energy allowed ROE is required to be set equal to the Yukon Energy's fair return on common equity less 50 basis points (0.5%) to reflect the OIC 1995/90 (as amended by OIC 1998/32) adjustments.

Accordingly, the Yukon Energy proposed ROE for 2012 and 2013 is 8.77%[10]. Yukon Energy proposes that the long-standing equity ratio of 40% also continue to apply to YEC's long-term capital structure for rate base financing (with a long-term debt ratio of 60%).

[10] This provides a reasonable ROE comparable to other small Northern Utilities – On April 21, 2011, Northland Utilities Limited (NUL) filed a General Rate Application to the Northwest Territories Public Utilities Board (PUB) for its Yellowknife and Northwest Territories divisions for the test years 2011 through 2013. Northland requested that the Board set the ROE for each of the test years 2011-2013 at the percentage determined on a generic basis for all Alberta utilities for 2011, as determined in the 2011 Alberta Generic Cost of Capital Proceeding, plus a risk premium of 0.5%. However, at the time of the GRA filings, the AUC was still in the process of determining ROEs for all Alberta utilities so Northland requested that the last approved ROEs of 9.1% be used as a placeholder for NUL (NWT) and NUL (YK) until the AUC decision was available in late 2011.

TAB 9
2010 AUDITED FINANCIAL STATEMENTS

Yukon Energy Corporation

Financial Statements

December 31, 2010

Yukon Energy Corporation

Financial Statements

December 31, 2010 **Page**

YUKON ENERGY

YUKON ENERGY CORPORATION
P.O. Box 5920
WHITEHORSE
YUKON Y1A 6S7
(867) 393-5300

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

May 10, 2011

Auditor General of Canada
Vérificatrice générale du Canada

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of the Yukon Energy Corporation

Report on the Financial Statements

I have audited the accompanying financial statements of Yukon Energy Corporation, which comprise the balance sheet as at 31 December 2010, and the statement of operations, comprehensive income and retained earnings and statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of Yukon Energy Corporation as at 31 December 2010, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Report on Other Legal and Regulatory Requirements

In my opinion, the transactions of Yukon Energy 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 by-laws of Yukon Energy Corporation.

Sheila Fraser

Sheila Fraser, FCA
Auditor General of Canada

11 May 2011
Vancouver, Canada

240 rue Sparks Street, Ottawa, Ontario K1A 0G6

Yukon Energy Corporation
Balance Sheet
(in thousands of dollars)

As at December 31,	2010	2009
Assets		
Current		
Cash	$ 25,847	$ 10,731
Accounts receivable (Note 4)	29,242	9,710
Materials and supplies	2,648	2,715
Prepaid expenses	368	394
	58,105	23,550
Customer contribution financing (Note 5 and 24)	**17,424**	17,424
Deferred uninsured losses (Note 6)	**432**	111
Diesel contingency fund (Note 7)	**891**	887
Property, plant and equipment (Note 8)	**287,350**	212,918
Deferred charges and intangible assets (Note 9)	**18,963**	13,451
	$ 383,165	$ 268,341
Liabilities		
Current		
Accounts payable and accrued liabilities (Note 10)	$ 16,859	$ 6,616
Construction Financing (Note 11)	47,500	25,000
Current portion of long-term debt (Note 14 and 24)	3,864	3,783
	68,223	35,399
Faro mine dewatering deferral revenue (Note 12)	**397**	397
Long-term pension liability (Note 19)	**1,035**	1,036
Contributions in aid of construction (Note 13)	**140,686**	59,316
Regulatory provision for future removal and site restoration costs	**4,764**	5,008
Diesel contingency fund (Note 7)	**891**	887
Long-term debt (Note 14 and 24)	**101,449**	105,355
	317,445	207,398
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	**26,720**	21,943
	65,720	60,943
	$ 383,165	$ 268,341

Commitments and Contingencies (Notes 20 and 21)
The accompanying notes are an integral part of the financial statements.

Approved by the Board

_____, Chair

_____, Director

Yukon Energy Corporation

Statement of Operations, Comprehensive Income and Retained Earnings
(in thousands of dollars)

For the year ended December 31,	**2010**	2009
Revenue		
Sales of power (Note 15)	$ 32,178	$ 31,547
Other	476	866
	32,654	32,413
Operating expenses		
Administration (Note 16)	7,938	8,016
Operations and maintenance (Note 17)	7,899	7,597
Amortization of property, plant and equipment	5,657	5,427
Amortization of deferred charges	860	1,630
Amortization of intangible assets	548	505
	22,902	23,175
Income from operations	**9,752**	9,238
Other income		
Allowance for funds used during construction	514	392
Amortization of capital assistance	378	378
Interest income	1,238	1,165
	2,130	1,935
Other expenses		
Interest on borrowings	7,005	6,894
Provision for uninsured losses (Note 6)	100	150
	7,105	7,044
Net income	**4,777**	4,129
Other comprehensive income	-	-
Comprehensive income	**4,777**	4,129
Retained earnings, beginning of year	**21,943**	21,777
Dividend	-	(3,963)
Retained earnings, end of year	**$ 26,720**	$ 21,943

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,	2010	2009
Operating activities		
Cash receipts from customers	$ 32,679	$ 31,958
Cash paid to employees and suppliers	(5,923)	(18,378)
Interest paid	(7,005)	(6,894)
Interest received	1,616	1,543
Cash provided by operating activities	**21,367**	8,229
Financing activities		
Repayment of long-term debt	(4,139)	(4,532)
Proceeds (repayment) of short-term financing	(25,000)	25,000
Proceeds from construction financing	47,500	-
Contributions in aid of construction	61,813	1,552
Cash provided by financing activities	**80,174**	22,020
Investing activities		
Additions to property, plant and equipment	(79,505)	(18,283)
Additions to deferred charges and intangible assets	(6,920)	(4,984)
Payments from long-term receivable	-	495
Cash used in investment activities	**(86,425)**	(22,772)
Net increase in cash	**15,116**	7,477
Cash, beginning of year	**10,731**	3,254
Cash end of year	**$ 25,847**	$ 10,731

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, 2010

1. NATURE OF OPERATIONS

Yukon Energy Corporation (the "Utility") is incorporated under the *Yukon Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation (YDC), a corporation owned by the Government of Yukon (YG). 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. As 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 reviewed and 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 borrowing costs related to borrowing that portion of the rate base which is financed with debt plus the costs to provide a reasonable rate of return on that portion of the rate base which is financed with equity).

As well, in the first stage, the YUB reviews the addition of costs to the 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 filed for the 2008 and 2009 forecast years.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2010

1. NATURE OF OPERATIONS - continued

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 capital structure of 60% debt and 40% equity at year end. Annual dividends are declared to the parent and typically loaned back in order to maintain this ratio.

2. 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 differ from the accounting policies prescribed by using GAAP. In particular, the timing of the Utility's recognition of certain assets, liabilities, revenues and expenses as a result of regulation differ from that of a non-regulated enterprise. The impact on the financial statements of accounting for rate regulated operations are further described in Note 3. 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 7.09% for 2010 (2009 - 7.61%). Upon retirement or disposal, any gain or loss is charged to income in the current year for assets amortized on an individual basis, or charged to accumulated amortization for assets amortized on a pooled basis.

Faro mine dewatering deferral revenue
Faro mine dewatering deferral revenue represents amounts ordered by the YUB to be held by the Utility on behalf of ratepayers. The YUB has sole discretion to direct disposition of these funds, typically through refunds to customers or applied to ratepayer deficits.

Deferred uninsured losses
The Utility maintains a regulatory account for recording 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.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2010

2. SIGNIFICANT ACCOUNTING POLICIES - continued

Deferred charges
Deferred charges are recorded at cost less accumulated amortization.

All deferred charges are amortized to earnings on a straight-line basis over terms approved by the Yukon Utilities Board.

Cost of feasibility studies and infrastructure planning which did not result in a capital project are amortized over terms raging between five and ten years.

IFRS costs are associated with the accounting conversion from Canadian Generally Accepted Accounting Principles to International Financial Reporting Standards.

Deferred customer service costs are amortized over twelve years.

The deferred hearing cost account is used to record the deferral of costs associated with preparation and defense of applications to the YUB. The periods of amortization range from 10 to 45 years.

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.

Deferred insurance proceeds
Deferred insurance proceeds represents a gain on fire insurance proceeds received related to a fire at the Whitehorse Rapids Generating Station in 1997. The proceeds are being amortized to income on the same basis as the replacement assets.

Diesel contingency fund
The Utility maintains an asset and an offsetting liability on behalf of ratepayers. The fund is used to reimburse 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 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 the lesser of average cost and net realizable value. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined. Major spare parts are recorded in the Utility's books as property and equipment.

Property, plant and equipment
Property, plant and equipment is stated at cost, other than the AFUDC component which is recorded under rate regulated accounting. Cost includes materials, direct labour, a proportionate share of directly attributable administration overhead, and finance charges capitalized during construction, less accumulated amortization.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2010

2. SIGNIFICANT ACCOUNTING POLICIES - continued

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	30 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.

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 or Government. These contributions are deferred upon receipt and 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 operations 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. These costs are treated as intangible assets and are measured at initial cost and amortized over the life of the water license.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2010

2. SIGNIFICANT ACCOUNTING POLICIES - continued

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, amortization of past service benefits and plan enhancements, and actuarial gains and losses. Unrecognized gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees, which is currently 9 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, employee pension obligations and regulated assets and liabilities. Actual results could differ by a significant amount from these estimates.

Management's estimates and assumptions, especially those affecting the reported amounts of regulated 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.

Environmental liabilities
Environmental liabilities consist of the estimated costs related to the remediation of environmentally contaminated sites. The Utility will accrue a liability and record an expense, related to present or past activities of the Utility, when there is a legal obligation to remediate the contamination and the costs can be reasonably estimated. If the likelihood of the Utility's obligation to incur these costs is either not determinable or the costs cannot be reasonably estimated, the contingency is disclosed in the notes to the financial statements. The Utility reviews its estimates of future environmental liabilities on an ongoing basis as described in Note 21.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2010

ACCOUNTING CHANGES

Future Accounting Changes
On February 13, 2008, the Canadian Accounting Standards Board of Canada (AcSB) confirmed the adoption of IFRS as issued by the International Accounting Standards Board (IASB) in place of Canadian Generally Accepted Accounting Principles (GAAP) effective January 1, 2011.

The IASB has undertaken a project to review and assess accounting for rate regulated assets and liabilities. The timeline for completion of this project is not currently known. On September 10, 2010 the AcSB approved an option to defer conversion to International Financial Reporting Standards (IFRS) for one year for rate-regulated entities. The Utility has opted to take this deferral option and will therefore continue to prepare financial statements in accordance with Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook up to the period ending on December 31, 2011.

The Utility will continue to assess the IASB's deliberations on the project. At the same time, we are currently assessing, through consultation with our external experts, whether any of our regulatory accounts could be recognized under the current IFRS framework. If rate-regulated accounting were not permitted and none of our regulatory accounts were determined to fall under the current IFRS framework, the write-off of our regulatory assets and regulatory liabilities would result in a net reduction to retained earnings of approximately $2.7 million as at December 31, 2010. Regulatory accounting affects the timing of the accounting recognition of costs, revenues, losses and gains. Therefore, to the extent that we may be unable to recognize regulatory assets and liabilities after implementing IFRS in 2012, our statement of operations may be impacted by a change in the timing of recognition of these amounts in our statement of operations.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2010

3. 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 on the statement of operations as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in income in the period that the YUB renders a subsequent decision.

Regulatory assets represent future costs associated with certain revenues, 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.

In the absence of rate regulation the Utility's net income would have decreased by $7,295,000 in 2010 (2009 - decreased by $4,199,000). The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event:

	2010	2009	Expected remaining recovery/ settlement (years)	For 2010: 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 and infrastructure planning	$ 11,463	$ 6,200	5 to 10	$ (5,263)
Deferred customer service costs	635	700	10	65
Hearing costs	1,635	1,074	10 to 45	(561)
Dam safety review	119	-	5	(119)
IFRS planning	434	255	Indeterminate	(179)
Deferred uninsured losses (Note 6)	432	111	Indeterminate	(321)
Diesel contingency fund (Note 7)	891	887	Indeterminate	(4)
	15,609	9,227		(6,382)
Regulatory liabilities:				
Faro mine dewatering deferral revenue (Note 12)	397	397	Indeterminate	-
Deferred insurance proceeds (Note 13)	6,816	7,086	25	(270)
Regulatory provision for future removal and site restoration costs	4,764	5,008	Indeterminate	(244)
Diesel contingency fund (Note 7)	891	887	Indeterminate	4
	12,868	13,378		$ (510)
Net impact of assets and liabilities	$ 2,741	$ (4,151)		$ (6,892)
Impact of other items through Income statement				
AFUDC				(514)
Fuel Price Adjustment				111
Total effect				$ (7,295)

Yukon Energy Corporation

Notes to Financial Statements
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December 31, 2010

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION - continued

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 and infrastructure planning
The Utility undertakes certain projects whose objective is to determine the feasibility of a range of solutions. While in progress, the costs of these feasibility projects are included in these accounts. As well, if the feasibility project determines there is not a viable solution, these projects are closed out and amortized to income over a prescribed number of years. These values are also included in the feasibility accounts. The cost of feasibility projects that result in a capital project are transferred to the cost of the resultant project. In the absence of rate regulation, expenses in 2010 would have been $5,263,000 higher. (2009 - $3,512,000 higher expenses)

Deferred customer service costs
The costs associated with negotiating terms of service with a new industrial customer. In the absence of rate regulation, expenses in 2010 would have been $65,000 lower. (2009 - $64,000 lower expenses)

Hearing costs
These costs are associated with the YUB regulatory proceedings. The costs consist primarily of various rate and project review proceedings. The Utility is directed to defer and amortize the costs over terms at the discretion of the YUB. In the absence of rate regulation, expenses in 2010 would have been $561,000 higher. (2009 - $274,000 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 and YUB Order 2009-8. In the absence of rate regulation, expenses in 2010 would have been $119,000 higher. (2009 - $13,000 lower expenses)

IFRS planning
These costs are associated with the accounting conversion from Canadian Generally Accepted Accounting Principles to International Financial Reporting Standards. In the absence of rate regulation, expenses in 2010 would have been $179,000 higher. (2009 - $255,000 higher expenses)

(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 an asset and a liability. The DCF attracts interest based upon short-term bond rates in which the Utility invests the funds. Any negative balance attracts interest at the lowest short-term borrowing rate available to the Utility through its line of credit.

Yukon Energy Corporation

Notes to Financial Statements
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3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION - continued

(b) Diesel contingency fund - continued
Pursuant to YUB order 1996-6, the Utility from time to time is required to transfer amounts to or from the fund 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 income and expenses in 2010 would have been higher by $4,000 from interest earned on the DCF. (2009 - $4,000 higher income and expenses)

(c) Deferred uninsured losses
The YUB has approved the use of a deferral account for uninsured damages and injuries as a means of self-insurance. The account is maintained through an annual provision approved by the YUB. In order to eliminate the deficit rate payers owed as a result of uninsured losses, the Utility was directed by YUB Order 2009-8 to record annual provision of $100,000 in 2010 and each subsequent year. In the absence of rate regulation, GAAP would require costs to be expensed as incurred and, therefore, expenses in 2010 would have been higher by $321,000 (2009 - $32,000 lower expenses). The period over which the provision will be recovered is dependent on the magnitude of future actual losses incurred and cannot be estimated.

Regulatory liabilities

(d) 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 revenue account.

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.

(e) Deferred insurance proceeds
The deferred insurance proceeds relates to a fire at the Whitehorse Rapids Generating Station in 1997 which, pursuant to YUB 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 2010 would have been lower by the amount of the amortization of $270,000 (2009 - $270,000 lower).

(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 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. YUB Order 2005-12 also directs the Utility to notify interveners and interested parties when the balance of the provision reaches $2,000,000.

Yukon Energy Corporation

Notes to Financial Statements
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3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION - continued

(f) Regulatory provision for future removal and site restoration costs - continued
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 2010 expense would have been higher by the amount of actual removal and site restoration costs incurred in the year of $244,000 (2009 expenses - $160,000 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 2010, fuel expenses were deferred and consequently lower by $111,000 (2009 fuel expense lower by $133,000).

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 amortized over future periods as part of the total cost of the related asset, based on the expectation that amortization 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. In the absence of rate regulation, revenue would be $514,000 lower (2009 - $392,000 lower).

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 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.

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.

Yukon Energy Corporation

Notes to Financial Statements
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December 31, 2010

4. ACCOUNTS RECEIVABLE

	2010	2009
Green Infrastructure Funding (Note 13)	$ 22,757	$ 3,200
Wholesale energy sales	3,015	2,761
Retail energy sales	2,963	1,537
Other	507	2,212
	$ 29,242	$ 9,710

5. CUSTOMER CONTRIBUTION FINANCING

Under the terms of a Power Purchase Agreement with an industrial customer, the Utility has agreed to finance the cost of transmission assets built to serve the customer. Initial financing started November 22, 2008, the date the transmission line came into service. The financing is structured in two parts: a $7.2 million contribution towards the cost of the main line expansion and $10.8 million contribution for the cost of the 27 kilometre spur line to the mine for a total of $18 million. The customer is obligated to make interest only payments on the outstanding debt until 2012. From 2012 to 2017, the customer is obligated to make blended principal and interest payments such that the debt is extinguished by November 2017. This repayment schedule is subject to verification of mine life based on assessment of available reserves. At the direction of the YUB, the collection risk on this instrument is borne by YDC. Accordingly, YDC has loaned cash in an amount equal to this receivable at substantially the same terms. The Utility has recorded this loan as long term debt (see Note 14) and, if the industrial customer defaults on their debt, the Utility is released from the obligation to re-pay YDC. Subsequent to year end this financing has been paid in full. (see Note 24)

6. DEFERRED UNINSURED LOSSES

	2010	2009
Opening balance	$ 111	$ 556
Provision	(100)	(150)
Transfer from Regulatory liabilities (Note 12)	-	(413)
Losses incurred		
Asset replacements	421	118
Closing balance	**$ 432**	$ 111

YUB Order 2009-8 directed the Utility to charge $100,000 to this provision starting in 2010.

7. DIESEL CONTINGENCY FUND

	2010	2009
Opening balance	$ 887	$ 883
Interest	4	4
Closing balance	**$ 891**	$ 887

The annual return on investment for 2010 was 0.50% (2009 - 0.45%). The fair market value of these investments is equal to the carrying amount due to the short term maturity of the investments.

Yukon Energy Corporation

Notes to Financial Statements
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December 31, 2010

8. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	**2010** Net book Value	2009 Net book Value
Generation	$ 148,508	$ 57,245	$ 91,263	$ 87,679
Transmission	85,422	16,436	68,986	69,667
Distribution	27,422	8,303	19,119	19,954
Buildings and other equipment	19,540	7,469	12,071	11,383
Transportation	4,313	1,367	2,946	2,221
Land and land rights	1,114	-	1,114	1,116
Construction-in-progress	91,851	-	91,851	20,898
	$ 378,170	**$ 90,820**	**$ 287,350**	$ 212,918

Included in construction-in-progress is $49.5 million for Mayo B and $28.0 million for Carmacks Stewarts phase 2 projects.

9. DEFERRED CHARGES AND INTANGIBLE ASSETS

	Cost	Accumulated Amortization	**2010** Net book Value	2009 Net book Value
Intangible assets:				
Deferred water licensing costs	$ 9,198	$ 4,521	$ 4,677	$ 5,222
Deferred charges:				
Feasibility studies and infrastructure planning	13,900	2,437	11,463	6,200
IFRS planning	434	-	434	255
Hearing costs	3,804	2,169	1,635	1,074
Deferred customer service costs	769	134	635	700
Dam safety review	332	213	119	-
	$ 28,437	**$ 9,474**	**$ 18,963**	$ 13,451

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2010	2009
Trade payables	$ 16,263	$ 5,945
Employee compensation	428	417
Other	168	254
	$ 16,859	$ 6,616

Yukon Energy Corporation

Notes to Financial Statements
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December 31, 2010

11. CONSTRUCTION FINANCING

	2010	2009
Short-term financing	$ -	$ 25,000
Construction financing	47,500	-
	$ 47,500	$ 25,000

Construction financing balances at December 31, 2010 are monies advanced from the parent to assist in the development of Utility infrastructure, primarily the Carmacks Stewart Stage 2 and Mayo B Hydro Electric Project. This funding will remain in place until the projects are placed in service at which point the repayment terms will be renegotiated. The projects are scheduled to be completed by the end of fiscal 2011. Interest on this funding is based on the Bankers Acceptance rate on the date of the cash draw plus 50 basis points. Interest is payable annually at December 31 and at the maturity date.

12. FARO MINE DEWATERING DEFERRAL REVENUE

	2010	2009
Faro mine dewatering deferral revenue account:		
Opening balance	$ 397	$ 1,191
Applied to revenue shortfall per YUB Order 2009-10	-	(381)
Offset to Deferred uninsured losses account per YUB Order 2009-8 (Note 6)	-	(413)
Closing balance	**$ 397**	$ 397

13. CONTRIBUTIONS IN AID OF CONSTRUCTION

	Gross	Accumulated Amortization	2010 Net	2009 Net
Contributions from Canada (Note 4)	$ 32,747	$ -	$ 32,747	$ 3,200
Capital assistance from parent since 1998	68,312	2,476	65,836	13,714
Contributions from customers since 1998	38,098	3,475	34,623	34,608
Pre-1998 contributions	1,739	1,075	664	708
Deferred insurance proceeds	11,602	4,786	6,816	7,086
	$ 152,498	**$ 11,812**	**$ 140,686**	$ 59,316

The Utility has entered into a contribution agreement with the Government of Canada for Green Infrastructure Funding for Stage 2 of the Carmacks to Stewart Crossing Transmission Line and the Mayo B Hydro Enhancement projects. The Utility is entitled to reimbursement of 50% of eligible costs to a maximum of $71 million during the period May 2009 to March 2012 subject to meeting structured reporting requirements.

The sources of contributions received prior to 1998 were not recorded separately.

Yukon Energy Corporation

Notes to Financial Statements
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14. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

	2010	2009
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	$ 24,111	$ 25,111
$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.	20,887	22,494
$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.	14,707	15,157
$18,000,000 term note related to the Transmission Line Construction Financing, bearing interest at 6.50% repayable in variable monthly installments due December 2017	17,424	17,424
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	4,251
Unsecured advance bearing interest at 4.65%, due one year after demand	3,901	3,901
Unsecured advance bearing interest at 5.28%, due one year after demand	3,963	3,963
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, 2016.The note is guaranteed by the Yukon Government.	5,724	6,472
Carmacks Stewart First Nation Liability		
Long-term liability payable to several First Nations related to the building of the Carmacks Stewart Transmission Line. These are non interest bearing, repayable in varying installments, due in 2028	274	294
	105,313	109,138
Less current portion	3,864	3,783
	$ 101,449	$ 105,355

Yukon Energy Corporation

Notes to Financial Statements
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December 31, 2010

14. LONG-TERM DEBT - continued

$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 2010 is 7.0% (2009 - 6.94%).

Mayo to Dawson Transmission Line Financing
The Utility obtained financing from YDC 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 depreciation, 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, YDC will pay the Utility the difference on or before March 31 of the next calendar year.

In 2010, benefits exceeded costs, which resulted in $993,000 in interest paid to YDC. (In 2009, benefits exceeded costs, which resulted in $1,022,000 in interest paid to YDC).

Unsecured Advances
The Utility did not declared a dividend to YDC (2009 - $3,963,000). The unsecured advances represent dividends which have been declared to YDC in prior years and lent back to the utility. Advances are unsecured and due one year after demand.

Transmission Line Construction Financing
The Utility obtained financing from YDC in the amount of $18 million for an industrial customer's Capital Cost Contribution for the transmission line from Carmacks to Minto Landing and Spur line to the customer. Financing of $16 million was obtained effective November 22, 2008, the date the transmission line came into service and an additional $1.9 million was obtained in 2009 after final projects costs were known. 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. The Utility is obliged to repay the loan when payments are received from the customer under the Power Purchase Agreement. YDC assumes all the risk involved in this debt. (See Note 24)

Long -term debt repayment
Scheduled repayments for all long-term debt are as follows:

2011	3,864
2012	4,203
2013	7,093
2014	7,374
2015	7,676
Thereafter	75,103
	$ 105,313

Yukon Energy Corporation

Notes to Financial Statements
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December 31, 2010

14. LONG-TERM DEBT - continued

Fair value
Fair value at December 31, 2010 of $124 million (2009 - $118 million) for all long-term debt including current portions was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

15. SALES OF POWER

	2010	2009
Wholesale	$ 23,301	$ 22,291
General Service	3,315	3,007
Industrial	3,311	3,191
Residential	1,524	1,535
Secondary Sales	644	1,442
Sentinal and Street Lights	83	81
	$ 32,178	$ 31,547

16. ADMINISTRATION EXPENSES

	2010	2009
Wages and benefits	$ 3,811	$ 3,723
Insurance and taxes	1,078	1,075
General office	994	1,132
Information systems	733	776
Training, recruitment and development	546	539
Environmental	298	237
Intercompany services	252	302
Board of Directors	87	113
Material management and contracting	81	54
Regulatory loss	58	65
	$ 7,938	$ 8,016

Yukon Energy Corporation

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17. OPERATIONS AND MAINTENANCE EXPENSES

		2010		2009
Wages and benefits	$	3,923	$	3,939
Maintenance				
- hydro, diesel and wind		1,031		762
- building and vehicle		1,011		1,002
- lines and substations		587		869
Fuel		1,189		870
Water level measurement		158		155
	$	**7,899**	$	7,597

18. RELATED PARTY TRANSACTIONS

The Utility is related in terms of common ownership to all Government of Yukon (YG) departments, agencies and Crown Corporations. Transactions are entered into in the normal course of operations with these entities. All transactions are recorded at the rates set out by the YUB.

Revenue from related parties is included in other revenue on the statement of operations. Interim Electrical Rebate program revenues are received from YDC in accordance with terms established by YG which established the program to protect certain ratepayers by minimizing the impact of rate increases. These revenues are included in the sales of power on the statement of operations.

The following table summarizes the Utility's related party transactions for the year:

		2010		2009
Revenue				
Sales of service to YDC	$	236	$	301
Program cost reimbursement from YG		109		140
Rate subsidy received from YDC		246		226
Operating expenses				
Payment of interest on borrowings from YDC	$	6,472	$	6,299
Payment for financial information system usage to YDC		-		147
Other receipts				
Capital Contributions from YDC	$	53,417	$	2,833
Construction Financing from YDC		47,500		-
Advance from YG		-		25,000
Other payments				
Payment of dividend to YDC	$	-	$	3,963

Yukon Energy Corporation

Notes to Financial Statements
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December 31, 2010

18. RELATED PARTY TRANSACTIONS - continue

At the end of the year, the amounts receivable from and due to related entities are as follows:

	2010	2009
YDC		
Accounts receivable	$ 233	$ 2,045
Accounts payable	$ 110	$ 109
Construction Financing (Note 11)	$ 47,500	$ 25,000
Current portion of long-term debt	$ 3,056	$ 3,035
Long-term debt	$ 96,258	$ 99,074
YG		
Accounts receivable	$ 152	$ 210

These balances are non-interest bearing and payable on demand except for long-term debt and Construction Financing (Note 11 and 14).

Yukon Energy Corporation

Notes to Financial Statements
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19. 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 3.0% 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 the year's maximum pensionable earnings.

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, 2010 by the consulting actuarial firm AON Consulting Inc. The next valuation for funding purposes will be conducted as of January 1, 2013. The pension costs and obligations were based on the data used in the January 1, 2010 funding valuation and have been projected to December 31, 2010 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, 2010. The plan assets are invested in a pooled balanced fund. The distribution of assets by major asset class is as follows:

	December 31, 2010	December 31, 2009
Equities	53.1%	51.4%
Fixed Income Securities	37.9%	39.5%
Real Estate	9.0%	9.1%

Yukon Energy Corporation

Notes to Financial Statements
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December 31, 2010

19. PENSION COSTS AND OBLIGATIONS - continue

Information about the Utility's defined benefit plan as at December 31, in aggregate, is as follows:

		2010		2009
Discount rate-accrued benefit obligation		5.75%		6.25%
Discount rate-benefit costs		6.25%		6.25%
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		2.00%		2.50%
Expected average remaining service period of active employees		9 years		12 years
Benefit obligation determined by actuarial valuation	$	11,100	$	10,491
Fair value of plan assets		8,902		7,751
Plan deficit	$	2,198	$	2,740
Unrecognised amount:				
- transitional asset		119		135
- net actuarial losses		(1,143)		(1,703)
Accrued benefit liability	$	1,174	$	1,172
Current portion of accrued benefit liability	$	139	$	136
Long-term portion of accrued benefit liability		1,035		1,036
Accrued benefit liability	$	1,174	$	1,172
Pension expense	$	507	$	584
Employer contributions	$	392	$	345
Employee contributions	$	121	$	112
Benefits paid	$	132	$	132

The accrued benefit liability has been recorded by the Utility and its current portion of $139,000 (2009 - $136,000) is included in accounts payable and accrued liabilities 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 2010, these were $289,000 (2009 - $256,000).

Total cash payments for employee future benefits for 2010, consisting of cash contributed by the Utility to its funded defined benefit pension plan and cash contributed directly to the RRSP were $681,000 (2009 - $601,000).

As at December 31, 2010, the Utility's defined benefit pension plan had 39 members (2009 - 39), and the RRSP had 56 members (2009 - 49).

Yukon Energy Corporation

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20. COMMITMENTS

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:

a) 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;
b) Heritage Mitigation Plan. The Utility did not incur expenditures in 2010 on heritage projects and the amount to be expended in the future has not yet been determined; and
c) 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.

Contractual obligations
The Utility has entered into contracts to purchase products or services for which the liability has not been incurred as at December 31 2010 as the product or service had not been provided. The committment at year end is $89,963,000.

21. 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.

The Utility has conducted environmental site assessments at all its diesel plant sites. At sites where environmental contamination was found and a legal obligation to remediate the site existed, the Utility has conducted a full remediation.

As at December 31, 2010 no new environmental liabilities, for which a legal obligation exists to remediate, have been identified by the Utility. The Utility will continue to use its Environmental Management System to monitor and assess previous and potential existing environmental liabilities on an ongoing basis.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2010, the Utility's financial instruments included cash, accounts receivable, long-term receivable, accounts payable and accrued liabilities and long term debt. The fair value of cash, accounts receivable, accounts payable and accrued liabilites approximate their carrying value due to the immediate or short-term maturity of these financial instruments.

The long-term receivable related to the Transmission Line Construction Financing is accounted for at amortized cost using the effective interest rate method. The fair value of the long-term receivable as at December 31, 2010 is approximately $19 million (2009 - $18.7 million).

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2010

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continue

The long-term debt is accounted for at amortized cost using the effective interest rate method. The fair value of the long-term debt is estimated by discounting the future cash flows using current rates for debt instruments subject to similar risks and maturities as disclosed in Note 14.

The Utility also has access to a $10 million line of credit. The account accrues interest on withdrawals at prime rate. The facility was not drawn on at year-end.

Interest rate risk
Interest rate risk is the risk that future cash flows or fair value of a financial instrument will fluctuate due to changes in market interest rates. The Utility is not exposed to significant interest rate risk due to its long-term debt having fixed interest rates.

Credit risk
Credit risk is the risk of failure of a debtor or counterparty to honour its contractual obligations resulting in financial loss to the Utility. The Utility's credit risk is minimal in that its primary customer is a regulated utility.

Liquidity risk
Liquidity risk is the risk that the Utility will not be able to meet its financial obligations as they fall due. The Utility's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Utility's reputation.

The Utility does not engage in hedging transactions.

23. CAPITAL MANAGEMENT

The Utility's capital is its equity which is comprised of share capital and accumulated funds in the form of retained earnings. The Utility manages its equity by managing revenues, expenses, assets and liabilities to ensure the Utility effectively achieves its objectives while remaining a going concern.

The Utility monitors its capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, which is comprised of long-term debt, including the portion of long-term debt due within one year. Short term debt related to assets under construction at the balance sheet date is excluded from the cost of debt calculation, as the assets are similarly excluded from the determination of rate base. Total capitalization is calculated as total debt plus total shareholder's equity as shown on the balance sheet. The Utility maintains a balance in retained earnings as an indicator of the Utility's equity position.

The Utility has a policy which defines it's capital structure at a ratio of 60% debt and 40% equity. This policy has been reviewed and accepted by the YUB.

The long-term debt with YDC of $17.424 million that relates to the Transmission Line Construction Financing is not included in this calculation. This long-term debt is linked with the long-term receivable from an industrial customer. The Utility bears no risk in holding this debt so the amount was removed from this calculation.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of dollars)

December 31, 2010

23. CAPITAL MANAGEMENT - continued

The table below summarizes the Utility's debt to total capitalization position:

(thousands of dollars)		**2010**		2009
Long-term debt due within one year	$	3,864	$	3,783
Long-term debt		101,449		105,355
Total Debt		105,313		109,138
Less debt related to the Transmission Line Construction Financing (Note 14)		17,424		17,424
Total debt to include in the calculation	$	87,889	$	91,714
Share capital	$	39,000	$	39,000
Retained earnings		26,720		21,943
Total equity		65,720		60,943
Total capitalization	$	153,609	$	152,657
Total debt to total capitalization		57 %		60 %

There were no changes in the Utility's approach to capital management during the period.

24. SUBSEQUENT EVENTS

Under the terms of a Power Purchase Agreement with an industrial customer, the Utility had agreed to finance the cost of transmission assets built to serve the customer. On January 19, 2011 this financing was paid in full by the industrial customer. On the same day, the balance owing on the $18,000,000 term note in the amount of $17,424,304 with Yukon Development Corporation related to the Transmission Line Construction Financing was paid in full.

On January 1, 2011, the Utility entered into an agreement with Yukon Development Corporation to renegotiate terms of all outstanding debt, excluding the term note related to the transmission line financing, between the two companies in the amount of $81,890,873. The term of the new loan is until December 31, 2015 with interest at 4.25%. Interest on the loan is payable on the last business day of each month. The Utility will pay $3,000,000 against the outstanding principal annually on December 31 starting on December 30, 2011. The Utility will repay the outstanding principal balance in full by December 31, 2015, unless alternative repayment is negotiated by the parties in writing.

25. COMPARATIVE FIGURES

Certain 2009 figures have been reclassified to conform with the current year's presentation.

TAB 10
DEPRECIATION STUDY

KPMG
cutting through complexity™

Preliminary Summary of Results– Narrative Report to be issued

Yukon Energy Corporation

Depreciation Study Project
Preliminary Recommendations

March 1, 2012

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March 1, 2012

PRIVATE

Mr. Ed Mollard
Chief Financial Officer
Yukon Energy Corporation
PO Box 5920
Whitehorse, Yukon Y1A 5L6

RE: Depreciation Study

Dear Mr. Mollard:

KPMG LLP's ("KPMG") Economic and Valuation Services Practice has completed its depreciation study of certain tangible asset classes of Yukon Energy Corporation (the "Subject Assets," "Subject Property," or "Subject"). The scope of our engagement is outlined on page two below.

We understand that the results of our depreciation study will be used by Yukon Energy Corporation ("Yukon") management ("Management") to assist in its establishment of depreciable lives for the Subject Assets. No other use is intended or should be inferred.

Our opinions and conclusions are set forth on the following pages. Our work paper files contain the documentation that accompanies our analyses and supports our conclusions.

While this preliminary document sets forth our conclusions, please note that it is not intended to be considered a complete narrative report. This document will be supplemented by a complete narrative report fully outlining our assumptions and methodologies which will be delivered at a future date.

Depreciation Study

Background

Yukon Energy Corporation

Yukon Energy Corporation ("Yukon") is a publicly owned electrical utility, which was established in 1987. Yukon provides electricity to approximately 15,000 consumers in the Yukon region of Canada and relies upon hydro, diesel, and wind technology in its electricity generation process.

Subject Property Overview

Yukon's generating capability is primarily based upon hydro and diesel technology.

The primary generation facilities are outlined below along with indications of current operating capacities.

- **Whitehorse Hydro –** 71% of design capacity
- **Aishihik Hydro –** 35% of design capacity
- **Mayo Hydro –** 58% of design capacity
- **Diesel Power –** Max capacity of 33%, diesel is needed for standby capacity in case of an emergency

Scope of Work

Our report has been conducted to assist with reviewing Yukon's existing depreciation policy and estimating reasonable depreciation rates and remaining useful lives for each asset account. The procedures in our analysis included, but were not limited to the following.

- Analysis of historical data, including;
  - Review of prior depreciation study results and other information available for in-scope assets to understand the nature of the assets, historical acquisition or construction dates, current depreciation rates, planned usage requirements and risk factors affecting useful lives and salvage values;
  - Interview engineers and other interested parties
- Reviewed and analyzed comparable company depreciation policies and normal useful life estimates;
- Reviewed assessment reports related to the subject assets to ascertain certain qualitative data;
- Discussed with management the alternative methods for depreciating components (e.g. straight line, declining balance or sinking fund); and
- Assessed which available depreciation rate assessment models are appropriate from a quantitative and qualitative perspective for the size of Yukon.

Date of Value

Our analysis was conducted as at December 31, 2010 (the "Testing Date").

Depreciation Study

Background

Description of Subject Assets – Accounts

The following table outlines the asset classes reviewed in the analysis as well as the relative weighting of each class with regards to total cost basis.

Class/Class Description	Percent of Total Cost
Land	0.4%
Hydro Plant - 140003	42.1%
Diesel Production - 140004	8.5%
Wind Turbine - 140005	1.1%
Main Transmission Facilities - 140006	29.9%
Sub Transmission Lines - 140007	5.4%
Distribution System - 140008	4.2%
Building and Other Equipment - 140009	6.8%
Transportation - 140014	1.5%
Total	**100.0%**

KPMG

Depreciation Study
Background

Description of Subject Assets – Subaccounts

Class/Class Description	Percent of Total Cost
Land	
No Identification Number	0.4%
Total Land	**0.4%**
Hydro Plant	
140003.2 Structures and Improvements	3.8%
140003.205 Reservoirs, Dams, and Waterways	31.5%
140003.506 Waterwheels,Turbines & Generation	3.7%
140003.6 Accessory Electric Equipment	2.3%
140003.7 Misc Power Plant Equipment	0.0%
140003.73 Fencing	0.0%
Total Hydro Plant	**42.1%**
Diesel Production	
140004.2 Structures and Improvements	0.5%
140004.201 Buildings and Improvements	0.1%
140004.403 Fuel Holders, Products, and ACC	0.4%
140004.5 Generating Equipment and Prime	5.5%
140004.508 0.0%	
140004.6 Accessory Electric Equipment	1.5%
140004.7 Misc Power Plant Equipment	0.5%
Total Diesel Production	**8.5%**
Wind Turbine	
140005.4 Wind Turbine	1.1%
Total Wind Turbine	**1.1%**

Class/Class Description	Percent of Total Cost
Main Transmission Facilities	
140006.3 Poles and Fixtures	12.4%
140006.304 Brushing	3.4%
140006.305 Survey Costs	1.0%
140006.402 Overhead Conductors / Poles	5.5%
140006.404 Overhead Conductors / Towers	0.1%
140006.71 Substation Equipment	7.5%
140006.72 Substation Buildings	0.0%
140006.73 Substation Fences	0.0%
Total Main Transmission Facilities	**29.9%**
Sub Transmission Lines	
140007.3 Poles and Fixtures	1.3%
140007.301 25Kv Minto Spur- Structure	0.9%
140007.304 Brushing	0.0%
140007.305 Survey costs	0.0%
140007.306 0	.2%
140007.307 0	.0%
140007.401 Overhead Conductors	0.3%
140007.405 Underground Conductors / Conduit	0.0%
140007.407 0	.3%
140007.711 2	.3%
Total Sub Transmission Lines	**5.4%**

Depreciation Study
Background

Description of Subject Assets (continued)

The following table outlines the asset classes reviewed in the analysis as well as the relative weighting of each class with regards to total cost basis.

Class/Class Description	Percent of Total Cost
Distribution System	
140008.3 Poles and Fixtures	1.3%
140008.304 Brushing	0.0%
140008.305 Survey costs	0.2%
140008.401 Overhead conductors - Poles	0.0%
140008.41 Overhead Costs	0.7%
140008.51 Underground Services	0.0%
140008.55 Wind Monitoring Equipment	0.0%
140008.61 Meters	0.1%
140008.62 Meter Equipment	0.1%
140008.71 Substation Equipment	0.4%
140008.72 Substation Buildings	0.0%
140008.815 Street Lights	0.2%
140008.905 Line Transformers	1.2%
140008.961 Sentinel Lights	0.0%
Total Distribution System	**4.2%**

Class/Class Description	Percent of Total Cost
Building and Other Equipment	
140009.11 Survey Costs Land	0.0%
140009.2 Structures and Improvements (Hydro)	0.2%
140009.201 Building and Improvements	3.0%
140009.202 Office Furniture and Equipment	0.5%
140009.21 Communication Site Towers	0.0%
140009.22 Communication Site Fences	0.0%
140009.31 0.0%	
140009.32 Computer Hardware	0.7%
140009.33 Computer Software	0.3%
140009.505 Tool and Instruments	0.3%
140009.507 Wind monitoring equipment	0.0%
140009.605 Communication Equipment	1.3%
140009.81 Company Owned Houses / Land	0.0%
140009.82 Company Owned Houses	0.5%
140009.9 0.0%	
Total Building and Other Equipment	**6.8%**
Transportation	
140014.411 Utility Vehicles	0.1%
140014.412 Sedans and Stationwagons	0.0%
140014.42 0.0%	
140014.43 Pole Trailers > 10,000 Lbs	0.0%
140014.44 Trucks 3/4 to 2 Ton	0.8%
140014.47 Trucks > 3 Ton	0.2%
140014.49 0.4%	
Total Transportation	**1.5%**

Depreciation Study

Methodology – Depreciation & Life Estimation

Depreciation

Depreciation, for accounting purposes, reflects the consumption of capitalized assets over an estimated service life that accounts for the period of time the assets will be utilized. In terms of estimating depreciation expense, the most common method relied upon is the age/life or straight-line method whereby the cost of an assets is amortized in equal installments over its estimated economic life.

For the purposes of our analysis, and based on discussions with company management we have assumed the straight-line method to estimate depreciation expense.

Life Estimation

As previously noted, to estimate depreciation it is necessary to estimate the service life of each asset group. The concept of an average service life implies that the units within the asset group have different lives. In estimating the average service life of an asset group, there are several accepted methodologies, each of which relies on historical data of the asset group as a whole: actuarial, simulated plant balance, and turn over.

Actuarial methodologies include: the retirement rate method, the original group method, and the individual unit method. The retirement rate method is considered the preferred method as it examines the additions and retirements of an asset group over the entire period under analysis. Conversely, the original group method focuses on the original asset group only and its corresponding retirements; and the individual unit method focuses on retirements only.

The simulated plant balance methodology is a difficult process to implement but is otherwise useful. Under this method, survival ratios under different survivor curves are utilized to create a simulated account balance. Each simulated account balance is compared to the actual asset account history, and the best match is selected as the appropriate survivor curve.

The turnover methodologies, including methods such as the half-cycle method and the asymptotic method, are generally considered weaker methods than the actuarial methods previously discussed. Turnover methods utilize retirement ratios without consideration to the age of the assets. Therefore, this method is useful in circumstances of limited data, but is also a weaker approach when asset age data is available.

The objective of each method is to determine the average service life of the asset group based on historical retirement patterns and the balance of assets surviving at each measured interval of time. It should be noted that, while actual data is heavily relied upon, a prudent level of judgment is also applied in estimating average service lives as there are limitations to what is achievable solely with quantitative methods.

In addition to a review of historical data, there are also qualitative procedures taken to measure the average service life of an asset group. The primary qualitative method is the comparable company method. In the comparable company method, asset lives of similar companies are collected and reviewed. Comparable companies were selected on the basis of owning and operating the same type of hydro and electrical generation assets as Yukon Energy. Upon the completion of the review, ranges of comparable average service lives are created by asset category and utilized as an indication of accepted average service lives within the subject industry.

In our analysis, we have applied both quantitative and qualitative procedures in estimating the average service lives of the subject assets. In conducting our estimation of average service lives, we applied an actuarial methodology referred to as the annual-rate method.

Net Salvage Estimates

In our analysis, we have reviewed the current net salvage estimates applied by Yukon. As these estimates are highly subjective, we have based our review upon our prior experience conducting similar analyses. Estimates of net salvage have been made on a percentage basis by class and are applicable to the historical cost basis of the assets.

Depreciation Study

Methodology – Quantitative Approach

Evaluation of Statistical Data

The results of the statistical analyses are indications of past experience and are studied to establish trends in historical service life, retirement dispersion patterns as given by Iowa-curves, and net salvage. Indicators of goodness-of-fit, a review of recorded accounting data, knowledge of the type of property involved, and the experience of others with similar property, including the depreciation parameters of the previous depreciation study, are used as aids in these determinations. Historical service lives and Iowa-type curves also are modified, if appropriate, to reflect future service conditions.

In establishing the service life estimates, consideration must be given to expected future conditions not reflected in historical statistics. If the factors that determine the historical average service life will not change significantly in the future, the historical average service life can be a reasonable estimate of the future average service life. However, changing technology, company growth, environmental and regulatory requirements, customer demands, and sometimes the experience of other utilities have a definite effect and must be considered in the determination of normal useful lives, future average service life, remaining life, and net salvage.

Statistical Analysis

In estimating average service life utilizing quantitative procedures, historical data was reviewed and analyzed with consideration to retirement patterns. Survivor curves, specifically Iowa Curves, were utilized in our analysis.

Survivor curves provide an indication of the percentage of an asset group surviving at different intervals of time. The slope of the survivor curve is determined by the changes in mortality that occur over the duration of an asset group's average service life. Through the utilization of survivor curves, it is possible to estimate the average service life, average remaining life, and probable life of an asset group.

In our analysis, we analyzed historical retirement patterns for each asset class and conducted quantitative procedures to best fit the historical data to the most applicable Iowa Curves. While this was our primary quantitative method, it should be noted that certain adjustments and iterative processes were conducted to ensure that the most appropriate Iowa Curve was selected.

When conducting the statistical analysis, there were certain asset classes whose quantitative data presented limitations and required adjustments. Such instances included limited periods of experience (i.e. a long lived asset group with meaningful data over only a short duration) and wide experience bands with insignificant changes to the asset base, thereby making the comparative analysis over the entire duration of the experience infeasible.

In order to normalize the data for comparative purposes, the following procedures were conducted.

Depreciation Study

Methodology – Quantitative Approach (continued)

Information Gathering and Processing

The accounting history of additions, retirements, and balances is used to study service life experience and trends for various regulated power generation plant accounts. When the dates of the installation and retirements are known and appropriately complied, study procedures known as actuarial methods can be used. When such data are not available in a reliable form, techniques are available to simulate actual vintages of retired property. In this instance we were provided with information from a previous depreciation study as well as the additions and deletions from 2003 through year-end 2010 by management and were used as the basis of our depreciation study.

Determination of Average Service Life

The average service life of the facilities were developed using the retirement rate method as well as the comparable company method.

The retirement rate method involves estimating the appropriate survivor curve for all property groups and were based upon data from a previous depreciation study as well as additions and deletions provided by management from 2003 to 2010. The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each group is retired.

In the comparable company method, comparable regulated utility companies were researched in the US and Canada. Information from the companies' annual reports was summarized and compared to the subject company. Information gathered included: company overview, geographic location, customers served, methods of power generation, transmission network, PP&E accounting lives by asset type, etc. The average service lives are then compared to the subject and used as a secondary data point.

A business description for each of the selected comparable companies is found in the "Comparable Companies" section below. The depreciable lives utilized by the comparable companies are discussed in the applicable asset account sections.

Extrapolation Methods

When limited data was available, methods of extrapolation were applied to derive an estimate of future retirement patterns, which were then utilized in the curve fitting process to identify the Iowa Curve the most appropriately reflected the survivor patterns of the subject asset group.

Methods of extrapolation were performed by analyzing the number of data points (on the survivor curve) for a given asset class, and measuring the geometric and arithmetic annual rate of change between the first and last data point. Utilizing the two calculated rates of change, two additional scenarios were constructed for each asset class under analysis by extrapolating from the last observed data point on the survivor curve. The analysis of each asset class was performed with and without the extrapolation techniques in order to develop various scenarios in which to examine the historical asset retirement patterns. Judgment was used to determine whether an extrapolation of asset retirement patterns increased or decreased the usefulness of the quantitative analysis. Whether an extrapolation of the data was considered the best scenario in the quantitative analysis is noted at the bottom of each graphical analysis page in the individual account sections of this report.

Comparable Curve Fitting

In the event that ample data was unavailable to conduct curve fitting procedures, average service lives derived based on comparable asset groupings. An illustration of this procedure is seen with structures and improvements that are noted in different accounts, but are expected to experience similar patterns of survival. Thus, it is not unreasonable to assume that similar assets found in different accounts would experience the comparable mortality rates.

Depreciation Study

Methodology – Qualitative Approach

Qualitative Approach

While a quantitative approach to estimating average service lives is based on actual retirement experience and discrete data as it relates to a specified group of assets, there are limitations of applying a methodology that relies strictly on quantitative methods.

Relying solely upon quantitative data presents several circumstances that can lead to an inaccurate measurement of average service life. First, the population of data being relied upon can have a limited duration of experience. Such circumstance arises primarily when reviewing long lived assets. For example, if an asset group is commonly assigned an average service life of 75 years, but the subject population of data only has a meaningful duration of 15 years, then there could be a lack of empirical data to support a 75 year life for the subject population despite the common acceptance of 75 years for the subject asset group.

A similar occurrence arises when an asset group experiences a material change that is not directly related to the retirement of assets. Such a change could be related to the addition of assets to an asset grouping that materially changes the balance in the account or significant retirements that are unrelated to the assets functionality.

Given the limitations of relying solely upon quantitative methods to estimate average service life, we have incorporated certain qualitative methods into our analysis.

Comparable Companies

The primary qualitative method utilized to measure average service life is the comparable company method. In applying this method, the average service lives applied for similar asset groups by other companies is relied upon. Such data is commonly available in public company filings as well as depreciation studies that have been made publicly available.

The comparable companies relied upon in our study included, but was not limited, to the following:

- **British Columbia Hydro and Power Authority –** British Columbia Hydro and Power Authority, which operates as BC Hydro, distributes electricity to the 1.8 million residential and business customers. The province-owned utility owns more than 46,500 miles of transmission and distribution lines, and it operates hydroelectric and fossil-fueled power plants about 11,350 MW of generating capacity. Subsidiary Powerex markets and trades energy throughout North America. To increase efficiencies in green power production, in 2010 BC Hydro consolidated its transmission operations with those of the province-owned British Columbia Transmission. A Crown corporation owned by British Columbia, BC Hydro is regulated by British Columbia Utilities Commission.
- **Manitoba Hydro –** For this company, water and electricity are a productive mix. Manitoba Hydro-Electric (commonly called Manitoba Hydro) provides electricity to 532,000 customers in the province of Manitoba. Its power is generated from hydroelectric facilities capable of producing about 32 billion kilowatt-hours of electricity per year. Manitoba Hydro, which is owned by the government of Manitoba, also exports power to utilities and energy marketers in the US and other Canadian provinces. Through its Centra Gas subsidiary, the company distributes natural gas to 264,300 residential, commercial, and industrial customers in 100 communities in Manitoba.

Depreciation Study

Methodology – Comparable Companies

Comparable Companies (continued)

- **Newfoundland Labrador Hydro –** Newfoundland and Labrador Hydro (Hydro), a Nalcor Energy company, has an installed generating capacity of 1,635 megawatts (MW). Over 80% of the energy generated in 2010 was clean, hydroelectric generation. Hydro's regulated assets include: nine hydroelectric generating stations, one oil-fired plant, four gas turbines, and 25 diesel plants. Our company also maintains 54 high-voltage terminal stations, 25 lower-voltage interconnected distribution stations, and thousands of kilometres of transmission and distribution lines.
- **Snowy Hydro Limited –** Snowy Hydro Limited (Snowy Hydro) provides energy to the National Electricity Market (NEM) participants. It is a supplier of price risk financial hedge contracts to the electricity industry, and supply risk assurance to the irrigators industry. The company owns and operates the 3800 megawatt (MW) Snowy Mountains Hydro Electricity Scheme, 300MW Valley Power and 320MW Laverton North gas fired power stations, which are situated in Victoria. It operates a network of seven plants, 31 generation units 15 dams and 225 kilometers (km) of aqueducts and tunnels in the Kosciuszko Naional Park. Snowy Hydro also provides water for environmental releases and water to in-land irrigators.
- **NextEra Energy –** NextEra Energy, Inc. (NextEra) is a publicly traded utility and gas company. It engages in the provision of electricity and other related products and services in the US. The company operates business through its two subsidiaries, namely, Florida Power & Light Company (FPL); and NextEra Energy Resources, LLC (NextEra Energy Resources). FPL is an electric utility company, supplying power to more than 8.7 million customers and is active in energy conservation programs. NextEra Energy Resources provides electricity using clean and renewable fuels such as wind power and solar power. NextEra has combined generating capacity of about 43,000 megawatts (MW).

Comparable Companies (continued)

- **FirstEnergy Corp –** FirstEnergy Corp. (FirstEnergy) is an energy holding company. Through its subsidiaries and affiliates, the company is active in the generation, transmission and distribution of electricity. In addition, the company also provides energy management and other energy-related services. FirstEnergy serves nearly 11.3 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. Its generation subsidiaries operate power plants with a total system capacity of more than 13,000 MW. The generation portfolio of the company is comprised of coal-fired units, nuclear plants, gas & oil based plants, hydroelectric plants and wind generation plants.
- **ALLETE Inc. –** ALLETE, Inc. (ALLETE) is engages in the provision of energy services in the upper Midwest and also participates in real estate holdings in Florida. The company operates its business through two segments, namely, Regulated Operations, and Investments and Other. The Regulated Operations segment is engaged in the retail and wholesale of rate-regulated electric, natural gas, and water services. The Investments and Other segment are engaged in the coal mining business in North Dakota and real estate business in Florida. The company operates its business activities through four subsidiaries, namely, Minnesota Power, Superior Water Light and Power, BNI Coal, and ALLETE Properties.

Depreciation Study

Methodology – Comparable Companies

Comparable Companies (continued)

- **NRG Energy, Inc. –** NRG Energy, Inc. (NRG Energy) is a wholesale power generation company in the US. It is engaged inownership, development, construction and operation of power generation facilities across the country. The company generates power through a diversified portfolio products such as nuclear, wind and solar power. NRG also engages in the transaction and trading of fuel, energy and related products and provides transportation services in the US and international markets. In addition, NRG Energy together with its subsidiaries, engages in supply of electricity, energy services, and cleaner energy and carbon offset products to retail electricity customers.
- **Duke Energy Corporation –** Duke Energy Corporation (Duke Energy) is an energy utility company, engaged in the generation, transmission and distribution of electricity, natural gas and related energy services. It owns and operates regulated and unregulated power plants in North America and Latin America regions. The company has its operations in Indiana, Kentucky, North Carolina, Ohio and South Carolina in the US and in Brazil, Peru and Ecuador, El Salvador, Guatemala and Argentina. Duke Energy supplies and distributes electricity to approximately, four million US customers and has around 35,000 MW of the US generating capacity.
- **Southern Power –** Southern Power, a subsidiary of Southern Company, is among the largest wholesale energy providers in the Southeast U.S, meeting the electricity needs of municipalities, electric cooperatives and investor-owned utilities. The company owns and operates more than 7,500 megawatts with facilities in Alabama, Florida, Georgia and North Carolina and has an additional 820 megawatts committed to construction in North Carolina and Texas.

Comparable Companies (continued)

- **Green Mountain Power Corporation –** Green Mountain Power Corporation (Green Mountain Power Corporation) is a public utility company. The company is engaged in the distribution of electricity to the customers in the state of Vermont, US. In addition to this, its business activities comprised of nearly over 4,700 miles of its transmission and distribution lines. Further, it holds 29% working interest in Vermont Electric Power (VELCO), which is a high-voltage transmission operator in the state. During 2008, the company's customer base comprised of residential, commercial, and industrial. In addition, Green Mountain Power Corporation also offers wholesale electricity in New England, US.
- **Idaho Power Corporation –** Idaho Power Company (IPC) is a wholly-owned subsidiary of IDACORP, Inc. It is engaged in the generation, purchase, transmission, distribution and sale of electric energy. The company serves more than 492,000 general and business customers. The company generates hydroelectric power and thermal power and holds franchises in 71 cities in Idaho and nine cities in Oregon. IPC purchases power from private developers and from other utilities and power wholesalers. It also received certificate from respective public utility regulatory authorities to serve all or a part of 25 counties in Idaho and three counties in Oregon.

Depreciation Study

Methodology – Comparable Companies

Comparable Companies (continued)

- **Northern States Power Corporation –** Northern States Power Company, together with its subsidiaries, engages in the generation, purchase, transmission, distribution, and sale of electricity in Minnesota, North Dakota, and South Dakota. It also purchases, transports, distributes, and sells natural gas to retail customers, as well as transports customer-owned natural gas in Minnesota and North Dakota. The company provides electric utility services to approximately 1.4 million customers; and natural gas utility services to approximately 0.5 million customers. It principally serves residential, commercial, and industrial customers, as well as public authorities and other customers. The company was incorporated in 2000 and is based in Minneapolis, Minnesota. Northern States Power Company is a subsidiary of Xcel Energy Inc.
- **Pacificorp –** PacifiCorp is engaged in generation, transmission and distribution of electricity. The company is a subsidiary of MidAmerican Energy Holdings Company (MEHC). PacifiCorp generates electricity through 78 coals, natural gas, hydroelectric, geothermal and wind based power plants with a total power generating capacity of 10,623MW. PacifiCorp transmits and distributes electricity over 16,200 miles of transmission lines. It is also involved in buying and selling of electricity on a wholesale basis. PacifiCorp has three business units, namely, Pacific Power, Rocky Mountain Power and PacifiCorp Energy.
- **PG&E Corporation –** PG&E Corporation (PG&E) is an energy-based holding company operating through its subsidiary, Pacific Gas and Electric Company (Pacific Gas and Electric), a public utility engaged in the following businesses: electricity and natural gas distribution; electricity generation, procurement, and transmission; and natural gas procurement, transportation, and storage. The company operates in northern and central California in the US. PG&E is headquartered in San Francisco, California and employed 19,424 people as of December 2010.

Comparable Companies (continued)

- **Public Service Company of Colorado –** Public Service Company of Colorado (PSCCo.) provides electricity and gas to a territory that includes Denver and other cities as well as rural sections of Colorado. Through its subsidiary, Cheyenne Light, Fuel & Power Co., the utility also serves customers in the environs of Cheyenne, Wyoming. Other subsidiaries of PSCCo. include Fuel Resources Development Co. (Fuelco), which explores for and develops new sources of oil and natural gas, and Westgas, which purchases, transmits, stores, and sells natural gas.
- **Public Service Company of New Hampshire – Northeast Utilities –** The Public Service Company of New Hampshire (PSNH) provides electricity across the Granite State. The company provides electric utility services to more than 490,000 homes and businesses in a 5,630-sq.-mi. area that encompasses more than 210 New Hampshire communities. Although the Northeast Utilities subsidiary owns three fossil-fueled and nine hydroelectric power plants that generate approximately 1,200 MW of capacity for transition and default energy services, it also has contracts to purchase power and buy it in the open market.

Depreciation Study

Methodology – Depreciation Expense

Depreciation Expense

As previously noted, depreciation expense was estimated based on the straight-line method where the average service life method was utilized to develop the depreciation period. All estimates have been made as at the Testing Date and appear on the following slide.

Accumulated Depreciation

After conducting quantitative and qualitative analyses, a conclusion was made for each asset class regarding average service life, probable remaining service life, and net salvage.

To calculate accumulated depreciation, the surviving cost basis as at the Testing Date was apportioned over the age of each asset group on a straight-line basis. The resulting estimate of accrued depreciation was then compared to the actual book accumulated depreciation. The resulting difference between estimated accumulated depreciation and book accumulated depreciation is noted as a variance which is then recaptured over the estimated average remaining life. The recapture described is referred to as a true-up provision which is illustrated on the following slide.

Results by Account

Number	Description	KPMG Estimated Survivor Curve	As of December 31, 2010												
			Provided by Yukon Management							Depreciation Expense			Depreciation Add-Back		
			Surviving Original Cost at 12/31/2010	Accumulated Depreciation	A/D Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accrued Depreciation	Accumulated Depreciation Variance	Annual Accrual Amount	Rate (%)	KPMG Probable Remaining Life [1]	Annual Provision for True-Up	Accounting Effective Age	KPMG Concluded Effective Age
Land															
n/a	Land	n/a	1,126,675	(13,369)	699	(87)	1,113,918	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Land			**1,126,675**	**(13,369)**	**699**	**(87)**	**1,113,918**	-	-	-			-		
Hydro Plant															
140003.200	Structures and Improvements	72 - R2	10,854,779	(3,558,901)	398,145	(77,806)	7,616,217	(2,261,412)	(977,149)	150,761	1.39	35	27,919	15	39
140003.205	Reservoirs, Dams, and Waterways	103 - R3	89,859,047	(39,320,006)	1,231,383	(215,442)	51,554,982	(20,172,923)	(18,131,142)	872,418	0.97	65	278,941	23	39
140003.506	Waterwheels,Turbines & Generation	85 - R3	10,431,950	(1,535,720)	27,655	11,344	8,935,229	(1,227,288)	(269,433)	122,729	1.18	47	5,733	10	39
140003.600	Accessory Electric Equipment	45 - R3	6,489,762	(1,301,774)	65,942	(9,942)	5,243,987	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140003.700	Misc Power Plant Equipment	30 - R2	2,542,719	(609,657)	83,244	(20,059)	1,996,247	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140003.730	Fencing	30 - R2	48,758	(5,999)			42,758	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Hydro Plant			**120,227,014**	**(46,332,057)**	**1,806,369**	**(311,906)**	**75,389,420**	**(23,661,624)**	**(19,377,725)**	**1,145,908**			**312,592**		
Diesel Production															
140004.200	Structures and Improvements	72 - R2	1,525,367	(593,353)	(219,959)	43,814	755,870	(336,646)	(432,852)	21,186	1.39	57	7,594	16	16
140004.201	Buildings and Improvements	55 - R1	307,094	(44,610)	(4,186)	666	258,964	(27,629)	(20,501)	5,584	1.82	50	410	5	5
140004.403	Fuel Holders, Products, and ACC	25 - R2	1,015,105	(623,699)	(122,114)	50,429	319,722	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140004.500	Generating Equipment and Prime	40 - R2	15,732,200	(6,322,968)	(1,672,846)	523,156	8,259,542	(6,740,580)	(732,079)	393,305	2.50	13	56,314	17	30
140004.508		n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n.a.	n/a	n/a
140004.600	Accessory Electric Equipment	45 - R3	4,278,353	(708,479)	(478,962)	72,911	3,163,823	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140004.700	Misc Power Plant Equipment	30 - R2	1,478,633	(397,778)	(371,646)	103,130	812,339	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Diesel Production			**24,336,753**	**(8,705,409)**	**(2,869,713)**	**794,107**	**13,799,285**	**(7,104,854)**	**(1,185,431)**	**420,074**			**64,318**		
Main Transmission Facilities															
140006.300	Poles and Fixtures	65 - R3	35,465,743	(4,941,581)	(1,517,669)	180,689	29,187,181	(4,910,641)	(1,367,921)	545,627	1.54	41	33,364	9	25
140006.304	Brushing	50 - R3	9,739,372	(1,130,197)	48,456	(5,815)	8,651,816	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.305	Survey Costs	50 - R2.5	2,787,405	(324,301)	(61,687)	7,403	2,408,819	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.402	Overhead Conductors / Poles	50 - R3	15,729,233	(1,865,191)	(45,903)	4,261	13,822,400	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.404	Overhead Conductors / Towers	50 - R3	277,975	(66,506)	(7,067)	848	205,250	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140006.710	Substation Equipment	54 - S0	21,342,570	(6,051,540)	(738,810)	94,989	14,647,209	(6,061,782)	(633,579)	395,233	1.85	34	18,635	15	21
140006.720	Substation Buildings	55 - R1	32,750	(7,756)	(496)	74	24,573	(5,955)	(2,223)	595	1.82	35	64	10	21
140006.730	Substation Fences	20 - R4	46,953	(8,829)	769	(230)	38,663	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Main Transmission Facilities			**85,422,003**	**(14,395,902)**	**(2,322,408)**	**282,218**	**68,985,912**	**(10,978,378)**	**(2,003,723)**	**941,455**			**52,062**		
Sub Transmission Lines															
140007.300	Poles and Fixtures	45- R3	3,618,635	(1,601,236)	(780,721)	103,059	1,339,737	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.301	25Kv Minto Spur- Structure	n/a	2,646,132	(459,388)	-		2,186,743	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.304	Brushing	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.305	Survey costs	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.306		n/a	432,533	(75,099)			357,434	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.307		n/a	95,136	(16,516)			78,620	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.401	Overhead Conductors	45- R3	989,127	(378,143)	(112,184)	17,189	515,989	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.405	Underground Conductors / Conduit	45 - S3	83,873	(32,775)	(194)	36	50,940	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.407		n/a	920,693	(159,839)			760,853	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.710	Substation Equipment	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140007.711		n/a	6,705,507	(1,164,126)			5,541,381	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Sub Transmission Lines			**15,491,635**	**(3,930,691)**	**(893,099)**	**120,284**	**11,518,772**	-	-	-			-		

Number	Description	KPMG Estimated Survivor Curve	As of December 31, 2010												
			Provided by Yukon Management							Depreciation Expense			Depreciation Add-Back		
			Surviving Original Cost at 12/31/2010	Accumulated Depreciation	A/D Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accrued Depreciation	Accumulated Depreciation Variance	Annual Accrual Amount	Rate (%)	KPMG Probable Remaining Life [1]	Annual Provision for True-Up	Accounting Effective Age	KPMG Concluded Effective Age
Distribution System															
140008.300	Poles and Fixtures	35 - R2	3,570,732	(626,163)	(14,629)	2,628	2,932,567	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.304	Brushing	50 - R2	44,763	(10,680)	(3,235)	427	31,275	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.305	Survey costs	50 - R3	500,981	(43,799)	297		457,478	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.401	Overhead conductors - Poles	35 - R2	74,570	(13,959)			60,611	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.410	Overhead Costs	40 - R2	1,984,394	(429,445)	(78,539)	13,293	1,489,703	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.510	Underground Services	40 - R2.5	6,379	(1,651)	(454)	93	4,367	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.550	Wind Monitoring Equipment	n/a	n/a					n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.610	Meters	30 - R2	281,251	(106,358)	(33,787)	7,409	148,515	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.620	Meter Equipment	30 - R2	314,136	(74,287)	3,308	(555)	242,603	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.710	Substation Equipment	40 - R2	1,188,413	(263,858)	(50,938)	9,459	883,075	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.720	Substation Buildings	55 - R1	64,798	(25,321)	(20,272)	3,619	22,824	(22,455)	(19,520)	1,178	1.82	37	528	19	19
140008.815	Street Lights	40 - R2	573,505	(112,169)	(99,674)	17,096	378,758	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.905	Line Transformers	40 - R2.5	3,290,797	(1,206,043)	(564,652)	107,313	1,627,415	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140008.961	Sentinel Lights	30 - L2	35,580	(18,984)	(12,948)	4,109	7,757	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Distribution System			**11,930,298**	**(2,932,718)**	**(875,523)**	**164,891**	**8,286,948**	**(22,455)**	**(19,520)**	**1,178**			**528**		
Building and Other Equipment															
140009.110	Survey Costs Land	50 - R2	4,321	(1,261)	(601)	83	2,543	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.200	Structures and Improvements (Hydro)	40 - R2.5	490,156	(97,536)	(3,049)	479	390,050	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.201	Building and Improvements	55 - R1	8,458,407	(2,274,046)	(459,881)	79,602	5,804,082	(1,707,364)	(946,961)	153,789	1.82	45	21,044	11	11
140009.202	Office Furniture and Equipment	20 - SQ	1,389,826	(630,145)	(130,011)	54,324	683,995	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.210	Communication Site Towers	30 - R2	19,297	(6,320)	(1,115)	240	12,102	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.220	Communication Site Fences	20 - R4	36,663	(15,689)	326	(105)	21,195	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.310		n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.320	Computer Hardware	5 - SQ	1,920,814	(812,719)	70,421	(70,421)	1,108,095	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.330	Computer Software	5 - SQ	842,508	(333,477)	(7,872)	7,872	509,031	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.505	Tool and Instruments	20 - SQ	998,579	(353,282)	(168,321)	61,636	538,612	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.507	Wind monitoring equipment	n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.605	Communication Equipment	20 - L4	3,780,557	(1,291,842)	(53,911)	22,314	2,457,118	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.810	Company Owned Houses / Land	30 - R3	36,512	(14,062)	7,862	(1,902)	28,410	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.820	Company Owned Houses	30 - R3	1,421,362	(1,260,705)	365,433	(89,514)	436,576	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140009.900		n/a	n/a	(14,523)			229,024	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Building and Other Equipment			**19,399,002**	**(7,134,653)**	**(380,719)**	**64,609**	**12,678,882**	**(1,707,364)**	**(946,961)**	**153,789**			**21,044**		
Transportation															
140014.411	Utility Vehicles	7 - L2	181,452	(143,408)	12,716	(12,716)	38,044	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.412	Sedans and Stationwagons	7 - L2	118,637	(106,473)	6,160	(6,160)	12,164	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.420		n/a	66,929	(240)			66,690	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.430	Pole Trailers > 10,000 Lbs	25 - R1.5	34,810	(5,599)	(748)	189	28,652	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.440	Trucks 3/4 to 2 Ton	10 - R2	2,217,586	(934,130)	(17,178)	15,617	1,281,895	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.470	Trucks > 3 Ton	20 - R3	692,397	(134,682)	(12,391)	4,225	549,549	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140014.490		n/a	1,001,630	(31,812)			969,818	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Transportation			**4,313,442**	**(1,356,344)**	**(11,441)**	**1,154**	**2,946,811**	-	-	-			-		
Total			**285,395,726**	**(86,023,946)**	**(5,809,234)**	**1,168,188**	**196,435,568**	**(43,474,674)**	**(23,533,360)**	**2,662,404**			**450,543**		

Notes:
[1] Calculated based on the concluded effective age and the remaining area under the survivor curve.
[2] "n/a" values reflect asset classes which KPMG reviewed, however a change was deemed unnecessary.

TAB 11
ORDERS IN COUNCIL

YUKON

CANADA

ORDER-IN-COUNCIL 2012/ 68

PUBLIC UTILITIES ACT

Pursuant to subsection 17(1) of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows

1 The annexed *Direction Amending the Rate Policy Directive (1995)* (O.I.C. 1995/090) is made.

Dated at Whitehorse, Yukon,
26 April 2012.

YUKON

CANADA

DÉCRET 2012/ 68

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

Conformément au paragraphe 17(1) de la *Loi sur les entreprises de service public*, le commissaire en conseil exécutif ordonne ce qui suit :

1 Est établie l'*Instruction modifiant les Instructions sur la politique tarifaire (1995)* (*Décret 1995/090*), paraissant en annexe.

Fait à Whitehorse, au Yukon,
le 26 avril 2012.

Commissioner of Yukon/Commissaire du Yukon

R-PUA-IndRates-12-FIN

PUBLIC UTILITIES ACT

DIRECTION AMENDING THE RATE POLICY DIRECTIVE (1995)

1 This Direction amends the *Rate Policy Directive (1995)*.

2 Section 2.1 is replaced with the following

"Retail and major industrial rate adjustments

2.1(1) The Board must ensure that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and, subject to subsection (2), to the class of major industrial customers.

(2) If the rates charged to retail customers for all or any part of 2012 are to be increased , then for that same period the greater of that increase and the percentage increase approved in Board Order 2011-14 is to apply to the class of major industrial customers.

(3) This section expires on December 31, 2013."

3 Subsection 6(3) is replaced with the following

"(3) Despite subsection (1), the Board must ensure that the rates charged to major industrial customers until December 31, 2013 conform to Rate Schedule 39, Industrial Primary, attached hereto as Schedule A, except that section 2.1 prevails over that Rate Schedule to the extent of any inconsistency."

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

INSTRUCTION MODIFIANT LES INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

1 La présente instruction modifie les *Instructions sur la politique tarifaire (1995)*.

2 L'article 2.1 est remplacé par ce qui suit :

« Ajustements tarifaires pour les clients au détail et industriels majeurs

2.1(1) La Commission veille à ce que les ajustements tarifaires pour les clients au détail et industriels majeurs s'appliquent de façon uniforme en pourcentage à toutes les catégories de clients au détail et, sous réserve du paragraphe (2), à toutes les catégories de clients industriels majeurs.

(2) Lorsque les tarifs facturés aux clients au détail pour la totalité ou une partie de 2012 doivent faire l'objet d'une augmentation, ne s'applique à la catégorie de clients industriels majeurs pour cette même période, que le plus élevé entre cette augmentation et le pourcentage de l'augmentation, approuvés dans l'ordonnance de la Commission 2011-14.

(3) Le présent article vient à échéance le 31 décembre 2013. »

3 Le paragraphe 6(3) est remplacé par ce qui suit :

« (3) Malgré le paragraphe (1), la Commission veille à ce que les tarifs facturés aux clients industriels majeurs jusqu'au 31 décembre 2013 respectent l'annexe tarifaire n° 39, Clients industriels, paraissant à l'annexe A, sauf l'article 2.1 qui a préséance sur cette annexe tarifaire dans la mesure de leur incompatibilité. »

YUKON

CANADA

Whitehorse, Yukon

ORDER-IN-COUNCIL 2008/149

PUBLIC UTILITIES ACT

Pursuant to section 17 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows

1 The annexed Directive to amend the *Rate Policy Directive (1995)* is hereby made.

Dated at Whitehorse, Yukon,
this October 3 2008.

YUKON

CANADA

Whitehorse, Yukon

DÉCRET 2008/ 149

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

Le commissaire en conseil exécutif, conformément à l'article 17 de la *Loi sur les entreprises de service public*, décrète :

1 Sont établies *les Instructions modifiant les Instructions sur la politique tarifaire (1995)* paraissant en annexe.

Fait à Whitehorse, au Yukon,
le 3 octobre 2008.

Administrator of Yukon/Administrateur du Yukon

Directive amending the Rate Policy Directive (1995).doc

PUBLIC UTILITIES ACT

DIRECTIVE TO AMEND THE RATE POLICY DIRECTIVE (1995)

1 This Directive amends the *Rate Policy Directive (1995)*.

2 The following section is added immediately after section 2 of the said Directive.

"Retail rate adjustments

2.1(1) The Board must ensure that rate adjustments for retail customers apply equally, when measured as percentages, to all classes of retail customers.

(2) This section expires on December 31, 2012."

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

INSTRUCTIONS MODIFIANT LES INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

1 Les présentes instructions modifient les *Instructions sur la politique tarifaire (1995)*.

2 L'article suivant est ajouté après l'article 2 des mêmes instructions.

« Ajustements des tarifs de détail

2.1(1) La Commission s'assure que les ajustements tarifaires pour les clients au détail s'appliquent uniformément en termes de pourcentage à toutes les catégories de clients au détail.

(2) Le présent article vient à échéance le 31 décembre 2012. »

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.

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.

S. VanBibber

Commissioner of Yukon/Commissaire du Yukon

Industrial primary rate directive .doc

PUBLIC UTILITIES ACT

MAJOR INDUSTRIAL CUSTOMER DIRECTIVE

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.

LOI SUR LES ENTREPRISES DE SERVICES PUBLICS

RÈGLEMENT SUR LES INSTRUCTIONS SUR LES CLIENTS INDUSTRIELS MAJEURS

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 1er janvier 2008 au 31 décembre 2012 respectent l'annexe tarifaire nº 39, Clients industriels, paraissant à l'annexe A. »

3 Le présent décret expire le 1er 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 Nº 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 mois 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'écrêtement 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 1er 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%).

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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 intérimaires 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

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YUKON TERRITORY

CANADA

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.

Whitehorse, Yukon

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.

Commissioner of the Yukon/Commissaire du Yukon

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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

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1995/90

RATE POLICY DIRECTIVE (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 indus-

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

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"

1995/90

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»

«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"

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 percent (.5%).

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 %).

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.

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.

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

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

1995/90

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-

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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.