YUKON ENERGY CORPORATION

AN APPLICATION BY YUKON ENERGY CORPORATION (YEC) FOR APPROVAL OF THE POWER PURCHASE AGREEMENT (PPA) BETWEEN YEC AND ALEXCO RESOURCE CORP. (ALEXCO)

INTERROGATORY RESPONSES FILED

DECEMBER 1, 2010

LEADING EDGE
(LE)

REFERENCE: **PPA**

QUESTION:

Clause 1.1(h):

a) Various sources indicate that one ampere is approximately 6.241 X 1018 electrons per second rather than 6.023 X 1023 quoted in this clause, please clarify.

ANSWER:

(a)

The definition of "ampere" relied upon was taken from Bonneville Power Administration website at the following link:
http://www.bpa.gov/corporate/pubs/definitions/a.cfm#ampere.

REFERENCE: **PPA**

QUESTION:

Clause 1.1 (lll):

a) Please confirm that YEC intends the “Power Factor” as defined to be the monthly average power factor (as used in clause 4.6 for example) rather than any shorter period value, or range of values over a longer period (such as a billing period).

ANSWER:

(a)

Power Factor is used in the agreement only in clause 4.6, where the normal intent is to determine this on a monthly average basis.

REFERENCE: **PPA**

QUESTION:

Clause 1.1 (ppp):

a) There seems to be some words missing from this definition, please clarify.

ANSWER:

(a)

The definition of "volt" provided in section 1.1. (ppp) is missing the words "a circuit". The complete definition of "volt" is as follows: "The unit of electromotive force, or voltage, that if steadily applied to a circuit having a resistance of one ohm will produce a current of one ampere[1]."

[1] http://www.bpa.gov/corporate/pubs/definitions/tuv.cfm

REFERENCE: **PPA**

QUESTION:

Clause 5.1(a):

a) What was the final actual cost for the 1.65km Initial Mine Facilities Spur?

b) What was the final actual YEC cost to negotiate and conclude the PPA?

c) With respect to charging Major Industrial Customers YEC's costs to negotiate PPAs, what precedents are there? Did the Minto mine pay YEC's costs to negotiate their PPA?

ANSWER:

(a)

The YEC capital costs recorded to date for construction of the 1.65 km Initial Mine Facilities Spur are $346,666, which includes all major contractor costs and AFUDC (see also UCG-YEC-1-9). In accordance with the PPA (section 5.1), 50% of estimated costs ($165,000) were invoiced and paid by Alexco in October. The final invoice for these costs was delayed beyond the time period provided for in section 5.1(b) to allow YEC to resolve certain issues; however, YEC's rights to recover these costs remain protected (see section 6.3). This work order is being finalized in early December whereupon the balance owing will be invoiced to Alexco.

(b)

The YEC costs recorded to date to negotiate and conclude the PPA are $95,675 (see also UCG-YEC-1-8). In accordance with the PPA 50% of estimated costs ($50,000) were invoiced and paid by Alexco in October. The balance of this work order will be invoiced to Alexco in December.

(c)

There are no precedents for charging Major Industrial Customers YEC's costs to negotiate PPAs with these customers. There was no provision in the Minto PPA for YEC's costs to negotiate and conclude that PPA be charged to the Minto mine.

REFERENCE: **PPA**

QUESTION:

Clause 6.1: With respect to the totalizing of the meters so that only one bill is issued please explain:

a) If the bill will be calculated on the basis of the sum of the (two or more) energy readings and the sum of the (two or more) peak monthly demand readings, (i.e. with the two meters completely independent of each other) or,

b) Will the demand reading of the (two or more) integrating meters be electronically totalized in one of the meters or a separate data storage device every hour so that a true aggregate peak Alexco demand is recorded for the purposes of calculating the demand related charges (and added to the summed energy related charges).

c) If the answer to the above is the method describe in (a) are there not meters available that can communicate to a totalizing device so that true overall property demand patterns are recorded?

d) If the answer to the above is the method described in (a), please explain why Alexco should not benefit from being more energy efficient on their overall electrical energy consumption patterns by reducing the demand load at one or more points of delivery when the demand load at another point of delivery is expected to be peaking (overall district demand management)?

e) Will YEC install meters, and other equipment if necessary, to enable Alexco's coincident demand contribution to the system demand to be determined? If not why not?

ANSWER:

(a) and **(b)**

At the time of negotiating the PPA, the intent of the terms within clause 6.1 was to have one Alexco Power Bill issued for all Points of Delivery to be charged under the Firm Mine Rate, resulting in one monthly Fixed Charge, one demand charge, and one energy charge. As set out in clause 6.1, the demand and energy charges for a billing month were intended to be based respectively on the total at these Points of Delivery of the monthly Electric Energy and the relevant Electric Demand used to determine billing demand at each Point of Delivery.

It was not intended at the time of negotiating the PPA to incur the added costs at this time for equipment and services as required to totalize multiple meters to achieve an aggregate peak Alexco demand for purposes of calculating demand related charges. However, there was no intent to prohibit such measures - and, in the event that Alexco agreed to provide for any such added costs reasonably required by YEC, the intent is to ensure that YEC is authorized to proceed with such additional measures.

(c)

Yes. Equipment and processes do exist to totalize and record property demand patterns. YEC would use such equipment and processes in the event that Alexco so elected to provide for any added costs reasonably required by YEC.

(d)

As reviewed in response to (b) and (c) above, the intent is that Alexco can elect to benefit from being more energy efficient on their overall electrical energy consumption patterns by reducing the demand load at one or more points of delivery when the demand load at another point of delivery is expected to be peaking (overall district demand management).

Section 4.7 of the current ESRs (or Section 7.7 of the proposed Terms and Conditions) provides conditions under which the Customer and Company may agree that the demand and energy at each point of service to a Customer may be totalized and only

one bill issued for each billing period. These current ESR provisions (and proposed Terms and Conditions) require that the Customer pay the incremental costs associated with totalized metering.

At this time, YEC and Alexco have agreed to total the demand and energy on one bill. The processes, equipment required and ramifications of electronically totalizing more than one meter to derive an aggregate peak demand were not fully contemplated between parties at the time of negotiating the PPA.

As noted in response to (c) above, subject to the Board approving this provision of the PPA, at a later date the parties may arrange to totalize demand in the interest of promoting demand management. YEC has yet to gain an operational profile and experience with this customer before committing to totalizing the bill as other issues may have higher priority to be addressed. Alexco will also need to agree to pay related added costs.

(e)

Yukon Energy will be installing data loggers to monitor and determine the coincident peak associated with serving the Alexco load.

At present, the communications infrastructure does not exist to accommodate electronically totalizing multiple points of service. Per the ESRs, the capital and monthly costs to achieve this goal will have to be paid by Alexco. In the meantime Yukon Energy will monitor and share the data logger and monthly meter information with Alexco and discuss further improvements to facilities and operating practices to manage the Alexco peak demand.

REFERENCE: **PPA**

QUESTION:

Clause 14.2:

a) Why was this clause inserted into the PPA? Does YEC anticipate selling all or any part of its interest in the Transmission Facilities? Please elaborate.

ANSWER:

(a)

YEC does not anticipate selling all or any part of its interest in the Transmission Facilities. This is a standard clause inserted into PPAs to protect the Customer and essentially mirrors section 17.2 of the Minto PPA (which relates in that case to the sale of the Transmission Project).

REFERENCE: **PPA**

QUESTION:

Rate Schedule 39, Billing Demand and Winter Contract Load: In the recent GRA Phase II hearing YEC representatives indicated that seasonal rates were not practical as the winter power cost structure was essentially the same as the summer power cost structure.

a) Why then are the peak demands recorded in the months of April through September excluded from the previous 12 month period for demand billing?

b) Why then is there provision for a winter contract load?

ANSWER:

(a) and **(b)**

The Billing Demand provisions of Rate Schedule 39 relating to a Billing Demand ratchet based on the months excluding April through September have been long established; the winter contract demand load provisions were approved at the time of the Minto PPA to allow for potential shaving of peak winter demand load by a Major Industrial Customer. These provisions were known at the time of the recent GRA Phase II hearing, along with other Rate Schedule 39 provisions (i.e., Base Load Energy) to accommodate stepped energy rates for such customers when appropriate. No seasonal energy rate is provided for in Rate Schedule 39.

The testimony on seasonal rate options during the recent GRA Phase II hearing focused on retail rates for residential or general service customers and was not focused on Rate Schedule 39 applicable to Major Industrial Customers. As discussed in that hearing, a range of material additional implementation issues arise in assessing seasonal rates for retail customers (assuming that energy rate variances by season were also to be included) and this rate option was therefore not recommended for current implementation or consideration.

UTILITIES CONSUMERS GROUP
(UCG)

REFERENCE: Application, September 28, 2010 Cover Letter, Page 1

"Alexco intends to develop Mines and Mills (collectively referred to as Mine Facilities) in the Mayo-Keno area as described in Figure C-1, Schedule C of the PPA (the District). Alexco is currently developing the Initial Mine Facilities with the intent in 2010 of commencing milling operations at the Initial Mill Site and mining operations at the Initial Mine Site as defined in the PPA, and is expected to commence service as a Major Industrial Customer (as defined in OIC 1995/90) in October 2010".

REFERENCE: Proposed PPA - Initial Mine Facilities, Page 10

"Alexco's current estimate of the commissioning of the Initial Mine Facilities is mid-September, 2010. Alexco's current estimate of the actual commercial operation of the Initial Mine Facilities is mid-October, 2010. Alexco will from time to time provide written notice to YEC of Alexco's progress under this Section 3.3 and Alexco's best estimate of the likely Commercial Operation Date and as soon as practical. Alexco will provide written notice to YEC of the Mine Facilities Operation Date for the Initial Mine Site and the Mine Facilities Operation Date for the Initial Mill Site. Alexco will ensure that the Initial Mine Facilities will be able to receive Grid Electricity from YEC at each Point of Delivery on the Mine Facilities Operation Date for that facility and Alexco will receive Grid Electricity from YEC on the Commencement of Delivery for Points of Delivery. YEC will provide written notice to Alexco of the date of the Commencement of Delivery for each Point of Delivery for the Initial Mine Facilities".

QUESTION:

a) Please provide an update regarding Alexco's operations including a monthly history of grid electricity use as supplied by YEC.

b) Please provide a copy of all written notices provided to YEC by Alexco regarding operations dates.

c) Please provide a copy of all written notices provided to Alexco by YEC regarding the date of the Commencement of Delivery for each Point of Delivery for the Initial Mine Facilities.

d) Please provide details of any on-site generation available to run any of Alexco's proposed facilities.

ANSWER:

(a)

Alexco commenced service as a Major Industrial Customer as of November 1st. Mill energy loads during November (and particularly during the first half of that month) were below pro-rated annual levels in the PPA for year 1 Estimated November energy use for Alexco's operations is as follows (includes estimates for final days of this month):

	Energy (kWh)	Demand (kVA)
Mill	339,500	1327
Mine	395,800	877

(b) and **(c)**

YEC has no written notices from Alexco regarding operations dates. YEC was informed verbally in late October that commercial operation of the Mill was expected on November 3rd, although the Mine Facilities Operation Date for both the Initial Mine and the Initial Mill was considered to have occurred by November 1st and the Commercial Operation Date under the PPA was November 1st.

Similarly, there is no written notice provided to Alexco by YEC regarding the Commencement of Delivery for each Point of Delivery for the Initial Mine Facilities. The Initial Mine Site was connected to the grid prior to the PPA, and the Initial Mill Site was connected to the grid on October 6th. The Commencement of Delivery for the Initial Mine Facilities occurred on November 1st concurrent with the Commercial Operation Date.

(d)

Alexco has informed YEC that it has approximately 275 kW of generating capacity available at the Bellekeno Mine to maintain ventilation, pumping, water treatment and heat in the event of a prolonged power outage, and an additional 250 kW of generating capability soon to be installed at the Initial Mill to maintain heat and critical circulation during a prolonged power outage. This generating capacity is provided from two independent 600v diesel powered generators.

REFERENCE: Proposed Power Purchase Agreement

The proposed PPA has been dated September 1, 2010. Section 2.1 – Term indicates that "this Agreement will commence as of the date of this Agreement"

QUESTION:

a) Please confirm that the proposed PPA will not be effective until it has been approved by the YUB.

b) Please explain what provisions are in place to change the effective date of the proposed PPA once YUB approval has been issued.

ANSWER:

(a) and **(b)**

The PPA is effective as of September 1, 2010 and this date will not change once the YUB approval has been issued.

The September 28, 2010 Application is seeking Board approval of the Alexco Fixed Charge, the customer contribution for all Capital Costs, the customer obligation to pay for future Decommissioning Costs, and the section 6.1 provision for one bill.

The parties are proceeding based on the Agreement on the understanding that the above are subject to Board approval, and will comply with whatever the Board approves in relation to the Agreement. The Effective Date will remain the same.

REFERENCE: Application, September 28, 2010 Cover Letter, Page 4

"The PPA Fixed Charge of $7,289/month ($87,468 per annum) assigns to Alexco 85% of YEC 2010 annual owner costs (depreciation and return) related to the defined Transmission Facilities primarily developed in the past to serve industrial customers in the District (i.e. UKHM). YEC's annual owner costs for the Transmission Facilities for 2010 are derived in Attachment B at $102,900 ($8,575 per month).

REFERENCE: Proposed Power Purchase Agreement - Attachment B - YEC Annual Transmission Facilities Costs

In Attachment B, YEC has provided a half page summary of how YEC's annual Transmission Facilities costs of $8,575 per month were determined.

REFERENCE: Appendix A to YUB Board Order 2007-5 – Page 5 of 27

"The Board agrees with Intervenor concerns regarding the lack of a complete COS study. The Board is of the view that due to the articulating nature of a COS study, rates cannot be developed in isolation".

REFERENCE: OIC 2007-94 – Major Industrial Customer Directive – Schedule A

"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".

QUESTION:

a) Provide a paper copy and a working electronic copy of the cost of service study used to determine YEC's annual Transmission Facilities costs of $8,575 per month and that prove that the proposed firm mine rates in Attachment C of the proposed Power Purchase Agreement are sufficient to recover revenue requirement allocated to the industrial rate class and, in particular, Alexco.

b) Provide details of the functionalization, classification and allocation factors used in the cost of service study used to calculate the firm mine rate proposed to be charged to Alexco.

c) Provide details of all costs (directly assigned costs, allocated costs, etc.) that are proposed to be recovered through the proposed mine rates charged to Alexco.

d) Provide details of how the rates proposed to be charged to Alexco and other industrial customers in the Yukon are sufficient to recover the costs of service to the industrial customer class and that those costs have been determined by treating the whole Yukon as a single rate zone (as per OIC 1995/90).

e) Please explain why the demand and energy charges proposed to be charged to Minto and Alexco (per Attachment C – Firm Mine Rate of the proposed PPA) are still at the levels originally dictated by OIC 2007-94 rather than escalated per OIC directions.

f) Please explain why Attachment C – Firm Mine Rate of the proposed PPA does not include the last two clauses of OIC 2007-94 Attachment A referring to "Escalation of demand and energy charges" and "Adjustment of fixed charge".

g) Provide an amended Rate Schedule 39 showing demand and energy rates escalated per OIC 2007-94 and including the last two clauses of OIC 2007-94 Attachment A. Please provide all details related to the escalation factor used on demand and energy charges.

ANSWER:

(a) to **(d)**

A Cost of Service Study was not used to determine the annual Transmission Facilities costs. As noted during the recent 2009 Phase II Rate Application hearing, the Firm Mine Rate (Rate Schedule 39) is fixed by OIC until December 31, 2012. However, as noted in evidence during that proceeding, the 2009 COS demonstrates that that the industrial class is paying well in excess of its COS (with an R/C ratio of 109% as noted in the

Phase II Rate Application or 111% with corrections[1]). There was no evidence provided during the Phase II Rate proceeding to suggest that industrials are paying less than their cost of service.

(e)

OIC 2007/94 provides for annual "escalation" at January 1 of each year (from 2010 until 2012) based on the most recent 12 month implicit chain price index for GDP per Statistics Canada. During the process to finalize Rate Schedule 39 (early last fall) Yukon Energy committed to provide a letter to YUB by December 5, 2009 that would set out any required adjustment.

In 2009, there was no basis for an increase, i.e., the Implicit Chain Price Index (CPI) for the Third Quarter of 2009 was negative[2], indicating no increase in CPI and no requirement pursuant to OIC 2007/94 to escalate the demand and energy charges[3]. Given the OIC requires an adjustment for "escalation" and not reduction, no change to demand and energy charges in Rate Schedule 39 was required.

The most recent data available from Statistics Canada indicates that the Implicit Chain Price Index (CPI) 12 month escalation as of the Third Quarter of 2010 is 2.8%. Based on this latest data, there is a requirement pursuant to OIC 2007/94 to escalate the demand and energy charges at this time.

(f)

YEC addressed this issue in the 2008 process to review and approval a final Rate Schedule 39 and the current Rate Schedule 39 was approved on a final basis by the YUB in Order 2008-13.

In that process the YUB specifically asked (in YUB-YEC-2(b)) why sections entitled "Escalation of demand and energy charges" and "Adjustment of fixed charge" that were part of the attached Schedule A of OIC 2007/94 were not part of the final Rate Schedule 39. At that time YEC noted as follows:

[1] See YEC Final Argument page 8 and page 16.
[2] Information for the Third Quarter of 2009 indicated -3.5%.
[3] See http://www.statcan.gc.ca/daily-quotidien/091130/t091130a6-eng.htm

Yukon Energy is of the view that the referenced sections entitled "Escalation of demand and energy charges" and "Adjustment of fixed charge" that are part of the attached Schedule A of OIC 2007/94 do not need to be part of Rate Schedule 39 as approved by the Board from time to time to implement OIC 2007/94.

The OIC provides direction to the Board to ensure that adjustments are made to demand and energy charges and fixed rates in Rate Schedule 39 going forward. Under Yukon Energy's current application, the Board is required to review and approve all such changes; accordingly, the direction to undertake such changes does not need to be included specifically in the rate as proposed today in order to be implemented by the Board as required in the future.

(g)

See response to (f) above. The current rate schedule has been approved by the Board.

Please see attached correspondence recently filed with the YUB regarding the escalation of demand and energy charges effective January 1, 2011 pursuant to OIC 2007/94. The escalation factor is based on based on the most recent 12 month implicit chain price index for GDP per Statistics Canada[4].

[4] http://www.statcan.gc.ca/daily-quotidien/100831/dq100831a-eng.htm

YUKON ENERGY

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File: 2702-03-01

November 30, 2010

Mr. Bruce McLennan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon
Y1A 6L3

Dear Mr. McLennan,

RE: Rate Schedule 39 – Escalation of Demand and Energy Charges per OIC 2007/94

OIC 2007/94 provides for the "escalation" of demand and energy charges as follows:

> 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 project at market prices for Canada as reported by Statistics Canada.

As reviewed in Board Order 2008-13 which approved the current Rate Schedule 39 pursuant to OIC 2007/94, YEC committed to file for approval of the Board any further changes to Rate Schedule 39 as may be required to address escalation of demand and energy charges as provided for in OIC 2007/94. In this regard, YEC has also committed to submit a letter to the Board prior to December 5th of each related year setting out, for approval by the Board, the adjustments to rates as required to effect escalation of demand and energy charges as directed by OIC 2007/94.

The most recent data available from Statistics Canada, in the 12 month Implicit Chain Price Index is for the Third Quarter of 2010 and indicates that the latest percentage increase, is 2.8%[1]. Based on this latest data, there is a requirement pursuant to OIC 2007/94 to escalate the demand and energy charges for Rate Schedule 39 at this time by 2.8%, for rates to be effective January 1, 2011.

[1] See http://www40.statcan.gc.ca/l01/cst01/gdps05a-eng.htm

A reviewed Firm Mine Rate (Rate Schedule 39) with adjusted Demand and Energy charges is attached.

Yours truly,

Ed Mollard
Chief Financial Officer

Attachment

Effective; 2011/01/01
Supersedes: 2008/10/01

ATTACHMENT 1 – RATE SCHEDULE 39 WITH AMENDMENTS

FIRM MINE RATE
RATE SCHEDULE 39
INDUSTRIAL PRIMARY

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

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

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

(a) Demand Charge of $15.42/kV.A of Billing Demand

(b) Energy Charge of 7.81¢/kW.h for all energy used

(c) Fixed Charge

For service to Minto mine site, the Fixed Charge each month shall equal the payments then required under the Power Purchase Agreement (the **"PPA"**) dated February 8, 2007 as amended on May 14 and May 25, 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:

Effective; 2011/01/01
Supersedes: 2008/10/01

(a) the highest metered kV.A demand recorded in the current billing month;

(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; and

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.

REFERENCE: Application, September 28, 2010 Cover Letter, Page 4

"Alexco share of forecast load going through Transmission Facilities approximates 98%".

"The proposed 85% share as agreed in the PPA is based on NEB 1985 NCPC Report finding re: Faro mine which the YUB subsequently retained to set the fixed charge for the Faro Mine under Rate Schedule 39".

QUESTION:

a) Please provide a copy of the referenced NEB 1985 NCPC Report.

b) Please confirm YEC's understanding that the 138 kV transmission line from Whitehorse to Faro was built as a consequence of an agreement between the Government of Canada and Cyprus Anvil Mining Corporation to build a mining facility at Faro and that, in 1985, the NEB believed that it was doubtful that, in the absence of instructions from the federal government to do so, NCPC would have built the 138 kV transmission line.

c) Please confirm YEC's understanding that the criterion used in 1985 by NCPC in assigning assets to specific customers for the purpose of levying special charges was that assets that could reasonably be determined to be for the sole use of a particular customer or particular customer class were charged directly to that customer or class.

d) Please confirm that when the Cyprus Anvil Mining Corporation mine was operating, CAMC was assigned in excess of 95 percent of the annual costs of the transmission line with the remaining costs being assigned partly to the towns of Faro, Carmacks, and Ross River.

e) Please confirm YEC's understanding that no matter what percentage of costs were directly assigned to CAMC, the NEB felt that CAMC should also be assigned its share of the pooled costs.

f) Please provide details of any study comparable to the analysis supporting the NEB 1985 NCPC Report that has been completed for the Alexco mining facilities.

g) Please identify the parties that have "deemed" the proposed 85% allocation to Alexco as "reasonable".

ANSWER:

(a)

The relevant excerpt of the National Energy Board report into Matters Relating to the Northern Canada Power Commission (1985) dealing with the Whitehorse to Faro Transmission line is provided as **Attachment 1** to this response.

(b)

The NEB report notes its review of evidence from another process and conclusion that the transmission line was constructed pursuant to an agreement between CAMC and Canada. The NEB did not specifically note the line would not have been built absent instructions from the government, but stated its belief that NCPC would not have built the line "without requiring some form of guarantee to ensure existing customers would not be burdened with the cost of this facility if the mine were to shut down."

The full quote at page 43 of the NEB Report is as follows:

> A review of the 1983 inquiry's transcripts indicate that Whitehorse No. 3 and the transmission line to Faro were built in 1969 as a consequence of an agreement between CAMC and the Government of Canada to build a mining facility at Faro. NCPC was designated to provide some 9.3 MW of additional capacity to supply the new mining operation and to construct a transmission line from Whitehorse to Faro. The Board is doubtful that, in the absence of instructions from the federal government to do so, NCPC would have constructed a 288-kilimetre transmission line without requiring some form of guarantee to ensure that existing customers would not be burdened with the cost of this facility if the mine were to shut down.

(c)

Section 7.3.4.1 of the NEB report addresses "specific charges and credits" and notes as follows at page 41:

> The criterion used by NCPC in assigning assets to specific customers for the purpose of levying special charges was that assets that could reasonably be determined to be for the sole use of a particular customer or particular customer class were charged directly to that customer or class. Assets that fall into this category are facilities installed for a particular customer's need (i.e., diesel plant installed at Pine Point, NWT for Pine Point Mines Limited's 10 MW electric dragline operation) as well as substation facilities serving individual customers.

However, the following was specifically noted re: the treatment of transmission lines:

> In its submission, NCPC did not assign transmission lines to specific customers or classes. Under the proposed rate zone scenario, all transmission facilities within a rate zone were assumed by NCPC to be interconnected. In light of this assumption, NCPC considered it would be inappropriate to charge specific portions of the transmission system to individual customers as this would contradict its theoretical assumption that all consumers, regardless of location in the rate zone, share the same general production and transmission facilities.

The Board provided its conclusions on this issue at page 42 to 43:

> …in the absence of contractual arrangement, established Commission policy, or regulatory decision requiring a particular customer or group of customers to bear the cost of a new facility, be it a generating facility, transmission line or part of a distribution facility, the annual costs of such facilities should be included in the pooled costs to be allocation to all customers in the rate zone.
>
> Nevertheless, the Board believes that, in light of the circumstances surrounding the construction of the Whitehorse to Faro transmission line and the 5.2 MW diesel engine at Faro, a significant portion of these assets should, as was done in the past, be specifically assigned to CAMC.

(d)

As noted on page 43 of the 1985 NEB report, the NEB notes its understanding that when the Cyprus Anvil Mining Corporation mine was operating, CAMC was assigned in excess of 95 percent of the annual costs of the transmission line with the remaining costs being assigned partly to the towns of Faro, Carmacks, and Ross River.

However, in this report, the NEB specifically recommended a different assignment of these costs than had occurred previously when the Faro mine was operating. The NEB recommended that due to the "unusual circumstances surrounding the construction of the transmission line from Whitehorse to Faro" (i.e., where NCPC was instructed to build the line due to an agreement between Canada and CAMC), the line be treated as a "specific asset" and that 85% of the annual cost be assigned specifically to CAMC. The remaining 15% of annual costs were to be poled costs in the Yukon hydro rate zone to be allocated to all customer classes based on their respective demands. The NEB asserted that the 85% figure reflected the fact that CAMC would be assigned its share of pooled costs (in addition to the 85% of annual costs directly assigned).

(e)

Confirmed. As noted in (d) above the assignment was based on the rationale the 85% of directly assigned annual costs together with CAMC's proportional share of pooled costs (based on demand) was a fair sharing of costs for this specific asset.

(f)

In determining the fixed charge for Alexco, YEC relied upon the precedent and rationale for the fair allocation of costs provided in the 1985 NEB report. The analysis is provided in the Application, and specifically in Attachment B.

(g)

Based on past Yukon precedent, industrial customers are required to make contributions towards existing and new transmission infrastructure built specifically to provide industrial service to their mine site. See response to YUB-YEC-1-3(a) and (b), YUB-YEC-1-4(a), and YECL-YEC-1-4.

Past regulatory reviews by the NEB (in the 1985 NEB report) and by the YUB (for example in reviewing the 1996/97 COS in Order 1996-7) have determined an 85% direct assignment of annual costs and proportional share of pooled costs (based on respective demands for each of the customer classes) to be a reasonable allocation of costs for transmission facilities established to provide service to a mine site (as in the case of the Mayo-Keno facilities which were historically established to provide service to the UKHM mine). YEC has applied for approval of this treatment for the Mayo-Keno Transmission line as part of the current Application and it is for the YUB to determine if this remains a fair and reasonable allocation of costs for this type of specific asset.

Chapter 7
Fully Distributed Cost of Service Study

7.1 Introduction

The Board, in its August 1983 report, recommended that NCPC design cost-based rates. To design cost-based rates for an electric utility it is necessary to perform a fully distributed cost of service study.

7.1.1 Fully Distributed Cost of Service Study

The purpose of a fully distributed cost of service study is to allocate the net revenue requirement of a rate zone to specific customers and to the various customer classes in the zone. The costs allocated in this manner are then used in the design of cost-based rates for each class. The cost of service study is based on the principle that all utility costs can be either directly assigned to specific customers or related to demand, energy and customer components.[1] The basic tasks to be performed in such a study consist of functionalizing, classifying and allocating costs.[1]

The general procedures followed by NCPC in developing its test year cost of service study as described in its submission are as follows:

1. Total operating costs (excluding allocated head and regional office costs) were compiled and the rate base was identified for each proposed rate zone, i.e., Yukon hydro, Yukon diesel, NWT hydro, NWT diesel and Field, B.C.
2. Head office and regional office administration revenue requirements were allocated to the rate zones and to the various electrical, heat and water & sewage utilities on the basis of forecast direct salaries and wages.
3. Costs and rate base associated with the nonelectric utilities (heat and water & sewage services) were either directly identified or allocated to the nonelectric utilities.
4. Estimates of street lighting costs and associated rate base were compiled and the costs were assigned directly to the street lighting customer classification in each rate zone.
5. After removal of nonelectric and street light related costs and rate base, all remaining electric utility costs and rate base, including the allocated head and regional office costs for a rate zone, were functionalized, where possible, into the following categories: production, transmission, distribution, support facilities, plant administration and general expenses, employee facilities, and depreciation.
6. The functionalized costs and rate base were then classified to demand, energy and customer components taking into consideration, insofar as practical, standard industry practices as outlined in the National Association of Regulatory Utility Commissioners (NARUC) "Electrical Utility Cost Allocation Manual" and the American Public Power Association (APPA) "Cost Allocation Manual" and the recommendations contained in the Price Waterhouse Associates "Report on the Review of the Cost of Service Methodology" which was commissioned by NCPC. A tabulation of the classification factors used and the rationale supporting them were included in the submission. In several instances, judgement was required on NCPC's part to derive a reasonable estimate of an appropriate classification factor.
7. Where specific assets have been provided to serve a particular customer or customer class, depreciation and rate base were assigned directly to that customer or customer class.
8. All costs classified as demand, energy and customer were then allocated to each customer class, based respectively on each customer class' noncoincident peak demand, kW.h sales plus losses and weighted number of customers. (The weighted number of customers is used so that the additional expense of serving a large industrial or wholesale customer as compared with a residential customer is recognized.)
9. The total revenue requirement for each customer class or specific customer is the sum of:

1 These terms are defined in the definition section of this report.

allocated demand costs;
allocated energy costs;
allocated customer costs;
specific charges; and
allocated return on rate base; less
allocated miscellaneous revenue credit.

The Board's findings regarding the procedures used by NCPC in its fully distributed cost of service study are provided in the succeeding sections of this chapter. The results of the Board's recommendations are summarized in Tables L-1 to L-7 in Appendix L.

7.1.2 Accounting System

The financial information required for a cost of service study is obtained from the accounting records of an electric utility. NCPC testified that there is no uniform system of accounts for electric utilities in Canada and that the Commission believed that each individual utility in Canada has devised an accounting system best suited to its own situation. The Commission stated that its accounting system is one that developed over time and, although suitable to conduct its operations under the NCPC Act, would nevertheless require some revisions in order to make it more useful for cost of service study purposes.

The Board recognizes that such revisions are complex and would require considerable resource commitments. Nevertheless, the Board encourages NCPC to make the necessary improvements so that costs can be more readily identified by functional and sub-functional categories and segmented in such a way as to be more useful for allocation purposes. Such changes should be instituted at the beginning of a fiscal year.

7.1.3 Allocation of Head and Regional Office Costs to Rate Zones

NCPC's proposed method for allocating head and regional office costs to each rate zone and the Board's recommendations thereon are discussed in Sections 6.6 and 6.7.

7.2 Functionalization Procedures

Intervenors did not express any serious objections regarding the functionalization procedures used by NCPC in its submission. Suggestions were made, however, that NCPC consider making at least the following improvements in the future. It was suggested that, in the hydro rate zones, NCPC should show separately the net plant in service of the hydro assets and the diesel assets rather than grouping them. Distribution-related assets and costs should be sub-functionalized so that assets and costs, such as meters and meter maintenance, which are related solely to serving customers, can be assigned specifically to that classification. Further, demand-related distribution assets and costs should be sub-functionalized to differentiate between services provided at primary and secondary voltage levels. In addition, customer accounting expenses including meter reading, customer service and informational expenses, and sales expenses which vary with customers should be shown separately and should be classified entirely to the customer cost component.

The Board encourages NCPC to make the necessary modifications to its accounting system to accommodate the above suggestions.

7.3 Classification Procedures

The principal issues addressed during the inquiry regarding NCPC's classification procedures were:

1. NCPC's decisions to classify:
   - production rate base in each hydro rate zone 100 percent to demand,
   - production operating costs 95 percent to demand and 5 percent to energy, and
   - distribution assets and costs 80 percent to demand and 20 percent to customer; and
2. the assignment of specific charges to specific customers.

7.3.1 Production Rate Base

On the recommendation of Price Waterhouse as set out in its report to NCPC, the Commission classified its entire production net plant in service 100 percent to demand in each rate zone. The rationale for assigning all production-related facility costs to demand is that these costs, which are incurred to meet capacity requirements, are fixed costs and do not vary with the energy produced by the facility.

Only YTG took exception to NCPC's proposal to classify production assets 100 percent to demand. An expert witness for YTG stated that most Canadian utilities recognize that generation is put in place to meet energy as well as capacity needs and that if generation were only in place to meet capacity it would be installed at minimal cost, i.e., diesel generators or gas turbines would be used. He further stated that the reason more expensive capacity such as hydro is installed is to provide lower cost energy than is possible using diesel generators or gas turbines.

In his direct evidence, the witness indicated that the significance of overemphasizing demand in cost classification is that such an approach penalizes

customer classes with lower than average load factor.

He went on to cite a number of utilities in southern Canada; namely, Ontario Hydro, B.C. Hydro and Manitoba Hydro, which he indicated classify at least 50 percent of their production assets to energy. (It was noted that all of these utilities have sizeable investments in hydro assets.)

He explained that B.C. Hydro uses what he thought could be called a plant factor method to classify production rate base to demand and to energy. He indicated that this method takes the demand imposed on a particular plant at the time of the system's peak and compares that to the average load that the generating plant unit puts forth during the year. He stated that, if applied to Whitehorse No. 4, this method would assign the production rate base 100 percent to energy. He noted, however, that other methods employing plant factors might not lead to that type of result.

He concluded by stating that, at least for the first inquiry into cost-based rates for NCPC, there is merit in a simplistic approach as opposed to one in which a number of plant factors must be justified. He suggested that a simple middle of the road approach that would assign 50 percent to demand and 50 percent to energy might be appropriate.

The expert witness for CAMC stated that the objective of any cost allocation process should be to come up with a fair allocation of costs between high and low load factor customers. This witness indicated that a criticism of the plant factor method is that it causes volatility of pricing because the plant factors of each plant change over time as the system evolves. Thus, the plant factor method can yield allocation factors which vary from year to year.

NCPC testified that it saw merit in moving away from its 100 percent demand classification and assigning perhaps 20 percent of the production asset costs to energy in the hydro rate zones.

The expert witness for Cominco supported NCPC's position. He stated that, based on his experience, he would generally be more comfortable with the 80/20 split suggested by NCPC than with the 50/50 split suggested by the witness for YTG.

Based on the evidence, the Board is of the view that production-related assets in rate zones with large hydroelectric components should not be classified entirely to demand. For the test year, the Board has used the 80 percent demand 20 percent energy split suggested by NCPC in designing cost-based rates in the hydro rate zones.

With respect to the diesel rate zones, the Board notes that no intervenor objected to NCPC's classification of production plant 100 percent to demand. The Board finds this classification acceptable.

7.3.2 Production Operating Expenses

NCPC classified production operating expenditures as being 95 percent demand-related and 5 percent energy-related based on the recommendations contained in the Price Waterhouse report. The APPA Cost Allocation Manual indicates that the classification of operating expenses to cost components generally follows the same classification that is determined for the electric plant function. Production expenses can therefore be classified to demand and energy in accordance with the classification of production rate base to demand and energy.

Since the Board recommends classification of production rate base in the hydro rate zones 80 percent to demand and 20 percent to energy for the test year, the Board also finds it appropriate to similarly classify production operating expenses.

7.3.3 Distribution Rate Base and Expenses

In its submission, NCPC classified distribution assets and expenses as 80 percent demand-related and 20 percent customer-related with no differentiation between primary and secondary levels of service. The NARUC Electric Utility Cost Allocation Manual suggests that distribution costs may be split between demand and customer classifications using one of several acceptable methods, including the minimum intercept and minimum size methods.

The APPA manual describes the minimum intercept method as one which seeks to identify a common investment per customer made in a line transformer related to a no-demand situation. All additional investment costs for a transformer would be related to demand requirements. The minimum size method assumes that the current cost of installing the minimum size pole, conductor, transformer, etc., is reflective of the customer-related portion of investment in distribution plant.

NCPC did not utilize any of the methods suggested in the NARUC manual. The Commission based its customer classification percentage on an examination of NCPC's distribution facilities, with 12 percent being identified as associated with customer metering and an additional 8 percent added to cover service drops and associated equipment.

YECL, in its direct evidence, explained the method it uses to identify an appropriate customer cost. Expert witnesses for other intervenors were generally more

in favour of YECL's analysis because they were of the view that this method is less arbitrary than NCPC's approach.

Cominco's expert witness, when asked if an allocation of 50 percent demand and 50 percent customer would be more reasonable than an 80/20 split in the absence of a more detailed analysis, indicated that he would prefer the 80/20 split. He felt that 50/50 would classify too great a proportion of distribution costs as customer-related. He stated that where distribution systems are fairly concentrated such as those of NCPC in the Northwest Territories, i.e., people are living in small communities and not on farm roads at intervals of a mile apart, the customer component of distribution costs is apt to be rather small.

The Board is persuaded by the evidence to accept NCPC's classification of distribution rate base and expenses for the test year, but recommends that in the future NCPC use a more systematic approach to determine classification factors for the distribution system and that direct assignment and primary/secondary cost separations be made where appropriate.

7.3.4 Specific Charges and Credits

7.3.4.1 Specific Charges

The criterion used by NCPC in assigning assets to specific customers for the purpose of levying special charges was that assets that could reasonably be determined to be for the sole use of a particular customer or particular customer class were charged directly to that customer or class. Assets that fall into this category are facilities installed for a particular customer's need (e.g., the diesel plant installed at Pine Point, NWT for Pine Point Mines Limited's 10 MW electric dragline operation) as well as substation facilities serving individual customers.

In its submission, NCPC did not assign transmission lines to specific customers or classes. Under the proposed rate zone scenario, all transmission facilities within a rate zone were assumed by NCPC to be interconnected. In light of this assumption, NCPC considered it would be inappropriate to charge specific portions of the transmission system to individual customers as this would contradict its theoretical assumption that all consumers, regardless of location in the rate zone, share the same general production and transmission facilities.

7.3.4.2 Specific Charges to Cyprus Anvil Mining Corporation

YECL questioned the reasonableness of the test year specific charges of $8,231 assigned by NCPC to CAMC. YECL filed an extract from NCPC's 1982 filing with the Yukon Electrical Public Utilities Board which identified, for the fiscal year 1982/83, some $845,000 of interest and depreciation associated with assets that appeared to have been specifically assigned by NCPC to only CAMC. A review of the evidence presented in the Board's 1983 inquiry revealed that only $491,635 of the total $845,000 had actually been assigned to CAMC, the remainder having been assigned to various locations served by YECL and to the Town of Faro.

NCPC, when asked what other assets might have been specifically assigned for the test year if it had not taken the approach of considering the two Yukon hydro systems to be interconnected, identified the following assets:

1. the 138 kV transmission line from Takhini substation, just outside of Whitehorse, to Faro would be partially assigned to Carmacks, Town of Faro, CAMC, and Ross River;
2. the 5.2 MW generating plant at Faro would be assigned as a stand-by unit for the Town of Faro and CAMC. As well, it could be partially assigned to Ross River because NCPC could energize that line with that unit; and
3. the Faro to Ross River transmission line would be fully assigned to Ross River.

NCPC stated that if it had not assumed the hydro systems to be interconnected, specific assignments also could have been made in the Mayo system. The line from the Mayo plant to Keno City and to United Keno Hill Mines would be considered a lateral supply and it would have been assigned partly to United Keno Hill Mines and partly to YECL at Keno City.

NCPC outlined further that, in the NWT hydro rate zone, the 138 kV line between Fort Smith and Pine Point could have been assigned to the Town of Pine Point and to Pine Point Mines, and the portion of the line from Pine Point to Fort Resolution could have been assigned to Fort Resolution.

The Board believes that, in the absence of contractual arrangements, established Commission policy, or regulatory decisions requiring a particular customer or group of customers to bear the cost of a new facility, be it a generating facility, transmission line or part of a distribution facility, the annual costs of such facilities should be included in the pooled costs to be allocated to all customers in the rate zone.

Nevertheless, the Board believes that, in light of the circumstances surrounding the construction of the

Whitehorse to Faro transmission line and the 5.2 MW diesel engine at Faro, a significant portion of these assets should, as was done in the past, be specifically assigned to CAMC.

With respect to the 5.2 MW diesel generating unit, the Board is of the view that the annual costs of this unit should be assigned only to CAMC and the communities of Faro and Ross River as it provides no benefits to the other customers in the Yukon hydro rate zone. However, the Board notes that this unit, constructed in 1972, was depreciated using an estimated life of 10 years and therefore was fully depreciated prior to the test year.

Turning to the Whitehorse to Faro transmission line, a review of the 1983 inquiry's transcripts indicate that Whitehorse No. 3 and the transmission line to Faro were built in 1969 as a consequence of an agreement between CAMC and the Government of Canada to build a mining facility at Faro. NCPC was designated to provide some 9.3 MW of additional capacity to supply the new mining operation and to construct a transmission line from Whitehorse to Faro. The Board is doubtful that, in the absence of instructions from the federal government to do so, NCPC would have constructed a 288-kilometre transmission line without requiring some form of guarantee to ensure that existing customers would not be burdened with the cost of this facility if the mine were to shut down.

Further, it would appear that, when the mine was operating, CAMC was assigned in excess of 95 percent of the annual costs of the transmission line with the remaining costs being assigned partly to the towns of Faro, Carmacks, and Ross River. For the fiscal year 1983/84, the annual costs assigned by NCPC to each location and to CAMC are shown in Table 7-1.

Table 7-1

Whitehorse to Faro Transmission Line
Allocation of Annual Costs by NCPC

	1983/84 Annual Cost	Percentage
CAMC	$287,943	96.8
Ross River	1,174	0.4
Carmacks	676	0.2
Faro Townsite	7,623	2.6
Total	**$297,416**	**100.0**

Source: NEB Inquiry EHR-1-83, Exhibit 41.

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

Using this approach, $240,890 of the estimated test year cost of $283,401 for the Whitehorse to Faro transmission line has been specifically assigned to CAMC. The derivation of the estimated test year cost of the transmission line is shown in Table 7-2. The Board recommends that this amount be recovered from CAMC in 12 equal monthly installments.

Table 7-2

Whitehorse to Faro Transmission Line
Estimate of Specific Costs for the Test Year

Asset	In-Service Year	Asset Life	Annual Straight-line Depreciation	Average Net Book Value
Transmission Line (original cost $3,416,150)	1970	30	$113,872	$1,537,262
Right-of-Way (original cost $563,717)	1970	20	28,186	98,648
			$142,058	**$1,635,910**

Annual Straight-line Depreciation Expense	$142,058
Return (8.64% x $1,635,910)	141,343
Total Annual Costs	**$283,401**
Assigned to CAMC ($283,401 x 0.85)	**$240,890**

7.3.4.3 Specific Charges to Pine Point Mines

In 1979, NCPC installed three 2.5 MW Ruston diesels at Pine Point under an agreement between NCPC and Pine Point Mines whereby the mine agreed to pay for the capital and interest costs of these facilities.

In its submission, NCPC assigned specific charges to Pine Point Mines amounting to the payment due to NCPC in 1985/86 under the agreement. Although Pine Point Mines did not express any concern

regarding the annual amount due under the agreement and assigned to it in the submission, it did, as discussed in Section 8.3.7.1, question whether the amount should be paid in monthly or annual installments.

7.3.4.4 Specific Credits

NCPC provides a specific credit to only one customer on its system: Con Mine in the NWT hydro rate zone. A credit of $9,500 has been applied to the cost of service of Con Mine to compensate for the wheeling of power on the Con transmission line. This amount has been charged back to the residential, commercial and wholesale rate groups as these groups benefit from this wheeling of power. The Board notes that no intervenor raised any objection to this credit and the Board finds the amount of the credit to be acceptable for the test year.

YECL, in final argument, argued that it ought to receive a similar credit for services supplied at Carmacks, Ross River and Haines Junction where it owns the step-down substations, whereas at other locations the transformer facilities are owned by NCPC and provide service to YECL and industrial customers at step-down voltages. The Board recommends that NCPC consider the appropriateness of granting such a credit to YECL in the future.

7.4 Allocation Procedures

Having functionalized and classified rate base and revenue requirement, the final step in the cost of service study is to allocate the classified costs to the various customer classes using appropriate demand, energy and customer allocation factors.

A number of issues were raised regarding NCPC's approach to cost allocation. These are dealt with in succeeding sections and are as follows:

1. NCPC's failure to allocate demand or customer costs to secondary industrial (interruptible) users (Section 7.4.1);
2. NCPC's incremental approach which underallocated costs to the street lighting class (Section 7.4.2);
3. NCPC's method of calculating the noncoincident peak demands of the residential and commercial classes (Section 7.4.3.1);
4. NCPC's use of an instantaneous demand meter to determine Con Mine's noncoincident peak demand (Section 7.4.3.3);
5. the inconsistency of using kilowatts and kilovolt amperes as the basis for allocating costs to customer classes (Section 7.4.3.4);
6. NCPC's exclusion of internal sales in determining energy sales for cost allocation purposes (Section 7.5);
7. the failure of NCPC to attempt to segregate distribution line losses from transmission line losses (Section 7.6); and
8. NCPC's customer weighting factors for the wholesale, and primary and secondary industrial classes (Section 7.7).

7.4.1 Industrial Secondary Class (Interruptible Service)

In the Yukon hydro rate zone, NCPC provides energy on an interruptible basis to United Keno Hill Mines and the Whitehorse Hospital for electric boiler consumption. In its submission, NCPC allocated only energy costs to the interruptible service. No demand or customer costs were allocated to this service.

Considerable concern was expressed by intervenors over the proposed rate for interruptible service. A number of intervenors were of the view that demand and customer costs should also be allocated to the class because the current excess capacity in the Yukon hydro rate zone suggests that the interruptible service will likely be without interruption and will, therefore, be virtually guaranteed the same service provided to others by NCPC. Concern was also expressed that, with a rate of 0.961¢ per kW.h and little likelihood of interruption, NCPC would be inundated with requests for interruptible service, leaving the remaining firm service customers to pick up all the demand- and customer-related costs of the system.

Based upon the Board's recommendation in Section 8.3.6 that the rates for the test year for interruptible service be set at 3.49¢ per kW.h for Whitehorse Hospital and 2.58¢ per kW.h for UKHM, the Board has estimated NCPC's test year revenue from interruptible sales to be $1,000,310 comprised of $270,900 from sales to United Keno Hill Mines and $729,410 from the Whitehorse area.[1]

Although the Board is recommending value-of-service pricing in determining the rates for customers in this class (see Section 8.3.6), the Board is of the opinion that, for cost allocation, the interruptible customer class should be assigned both energy

1 NCPC stated it is hopeful of providing electricity for boiler purposes to other customers in the Whitehorse area during the test year. Since rates for these customers have not been established, the Board has applied the Whitehorse Hospital rate to all expected sales in the Whitehorse area.

and customer costs and where appropriate a portion of demand costs in order that proper costs for the other customer classes can be determined.

The Board believes that the allocation of costs to the interruptible class can be accomplished by first treating the interruptible class like any other class for the purpose of allocating energy and customer costs. Then, having determined beforehand the value-of-service price and therefore the projected revenue associated with providing interruptible service, the amount of the demand costs to be allocated to this class would be the remainder after deducting the allocated energy and customer costs from the forecast interruptible sales revenue. After deducting the interruptible class' share, the remaining demand-related costs in the rate zone would be allocated to the other classes based on their respective noncoincident demands.

7.4.2 Street Lighting

In its submission, NCPC proposed to treat street lighting on an incremental basis for cost allocation purposes. Using this approach, NCPC did not assign any joint rate base related to production, transmission or distribution, nor any joint costs relating to transmission, distribution or support facilities to the street lighting class. The Price Waterhouse report noted that this methodology represented a departure from NCPC's current practice of treating street lighting like any other customer class, wherein demand costs are allocated to street lighting on the basis of kW demand, energy costs are assigned on the basis of kW.h consumed plus losses, and customer costs are allocated assuming that street lighting represents one customer.

Intervenors were opposed to NCPC's proposed incremental approach for two reasons: first, street lighting contributes to the system peak in the North; and second, when using the noncoincident peak method of allocation, no class should be exempt from demand charges.

Based on the evidence, the Board recommends that NCPC's proposed incremental approach be rejected and that the Commission continue its current practice of treating street lighting like any other class for cost allocation purposes. In assigning customer costs to street lighting, the Board, for cost allocation purposes, has deemed street lighting to represent one customer in each community where NCPC provides such service. In deriving the revenue requirement for street lighting, the Board made specific assignments for direct maintenance, head and regional office administration, depreciation and return. In addition, functionalized costs, excluding head and regional office costs, were allocated to the street lighting class using demand, energy, and customer factors.

7.4.3 Demand Cost Allocation Factors

The allocation of demand-related costs to customer classes is based on the relative demand placed on the electric utility system by each customer class. NCPC has used the noncoincident peak method of determining the relative demand of each customer class.

Intervenors agreed that, for the time being, NCPC should continue to use the noncoincident peak method for allocating demand costs. However, intervenors did raise a number of concerns regarding the calculation of noncoincident peak demands for the street lighting, residential and commercial classes, and for Con Mine.

As discussed in Section 7.4.2, the Board has recommended that street lighting be treated like any other customer class. The Board, therefore, recommends that street lighting be assigned demand costs based on its noncoincident peak demand.

7.4.3.1 Residential and Commercial Demands

Since all of NCPC's industrial and wholesale customers in the hydro zones are demand-metered, NCPC had available to it the noncoincident peak demands of each of the customers in these two classes. However, none of NCPC's residential customers are demand-metered, and the proportion of NCPC's commercial customers who are demand-metered ranges from 5 to 65 percent in the various rate zones. Therefore, in its submission, NCPC resorted to a formula that applies the load factor of the customer class to the kW.h sales and losses of the class to calculate the commercial and residential noncoincident demands. The load factors of the commercial and residential classes were assumed by NCPC to be equal to the system load factor plus one percent and the system load factor minus one percent, respectively.

During cross-examination, NCPC was unable to substantiate the ± 1% formula, except to say that it had previously been recommended to the Commission.

Many intervenors took issue with NCPC's manner of calculating the residential and commercial demands, suggesting that the ± 1% factor was unrealistic and that the application of such a formula understates the demands of the two classes.

YECL was the first intervenor to address its concerns regarding the ± 1% formula. A witness for YECL

stated that he had never before seen that method. In his cost of service study, he used residential and commercial load factors of 55 percent and 66 percent respectively. His judgement came from load research that Alberta Power Limited had done on communities in Alberta, which indicated that load factors for the residential class would vary from 45 percent to 55 percent and for the general service class from 50 percent to 80 percent.

An expert witness representing YTG echoed the concerns of YECL. In his study, he used load factor estimates of 34 percent for the residential and small commercial customer classes and 45 percent for large commercial customers, which he stated were based upon estimates made by Saskatchewan Power Corporation. Upon further review, he believed these load factors to be a bit low. He suggested that the load factors might be closer to 38 percent for small customer groups in Quebec and in the 50 percent range for retail class customers in Newfoundland. In B.C. and Ontario, based on coincident load factors, which he would expect to be a little higher than the class noncoincident load factors, the range was 47 percent to 50 percent.

NCPC, when asked what might be reasonable load factors for these two classes, suggested load factors ranging from 45 to 55 percent for residential customers and from 50 to 60 percent for commercial customers.

The witness for YTG considered these ranges to be acceptable and concluded his comments on this topic by stating that, in light of the evidence, he would suggest that the commercial load factor should be quite a lot higher than the residential load factor. He thought that one could adopt a ten percentage point spread in load factor, for the test year, and "move forward until somebody has some better evidence".

Cominco's expert witness also took exception to NCPC's ± 1% formula and introduced another method of determining noncoincident demands for these two classes of customers.

He stated that billing demands comprised of both estimates and, where available, meter readings provide a fair approximation of the actual noncoincident demands placed on the system by the commercial class. This witness proposed that, since such information is available, that it be used for cost allocation. However, he noted that the billing demands in NCPC's addendum to its submission are an average for the year and that the true peak demand of the customers are actually somewhat higher. Using an estimate of a peak-to-average factor of 1/.85, he adjusted the average demands upwards to represent peak demands for the test year.

Turning to residential demands, this witness, in a revised Appendix II to Cominco's direct evidence, indicated that, based on research conducted elsewhere, the average customer contribution to system coincident peak demand would be 2.6 kW, or 4 350 kW for the class in the NWT hydro rate zone.[1]

However, he noted that the residential class does not necessarily peak when the system peaks. Using a system coincidence factor of 0.84, he adjusted the residential demand in his example upwards to its class coincident peak demand of 5 179 kW. He then recognized that not all customers within the residential class peak at the same time. To adjust for this, he used a class coincidence factor of 0.81 to arrive at a noncoincident peak of 6 394 kW. He made this adjustment so that the residential customers would be treated in a manner consistent with NCPC's treatment of industrial and wholesale customers, where each individual customer's demand was summed to obtain a noncoincident peak demand of the class. In his original appendix, the witness noted that NCPC did not adjust its load factor formula by a class coincidence factor and, therefore, the results of NCPC's formula represent the coincident demand of the class; not the noncoincident demand.

The Board notes that the effect on many of the customer classes of adopting the methods proposed by the witness for Cominco in place of NCPC's ± 1% method could be dramatic. The Board also notes that the methods proposed by Cominco require that several parameters be estimated (i.e., system coincidence factor, class coincidence factor, average residential demand at system peak, and peak-to-average factor). Cominco's proposal was only introduced as evidence in the proceedings after the direct and cross-examination of NCPC and all other intervenors (except GNWT) had been completed. The Board believes that, although the methodology proposed by Cominco may have merit, there is a lack of evidence to support the adjustment factors (particularly a lack of data applicable to operations North of 60°) and further that such factors should be subject to full and proper examination by all interested parties before being recommended for implementation.

The Board, after considering the evidence, recommends that, for the test year, NCPC retain the use of a load factor approach for determining residential

1 Cominco's expert witness used the NWT hydro rate zone as an example: 1,673 customers x 2.6 kW/customer = 4 350 kW.

and commercial demands in each rate zone, but that the load factors reflect a more realistic spread of 10 percentage points as suggested by the expert witness for YTG. The Board, in determining cost-based rates for the test year, has used load factors of 45 and 55 percent for the residential and commercial classes, respectively, in each rate zone. The Board notes that these load factors are within the ranges suggested by NCPC and intervenors.

7.4.3.2 Industrial and Wholesale Demands - NWT Diesel Rate Zone

NCPC also used a formula to calculate the demands of the industrial and wholesale customers in the NWT diesel rate zone. In the formula, the load factors of the two classes were assumed by NCPC to equal the system load factor of 55.8 percent.

No intervenor raised any concern regarding NCPC's method of determining demands for the wholesale and industrial classes in the NWT diesel rate zone. Therefore, the Board accepts the load factors as determined by NCPC for the test year.

7.4.3.3 Con Mine Demand

During the inquiry, NCPC indicated that it measures Con Mine's demand using an instantaneous demand meter, whereas the Commission measures all other major customers' demands using 15-minute average demand meters.

The Board notes that the metered demands of NCPC's major customers formed the basis of the Commission's forecast of test year demands for each of these customers.

In its direct evidence, Con Mine indicated that, with its demand being metered using an instantaneous meter, it felt it was being discriminated against.

NCPC indicated that it allows Con to skip ore only during the period between 8:00 p.m. and 7:00 a.m. and explained that, when Con is skipping ore, the mine can have an instantaneous peak requirement of up to 4.7 MW in a period of approximately a minute and a half or a swing of approximately 2.7 MW. NCPC stated that, even though Con is allowed to skip ore only during the off-peak period, NCPC must nevertheless use diesel generation to meet its peak during the winter period. As a result, NCPC indicated that it must keep additional diesel generation on the system not only to provide Con with capacity, but also to take the swings.

Cominco acknowledged that Con's peak demand occurs when the mine is skipping ore or waste from the mine. However, Con argued that because the mine is allowed to skip only in the off-peak period, its demand does not contribute to the overall system peak. Further, when Con wishes to skip ore, it must get prior approval from NCPC. Cominco also pointed out that, when NCPC has a problem on its system, Con is the first load to be dropped and the last to come back on. Finally, Cominco noted that, if NCPC's system fails, NCPC draws on Con's power source for NCPC's other customers. Cominco acknowledged that under this arrangement a credit is given automatically by the meter but that there is no recognition given to the stand-by nature of Con's facilities.

In final argument, Cominco submitted that Con should not be discriminated against in terms of a different type of meter and, if anything, Con should receive preferential treatment in recognition of its stand-by function and the restrictions which are imposed on it and not on the other industrial customers. However, Cominco was also of the view that, if there were any additional facilities put in place or put in on a stand-by basis specifically to serve Con Mine, the costs of those should be recognized in Con's rates.

The City of Yellowknife and ICG indicated that, in the past, the NWT Public Utilities Board had approved NCPC's use of an instantaneous demand meter for Con. These two intervenors argued that, in the absence of any compelling new evidence to the contrary, NCPC should continue to use an instantaneous demand meter for Con Mine.

The Board is of the view that, in determining the appropriate demand for Con Mine for cost allocation, all factors must be taken into consideration including the restrictions placed on the mine's utilization of its hoist and the stand-by nature of Con's power facility. Accordingly, the Board recommends that Con's non-coincident peak demand for cost allocation be determined on the basis of a 15-minute interval.

During the inquiry, Cominco indicated that it believed that an appropriate 15-minute demand for the mine could be arrived at by subtracting 900 kV.A from the demand measured by the instantaneous demand meter. Cominco indicated that this figure was based on the results of a report done by Thomas Associates in which the figure of 900 kV.A was determined by actual measurement.

The Board accepts this adjustment as reasonable and, accordingly, has decreased Con Mine's non-coincident demand for the test year by 900 kV.A. However, in recommending that Con's demand in the future be determined on the basis of a 15-minute interval, the Board also recommends that Con's

future rates should reflect any incremental costs that can be directly attributed to the demands placed on NCPC's system in providing power to accommodate Con's ore-skipping operation.

7.4.3.4 kW vs. kV.A

NCPC testified that the demands of its major wholesale customers, industrial customers with the exception of Pine Point Mines and Dome Petroleum Limited (Dome), and some of its commercial customers are measured and expressed in kV.A. The demands of all other customers are either estimated or measured and expressed in kWs.[1] NCPC acknowledged that, in the cost allocation and rate design sections of its submission, it had used kWs and kV.As interchangeably. As such, NCPC had implicitly assumed a one-to-one relationship between kWs and kV.As. The Board notes that the true relationship is that kWs equal kV.As times power factor. Therefore, kWs equal kV.As only when the power factor of the customer or class is unity.

Intervenors and NCPC agreed that, ideally, to avoid inter-class inequities, the demands of all classes for cost allocation purposes should be expressed in a common unit of measurement.

The Board agrees that, ideally, the demands of all customer classes should be expressed in the same units of measurement for cost allocation purposes (be it kWs or kV.As) and therefore, recommends that NCPC consider using only one or the other in future submissions. However, for the test year, the Board, in determining the demands for each customer class, has not converted NCPC's kWs to kV.As or vice versa, with the exception of Pine Point Mines' demand.

NCPC indicated during the inquiry that the demands of two of its three industrial class customers in the NWT hydro rate zone; namely, Con Mine and Giant Yellowknife Mines Ltd., were expressed in kV.As, whereas the demand of the third customer, Pine Point Mines, was expressed in kWs.

The Board believes that, where a class is comprised of so few customers, expressing the demands of all but one customer in kV.As creates an obvious intra-class inequity.

During cross-examination, NCPC indicated that it believed the power factor of Pine Point Mines to be roughly .95. The Board notes that Pine Point Mines did not challenge this figure and further that Cominco's expert witness believed that demand costs should be allocated to customer classes on the basis of kV.A demand.

The Board believes that, where administratively practicable, intra-class inequities should be eliminated and therefore, recommends that, for cost allocation and rate design purposes, Pine Point Mines' demand in the test year be expressed in kV.A. Accordingly, the Board has divided Pine Point Mines' kW demand by .95 to arrive at an equivalent demand expressed in kV.As.

7.4.3.5 Determination of Demands in Future

Having reviewed specific concerns as outlined in Sections 7.4.3 to 7.4.3.4, the Board recommends that NCPC should examine various methods of determining demands for the residential and commercial customers in all zones and for the wholesale and industrial customers in the NWT diesel rate zone with a view to coming up with more appropriate demands for these classes in the future, and further, that NCPC be able to justify whatever method it incorporates in future submissions.

7.5 Internal Sales

In determining energy sales for residential customers in each rate zone for the test year, NCPC excluded energy sales to its own employees. Intervenors took the position that these sales, referred to as internal sales by NCPC, should have been included in residential energy sales for cost allocation and rate design purposes.

NCPC testified that, in light of its current utility benefit package with its employees, it considers internal sales to be similar to energy consumed in its plants in that it is effectively a cost of doing business. Presently, NCPC charges each employee, excluding those in head office, a flat amount of $70 per month for utilities, with NCPC picking up the total cost of each employee's utilities.

In NCPC's opinion, this is an untenable situation for it to be in. NCPC, in effect, has no control over the amount of assistance it provides to each employee because at a flat rate of $70 per month regardless of consumption, the employees have no incentive to conserve energy. NCPC, therefore, is taking steps to alleviate this situation. During cross-examination, NCPC indicated that it proposes to implement a utility user-pay program for employees in the Yukon and NWT hydro rate zones in the test year. Such a plan would roll into the employee wage package an acceptable level of offset of remuneration that would

1 kV.As recognize the reactive power drawn from the system by the customer whereas kWs do not. Depending upon the customer's power factor, kV.As equal or exceed kWs.

compensate for the current utility package, but would require the employee to pay his own utility bills.

Because NCPC included, in its submission, a utility offset amount in wages and salaries in both hydro rate zones, NCPC agreed that employees in these two zones should be considered as normal bill-paying electric utility residential customers in the test year, and that, therefore, it would be appropriate to include energy sales to the employees (i.e., internal sales) in determining total residential energy sales. However, since NCPC is not proposing to implement the new benefit package in the diesel rate zones, NCPC was of the view that it should continue to exclude internal sales in estimating energy sales for residential customers in those rate zones.

The Board concurs with NCPC's position regarding the treatment of internal sales for cost allocation and rate design purposes in the diesel rate zones, and with NCPC's views on including internal sales in residential sales in the hydro rate zones. The Board, therefore, has adjusted upwards only NCPC's estimate of the residential energy sales in the hydro rate zones to include internal sales in the test year.

7.6 Allocation of Line Losses

Energy costs are allocated to customer classes in a cost of service analysis according to their respective kilowatt-hour sales including system losses. When allocating system losses to customer classes in its submission, NCPC made no attempt to differentiate between losses on transmission lines and losses on distribution lines. Total line losses in each rate zone were simply allocated to all classes based on the ratio of each class' energy consumption to total sales.

A number of intervenors took exception to NCPC's approach because it effectively assigned a portion of distribution losses to the wholesale and industrial classes which do not use the distribution facilities. They argued that distribution losses should be allocated only to the residential, general service and street lighting categories.

NCPC agreed with this approach, but indicated that it does not have metering that would identify separately distribution and transmission losses, nor had it attempted to estimate such losses.

A witness for YECL suggested that NCPC use a loss factor of ten percent of sales to determine distribution losses. This factor was based on his company's experience of supplying electricity in Yukon. Witnesses for other intervenors supported the reasonablensss of this factor and a witness for NCPC thought that a distribution loss factor of 10 to 12 percent of sales would be reasonable.

While in due course one could look to better estimates from NCPC upon which to base distribution line losses in each rate zone, the Board recommends that, for the test year, NCPC use a loss factor of 10 percent of sales to the residential, general service and street lighting classes to determine distribution losses attributable to those classes. Further, the resulting transmission losses in each rate zone (total losses minus distribution losses) should be apportioned to each class in the rate zone based upon its ratio of energy sales plus distribution losses (if any) to total energy sales plus distribution losses in the zone.

7.7 Customer Weighting Factors

The allocation of customer costs to customer classes is based on the number of customers in each class multiplied by appropriate weighting factors to reflect differences in the costs of providing service to the various classes. For example, the NARUC manual indicates that the capital cost of meters is a cost requiring weighting for different classes because the metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for a single residential customer.

7.7.1 Wholesale and Industrial (Primary) Classes

As a guide to determining appropriate weighting factors for assigning customer-related costs to the industrial (primary) and wholesale classes in the hydro rate zones and the industrial (primary) class in the NWT diesel rate zone, NCPC used a method which considered the installed capital cost of metering. This method yielded a ratio of 115 to 1 for wholesale and industrial (primary) customers compared to residential and commercial customers. NCPC did not, however, believe that a factor based solely on metering costs was a reasonable basis for allocating all customer costs to these classes and, therefore, chose a weighting of 80 which NCPC believed to be comparable to the upper limit of the 20 to 80 range suggested in the NARUC manual.

In response to an information request, NCPC indicated that customer-related expenses for industrial (primary) and wholesale customers exceed those for residential and general service customers by an approximate factor of 22 for metering-related costs and by a factor of 50 to 60 for other customer-related costs.

NCPC agreed that, if the weighted average of meter-related and other customer-related costs were calculated, the customer costs for industrial (primary) and wholesale customers would exceed those for residential and general service customers by a factor of only 45 to 55.

Intervenors also questioned the reasonableness of the weighting factor used by NCPC. Cominco's expert witness performed his own analysis, the results of which suggested to him a range of 38 to 50.

Based on the evidence, the Board recommends that, for the test year, a weighting factor of 50 be used for assigning customer-related costs to the wholesale and industrial (primary) classes in each hydro rate zone and to the industrial (primary) class in the NWT diesel rate zone.

It was also noted that, in the NWT diesel rate zone, NCPC has classified some 50 customers as being "wholesale" for cost allocation purposes, but has assigned them a class weighting factor of only one. NCPC explained that the "wholesale" designation was used simply to distinguish these customers (Transport Canada and GNWT), which are supplied at primary voltage and provide their own secondary transformation and distribution, from other commercial customers using NCPC's distribution system. The Board finds NCPC's weighting factor for the "wholesale" class in the NWT diesel rate zone to be acceptable.

7.7.2 Industrial (Secondary) Class

In the Yukon hydro rate zone, NCPC did not allocate any customer-related costs to industrial (secondary) customers. NCPC indicated that, if it were deemed appropriate to allocate such costs to the secondary class, a weighting factor of 10 might be more appropriate than a factor of 80 because the customers in this class are not demand-metered as are primary industrial customers and the customer bill for one such customer is calculated by hand.

The Board recommends that a weighting factor of 10 be used for the test year for assigning customer-related costs to this class.

7.7.3 Number of Customers

NCPC stated that the number of customers projected for the test year as presented in the submission was the actual number of customers serviced as at 31 March 1984. During cross-examination, NCPC indicated that the number of customers in certain communities, particularly Dawson, Yukon, varies from summer to winter. NCPC agreed that, for cost allocation purposes, it would have been more appropriate to weight the number of customers during the year rather than taking the count at one point in time.

The Board recommends that, in the future, NCPC use a 12-month average to determine the number of customers in each class in each rate zone for cost allocation purposes.

7.7.3.1 NWT Diesel Rate Zone

In its submission, NCPC used seven as the number of industrial customers for cost allocation purposes, but used five in the design of rates for this class.

NCPC acknowledged that it had assumed that two services at Norman Wells for Esso Resources Canada Limited would have no consumption in the test year but would remain connected. However, these two services were subsequently disconnected in the fall of 1984.

Accordingly, the Board has used five as the number of customers for both cost allocation and rate design purposes.

7.8 NWT Heat and Water & Sewerage Rate Zones

In addition to providing electric utility service, NCPC provides a heat service at Inuvik and Frobisher Bay, and a water & sewage service at Inuvik. NCPC distributes the heat at Inuvik. At Frobisher Bay, the Commission provides heat on a wholesale basis to GNWT for subsequent distribution by the government.

NCPC's plant at Inuvik houses facilities for all three utility services while the plant at Frobisher Bay supports the electricity and heat services.

In its submission, NCPC assigned specific water & sewerage and heat-related equipment directly to each utility service. The powerhouse and equipment common to all services were allocated on the basis of the relative floor area occupied by each utility service in the powerhouse. A further allocation of production fuel costs at Inuvik was then made between heat and water & sewerage on the basis of the BTUs utilized by each service.

The fuel tanks and fuel handling equipment common to the services were allocated on the basis of the relative fuel consumption of each service. Having determined the total rate base for each service, NCPC allocated an appropriate return on rate base.

NCPC allocated head and regional office costs to the heat and water & sewerage rate zones on the basis of direct salaries and wages. Specific operating costs were identified and assigned directly to the heat and water & sewerage rate zones. Common operating costs were allocated between services using factors estimated by the superintendent at each plant.

The Board accepts as reasonable the allocation methodology used in the submission for the heat and water & sewerage rate zones with the exception of the head and regional office allocations. The recommended method of allocating these costs is outlined in Sections 6.6 and 6.7.

REFERENCE: Application, September 28, 2010 Cover Letter, Page 2

"At the Commercial Operation Date, Yukon Energy will supply power to Alexco under the approved and final Industrial Firm Rate Schedule 39 (Rate Schedule 39) which fixes industrial rates for demand and energy. Under the PPA, Alexco also agrees to pay Capital Costs and Decommissioning Cost for any additional Mine Facilities Spurs YEC agrees to develop to serve Mine Facilities in the future".

QUESTION:

a) Please confirm YEC's understanding that it cannot charge any rate that has not been approved by the YUB.

b) Assuming that Alexco qualifies as a Major Industrial Customer per OIC 1995/90 prior to the YUB approving an amended Rate Schedule 39, please confirm that, upon becoming a Major Industrial customer, Alexco will be charged the existing Firm Mine Rate originally designed when Minto became a Major Industrial Customer.

c) Please confirm that once the YUB approves an amended Rate Schedule 39, Alexco will be responsible for all charges based on the amended Rate Schedule 39 retroactively to the date that it qualified as a Major Industrial Customer.

d) Does the proposed PPA contain any annual Minimum Take or Pay provision and take-or-pay provisions over the life of the proposed PPA?

e) Provide an explanation of the differences between the proposed Alexco PPA and the Minto PPA.

ANSWER:

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

Confirmed, although there is not principle or precedent for retroactive ratemaking in Yukon. Alexco has agreed to pay the Fixed Charge subject to Board approval, i.e. in the event that this charge is not approved or is modified, the Alexco payments will be accordingly adjusted.

(d)

There is no take-or-pay provision in the PPA. As dicussed in the Application letter (pages 5-7) and in the PPA (Part 5), Alexco is paying the Capital Cost contributions within a short, specified timeframe following the execution and delivery of the Agreement and commissioning of the facilities. There is no provision for a loan to the mine over an extended period as was the case for the Minto PPA (which required security in the form of a take-or-pay arrangement over the period of the loan).

(e)

Please see response to YECL-YEC-1-4(k).

REFERENCE: Application, September 28, 2010 Cover Letter, Page 3

"YEC notes that under the current ESRs, section 4.7 would not permit totalized metering in this instance as the Points of Delivery are not located within a radius of a half a mile of each other – and therefore, until such time as the current ESRs are modified to so permit this totalized metering, YUB approval is being sought to proceed with the above provision of section 6.1 of the PPA".

QUESTION:

a) Please confirm YEC's understanding that the existing Electric Service Regulations (ESRs) apply to YEC, YECL and to every Customer to which YEC and YECL provide a service connection.

b) Does YEC consider each service connection a customer?

c) Does YEC consider multiple points of delivery to the same individual or company as a single service connection?

d) How many different service connections to the grid does Alexco currently have (i.e., mill, mine, camp, etc.) and how many more do they plan to add?

ANSWER:

(a)

Confirmed.

(b) and **(c)**

YEC does not consider each point of delivery a customer but does consider each point of delivery as an account. An individual or company may have multiple points of delivery or accounts.

(d)

For the purpose of the PPA Alexco has two Points of Delivery (Initial Mine & Initial Mill). Other existing points of delivery served under other rate schedules are not covered by the PPA.

Future Points of Delivery may be required as determined through ongoing exploration and mine development activities by Alexco but YEC has not been notified of these points at this date.

REFERENCE: Application, September 28, 2010 Cover Letter, Page 2

"The PPA sets out each Party's rights and obligations with respect to the sale of Grid Electricity by YEC to Alexco for Mine Facilities in the District".

QUESTION:

a) Are any of the current facilities operated by Alexco using electrical space heating? Are there any plans to use electric space heating? Please identify and explain.

ANSWER:

(a)

YEC does not normally receive this type of customer-specific information and can provide no further information in this regard.

REFERENCE: Application, September 28, 2010 Cover Letter, Page 5

"Under the Alexco PPA, Capital Costs are to be paid by Alexco for all Mine Facilities Spurs that YEC agrees to develop to provide grid service to the Mine Facilities as well as for YEC's costs to negotiate and conclude the PPA (and such costs are to be fully paid shortly after Commencement of Delivery to the relevant Mine Facilities)".

QUESTION:

a) Please provide details of all costs incurred to date to "negotiate and conclude the PPA" and the expected total costs. Include in the breakdown a separation between the costs related to internal staff and external consultants as well as a breakdown of regulatory costs, administrative overhead, and other costs incurred.

ANSWER:

(a)

The total costs to negotiate and conclude the PPA are expected to be close to the estimated cost of $100,000. Costs to date as noted in LE-YEC-1-4(b) are per table below:

PPA Negotiation Costs		
Legal	$	74,393
Consultants	$	17,565
Contractors	$	714
ES&G Build-up	$	927
AFUDC	$	2,076
Grand Total	$	95,675

REFERENCE: Application, September 28, 2010 Cover Letter, Page 5

"Under the Alexco PPA, Alexco has agreed to pay the Capital Costs for any Mine Facilities Spurs that YEC develops as required to provide service from the grid to the Initial Mine Facilities and for any other mine facilities that YEC may agree to connect in the future".

REFERENCE: Application, September 28, 2010 Cover Letter, Page 6

"Capital Costs to be paid by Alexco include all of YEC's reasonably incurred costs and expenses for the design, engineering, procurement, construction, and commissioning of the Mine Facilities Spurs, as UCG Information Request No. 1 (November 24, 2010) Page 5 of 8 well as YEC's costs and expenses reasonably incurred to negotiate and conclude the PPA with Alexco".

QUESTION:

a) Please provide a breakdown of the costs that will be included under "Capital Costs" and identify which of these costs will lower the revenue requirement of all other customers. UCG is particularly interested in the amount of costs currently included in rates charged to other customers (internal staff, consultants, overheads, etc.) that will now be recovered from Alexco.

ANSWER:

(a)

Please see table below (see also LE-YEC-1-4(a)):

Alexco Capital Costs	69 kV Spur
Regular time	$ 55,473
Overtime @ double time	$ 15,153
Meals	$ 5,747
Accommodation	$ 6,330
Incidentals	$ 1,121
Materials	$ 137,597
Car/Equipment Rental	$ 2,460
Courier/Freight	$ 917
Contractors	$ 84,623
ES & G (Overhead)	$ 30,942
AFUDC	$ 6,303
Grand Total	$ 346,666

The Capital Costs paid to YEC by Alexco pursuant to the Agreement cover the new costs to construct the Mine Facilities Spurs from the Mayo-Keno Transmission Line to the Mine Site. These costs are not currently in rate base, and will not be included in future net ratebase and consequently will not be included in rates to be charged to retail ratepayers, i.e., the construction of the line will not lower or increase costs to retail ratepayers.

The Fixed Charge to be paid by Alexco reflects costs currently included in rates charged to other customers that will now be recovered from Alexco. The other revenues recovered from Alexco, net of any incremental costs incurred related to serving the Alexco load, will also go (in future GRAs) to reduce costs to be recovered from other ratepayers.

REFERENCE: Application, September 28, 2010 Cover Letter, Page 6 / Proposed PPA, Pages 14-15

"Section 5.1(a) - The first YEC invoice for 50% of the estimated Capital Costs (as set out in this section) relating to the Initial Mine Facilities Spurs and negotiation of the PPA is to be provided within 30 days of execution and delivery of the Agreement;

Section 5.1(b) - The second and final YEC invoice for Capital Costs for the Initial Mine Facilities Spurs is to be provided by YEC to Alexco within 30 days of YEC's notice that the Initial Mine Facilities Spurs are commissioned and available to provide Grid Electricity to the Initial Mine Facilities pursuant to the Agreement; and

Section 5.1(c) – YEC will invoice Alexco for the Capital Costs related to negotiation and conclusion of the PPA that exceed the related amount invoiced under section 5.1(a), as and when such costs are incurred and invoiced to or paid by YEC".

QUESTION:

a) Please provide copies of each of the referenced invoices and confirmation that Alexco has paid each invoice as required in the proposed PPA.

ANSWER:

(a)

It is not Yukon Energy's practice to provide individual customer billing information publically. A sample bill calculation is provided in YUB-YEC-1-1.

YEC has not yet issued invoices pursuant to section 5.1 (b) or (c) of the PPA.

REFERENCE: Application, September 28, 2010 Cover Letter, Page 7

"Negotiation of a PPA with an industrial customer whereby the customer agrees to pay the full costs of the spur line dedicated solely to provide service to that site (as well as the full costs to negotiate and conclude the Agreement) provides the necessary assurance and protection for ratepayers that any cost risks related to these specific transmission facilities will not be shouldered by ratepayers in the future".

QUESTION:

a) Please identify those parts of the proposed PPA that guarantee that Yukoners (as either electricity ratepayers or as tax payers) will not have to pay for any costs associated with spur line facilities to Alexco.

ANSWER:

(a)

The PPA does not set out "guarantees". As noted on pages 5-7 of the Application letter (dated September 28, 2010), pursuant to the Agreement, Alexco is responsible for payment of the Capital Costs as defined, and Decommissioning Costs as defined, as each relate to spur line facilities that YEC is providing to Alexco. Relevant sections of the PPA in this regard are outlined and specified at page 6 and 7 of the Application letter. In the PPA, Payment of Capital Costs is addressed in Part 5 and payment of Decommissioning Costs is addressed in Part 12. These provisions of the PPA are subject to approval of the Board, as set out in the Application.

REFERENCE: Application, September 28, 2010 Cover Letter, Page 7

"Pursuant to Part 11 of the Alexco PPA, Alexco will be responsible for all Decommissioning Costs incurred by YEC. Decommissioning Costs to be fully paid by Alexco include the following costs defined in section 1.1(o) of the PPA: All decommissioning and other costs to be incurred by YEC and agreed to be recovered from Alexco (including without limitation, costs to take down and remove facilities and costs to restore any property under applicable law, less credits for recovery sales of any materials removed and sold) reasonably required to remove such parts of the Mine Facilities Spurs to be decommissioned".

QUESTION:

a) Given that the proposed PPA is between YEC, Alexco Keno Hill Mining Corp., Elsa Reclamation & Development Company and Alexco Resource Corp., please identify those parts of the proposed PPA that clearly sets out the liability of each party and ensures that enough monies will be collected to guarantee that Yukoners (as either electricity ratepayers or as tax payers) will not have to pay for any costs associated with decommissioning.

ANSWER:

(a)

Alexco Keno Hill Mining Corp (AKHM), Elsa Reclamation & Development Company Ltd. (ERC), and Alexco Resources Corp (AXR) are all Parties to the Agreement. Further the definition of "Party" or "Parties" provided in section 1.1(iii) means YEC and Alexco, and in the case of Alexco, includes any of Alexco's Affiliates who become a Party to this Agreement under Section 4.5 of the Agreement.

Provision for Decommissioning is provided in Part II and provides that Alexco will be responsible for all Decommissioning Costs incurred by YEC. Definitions (section 1.1 (e)) provide that "Alexco" refers collectively to AXR, AKHM, ERC and all Alexco Affiliates who become a Party to this Agreement under Section 4.5. Alexco is required to provide specific funds in this regard, as set out in Part 11 of the PPA; these are the same

decommissioning cost provisions as approved by the Board for the Minto Mine PPA, and are triggered by the occurrence of a Mine Facilities Closure Date at any Mine Facility.

REFERENCE: Proposed PPA, Page 1

Agreement between YEC, Alexco Keno Hill Mining Corp., Elsa Reclamation & Development Company and Alexco Resource Corp.

QUESTION:

a) While one party (Elsa Reclamation) is a "Yukon Territory corporation" and another (Alexco Resource Corp.) is "extra-provincially registered in the Yukon Territory", do any of the parties to the proposed PPA (other than YEC) operate or intend to operate permanent offices within the Yukon?

b) Please confirm that each of the Alexco affiliates is liable for all aspects of the proposed PPA.

ANSWER:

(a)

The requested information is not relevant to this Application and is out of the scope of this proceeding.

(b)

The liability of each Party to the Agreement is identified in and as set out in the Agreement; Alexco Keno Hill Mining Corp., Elsa Reclamation & Development Company Ltd., and Alexco Resources Corp. are all Parties to the Agreement. Further the definition of "Party" or "Parties" provided in section 1.1(iii) means YEC and Alexco, and in the case of Alexco, includes any of Alexco's Affiliates who become a Party to this Agreement under Section 4.5 of the Agreement.

REFERENCE: Proposed PPA, Page 1

"Alexco is developing the Initial Mine Facilities with the intent of commencing milling operations at the Initial Mill Site and mining operations at the Initial Mine Site in 20I0, and of developing other Mines and Mills in the District in the future.

QUESTION:

a) Please provide a copy of the mining / milling operations feasibility study and / or business case analysis relied upon by YEC to proceed with the proposed PPA.

ANSWER:

(a)

YEC did not rely on a particular mining/milling operations feasibility study or other business case analysis to proceed with the current PPA.

Per Part 5 of the Alexco PPA, the mine is paying the Capital Costs currently associated with this PPA soon after execution of the Agreement limiting any risk in this regard. The circumstances surrounding the negotiation of the Alexco PPA are not the same in this regard as existed for the negotiation of the Minto PPA.

REFERENCE: Proposed PPA – Definitions and Interpretation, Page 6

"(rr) Major Industrial Customer" means a customer of YEC, or of any other regulated electric utility in the Yukon Territory, engaged in manufacturing, processing, or mining whose electrical service is inter-connected with electrical service provided to any other customer of such electric utilities and whose peak Electric Demand exceeds 1,000 kW or any future replacement definition or replacement service capacity threshold applicable to manufacturing, processing or mining activities of Alexco, as approved by the YUB".

REFERENCE: OIC 1995/90 – Rate Policy Directive

"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"

QUESTION:

a) Please explain the need to vary the definition of Major Industrial Customer used in the proposed PPA from that legislated for use in the Yukon for rate setting purposes.

ANSWER:

(a)

The PPA restates the definition of Major Industrial Customer as required for the purposes of this Agreement without varying the key elements as currently defined in OIC 1995/90; the PPA also provides for any future change to this definition that may be approved by the YUB.

The definition of Major Industrial Customer provided in the PPA (section 1.1 (rr)) is as follows:

> "Major Industrial Customer" means a customer of YEC, or of any other regulated electric utility in the Yukon Territory, engaged in manufacturing, processing, or mining whose electrical service is inter-connected with electrical service provided

to any other customer of such electric utilities and whose peak Electric Demand exceeds 1,000 kW or any future replacement definition or replacement service capacity threshold applicable to manufacturing, processing or mining activities of Alexco, as approved by the YUB."

The definition provided in the PPA complies with the definition in OIC 1995/90[1] and incorporates the factors that define industrial customers under the current rate policy, i.e., under the PPA a Major Industrial Customer means:

- A customer of YEC or any other regulated electric utility in Yukon;

- A customer engaged in manufacturing, process or mining whose peak Electric Demand excess 1,000 kW (or 1 MW) – as specified in the OIC direction; and

- A customer whose electrical service is inter-connected with electrical service provided to any other customer of such electric utilities, i.e., does not apply to an isolated industrial customer[2] as defined in OIC 1995/90.

The PPA definition also makes allowances for "any future replacement definition or replacement service capacity threshold applicable to manufacturing, processing or mining activities of Alexco, as approved by the YUB".

[1] Per OIC 1995/90 "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;"

[2] Per OIC 1995/90: "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;"

REFERENCE: Proposed PPA – Alexco Forecasts, Page 11

"Alexco will provide to YEC annual written forecasts ("Alexco Forecasts") of the Grid Electricity requirements of the Mine Facilities at the Points of Delivery for each of the succeeding five calendar years, so as to allow YEC to forecast the future Electric Demand and Electric Energy loads on its facilities".

QUESTION:

a) Please describe the reporting, if any, to the YUB that will be undertaken with respect to these forecasts.

b) Please outline how the additional costs associated with this forecasting exchange will be directly recovered from Alexco and not other ratepayers.

ANSWER:

(a)

Pursuant to past practice and current Yukon Energy practice, information on YEC's load forecasts is provided in general rate applications or other similar regulatory filings with the Board.

(b)

The additional cost of this forecast exchange, which are expected to be minimal, is an operational cost of YEC and not included in the Capital Costs, Decommissioning Costs or any other costs to be recovered from Alexco.

REFERENCE: **Proposed PPA – Alexco Standards for Usage of Electricity, Page 14**

"Alexco will regulate its electrical load so that the Power Factor for the Mine Facilities at any Point of Delivery is maintained within a reasonable operating range as agreed to by the Parties from time to time, acting reasonably. Alexco will operate its equipment and use the Grid Electricity at the Mine Facilities so as not to endanger any of YEC's plant or equipment or cause any unacceptable fluctuations of YEC's electrical system".

QUESTION:

a) How many electrical motors will Alexco be using?

b) How many of these have energy saving controls (i.e., speed control mechanisms) allowing ramp-down when not so much energy is needed or during peak loads)?

c) How many electrical pumps will Alexco be using?

d) How many of these have energy saving controls (i.e., speed control mechanisms) allowing ramp-down when not so much energy is needed or during peak loads?

e) Does Alexco plan on using any electrical digging machines or pumps in the mine?

f) Provide an analysis of the generation available from Mayo facilities and the use of that generation at each customer class assuming Alexco's current energy requirements.

g) If and when Alexco requests to increase their energy requirements above what is now available from the Mayo generation facilities, how will they pay their share of the costs of generation and transmission facilities needed to serve them?

ANSWER:

(a) to **(e)**

YEC does not have, and is not able to provide, this customer-specific information. Further, it is not YEC's practice to provide individual customer information to the public.

(f)

As reviewed in past submissions to the YUB (including the YEC Resource Plan: 2006-2025), YEC's generation facilities at Mayo currently include approximately 5 MW of hydro at Mayo A and 2 MW of diesel generation capability. The new Mayo B additional generation is not planned to be in service until the end of 2011. YEC is not able to provide analysis as to the "use of that generation at each customer class"; however, prior to connection of the two grids, YEC expects that baseload diesel generation will be required on the Mayo Dawson grid over the 2010/2011 winter to supply the overall system load including the Alexco facilities. In May 2011 the Mayo Dawson and WAF grids are expected to be interconnected and surplus energy from WAF will be available to serve loads on the Mayo Dawson system (and vice versa).

(g)

Alexco will pay for its future energy requirements in accordance with Rate Schedule 39, as approved by the Board from time to time and including any Rider D rates in effect from time to time. In addition, as provided for in the PPA for any increase in Maximum Electric Demand or new Points of Delivery, Alexco will pay for any additional Capital Costs that YEC must incur in the event that new Mine Facilities Spurs or related costs are required to serve Alexco loads.

Rate Schedule 39 is fixed by OIC 2007-94 until December 31, 2012.

The Alexco Fixed Charge ensures that Alexco pays its share of costs for the 69 kV Mayo-Keno Transmission line originally built and maintained to provide service to the mine site (i.e., 85% direct contribution and proportional share of pooled costs). See UCG-YEC-1-4, YUB-YEC-1-3(a) and (b), YUB-YEC-1-4(a), and YECL-YEC-1-4.

With regard to other bulk transmission and generation costs (not specified in the Alexco PPA), it is noted that Yukon is a cost of service based rate regulated jurisdiction, and that section 6.1 of OIC 1995/90 directs the Board to ensure that the rates charged to major industrial power customers "are sufficient to recover the costs of service to that customer class; those costs must be determined by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same."

REFERENCE: Proposed PPA – Alexco Power Bill, Page 15

"Alexco will pay YEC the amount set out in each Alexco Power Bill within 15 Business Days of the date of delivery of the Alexco Power Bill to Alexco".

QUESTION:

a) Please explain how this provision differs from the ESR provision for payment "by the date indicated on the bill". Please indicate how much time other customers are given to pay their bill.

ANSWER:

(a)

Electricity bills produced by the customer billing system have a "due by" date. Depending on the cycle read, this date is approximately 20 days after the customer receives the statement. Alexco bills are processed manually and due date is 15 days from date the bill is sent to Alexco; the same provision applies to the Minto Mine bills.

REFERENCE: Proposed PPA – Accrued Decommissioning Fund, Page 21

"YEC will deposit the Decommissioning Cost Payment for any Mine Facilities Spur into the Accrued Decommissioning Fund, and invest the Accrued Decommissioning Fund at 6.5% interest per annum to fund YEC's regulated rate base during the Term under this Part 11".

QUESTION:

a) Please provide details of the calculation of the referenced "6.5% interest per annum to fund YEC's regulated rate base".

ANSWER:

(a)

The Accrued Decommissioning Fund, including investment of Decommissioning Cost Payments at 6.5% interest per annum to fund YEC's regulated rate base during the Term under 11 of the Alexco PPA, is based on the method and number used for the Minto PPA. The YUB in Order 2007-5 (page 21) determined the establishment and use of the Minto Accrued Decommissioning Fund to be an acceptable method. YEC's Mayo B Part 3 Application noted (footnote 41 at page 29) that the weighted average cost of new capital for YEC as approved by the YUB for YEC's 2009 GRA is 6.56% (reflects 5.28% for new debt and 8.49% for equity, with 60% debt and 40% equity financing). See also response to YUB-YEC-1-8.

REFERENCE: Proposed PPA – Assignment, Page 26

"Neither Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld".

QUESTION:

a) Please confirm that the YUB must approve of any assignment of the proposed PPA.

ANSWER:

(a)

Not confirmed. YEC is not seeking Board approval of this provision in its requested approvals. Assignment is addressed in Part 14 of the PPA. As discussed in response to LE-YEC-1-6 this is a standard type of provision that was also included in the Minto PPA.

REFERENCE: Proposed PPA, Attachment C - Peak Shaving Credit Option

"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".

QUESTION:

a) Please describe how Alexco would qualify for this credit and specifically which winter seasons it would qualify.

b) Please describe how the proposed Peak Shaving Credit for Alexco allows for sufficient recovery of that portion of YEC's revenue requirement allocated to the industrial rate class for this service.

c) Please provide a paper copy and a working electronic copy of the cost of service study used to determine that the proposed peak shaving rate is sufficient to recover that portion of YEC's revenue requirement allocated to the industrial rate class for this service.

ANSWER:

(a) to **(c)**

See response to LE-YEC-1-7. The winter contract demand load provisions were approved at the time of the Minto PPA to allow for potential shaving of peak winter demand load by a Major Industrial Customer. Rate Schedule 39 (including this provision) has been fixed by OIC 2007-94 until December 31, 2012. As noted during the Phase II proceeding, COS results are not applicable to industrial rates until after this OIC expires.

Alexco would qualify for the credit based on the fact that it is an industrial customer taking service under Rate Schedule 39.

During the Minto PPA proceeding YEC discussed how the provision would apply to Minto mine (similar principles would apply to Alexco):

- Minto could nominate a winter peak contract load (the "Winter Contract Load") at no less than two-thirds of the Mine's maximum firm contract load (MVA), subject to the following terms and conditions:
    - Minto will not the exceed Winter Contract Load when the temperature in Whitehorse is below -30 degrees Celsius. YEC will provide Minto with sufficient notice in this regard;
    - If Minto contracts for a Winter Contract Load, a year's notice will be required to change any of the contract provisions; and
    - If Minto's load exceeds the Winter Contract Load, reasonable penalty provision will apply (see the Rate Schedule 39 provisions).

During the Minto PPA proceeding it was noted that both the Mine and ratepayers benefited from this provision as follows:

- The Peak Shaving Rate Option benefits YEC by lowering the need to plan for and run peaking diesels. It was noted that on the existing WAF system every increased degree between -24 degrees Celsius and -44 degrees Celsius currently tends to increase the system demand by about 400 kW per degree Celsius.

- If the Mine elects to use this rate option they will be provided a rate break to compensate for their inconvenience.

Attachment A of the Minto PPA Application (providing 2008 Yukon Industrial Cost of Service) noted that the Peak Shaving rate credit is consistent with the cost of service evidence (available for the Industrial class at that time and filed with the MInto PPA Application), and would result in positive outcomes for the customer and all ratepayers. The response to UCG-YEC-1-4 (filed during the Minto PPA hearing) noted that "the COS analysis [in Attachment A to the Minto PPA Application] illustrated that the revenue lost by YEC under the Peak Shaving Credit is less than the COS removed from the Industrial class (see Attachment A to Application, page A-16 – Industrial revenue to cost ratio under maximum potential credit is 102.5%).

The 2009 COS provided with the recent Phase II Rate Application notes that industrials are already paying in excess of the costs to serve that class (with an R/C ratio between 109% [noted in the Phase II Rate Application as filed] and 111% [with corrections

identified during that proceeding]). No additional analysis has been conducted, however, specifically related to the winter peak shaving provisions set out in Rate Schedule 39.

To date, no major industrial customer has in fact elected to use this winter peak shaving option.

YUKON ELECTRICAL COMPANY LIMITED
(YECL)

TOPIC: **Status of Alexco Load**

REFERENCE: **Requested Approvals Application, Page 1**

Alexco is currently developing the Initial Mine Facilities with the intent in 2010 of commencing milling operations at the Initial Mill Site and mining operations at the Initial Mine Site as defined in the PPA, and is expected to commence service as a Major Industrial Customer (as defined in OIC 1995/90) in October 2010. The Initial Mill Site is expected to be connected to the Transmission Facilities next week through the Initial Mine Facilities Spur that YEC has developed. The Initial Mine Site is already connected to the Transmission Facilities through facilities owned and operated by Alexco.

PREAMBLE:

YECL seeks to understand the status of the Initial Mine Site load and the Initial Mill Site load.

QUESTION:

a) Please provide status of the Initial Mine Site load and the Initial Mill Site load.

b) Please include the latest expected operating demand of both facilities.

c) Please confirm that OIC 1995/90 defines a major industrial customer as a major industrial customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer. If confirmed, please explain whether the size of the Initial Mine Site load and the Initial Mill Site load meets the criteria set out in OIC 1995/90.

ANSWER:

(a)

As at November 1, 2010 YEC first recorded a metered load in excess of 1,000 kVA at the Initial Mine Facilities, with 287 kVA at the Initial Mill Site and 858 kVA at the Initial Mine Site.

The Initial Mill Site was connected to the grid on October 6, 2010 and billing commenced at the Industrial Rate on November 1, 2010.

The Initial Mine Site (an already existing point of service) was transferred to the Industrial Rate on November 1, 2010.

(b)

The expected operating demand of both facilities remains as set out in the PPA.

The actual operating demand of the Initial Mill as recorded to date over the month of November was a peak of 1,407kVA.

The actual operating demand of the Initial Mine as recorded to date over the month of November was a peak of 906 kVA.

(c)

YEC confirms that OIC 1995/90 defines a major industrial customer 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.

The Initial Mine Site load and the Initial Mill Site load together, and the Initial Mill Site load on its own, exceed the 1 MW criteria for an industrial customer. The Initial Mine Site load does not, on its own, meet the criteria set out in OIC 1995/90.

The Initial Mine Facilities views the combined Mine and Mill loads as one, due to the overall reliance of the mill to receive product for processing from the mine and easily exceeds the 1 MW criteria.

TOPIC: **Exit Provisions**

REFERENCE: **Requested Approvals Application, page 2**

The PPA sets out each Party's rights and obligations with respect to the sale of Grid Electricity by YEC to Alexco for Mine Facilities in the District. This includes provisions related to the payment by Alexco of:

1) YEC's reasonably incurred costs and expenses (the "Capital Costs"):
   (a) To design, engineer, construct and commission a 1.65 km transmission line ("the Initial Mine Facilities Spur") to connect YEC's 69 kV Mayo-Keno Transmission Facilities (the Transmission Facilities") to the Alexco Initial Mill Site; and
   (b) To negotiate and conclude the PPA.

2) The costs to be incurred by YEC to remove such facilities after the Mine Facilities Shutdown Date ("the Decommissioning Costs").

PREAMBLE:

YECL seeks to understand the circumstances after the Mine Facilities Shutdown and the impact to ratepayers.

QUESTION:

a) Please provide an example of what costs other than "Decommissioning Costs" the customer would be required to pay to remove facilities in the event the Mine Facilities Shutdown after 5 years of service.

b) Is the customer required to pay for any un-recovered capital costs after exiting the system? If not, does YEC consider the un-recovered capital costs as stranded? If not, why not? If yes, who would be responsible to pay for the un-recovered capital costs?

c) Please describe what additional costs Alexco will be responsible for if the customer does not take the forecast minimum monthly energy.

d) Please describe what additional costs Alexco will be responsible for if the customer exceeds the forecast minimum monthly energy and (i) requires additional facilities due to load growth, and (ii) does not require additional facilities due to load growth.

ANSWER:

(a)

It is unclear what this question is asking. As reviewed below, the PPA sets out the costs that the customer is required to pay to YEC, including Decommissioning Costs. YEC is not able to provide an example of what costs the customer would be required to pay to YEC other than Decommissioning Costs and other payments as set out in the PPA.

Under the Agreement, Alexco is responsible for payment of the Alexco Power Bill, Capital Costs as defined in the Agreement and Decommissioning Costs (as defined in the Agreement.).

The definition of Decommissioning Costs[1] provided in the Agreement sets out the costs the customer would be required to pay YEC to remove facilities in the event of a Mine Facilities Shutdown; this definition includes "decommissioning and other costs to be incurred by YEC":

- Costs to take down and remove facilities; and

- Costs to restore any property under applicable law (less credits for recovery sales of any materials removed or sold).

[1] Per section 1.1 (o), Decommissioning Costs means "All decommissioning and other costs to be incurred by YEC and agreed to be recovered from Alexco (including, without limitation, costs to take down and remove facilities and costs to restore any property under applicable law, less credits for recovery sales of any materials removed and sold) reasonably required to remove such parts of the Mine Facilities Spurs to be decommissioned after a Mine Facilities Shut Down Date as YEC at that time may require to be decommissioned"

This definition includes all costs reasonably required to remove parts of the Mine Facilities Spur to be decommissioned after a Mine Facilities Shut Down date as YEC may require to be decommissioned at that time.

(b)

Given the provisions of the PPA, it is unclear what this question is asking. As reviewed below, the PPA sets out clearly the responsibility of the customer to pay for Capital Costs such that these costs are incurred and also required to be paid, long before the customer would be "exiting the system".

Alexco is responsible to pay all Capital Costs as defined under the Agreement. The Agreement fully addresses risks related to Capital Cost payment by Alexco as Capital Cost payments for Initial Mine Spurs are to be made shortly after commissioning of the facilities and provision of service to the mine (and are to be completed well before any mine closure or exit from the system). Further detail is provided below.

The payment of Capital Costs is addressed in Part 5 of the Agreement. With regard to the Initial Mine Facilities Spurs, Alexco has agreed to pay (within 15 days of receipt of invoice) the Capital Costs as invoiced by YEC. [See Alexco PPA, Part 5, section 5.1(a), (b), (c) and (d)]. These amounts are to be paid based on the following invoice timing provisions:

- **Section 5.1(a)** - The first YEC invoice for 50% of the estimated Capital Costs (as set out in this section) relating to the Initial Mine Facilities Spurs and negotiation of the PPA is to be provided within 30 days of execution and delivery of the Agreement;

- **Section 5.1(b)** - The second and final YEC invoice for Capital Costs for the Initial Mine Facilities Spurs is to be provided by YEC to Alexco within 30 days of YEC's notice that the Initial Mine Facilities Spurs are commissioned and available to provide Grid Electricity to the Initial Mine Facilities pursuant to the Agreement;

- **Section 5.1(c)** - YEC will invoice Alexco for the Capital Costs related to negotiation and conclusion of the PPA that exceed the related amount invoiced

under section 5.1(a) as and when such costs are incurred and invoiced to or paid by YEC; and

Pursuant to section 5.1(d), in circumstances where the final actual Capital Costs for the Initial Mine Facilities Spurs or for negotiation and conclusion of the Agreement are less than the amount invoiced under 5.1(a), YEC will set the difference off against any other amount owed by Alexco to YEC under the PPA or refund the difference.

With regard to development of future Mine Facilities Spurs [Section 4.5 and Part 5, section 5.2], Alexco agrees to pay to YEC the Capital Costs for any subsequent Mine Facilities Spurs that YEC agrees to develop (as provided in Section 4.5). This includes:

- Provision for payment of 50% of YEC's estimated costs for such facilities prior to YEC ordering equipment for or construction of such new Mine Facilities Spurs.

- The balance of such Capital Costs to be paid by Alexco to YEC within 30 days of notice by YEC that such Mine Facilities Spurs are commissioned and available to receive Grid Electricity to provide to Alexco.

(c)

Pursuant to the PPA, Alexco is responsible for payment of the Alexco Power Bill (defined as the monthly bill sent by YEC to Alexco under section 6.1), i.e., there are no additional take or pay provisions in this PPA. It is noted that under this PPA, all of YEC's incremental Capital Costs are to be recovered directly and without regard to actual power use.

(d)

Alexco, as any other customer provided firm service, is responsible for payment of invoices rendered for all Electricity delivered by YEC during the month, including when the customer exceeds the forecast monthly energy or the Maximum Electric Demand. Section 4.5 of the PPA sets out the provisions, including provisions for any new Capital Costs or increase to the Mine Firm Rate or other changes that may be required to the PPA, if Alexco requires an increase to its Maximum Electric Demand or a new Point of Delivery for a new Mine Facility.

TOPIC: **Terms and Conditions of Service (T&Cs) – Totalized Metering**

REFERENCE: **(1) Requested Approvals Application, Page 3**
(2) Power Purchase Agreement, Section 6.1

PREAMBLE:

YECL is seeking understanding how Section 7.7 (Totalized Metering) of the Terms and Conditions of Service as proposed in the YEC/YECL 2009 Phase II Application may be applied in the context of this Requested Approvals Application.

As set out on page 3 of the Requested Approvals Application:

Section 6.1 of the PPA also provides as follows:

If permitted by the ESRs or YUB, the Electric Demand and Electric Energy at the Points of Delivery will be totaled and only one bill will be issued for such Points of Delivery.

Tab 5 of the Yukon Energy and Yukon Electrical 2009 Phase II Rate Application sets out proposed adjusted Terms and Conditions of Service wherein section 7.7 would allow such totalized metering where (as in this PPA) it is specified in a contract. YEC notes that under the current ESRs, section 4.7 would not permit totalized metering in this instance as the Points of Delivery are not located within a radius of a half a mile of each other – and therefore, until such time as the current ESRs are modified to so permit this totalized metering, YUB approval is being sought to proceed with the above provision of section 6.1 of the PPA.

QUESTION:

a) Please explain in detail what YEC is requesting approval for in this Application with respect to reflecting Section 7.7 (Totalized Metering) of the proposed T&Cs as filed in YEC/YECL's 2009 Phase II Application.

b) Please explain the process how YEC will bill on the totalized metered data (i.e., whether the billing will be based on metered information from one upstream

meter that will meter all the facilities or the billing will be based on separate meter reads at each Point of Delivery that will be aggregated).

c) Please explain how the billing demand criteria from Rate Schedule 39 will be applied against the totalized metered information (i.e., will the ratchet provision apply to each Point of Delivery or the totalized metered data).

d) Please attach the Totalized Metering sections (i.e., S. 4.7) from the current approved T&Cs and the proposed 2009 Phase II T&Cs (i.e., S. 7.7), and discuss the differences between the two versions.

e) Please explain how S. 7.7 from the proposed 2009 Phase II T&Cs "would allow such totalized metering", while S. 4.7 from the current approved T&Cs "would not permit totalized metering".

f) Please provide any reference(s) from the recent 2009 Phase II proceedings that proposed an amendment to the T&Cs to allow such totalized metering.

ANSWER:

(a)

YEC is seeking YUB approval to have the monthly energy, demand and fixed charges totaled on one monthly invoice (see LE-YEC-1-5).

Section 7.7 (Totalized Metering) of the proposed T&Cs was referenced because the PPA meets the provision in Section 7.7 that:

> "..where specified in a contract, the Customer and Company may agree that the Demand and Energy at each Point of Service be totalized and only one bill issued for each billing period."

As the current ESRs do not reflect the "where specified in a contract" provision, YEC is seeking YUB approval to have one total bill in the event that Section 7.7 of the proposed T7C is not approved prior to the Board's decisions with regard to the Alexco PPA (see YUB-1-1(b)).

(b)

As reviewed in response to LE-YEC-1-5 and YUB-YEC-1-1(a), YEC intends to bill based on separate meter reads at each Point of Delivery that will be aggregated into one bill.

(c)

As reviewed in response to LE-YEC-1-5 and YUB-YEC-1-1(a), the ratchet provision will initially apply to the consolidated peak demand of the Points of Delivery and not to the totalized metered demand. This can be adjusted in the future in the event that the Board approves provision for one totalized bill, and Alexco seeks to have one totalized metered demand and agrees to reimburse YEC for the incremental metering costs required to provide such totalized metered demand.

(d) and **(e)**

From the current approved ESR's:

> **4.7 Totalized Metering**
>
> Normally, the Company will issue a separate bill for each point of delivery. When service is provided through multiple points of delivery to a customer's plant site consisting of centralized processing facilities or product transportation facilities located on lands leased or owned by the customer, where such multiple points of delivery are located within a radius of half a mile of each other, the customer and Company may agree that the demand and energy at each point of delivery be totalized and only one bill issued for each billing period.
>
> The customer shall pay the incremental metering cost associated with totalized metering.

From the Proposed 2009 Phase II T&Cs:

> **7.7 Totalized Metering**
>
> When Service is provided through multiple Points of Service to a Customer's plant site consisting of centralized processing facilities or product transportation facilities located on lands leased or owned by the Customer, where such multiple Points of Service are located within a radius of half a mile of each other, or where specified in a contract, the Customer and Company may agree that the Demand and Energy at each Point of Service be totalized and only one bill issued for each billing period. The Customer shall pay the incremental metering cost associated with totalized metering.

The material difference between the ESR versus the T&C version relates to the ability, without separate Board approval, to proceed with totalized metering when points of delivery for a customer are outside of a half mile radius between these points, i.e. the ESR version restricts the Companies' ability to offer totalized metering in such cases, while the T&C proposed in the Phase II Rate Application accommodates totalized metering in such cases when specified in a contract.

From YEC's perspective Alexco as an industrial customer requires two or more Points of Delivery for Major Industrial Customer power use related to the mining and processing of its product. This is acknowledged by the terms and commitments within the PPA.

(f)

See excerpt of proposed section 7.7 of the Terms and Conditions of service noted in (d) and (e) above. This proposed amendment was included in Tab 5 of the Phase II Rate Application. The provisions was not materially addressed in interrogatories or in cross-examination at the oral hearing.

TOPIC: **Estimation of the Monthly Charge**

REFERENCE: **Requested Approvals Application, Page 4**

PREAMBLE:

YECL is interested in system conditions in 1985 vs. 2010 and the validity of the 85% precedent.

QUESTION:

a) Please explain what was the original justification for the 85% direct cost allocation to the Faro Mine?

b) Please explain what criteria were used in determining the 1985 precedent was applicable to this agreement? How were the criteria weighted?

c) Please explain whether Minto Mine received a similar direct cost allocation for its PPA? Why or why not?

d) Please explain what similarities & differences exist between the Alexco deal in 2010 and the Faro deal in 1985?

e) Please explain if there is a similar amount of excess power available on the system in 2010 compared with 1985?

f) Please explain what percentage of system load does Alexco account for?

g) Please explain what percentage of system load did Faro Mine account for?

h) Please explain what is the life expectancy of Alexco's load?

i) Please explain how long will it take for Alexco's fixed charge to cover the capital cost of the transmission line, depreciation, and return?

j) Please explain why YEC believes the 1985 Faro precedent is still valid in 2010 and applicable to the Alexco PPA.

k) Please provide a comparison of the Alexco and Minto Mine PPAs showing the differences between the two agreements and provide explanations for the differences.

ANSWER:

(a)

See response to YUB-YEC-1-3(a) for review of past precedents; see also UCG-YEC-1-4.

(b)

Please see response to YUB-YEC-1-4(d).

(c)

The Minto PPA provides for Minto to pay the full cost of the Minto Spur line (constructed specifically to provide service to that mine site). Minto also paid a contribution towards the Capital Costs of CSTP Stage 1 pursuant to the Agreement (as approved by the Board in Order 2007-5). With regard to Minto, given the above required contributions, no additional direct allocation was made to Minto regarding pre-existing transmission infrastructure in place to provide service to the mine.

(d) and **(j)**

YEC has described the relevant Faro precedent in the September 28, 2010 Alexco PPA Application letter. Similarities and differences between the Alexco deal in 2010 and the NEB recommendation regarding Faro in 1985 regarding allocation of existing transmission fixed charges include:

- Unlike the circumstances surrounding the Whitehorse to Faro line built to service CAMC in 1969, there is no related agreement between Alexco and the Government of Canada or any other government.

- However, in both cases:
  - A line was built and maintained specifically to serve the mine site area:
    - In the case of the Whitehorse-Faro line to serve CAMC/and later Faro mine (see discussion in UCG-YEC-1-4(b)); and
    - In the case of Mayo-Keno line to serve UKHM (until its closure in the late 1980's). In the 1992 Capital Plan hearing, YEC noted that the required rebuild of the line (costing $1.5 to 2 million) could not be justified based on the current load following closure of the UKHM mine; YEC performed minimal capital improvements to maintain public safety on the basis that when UKHM or another mine commenced activities in the site area such costs would be assigned primarily to that customer.
  - In the case of both the Whitehorse-Faro line and the Mayo-Keno line, the line has been maintained to provide service to other much smaller non-industrial loads.
    - The NEB 1985 Report notes Whitehorse-Faro service to loads at Ross River, Carmacks and Faro townsite totaling 3.2% of load on the line when the Faro mine was operating.
    - The 1992 Review of Capital Resource Plans notes at that time the Mayo-Keno line served loads at the CBC, NWTel tower site, Silver Trail Lodge and a number of YTG Highways heat traces in culverts. Currently the line serves loads at Keno (approximately 0.3 GWh).
  - In the case of Faro mine the NEB, and later the YUB, agreed with the approach that the mine should be directly assigned 85% of the costs of the line as well as its share of the pooled costs.
    - As noted in the NEB Report CAMC was previously assigned 96.8% of the costs on the Whitehorse-Faro line when the mine had been operating, reflecting its share of load; the NEB held that 85% direct cost assignment together with CAMC's share of pooled costs in the Yukon hydro rate zone (based on its respective demand) to be a fair allocation of costs. The YUB accepted this

assignment for Faro in the 1992 COS and Rate Design proceeding and later in Order 1996-7.

- Alexco is currently expected to be 98% of the forecast load on the Mayo-Keno line. A similar assignment on the basis applied to CAMC/Faro is considered reasonable given the relative percentage of the mine's load to non-industrial loads using the line. As in the case of the Faro mine, in any future cost of service study the balance of the line's costs will be shared by this mine (and other industrial customers) based on the respective demand and/or energy allocations then used for such costs.

There is sufficient similarity in the circumstances of each of the Whitehorse-Faro line (in relation to CAMC/Faro) and the Mayo-Keno line (in relation to Alexco), including past commitments of YEC as regards capital costs spent on this line after the UKHM closure, that there is a basis to continue to apply the principles established in 1985 by the NEB and previously endorsed and approved by the YUB. In addition, in the case of Alexco there is a contractual arrangement through the PPA that provides specifically for this Fixed Charge allocation.

(e)

Compared to 2010, there was apparently considerably more surplus hydro available on WAF in 1985. However, the level of "excess power" or surplus hydro available on WAF in 1985 had no bearing on the NEB recommended 85% direct cost allocation to the Faro mine.

As the mine was not operating in 1985, the NEB found (section 4.2.5 of the 1985 report) that absent Whitehorse No. 4 the then current forecast load in the WAF system could be met without Whitehorse No. 4, i.e., there was surplus hydro at normal water flows. In its review of these specific charges to the Faro mine related to the Whitehorse-Faro line, the NEB looked at (among other considerations) the costs previously assigned to the mine when it was operating (at which time, prior to Whitehorse No. 4 development there would not have been any such similar surplus hydro on the WAF system).

(f) and **(g)**

Please see response to YUB-YEC-1-4(b) and (c).

(h)

The life expectancy of the Alexco load is dependent upon the expected development of other Mines and Mills in the District by Alexco, as provided for in the PPA. The life expectancy of the Initial Mine Facilities load is approximately five years – however, additional Mine Sites are expected to be developed by Alexco within this time period for milling at the Initial Mill Site such that the life expectancy of the Alexco load is beyond five years. By way of reference, the Mayo B Part 3 Application (Attachment D, page D-1) noted Alexco load as being expected to continue until Q2 2017.

(i)

Based on the information in Attachment B to the YEC filing regarding the Alexco PPA, approximately 39 years of depreciation would be required to fully recover the net book value of the Transmission Facilities as at the end of 2008 (ignoring any ongoing capital spending after 2008).

However, to be clear, Alexco under the PPA is paying the full Capital Cost of the Mine Facilities Spurs built by YEC specifically to serve the Alexco Mine Facilities. The Capital Costs for the Initial Mine Facilities are to be fully paid shortly after execution and delivery of the Agreement[1] and commissioning of the Mine Facilities Spur[2].

The Alexco Fixed Charge applies to the existing costs for the existing Transmission Facilities (i.e., existing the 69 KW Mayo-Keno transmission line) initially built to provide service to the UKHM mine site. This will be an ongoing charge applied to Alexco during the period when it receives service under Rate Schedule 39, and for the period under which the Mayo-Keno line is in service and required to be maintained to provide service to the Mine Facilities.

[1] The first YEC invoice for 50% of the estimated Capital Costs (as set out in this section) relating to the Initial Mine Facilities Spurs and negotiation of the PPA is to be provided within 30 days of execution and delivery of the Agreement.

[2] The second and final YEC invoice for Capital Costs for the Initial Mine Facilities Spurs is to be provided by YEC to Alexco within 30 days of YEC's notice that the Initial Mine Facilities Spurs are commissioned and available to provide Grid Electricity to the Initial Mine Facilities pursuant to the Agreement.

(k)

The Minto PPA as finally approved by the YUB was used as a template for the Alexco PPA; however the Alexco PPA is considerately simplified compared to the Minto PPA due to this different circumstances surrounding the negotiation of the respective Agreements and provision of service to each of the Mines. Material similarities and differences between the Alexco PPA and Minto Mine PPA as approved include:

- **Both PPAs apply the same Firm Mine Rate –** The same firm mine rate applies to both customers with the only variation being the Fixed Charge applied to Alexco (see (c) above regarding why no similar charge was included in the Minto Mine PPA with regard to existing transmission; under the Minto Mine PPA, the Fixed Charge addresses ongoing payments required for monthly Capital Cost Contributions).

- **The Minto PPA included provision for a Low Grade Ore Processing Secondary Energy Rate that is not referenced in the Alexco PPA –** This rate schedule cannot be implemented until audit and control measures and reporting requirements are established between YEC and Minto, and filed with the Board for approval. No similar rate is proposed for Alexco.

- **Capital Cost Contribution:**
  - **Principles for Contribution –** The Alexco PPA Application letter dated September 28, 2010, notes that the principles underlying the Alexco Capital Cost Contribution are based on the principles and precedents applied with regard to the Minto PPA and endorsed by the YUB in Order 2007-5. See pages 5-6 of the Application for description of the principles underlying the Capital Cost Contribution.
    - As was the case for the Minto Spur, Alexco is paying the full Capital Cost of Mine Facilities Spurs built specifically to provide service to the mine.
    - There is no new bulk transmission required to be developed to serve the Alexco mine site (unlike the case for Minto which included CSTP Stage 1). The relevant bulk transmission facilities providing service to Alexco are the existing Mayo-Keno line (and not the CSTP). In the case of the Mayo-Keno line, Alexco is being

assessed a Fixed Charge as described in pages 3-4 of the Alexco Application letter.

- **Loan Arrangement and Security provision –** The Minto PPA included more complex arrangements based largely on the fact that Yukon Energy was under the PPA loaning Minto the funds to invest in the CSTP Stage 1 Line and Minto Spur line, and Minto was to repay these funds over a 7 year period; YEC was also incurring potential net costs for CSTP Stage 1 development in the case of the Minto mine, and sought security and minimum annual payments to offset risks related to such costs. Related provisions included in the Minto PPA but not included in the Alexco PPA include the following:
    - **Take or Pay Provisions –** Minto has made a Minimum Take-or-Pay Amount commitment to pay at least $12 million for Grid Electricity during the first four years of YEC service, subject to certain provisions in Section 6.3 of the PPA. Absent a loan provision in the Alexco PPA, similar provisions were not included.
    - **YEC Security –** The specific risks related to the Minto PPA required that YEC ensure Minto had acceptable security for the payment of the Capital Cost Contribution, the Minto Power Bills, the Minimum Take-or-Pay Amount, the Decommissioning Cost Payment, and certain other obligations. YEC was required to conduct comprehensive due diligence with regard to the YEC Security, Minto and the Mine. The same level of risk is not present with regard to the YEC cost undertakings with regard to the Alexco PPA, and therefore no specific security for YEC was required of Alexco.
    - **Purchase of Minto Diesel Units –** Upon commencement of delivery under the Minto mine PPA, YEC was to acquire (subject to various conditions that have not been met to date) four 1.6 MW trailer mounted Diesel Units from Minto which will help to provide added security and also provide opportunities to minimize WAF system costs under certain circumstances. No similar provisions are included in the Alexco PPA.

With regard to the Alexco PPA, there are no loan provisions and the mine is paying full capital costs for the Initial Mine Facilities Spurs shortly after commissioning.

- **Decommissioning Costs** – As noted at page 7-8 of the Alexco PPA Application letter (dated September 28, 2010), the Alexco Decommissioning Cost arrangements are based on the provisions provided in the Minto PPA with provision for YEC to establish an Accrued Decommissioning Fund account. Similar to Minto, Alexco will make Decommissioning Cost Payments (based on the Estimated Decommissioning Costs) towards this account to be deposited into the account by YEC upon payment and invested at 6.5% interest per annum to fund YEC's regulated rate base during the Term under Part 11 of the Alexco PPA. The Estimated Decommissioning Costs to be paid to YEC by Alexco and invested by YEC will for any Mine Facilities Spur (or part thereof) be an amount equal to 25% of the Capital Costs incurred by YEC for that Mine Facilities Spur (or part thereof) [see section 1.1(x)].

- **Other provisions in the Alexco PPA are generally included in the Minto Mine PPA as approved by the Board** – Aside from differences related to the size and number of mine/mill sites, related differences in the facilities to be provided by YEC versus the mine customer, the other provisions (beyond those reviewed above) in the Alexco PPA are generally included in the Minto Mine PPA as approved by the Board, including provisions affecting annual load forecasts to be provided, Maximum Electric Demand increases, standards for usage of electricity, ESRs, billing/payment, metering, force majeure, representations and warranties, default, dispute resolution, indemnity, assignment, confidentiality, and general provisions.

TOPIC: **Alexco Standards for Usage of Electricity**

REFERENCE: **Requested Approvals Application, Section 4.6 of the PPA**

PREAMBLE:

YECL is seeking understanding of the technical requirements and standards for usage.

QUESTION:

a) Please define "a reasonable operating range" for Power Factor – for example, what is the low end? What is the high end?

b) Please define "unacceptable fluctuations of YEC's electrical system."

c) Please provide a copy of YEC's "reasonable standards of operation."

d) Please provide details of any curtailment of load rules placed on Alexco if the mine is causing system stability or power quality issues.

e) Please explain a circumstance in which YEC might consider 'endangering' its plant, or equipment, or electrical system for Alexco's operation, as set out in Section 4.6 of the PPA.

ANSWER:

(a)

A reasonable operating range for power factor would be considered between 0.85 and 1.0.

(b)

This is accordance with the CSA CAN3-C235-83 standard.

(c)

Please see the attached Alexco Operating Agreement provided as Attachment 1 to this response.

(d)

Please see the operating agreement provided as Attachment 1 to this response. Alexco is limited to 150 kW load pickup without prior notification to YEC.

(e)

However, it is noted that Section 4.6 is focused generally on ensuring that Alexco does not operate its equipment or cause unacceptable fluctuations of YEC's electrical system so as to endanger any of YEC's plant or equipment. This includes provision for YEC to provide notice to Alexco requiring the mine to remedy situations where Alexco fails to comply with requirements or standards of operation. If Alexco fails to comply with section 4.6 after such notice from YEC, then YEC may suspend supply of Grid Electricity and suspend service until the situation is remedied. Alexco may provide notice that it wishes YEC to operate any such equipment endangering YEC's plant or equipment or electrical system at Alexco's sole cost and expense. YEC will provide notice to Alexco as to whether it will operate such equipment – but in such case Alexco will indemnify and save harmless YEC against any costs, damages or losses associated with such operations. YEC is not aware of a specific circumstance where it might so agree to operate such equipment. Depending on the specific circumstances, and based on discussion with Alexco, YEC may allow a potentially endangering event if there were mitigative measures available that could be undertaken at no cost or at the customer's cost that would reduce to an acceptable level or eliminate any "endangering" activity.

YUKON ENERGY	OPERATING PROCEDURE OP-003	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Operations	Alexco Resources/YEC Operating Procedure
		ISSUED:	REVIEW DATE:	APPROVED BY:
		Oct 2010	Dec 2010	

1.0 Purpose

1.1 This procedure outlines the steps to take to ensure a reliable and safe supply of power to the Alexco Mine through a variety of circumstances.

2.0 General Information

2.1 *Definitions*

Operating Authority: The operating authority has overall responsibility for the operation of the transmission system, distribution system or isolated generation stations as applicable, and is responsible to make sure the Operator-in-Charge (OIC) responsibility is assigned. YEC has designated the Leadhand of the System Control Center (SCC) as the operating authority and the SCC operator on shift as the OIC.

Operational Interface Point: Location on the power system separating the responsibilities of respective Operating Authorities

The OIC is responsible for notifying adjoining Operating Authorities of:

- any operation of interface points
- the re-defining of the location of an interface point
- changes in the operating that impact their system

2.2 *YEC/Alexco Interface Points*

T250 89-90 – YEC owned 3 phase gang operated switch located immediately outside the Alexco Mill substation. The operation of this switch will only be performed by a qualified YEC employee.

YEC staff will not maintain or operate Alexco equipment.

2.3 *Contact Information*

SCC	1-867-393-5355 (recorded) 1-867-393-5324 (recorded)
YEC Director, Operations	1-867-393-5399 1-867-335-0424 (cell)
YEC Leadhand, SCC	1-867-393-5366 1-867-334-6904 (cell)

Alexco Daily Operations:

Alexco Mill Manager 1- 604- 248-4903
Cameron Lilly

Alexco Mill Superintendent 1- 604 - 637-5674
Katherine Penney

Alexco Overall Electrical Operations:

Site Services Manager 1 – 867 – 995 - 3113
Peter Johnson

3.0 Operating Procedure

3.1 Normal Operation

Daily Operating Communications

Under normal operating conditions the mine will be supplied from the YEC grid. Load changes greater than 150 kW or 200 hp are required to be communicated to SCC.

Plant Maintenance and Scheduling

To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by Alexco Resource need to be communicated to SCC at least one week in advance for shutdowns of up to 12 hours and one month for shutdowns longer than 12 hours. Operation of the Alexco backup diesel generation must be reported (capacity and duration) to SCC.

3.3 Loss of Supply - Short Term (less than 30 min)

In the event of a disturbance that results in the loss of grid power to the mine site the following steps will apply as directed by SCC.

a) The Alexco owned 3000 amp 600 volt main breaker (MB-1) and the 69 kV circuit switcher will open on under voltage protection. **Until Alexco provides a written guarantee of their main breaker MB-1 opening on undervoltage protection, YEC requests that the Alexco Mill contact YEC to confirm that MB-1 is open prior to the following step b) occurring.**

b) SCC will make one attempt to re-energize the line to the mine site.

c) If successful the mine personnel will disconnect loads so as to bring their pickup of electrical load down to less than 200 kW.

d) SCC will request the mine personnel to close the MB-1 main breaker; this is to assist with restoring the system as efficiently and safely as possible.

Once complete and with confirmation from SCC the mine may proceed with the restarting of their operation, ensuring communication with SCC on load pickups greater than 150 kW or 200 hp.

3.4. **Loss of Supply - Long Term (greater than 30 min)**
If SCC is unsuccessful in re-energizing the line to the mine site the following steps will apply as directed by SCC.

a) Mine personnel will ensure the MB-1 breaker and the 69 kV circuit switcher remain open.

b) If Alexco elects to go on diesel backup power it will be reported to SCC.

Once the line has been successfully energized to the mine site the following steps will apply.

c) SCC will request mine personnel to shutdown all backup diesel generation (if applicable).

d) SCC will request the mine personnel to disconnect loads to bring their pickup of electrical load down to less than 200 kW's

e) SCC will request the mine personnel to close the 69 kV circuit switcher followed by the MB-1 main breaker; this is to assist with restoring the system as efficiently and safely as possible.

Once complete and with confirmation from SCC the mine may proceed with the restarting of their operation, ensuring communication with SCC on load pickups greater than 150 kW or 200 hp.

.

YEC Director of Operations

Nov 4/10
Date

Alexco Resources

11/4/10
Date

TOPIC: **Fixed Monthly Charge**

REFERENCE: **Attachment B – YEC Annual Transmission Facilities Costs**

PREAMBLE:

YECL is seeking clarification how the fixed monthly charge is determined.

QUESTION:

a) Please provide additional details on how the fixed charge of $7,289 per month was calculated and what costs were included in the calculation of the embedded transmission facilities. Please provide schedules that support the amounts set out in Attachment B.

ANSWER:

(a)

Please see response to YUB-YEC-1-3(b).

TOPIC: **Diesel on the Margin**

REFERENCE: **Section 4.5 of the PPA**

PREAMBLE:

YECL is seeking understanding of the impact to Yukon ratepayers when load is added to the electric system that may result in diesel on the margin.

QUESTION:

a) When does YEC expect the transmission facilities serving Alexco to be integrated with the Whitehorse-Aishihik-Faro (WAF) electric system?

b) Under the scenario that would see the Alexco load integrated with the WAF system, please explain whether or not YEC would forecast diesel on the margin to occur.

c) If diesel on the margin were to occur as a result of the Alexco load, please explain in detail how YEC would recover its incurred costs associated with the diesel on the margin under the following scenarios:

   (i) The additional sales were not forecasted in a recent approved Phase I as part of the overall purchase power forecast; and

   (ii) The additional sales were forecasted in a recent approved Phase I as part of the overall purchase power forecast.

   As part of the explanation, please describe how YEC would recover its diesel on the margin costs from the industrial customer and from YECL?

ANSWER:

(a)

The Mayo Dawson and WAF grids are expected to be interconnected by May 2011.

(b)

Alexco's load is forecast to require diesel on the margin on the Mayo Dawson grid during the current 2010/2011 winter period.

By May 2011 there will be one integrated system. Yukon Energy's Mayo B Part 3 Application indicated that material baseload diesel generation would likely be required for the integrated grid in the 2012-2017 period (see Figure 2 from the Mayo B Part 3 Application showing the overall integrated grid forecast generation). With regard to YEC's forecast of diesel on the margin on WAF prior to that time period, please also see the response to YUB-YEC/YECL-1-15 provided in the recent Phase II Rate Application.[1] In summary, depending on actual grid system loads as well as actual water flow availability, diesel may or may not be required to service additional baseload on the integrated grid after the two grids are connected in May 2011.

(c)

In Yukon Energy's view, this question goes well beyond the scope of the current PPA Application and in essence seeks to review under various scenarios how YEC would recover its incurred costs when diesel is "on the margin". As noted above, this event will not occur solely due to connection of the Alexco load – and thus is not related to this PPA Application as such.

In simple terms, Yukon Energy will review on an ongoing basis the measures needed to recover its costs, including proceeding with new Phase 1 application where this is required to address the forecast loads and costs.

[1] For the 2009 test year on WAF, the referenced IR response noted that the methods used to prepare the diesel generation forecasts in the Mayo B Part 3 Application can similarly be applied. These system models look at the possible flow conditions that can arise on the hydro systems, and indicate that at the 2009 GRA approved load levels (approximately 325 GW.h YEC WAF hydro generation), no diesel would be required in 90% of cases (the wetter years on record), while in the remaining 10% of cases between 25 and 50 GW.h of diesel could be required (i.e., in the driest years that would be expected to arise). Over a long-term average, a load that required 325 GW.h of YEC baseload dispatchable generation (i.e., net of Fish Lake and wind generation) would be supplied by an average of approximately 321 GW.h of hydro and 4 GW.h of diesel.

As noted by Yukon Energy during the recent Phase II Rate Application hearing, utilities are normally at risk for their respective load forecasts. Yukon Energy serves industrial loads that interconnect with the grid and is at risk if such loads exceed approved forecasts and drive increased diesel generation costs. As also noted in that same hearing, in the event that diesel is forecast to be on the margin, YEC has the option in this regard to apply to the Board to implement the Base Load Energy rate provisions of Rate Schedule 39 in order to address this risk as regards existing Major Industrial Customer loads – however, this measure by itself cannot address the impact of new industrial customer loads as regards diesel generation requirements.

With regard to wholesale loads – the ERA in Wholesale Rate Schedule 42 only applies where diesel is on the margin and where YECL's retail loads on WAF exceed approved forecasts. As long as YECL's load remains at levels forecast and approved at the last GRA, or diesel is not on the margin for the integrated grid, the ERA will not be triggered.

YUKON UTILITIES BOARD
(YUB)

TOPIC: **Totalized Metering**

REFERENCE: **Alexco PPA, Section 6-1, Attachment A-19**

PREAMBLE:

Tab 5 of the Yukon Energy and Yukon Electrical 2009 Phase II Rate Application sets out proposed adjusted Terms and Conditions of Service wherein section 7.7 would allow such totalized metering where (as in this PPA) it is specified in a contract. YEC notes that under the current ESRs, section 4.7 would not permit totalized metering in this instance as the Points of Delivery are not located within a radius of a half a mile of each other – and therefore, until such time as the current ESRs are modified to so permit this totalized metering, YUB approval is being sought to proceed with the above provision as stated in section 6.1 of the PPA. If permitted by the ESRs or YUB, the Electric Demand and Electric Energy at the Points of Delivery will be totaled and only one bill will be issued for such Points of Delivery.

QUESTION:

a) Please provide sample bill calculations for typical Alexco demand and energy consumption that compare and contrast the expected rate revenues for (i) totalized metering under one bill and (ii) individual bills by each point of delivery. Please provide all relevant billing determinants and assumptions.

b) Given that the current ESRs, section 4.7 do not permit totalized metering and YEC is requesting totalized metering for this customer in advance of YUB review and approval of section 7.7, Terms and Conditions of the Energy and Yukon Electrical 2009 Phase II Rate Application, what treatment is proposed by YEC if section 7.7 of the ESRs is not approved by the YUB? Would Alexco be responsible to reimburse other customers in this rate class for the difference in rate revenues that result from totalized metering vs. individual bills for points of delivery effective from the commercial date of operation?

ANSWER:

(a)

Please see Table 1 below which provides Sample Monthly Bill Calculation. See response to LE-YEC-1-5 for review of assumptions for determining a total bill.

Table 1 - Sample Monthly Bill Calculation

		Separate Bills for each Point of Delivery			One Bill for all Points of Delivery
		Inital Mine	**Initial Mill**	**Total Alexco Bill**	**Initial Mine Facilities**
Energy	kWh	396,600	346,500		743,100
Demand	kVA	870	1,330		2,200
Energy Revenues	$0.076/kWh	$ 30,142	$ 26,334	$ 56,476	$ 56,476
Demand Revenues	$15/kVA	$ 13,050	$ 19,950	$ 33,000	$ 33,000
Fixed Charge	$7,289 per month	$ 7,289	$ 7,289	$ 14,578	$ 7,289
Energy & Demand & Fixed Charges		$ 50,481	$ 53,573	$ 104,054	$ 96,765
Rider F - Fixed	$0.00211 / kWh	$ 837	$ 731	$ 1,568	$ 1,568
Rider F - Variable	$(0.0009) / kWh	$ (357)	$ (312)	$ (669)	$ (669)
Total Chargres (before GST)		$ 50,960	$ 53,992	$ 104,953	$ 97,664

Assumptions:
a) Demand readings are not totalized to determine the overall maximum peak over 15 minute periods (or. alternatively, it is assumed that all Points of Delivery show peak demand at the same time).
b) Rider F rates as at Nov 2010

(b)

YEC is seeking approval of the Board for the totalized metering provision of the PPA in the event that the YUB chose not to approve, or delays approval of, Section 7.7 of the Terms and Conditions, i.e., no such approval would be needed if Section 7.7 of the Terms and Conditions is approved. YEC is seeking approval of the totalized metering provision of the PPA on the grounds that the ½ mile radius criteria in the ESR (T&C) is a guideline that acknowledges the inter-dependency of two points of service contributing

towards the existence of one mining operation. YEC also seeks approval to ensure, in any event, that only one Fixed Charge amount of $7,289 (or any other such amount as approved by the Board) is billed per month to Alexco, regardless of the number of Points of Delivery.

As reviewed in response to LE-YEC-1-5, at the outset the parties only contemplated totaling the energy and demand charges onto one bill so there would not be any difference in charges with regard to these amounts. However, in the event that YEC and Alexco were to proceed towards totalized billing based on the overall 15 minute maximum billing demand, then the demand charge would likely be lower than would otherwise occur (there is no meaningful basis at present to assess what this impact might be in practice).

The rationale for having one total bill is to ensure a fair and reasonable Fixed Charge and to provide the opportunity for Alexco to manage its overall demand during peak winter months so as to minimize its overall maximum load on the grid. Accordingly, Alexco would not be responsible to reimburse other customers in this rate class for any difference in rate revenues that result from totalized metering vs. individual bills.

REFERENCE: **Alexco PPA, Application, Requested Approvals**

PREAMBLE:

YEC indicates that "Each time that a Major Industrial Customer proposes to commence for the first time to receive Grid Electricity from the Transmission Facilities as defined in the PPA, the Alexco PPA (section 6.7) requires YEC to determine on a reasonable basis a proposed amended Fixed Charge applicable to Alexco reflecting an allocation of costs relating to the Transmission Facilities among the new Major Industrial Customers, Alexco and all other Major Industrial Customers receiving Grid Electricity from the Transmission Facilities."

QUESTION:

a) Please describe the proposed methodology for adjusting the Fixed Charge.

b) Please provide a sample calculation that shows a proposed amended Fixed Charge if another Major Industrial Customer the size of Alexco were to connect to the transmission facilities. Please provide all relevant assumptions.

ANSWER:

(a) and **(b)**

YEC intends to determine any amended Fixed Charge applicable to Alexco (as well as the Fixed Charge for any new Major Industrial Customer receiving Grid Electricity from the Transmission Facilities) based on the same methodology set out in the September 28, 2010 letter for the Alexco PPA approvals, and specifically Attachment B to that letter, using then up to date costs for the Transmission Facilities as well as forecast loads on the Transmission Facilities. This methodology has been described in detail as well in responses to YUB-YEC-1-3(b), and the source of this data in response to YUB-YEC-1-14(a). YEC's understanding is also that any such future determinations by YEC will continue to be subject to approval of the YUB.

By way of example, if a second Major Industrial Customer with the same load as Alexco was to connect today to the Transmission Facilities in the Keno area, that customer and Alexco would each be assigned a Fixed Charge of $3,644 per month equal to one half of 85% (or 42.5%) of the annual owner costs of $8,575 per month as set out in Attachment B to the September 28, 2010 letter for the Alexco PPA approvals.

REFERENCE: **Alexco PPA, Application, Page 3**

PREAMBLE:

Based on past Yukon precedent industrial customers are required to make contributions towards existing and new transmission infrastructure built specifically to provide industrial service to their mine site. In this regard, when dealing with established transmission facilities, these customers are to be assigned annual depreciation and return costs related to such transmission facilities.

QUESTION:

a) Please provide and cite all previous Board decisions where this precedent was accepted.

b) Please provide the detailed calculation of how the $7,289/month (Fixed Charge, Schedule A) was determined. Also, provide the calculation in electronic format, stating all assumptions.

c) Does YEC believe that new/incremental industrial customers should make any contributions to generation? Please fully explain your answer.

ANSWER:

(a)

Examples where this precedent was accepted are as follows (relevant excerpts are attached):

- **1992 COS and Rate Design preceding** (excerpt provided as Attachment 1) - In the 1992 COS and Rate Design Review, the Companies relied upon the rationale provided by the NEB to determine the proportion of the Faro to Whitehorse line to be assigned specifically to the industrial class (i.e., the Faro mine). (See discussion in YUB-YEC-1-4(a); YECL-YEC-1-4 and UCG-YEC-1-4).

- **Order 1993-8** (excerpt provided as Attachment 2) - The Board determined that there were no changes in circumstances that warrant changes to the cost of service or rate design principles from those established in the 1992 Cost of Service hearing and that that methodology and rate design proposed by the Companies was appropriate.

- **Order 1996-7** (excerpt provided as Attachment 3) - The Board confirmed that this treatment conformed with practices in Canada and the assignment of 85% specifically to the industrial rate class was based on usage and not related to the vintage of the customer since in the absence of the mine load the line would not have been built (see page 4-5 of Order 1996/7).

- **Order 2007-5 Minto PPA hearing** (excerpt provided as Attachment 4) - In Directive 9 of Order 2007-5 the Board noted it was satisfied with the quantum of the contribution paid by Minto to the CSTP as it exceeds the contribution level based on the then approved ESR Maximum Utility Investment (MUI) model. Further, the Board noted, "that Minto will be responsible for 100% of the costs of the Mine Spur further supports this position. The Board accepts all the points brought forward by YEC in response to YUB-YEC-1-7." At page 14 of the Order the Board specifically notes, "based on YEC response to YUB-YEC-1-7, the Board is persuaded that the approach used to calculate the portion of the CSTP that is funded by Minto is appropriate". The method is described as follows: "in the context of the above ESR terms and conditions, the PPA in effect assigns Minto 100% of the estimated costs of the facilities needed to be constructed to serve the Mine in the event that all such facilities were to be built solely to serve the Mine at 35 kV from Carmacks to the Mine, i.e., YEC is not proposing any utility investment to be planned towards the expected costs for such an extension."

(b)

The detailed calculation for the Alexco Fixed Charge of $7,289/month can be derived from Attachment B of the Application letter dated September 28, 2010. Attachment B provides the calculation of YEC's annual Transmission Facilities fixed costs of $8,575 per month; the Alexco Fixed Charge equals 85% of the Transmission Facilities calculated fixed cost per month is also provided (i.e., $8,575 * 0.85 = $7,289/month).

See Attachment 1 to this response which provides an excel sheet with the calculations in electronic format.

(c)

Consistent with other similar jurisdictions, under the present Yukon regulatory framework new/incremental industrial customers have not been required to make any direct contributions (outside of rate changes established for the Industrial class through normal cost of service principles) to the cost of new generation. For more detail regarding the charges applicable to Alexco specifically, and Yukon Major Industrial Customers generally, please see response to UCG-YEC-1-17(g).

While there is ample precedent in other jurisdictions for requiring contributions by customers for transmission costs to connect such loads to the grid, Yukon Energy is not aware of any precedents in any other similar hydro-based rate regulated jurisdictions where such customers are required to pay contributions towards generation[1].

[1] Contributions to "generation" in this regard are differentiated from contributions towards added facilities specifically installed to maintain power quality related to impacts of a customer's load (e.g., local operational spinning reserve that was required during Faro mine operation). Similarly, Yukon Energy is aware of a BC Hydro related policy (Tariff Supplement #6) whereby capital cost contributions to generation may be required from industrial customers with very large new loads (150 MVa or larger) coming on to the grid system if new local generation resources may be required (in addition to new transmission facilities) to ensure system stability and power quality.

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

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

8.3 Allocation of Transmission Plant

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

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

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

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

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

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

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

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

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

5.5.1 BOARD FINDINGS

The Board notes that the following amounts have been recorded in YECL's revised application:

	1993	1994	
Investment Income	$104,000	$ 84,000	(YECL Schedule 6)
Short Term Interest Expense	$ 59,000	$ 75,000	(Undertaking #43)

The Board reserves the right to examine these items of income and expense, and related asset and liability accounts, at the time of the Companies' next GRA and to amend their treatment at that time. The Board adjourns this matter sine die and reserves the right to deal with this issue at a later date.

6. COST OF SERVICE AND RATE DESIGN

According to the revised application, the proposed 1994 rates were designed to recover the combined YEC/YECL revenue requirement within the calendar year 1994. During the proceedings the Companies also proposed various rate increase scenarios, all of which included the collection of any 1993 deficiency, by way of a rider, over the calendar year 1994. The Companies also indicated that the rates were designed in accordance with Order-in-Council 1991/62. Further, the Companies noted that the:

> "Costs of service for each rate class have been determined using a methodology reviewed and approved by the Board during the 1992 Cost of Service and Rate Design hearing." (YEC/YECL 1993/94 Revised GRA, Page 3-3)

Curragh submitted the Evidence of Dr. Michael Ileo, who commented on the cost allocations used by the Companies and provided recommendations regarding the cost allocations as they related to Curragh. Dr. Ileo's Evidence assumes that the Faro mine is operating throughout 1994. His Evidence emphasizes marginal cost principles which require costs to be assigned to energy in peak and off-peak periods equivalent to those costs of the last units used to meet joint production needs in each period.

6.1 BOARD FINDINGS

The Board notes that, in determining the cost of electric service and rates charged to electricity customers in Yukon, the Board is guided by the Order-in-Council 1991/62. Pursuant to that OIC, the Board conducted a comprehensive review of cost of service and rate design and submitted a report to the Yukon Government dated June 1, 1992. In that report, the Board noted that:

> "... it is not appropriate to cast cost of service studies and rate design principles in stone. The Board recommends that it be provided with the flexibility to react to future changes in circumstances, and to determine the appropriate cost of service and rate design practices to be used in Yukon." (Review of Cost of Service To And Rates Charged To Electricity Customers in Yukon, Executive Summary, Page 3 of 3)

The Board has determined that there are no changes in circumstances that warrant changes to the cost of service or rate design principles from those established in the 1992 Cost of Service hearing. The Board finds that the cost of service methodology and rate design proposed by the Companies is appropriate at this time.

1996-7

AN ORDER IN THE MATTER of the *Public Utilities Act*
Revised Statutes, 1986, c. 143, as amended

and

A Joint Application by Yukon Energy Corporation and
The Yukon Electrical Company Limited

BEFORE: B. Morris, Chair; and)
G. Duncan, Acting Vice-Chair) June 11, 1996

ORDER 1996 - 7

1.0 APPLICATION

On November 17, 1995 Yukon Energy Corporation and Yukon Electrical Company Limited ("YEC/YECL, the Companies") filed with the Yukon Utilities Board ("Board"), pursuant to the *Public Utilities Act* ("Act") and Order-In-Council 1995/90, an Application requesting an Order granting new rates, effective with consumption January 1, 1996 with a further increase on January 1, 1997.

The General Rate Application also proposed changes in rate design, with average increases of 18 percent to the Industrial class, 4 percent to the Government Residential class, 12 percent decreases to the General Service non-government classes, and 23 percent decreases to Street Lights rates and Rate Riders for other new mines. The Application proposed to establish a Rate Stabilization Fund, amend Electric Service Regulations and withdraw previous reporting requirements.

In accordance with Board Orders, a negotiated settlement process took place and a public hearing into the Application was held beginning on March 18, 1996 in Whitehorse, Yukon.

2.0 NEGOTIATED SETTLEMENT

2.1 Overview

As a result of the public workshops and settlement discussions held during the week of March 4, 1996 a settlement agreement was achieved with respect to numerous issues in

the Companies' Application (Exhibit 142). The settlement participants agreed with the contents and details of the Application, except for certain adjustments and the identification of specific issues which were reviewed by the Board in a public hearing.

The settlement agreement also accepted the rate design philosophy of the Companies subject to review of cost of service allocations and the appropriate revenue/cost ratios that are to be achieved by various customer classes. Although the cost of service studies in the Application were accepted by all parties for this rate-making period, the Companies agreed to provide a preliminary community-based 1995 cost of service study by July 1, 1996. (T. 49) On March 15, 1996 the Companies filed the schedules required to calculate the revised revenue requirement based on the negotiated settlement package (Exhibit 148).

2.2 Revenue Requirement Decision

The Board has a statutory responsibility to regulate in the public interest and therefore the Board cannot accept a proposed settlement unless it is persuaded that the settlement agreement is in the best interest of the public. This ultimate responsibility cannot be delegated to the Board staff or to a negotiation group. During the public hearing, the Board heard evidence and argument with respect to the Application and the negotiated settlement package, with the exception of certain cost of service arguments to be filed by March 25, 1996. (T. 145)

The Board, being satisfied that the settlement agreement was in the best interests of the public, accepted the settlement package as presented and issued Order 1996-6 which also identified the hearing costs to be included in the Companies' revenue requirement.

3.0 COST OF SERVICE ISSUES

3.1 Line Losses

In its March 25, 1996 submission (Exhibit 181), the Anvil Range Mining Corporation (ARM) states that it represents about 40% of the total Yukon electrical load and therefore there is no reason that its line losses cannot be calculated independently. The Companies argue that, since the majority of line losses occur in low voltage distribution and not high voltage transmission, the losses attributed to ARM should not be based on the Yukon average.

Rates that are designed so that a customer only pays for costs of assets directly attributable to their load are essentially a regionalizing of the rate structure. In order to regionalize ARM's rates and charge them only for the system losses caused by their load, YEC/YECL would have to perform several system load flow studies with and without their load. To eliminate a degree of uncertainty, the load flow studies would have to be done under different demand and system configurations. These studies could then form the basis for calculating the system losses attributable to ARM (station loads

would have to be added on a prorated basis). In addition, system costs would need to be analyzed to determine what proportion of costs are attributable to ARM's losses. The appropriateness of regionalizing rates in the Yukon has not been determined and this hearing did not examine any such studies. Therefore, the Board has an insufficient base to draw any conclusions regarding the impact of such rates on other customer classes. At present sections 4 and 6 of OIC 1995/90 preclude the implementation of more than one rate zone. However, this issue may require future action and the Board will consider the merits of a more detailed evaluation at a later date.

According to ARM, evidence presented at previous GRA hearings has indicated that the line losses for the Faro mine were below the Yukon average (calculated to be 6.62%, by Dr. Ileo, a consultant representing Curragh in the 1993/94 General Rate Application hearing). Since studies are currently not available, ARM concludes that the Companies are simply estimating the results without supporting backup evidence. ARM therefore requests that the Board accept the conclusion reached by Dr. Ileo or direct the Companies to perform the studies to resolve the issue.

The Companies respond that Board Decision 1993-8 considered line losses and found that line losses for industrial customers should not be adjusted at the time. In addition, the Companies state that the Board concluded that circumstances had not changed to warrant a revision to the cost of service or rate design principles from those established in the 1992 Cost of Service hearing. The Companies submit that Anvil had not provided new information to the Board which would provide a basis to review the line losses with respect to the cost of service allocators and that, based on current evidence and prior hearing information, there is no justification for the Board to conclude that the determination of line loss is "discriminatory or unfair" (Exhibit 189).

The City of Whitehorse offered the view that the bulk of the line losses occur in the low transmission system while ARM is served at high transmission voltage. In this circumstance, it considers that the increase in line losses attributed to ARM is a result of the mine being at the end of a long transmission line from the hydro generation facility (Exhibit 186).

As stated by the Companies, the line loss calculation elements are transmission, distribution and station losses and each is integral to the line loss calculation (Exhibit 153). In the original Application, the line losses were calculated to be 13.47% but a subsequent study revised the losses to 11.13%. The Companies stated that there were a number of factors that accounted for this difference:

- The transmission line distance between hydro generation (which is dispatched before diesel generation) and the Faro mine causes significant line losses;

- Line losses are reduced when the diesel units at the Faro mine are operating;

- Station service electrical heating load can be derived from hydro (when there is surplus) or waste heat from the diesel generation units;

- System modeling error occurs when yearly energy values are converted to average demand; and

- The Companies have assumed that a new 3.0 MV diesel unit (installed in 1993) will be used heavily during the test years (Exhibit 153).

The Board accepts the revised line loss calculation of 11.13% as presented by the Companies. However, this issue may require future action and the Board will consider the merits of more detailed evaluation at a later date.

3.2 Demand Allocation based on KV.A and kW

ARM's concern is that the cost of service study is based on kWs and not KV.A; that the Companies have not adjusted KV.A's in the study to reflect a power factor of about .95; and therefore the electrical demand has been over estimated resulting in additional costs assigned to ARM which are not justified (Exhibit 181).

According to the Companies, the forecast demand was converted from KV.A to kW with the appropriate power factor before costs were allocated in the cost of service study. The power factor was determined on the basis of information provided by ARM while historical information was collected from the previous mine operator. Therefore ARM has its costs allocated on the same kW basis as every other customer (Exhibit 189).

The City of Whitehorse contends that the cost of service study is consistently based on the kW unit where appropriate, therefore there is no issue (Exhibit 186).

ARM may be confused with the rate structure. The rate form with a KV.A component is intended to encourage a high power factor and does not indicate the cost allocation process. The Board finds that the correct conversion to kW has been performed to determine the appropriate allocators.

3.3 Attachment to the System of a "New" Customer or an "Old" Customer

ARM argues that it is a new company that has taken over an old mine and that the Board should not permit the mine to be burdened with specific cost allocations that applied in the past. If this is taken to be the case, the transmission line from Whitehorse to Faro in fact was not designed for ARM and is fully depreciated, therefore the rate level to ARM should reflect the current cost of the line.

The Companies argue that the vintage of the customer is irrelevant in the development of a cost of service study, stating:

> "In fact this method specifically makes the vintage of (a) customer irrelevant, which combined with its stability makes the fully allocated embedded cost of service study the universal standard of fair cost allocation." (Exhibit 189)

It is the Companies' view that there have been no changes in circumstances that require a revision to the methodology from that established in the 1992 Cost of Service Report (Exhibit 189).

The City of Whitehorse states that ARM's argument is irrelevant and the mine should be treated like every other customer in the Yukon that must pay a rate based on the embedded cost of service (Exhibit 186)

The allocation of specific transmission costs to ARM conforms to similar practices in Canada. The assignment of 85% of costs of the Faro transmission line to the industrial rate class is based on usage and is not related to the status of old or new customer. In the absence of the mine load, the transmission line would not have been built. The current cost of service was prepared in accordance with the Board's recommendations in 1992 and subsequently reaffirmed in its Decision 1993-8 (Section 6.1, page 99).

The Board finds that the vintage of a customer is not currently appropriate to the development of the cost of service studies for the Yukon.

3.4 One Rate Zone, Pooling of Income Taxes and Other Costs

The Yukon has two electrical systems operating under different ownership. Each one has a different cost structure, one pays income taxes (YECL), and the other (YEC) does not. Although ARM is a customer of Yukon Energy Corporation, under the concept of tax pooling, it is responsible for taxes incurred by YECL. In ARM's opinion, the legal basis for pooling income tax costs has never been explained and the argument that the same class of customers must pay the same electrical rates whether they are customers of YEC or YECL is without foundation as YECL has no industrial customer class.

As well, according to ARM, any requirement to charge postage stamp rates does not preclude the Companies from determining the actual costs to supply each customer class, including large industrial customers such as ARM. ARM asserts that, without proper price signals, longer term strategies to develop power options cannot be developed. It argues that customers on the Whitehorse-Aishihik-Faro (WAF) system subsidize the diesel generation component of the system. The result is that the cost of diesel in outlying communities does not reflect actual costs and inhibits the development of competitive sources of alternative power generation.

ARM believes that tax revenues should be the source of funding for a social assistance policy and that two separate rate zones would eliminate the cross subsidization. The June 1985 NEB Decision indicated that there should be two separate rate zones divided between diesel and hydro (Exhibit 181).

The Companies point out that the present cost of service methodology, including the method of pooling income taxes and other costs, is the same as the method approved by the Board in the previous GRA. The Companies argue that there is no discretion provided to the Board or the Companies to decide costs that should be pooled. The rate charged by both companies, YEC and YECL should be the same and all areas of the Yukon must be pooled in determining a Yukon-wide cost of service (Exhibit 189).

The City of Whitehorse states that the Board is prevented from adopting ARM's argument under OIC 1995/90, Section 6 (1), which requires that rate levels for customers in the same class be identical across the Yukon (Exhibit 186).

The Board has a responsibility to represent all customers in all classes and cannot rely on an intervention by a single customer in any one class to adequately represent the entire class.

According to OIC 1995/90, Section 6 (1), pages 4 and 5, the following condition applies:

> **"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 by treating the whole of the Yukon as a single rate zone and the rate charged by both utilities must be the same."**

Therefore, in the Board's view, the entire Yukon must be treated as one rate zone and costs must be pooled in order to develop a rate that is equal for both utilities.

3.5 Classification of Whitehorse #4

According to ARM, the classification of Whitehorse #4 to 100% energy results in an unfair burden being placed on this industrial customer. Since the hydro facility is operated for baseload it is no different than Whitehorse #1, #2 or #3. Generation is operated collectively and one unit should not be separated out. ARM states that, if conventional utility practice were applied and Whitehorse #4 were considered the same as the other units for cost allocation purposes, then there would be less cost burden transferred to the mine.

The Companies state that the rationale for building Whitehorse #4 was to replace diesel generation with lower cost hydro generation, that no extra peaking capacity was provided to the WAF system, and that the classification to 100% energy has been examined in previous hearings without a change to this current method (Exhibit 189).

In the Cost of Service Study Report, the Board recommended that, based on the available evidence the appropriate method of classifying the costs associated with Whitehorse #4 was to apply 100% to energy. The Board at that time also recommended that the Companies perform a study of Whitehorse #4 to determine the impact on the capacity of Aishihik at the system peak. The results of that study were provided to the Board in the 1993/94 GRA Volume 1, Tab 5, pages 5.2 - 12/13 (YUB - YECL - 1 - 53). The resultant study confirmed the earlier conclusions.

The Board finds that the allocation factor used is appropriate and is consistent with past practice, and is appropriate at this time. However, the Board makes no

comment on the conclusions of the Company study and will consider the issue still subject to review at a later date if circumstances change.

3.6 Classification of Other Hydro Facilities

According to the Companies, the usual practice is to classify hydro facilities as 60% energy and 40% demand and that this procedure has been followed with the exception of Whitehorse #4 which reflects the specific cost causation for this facility. The Companies submit that the current classification which was accepted by the Board in the last GRA be approved as no valid alternative allocation has been proposed (Exhibit 189).

The City concluded that there is no new evidence before the Board that would change the classification of costs to energy and demand (Exhibit 186).

The Board accepts the allocation that has been proposed (YUB - YEC/YECL - 1 - 51). It was affirmed as Board Recommendation #2 in the Cost of Service Study Report and the Board agrees that there is no new evidence to change that opinion. However, the Board considers this issue open and subject to review in a future proceeding.

4.0 RUN-OUT RATES

It is New Era Electric Corporation's ("New Era") contention that run-out rates are important to provide the correct price signal to consumers so that conservation and energy alternatives can be properly evaluated. In fact, the run-out rates should properly incorporate long-run marginal costs.

New Era indicated that this currently is not possible since the Companies have not provided this information and are in violation of a Board Order (Cost of Service Study Report, page 40, Recommendation #11) which required a long-run marginal cost study to be performed on the system. This report stated that:

> "for the purpose of identifying long-run marginal costs that should appropriately be included in run-out rates, and the results of this study should be presented to the Board by the Companies at the time of the next general rate application."

New Era's review of the Good Hope Lake contract and the 1966 cost of service indicated that the operating and maintenance cost of $.016/kW.h is incorrect and that the proper rate should be in the range of $.064 to $.10/kW.h. Based on this information, New Era concluded that the Companies achieved a before-tax return on equity of between $67,000 and $134,000.

Since this information is vital to rate design and the Companies were unwilling to complete the assignment as the Board Order required, the intervenor requested that the Board appoint an independent consultant to develop the recommended study (Exhibit 176).

The Companies state that there is a distinction between "Recommendations" as set out in the 1992 Cost of Service Report and Board Orders as a result of a General Rate Application hearing. In any case the Board reviewed this "Recommendation" in the 1993/94 GRA (Section 5.2). The Companies provided the required information in the Capital Hearing submission (Table 1, page 2.3). The Board reviewed this analysis in the capital hearing and did not agree with New Era that the long-run diesel costs were unreasonable.

With regard to the diesel installation at Good Hope Lake, the Companies point out that it is outside the jurisdiction of the Board. It is a negotiated contract that therefore bears little resemblance to regulated diesel operation and, therefore it provides no basis for comparison with regulated communities in the Yukon.

The Companies submit that the run-out rates have been prepared on a basis that is consistent with OIC 1995/90 and which the Board approved in the 1993/94 GRA. This method was consistent with accepted rate design principles and reflects the incremental costs. The Companies assert that it is only New Era that demands a change in the rate to reflect long-run as opposed to short-run marginal costs (Exhibit 189).

The Board finds that the run-out rates have been designed consistent with rate design principles and specific directions established in OIC 1995/90. The resultant rate in each of the five zones (Hydro-Diesel, Watson System, Dawson System, Small Diesel and Old Crow) reflect short-run variable costs (Exhibit 1, Tables 3.2 and 3.3) which the Companies must meet.

Under item 10 of the Settlement, the Companies are committed to provide a cost assessment of each of the communities in the four rate zones (based on the 1992 methodology revised with current information). The Board is cognizant that rate design objectives may be in conflict and there must be trade-offs to achieve a particular outcome. In this case, revenue stability, recovery of cost and the appropriate price signal are achievable results in the current methodology that have been incorporated in the run-out rates. The Board agrees that it is necessary to provide the correct price signals to consumers which accurately reflects costs of providing service so that rational energy choices can be made. The Board believes that the study to be filed by the Companies on July 1, 1996 is an important element of future rate design and conservation programs. This material has been requested by intervenors previously and the Board hopes that distribution and consideration of this costing data will assist in building an ongoing productive consensus between the interests of customers and the Companies.

5.0 REVENUE/COST RATIOS

Subject to rates that are maintained to fund the Rate Stabilization Fund, the Application proposed rate adjustments for non-industrial customers that will bring revenues closer to costs for specific classes (Table 3.1). As previously noted, OIC 1995/90 requires that rates to the industrial class be sufficient to cover its cost of service. Arguments on the appropriate revenue/cost ratios to be achieved in the residential class were submitted by

the Utilities Consumers' Group and the Association of Yukon Communities, with reply by the Companies.

The Utilities Consumers' Group requests that the Board direct the Companies to not increase the revenue/cost ratio for the residential class above 75% for the test years or for the foreseeable future (Exhibit 180).

The Association of Yukon Communities requests that the revenue/cost ratio for the residential class remain at its present 78-80% range for the foreseeable future.

In the 1992 Review of Cost of Service and Rate Design, Recommendation #9, the Board recommended:

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

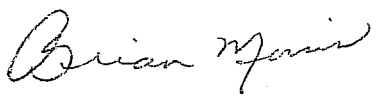
In 1996 the revenue/cost ratio for the non-governmental class was approximately 79% but after rate relief this declines to 68%. The Application does not propose any change in the non-government residential rate until the government rate relief has been eliminated since, until then, residential customers will see no changes in their bills and the correct price signal won't occur. However, the Board-approved reduction in revenue requirement will result in the residential revenue/cost ratio moving to 80% in 1997.

In the Board's view, this rate design provides a legitimate but modest signal that rates are moving in the correct relative direction to meet the respective costs of each class. The Companies are directed to file for approval tariff schedules together with supporting evidence that demonstrate compliance with the Board's Decision.

The Companies are to design a rate shift program that would target revenue/cost ratios in the range of 90% to 110% over a ten year period (T. 53). These proposals may include setting up a Rate Redistribution Fund which would hold a portion of the total rate relief in a particular year so that it can be used in subsequent years to mitigate a rate increase to a specific class.

DATED at the City of Whitehorse, in the Yukon Territory, this 11th day of June, 1996.

BY ORDER



Brian Morris
Chair

IN THE MATTER OF the *Public Utilities Act* Revised Statutes of Yukon, 2002, c.186, as amended

and

An Application by Yukon Energy Corporation (YEC) for approval of the Power Purchase Agreement (PPA) between YEC and Minto Exploration Ltd.

BEFORE: W. Shanks Chair) April 30, 2007
R. Hancock)
M. Phillips)

BOARD ORDER 2007-5

WHEREAS:

A. On June 1, 2006, Yukon Energy Corporation (YEC, or the Company) filed an application with the Yukon Utilities Board (the Board) to review its 20-Year Resource Plan: 2006-2025 (Resource Plan) to address Yukon's major electrical generation and transmission needs;

B. The Resource Plan sets out YEC's expected near-term and longer-term requirements. Four near-term projects are proposed in the Resource Plan. Four alternatives, based on various scenarios to meet the needs of industrial customers, are set out to meet longer-term requirements. Certain near-term planning activities are proposed to protect longer-term options to address new load requirements;

C. The Minister of Justice of the Government of Yukon requested that the Board review and hold a hearing on the Resource Plan. The Board forwarded its report with its recommendations on YEC's Resource Plan to the Commissioner in Executive Council on January 15, 2007;

D. In accordance with YEC's commitment and the recommendations in the January 15, 2007, report, on February 9, 2007, YEC filed the finalized PPA for review and approval by the Board;

E. In Board Order 2007-01, dated February 9, 2007, the Board established a procedural schedule for the PPA proceeding;

F. Through Board correspondence dated March 5, 2007, the Board granted the Utilities Consumers' Group's (UCG) request for a second round of Information Requests (IRs) pertaining to the Macquarrie Bank Financing (MBF). The Board directed that IRs were to be submitted to YEC by March 7, 2007, and responses were to be received from YEC by March 9, 2007;

G. On March 12, 2007, the Board received a Notice of Motion from UCG listing responses to its IRs that UCG deemed as deficient. UCG requested the Board direct YEC to provide "all materials requested by the Board and intervenors by way of information requests that it has not provided based in part on claims that the requested material is not currently in its possession or is confidential in nature";

H. On March 15, 2007, the Board received a Notice of Motion from Mr. P. Percival listing Information Responses that Mr. Percival identified as deficient responses to some of his IRs. Mr. Percival requested that the Board direct YEC to provide the information requested in his correspondence of that date;

I. On March 26, 2007, the Board issued Board Order 2007-03 in response to Notices of Motion from UCG and Mr. Percival for better IR Responses from YEC. Board Order 2007-03 directed YEC to respond to UCG-YEC-2-6 and UCG-YEC-2-10 and amended the remainder of the PPA proceeding schedule as follows:

Further IR Responses from YEC	March 28, 2007
Argument	April 4, 2007
Reply	April 10, 2007

J. The Board has considered the application, the evidence provided, and the arguments filed by YEC and the Intervenors and has made determinations on the Application.

NOW THEREFORE the Board orders as follows, with Reasons attached in Appendix A:

> The Board denies the PPA as applied for. In order to approve the PPA, certain changes are required as discussed in the attached Reasons for Decision. The Board directs YEC to revise the PPA based on the foregoing and file the revision with the Board by May 31, 2007. However, given the upcoming Board hearing directed by the Government of Yukon on the CSTP that is scheduled to commence May 15, 2007, the Board requests that YEC endeavor, by May 9, 2007, to reach an agreement in principle with Minto on the changes required by the Board in order for the Board to approve the PPA, and advise the Board of the status by that date.

DATED at the City of Whitehorse, in the Yukon Territory, the 30th day of April, 2007.

BY ORDER

M. P. Phillips

Michael Phillips
Board Member

Appendix A to YUB Board Order 2007-5

Reasons for Decision

A. Background

The Yukon Utilities Board (YUB or Board) received an Application dated February 8, 2007, from Yukon Energy Corporation (YEC) seeking approval for the Purchase Power Agreement (PPA) between YEC and Minto Exploration Ltd. (Minto).

The PPA Application stems from a commitment made by YEC during the review of YEC's 20-Year Resource Plan: 2006-2025 (Resource Plan) and in the submission of a PPA Term Sheet to the Board on December 21, 2006. The commitment by YEC was to file an Application seeking Board approval of the PPA for the supply of electricity by YEC to Minto through what is described as Stage One development of the Carmacks-Stewart Transmission Project (CSTP). Stage One of the CSTP is a 138kV transmission line from Carmacks to Pelly Crossing, with a spur line to the Minto mine. In the Application, YEC is seeking approval of:

- Firm Mine Rate: Approval of the Firm Mine Rate as set out in Schedule C of the PPA and Section 3.5 of the PPA with respect to any future adjustment of the Firm Mine Rate after 2008.
- Low Grade Ore Processing Secondary Energy Rate: Approval of the Low Grade Ore Processing Secondary Energy Rate as set out in Schedule D of the PPA.
- Mine Net Revenue Account: Approval of provisions respecting the Mine Net Revenue Account as set out in Section 3.6 of the PPA.
- Capital Cost Contribution: Approval of provisions respecting the Capital Cost Contribution as set out in Part 5 of the PPA.
- Take-or-Pay and YEC Security: Approval of provisions respecting the Minimum Take-or-Pay Amount and the YEC Security as set out in Part 6 of the PPA.
- YEC Purchase of the Diesel Units: Approval of provisions respecting the YEC purchase of the four diesel units as set out under Part 10 of the PPA.
- Decommissioning Costs: Approval of provisions respecting Decommissioning costs as set out in Part 11 of the PPA.

Section 3.2 of the Application provides a summary of the Timing Requirements and Conditions of the project and the PPA. Section 3.2 also states, "If any of the above conditions are not either fulfilled or waived on or before the date specified the PPA will be terminated." YEC requested a decision of the YUB by April 30, 2007, as one of these conditions is YUB approval of the PPA by that date.

The Board through Board Order 2007-01 set up the following process for this Application:

February 16: Intervenor Applications due
February 26: Information Requests to YEC due
March 8: Responses to Information Requests from YEC due
March 15: Intervenor Arguments due
March 22: YEC Reply Argument due

In its letter of February 15, 2007, to the Board, the Utilities Consumers' Group (UCG) requested clarification as to the scope of this proceeding and expressed concerns, based on the schedule for the proceeding, about opportunity for follow-up if information sought is either refused or incompletely answered. UCG was further concerned that without the establishment of an issues list, it would be difficult to judge the appropriateness of Information Requests (IRs). Yukon Electrical Company Ltd. (YECL) requested clarification of the process on February 16, 2007, and stated that regulatory efficiency would dictate that this process should be held jointly with any Part 3 Review ordered by the Minister.

The YUB provided a response on February 21, 2007, to the concerns expressed by UCG and YECL. In the Board correspondence of that date the Board stated that it expected YEC would not to take advantage of the fact there is no follow-up process and will provide complete responses in the first instance. The Board further stated that while related, it did not view the PPA Application as a part of the Resource Plan proceeding. The Board stated it was considering YEC's Application like any other application in that it would adjudicate on the matters requested by YEC.

The Direct Agreement between YEC, Minto, and Macquarie Bank Limited was submitted by YEC on February 22, 2007. On March 5, 2007, the Board approved a second round of IRs in response to requests from UCG and Peter Percival.

The Board received a Notice of Motion from UCG on March 12, 2007, outlining a list of Responses to IRs that in UCG's view were not adequately responded to by YEC. A Notice of Motion was also filed by Mr. Percival on March 15, 2007. YEC provided further clarification to its responses on March 13, 19 and 20, 2007.

On March 26, 2007, the Board issued Board Order 2007-03 which ruled on the Notices of Motion and updated the schedule for the remainder of the PPA as follows:

Directed IR responses from YEC	March 28, 2007
Argument (simultaneous)	April 4, 2007
Reply (simultaneous)	April 10, 2007

B. Issues

1. Firm Mine Rate

Section 4.1.1 of the Application states:

> YUB approval of the Firm Mine Rate, as set out in Schedule C of the PPA, is sought for initial delivery of Mine Firm electricity by YEC to Minto; approval is also sought for Section 3.5 of the PPA with respect to any future adjustment of the Firm Mine Rate after 2008.

It is also noted that:

> Pursuant to Order-in-Council 1995/90, YUB approval of any firm rate applicable to this customer must be sufficient to recover the costs of service to that customer class based on treating all of Yukon as one rate zone and pooling costs for both YEC and the Yukon Electrical Company Ltd. (YECL).[1]

Cost of service (COS) methods and principles were outlined in Schedule E of the Application, and in argument YEC stated that the "proposed rates were set according to rate making principles and methods that have been adopted and previously applied by the YUB".[2] YEC said that both YEC and Minto required "certainty regarding the nature of, and basic levels for, the rates that would be in effect for the Minto mine in 2008 when delivery of Grid Electricity is assumed to commence. Without that certainty Minto was not willing to commit to being responsible for the obligations it has undertaken under the PPA, and without those commitments YEC could not proceed with development of Stage One of the CS project"[3].

YEC stated during the negotiations that "Minto required some assurance that should the current environment with regard to the rate setting and rate regulation materially change to the extent that the cost of Grid Electricity, due to such a change, was less attractive than diesel generation, there was some measure of relief available to mitigate any significant losses suffered by Minto"[4].

Section 3.5 of the PPA provides that if the YUB alters terms and conditions of the PPA (including issuing increasing the Firm Mine Rate in a manner inconsistent with the COS principles and methods set out in Schedule E of the PPA) and this materially adversely affects the cost savings to Minto under the PPA, then YEC and Minto will reduce the Minimum Take or Pay amount to offset the loss of cost savings to Minto, and remove the YEC Security with regard to the Take or Pay amount.[5]

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[1] YEC Application to Approve Minto PPA, page A-1.
[2] YEC Argument, page 3.
[3] YEC Argument, page 3.
[4] YEC Argument, page 5.
[5] YEC PPA Application, Attachment E.

YEC submitted that the COS is reasonable in the absence of current General Rate Application (GRA) filings and joint COS studies prepared on a Yukon-wide basis by YEC and YECL[6]. YEC acknowledged the Board's responsibility to set rates and determine COS methods and that Rate 39 was not a Minto-only rate but applicable to all primary industrial customers.

UCG stated that YEC failed to comply with OIC 1995/090 [Rate Policy Directive (1995)] by not obtaining information from YECL for an accurate determination of a Yukon-wide revenue requirement and by not completing a comprehensive COS study.

Mr. Percival echoed many of the points the UCG brought up and in addition suggested a re-imposition of fuel adjustment rider, Rider F.

YECL noted that the fundamental premise of a COS study is cost causation. In YECL's view, cost causation stems from planning the needs of the system and requested clarification from the Board as to whether industrial load such as Minto is included in the Loss of Load Expectation (LOLE) and N-1 planning criteria. This is discussed further and addressed in s. 9(a) (Other Matters – Capacity Planning Criteria).

YEC stated that the proposed Firm Mine Rate and the inclusion of s. 3.5 of the PPA was because Minto sought stable rates. In response to this position, UCG submitted that Minto should face the same regulated rate risk as any other regulated rate customer, otherwise Minto would have an unfair advantage over other customers.

YEC's responded to Intervenors' submissions by suggesting that no evidence was presented to counter the COS as proposed. YEC also took the position that the Firm Mine Rate for 2008 is more than sufficient to cover the estimated COS for 2008.

Views of the Board

The Board considers there are two choices available to serve Rate 39 (Industrial Primary): one option is to use the existing rate (the rate approved in the last filed COS study), another is to utilize a new rate, which YEC has applied for in this Application. The existing rate, which is based on Faro mine assumptions and submitted 10 years ago, is not a practical option. Therefore, the Board must look at the new rate applied for by YEC. This rate is a result of negotiations with a single mine customer. It did not include data from or consider the ramifications to the other regulated Yukon utility, YECL.

Section 6(1) of OIC 1995/090 states: "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 by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same."

[6] YEC Argument, page 6.

The Yukon regulatory environment is one that prefers a direction of standardized utility practice in regard to rates. Such standardized utility practice includes providing a full COS calculation when designing new rates. The process to complete the necessary studies for the cost of service calculation, prepare the application and obtain regulatory approval for new rates can be protracted. The Board understands that YEC has faced strict time constraints with respect to the CSTP.

YEC acknowledges "[t]he Board alone has the power to set rates and determine COS methods used for rate setting purposes pursuant to its constituent legislation and regulations."[7] However, while YEC recognizes the jurisdiction of the YUB, the timing YEC has requested presented challenges for the Board and Intervenors in establishing and participating in the proceeding. Recognizing the time constraints faced by YEC, the Board has endeavored to meet these timelines; however, as a result, YEC's evidence in some areas is not as complete as the Board would normally expect, in particular, with respect to COS.

The Board agrees with Intervenor concerns regarding the lack of a complete COS study. The Board is of the view that due to the articulating nature of a COS study, rates cannot be developed in isolation. Therefore, the Board reiterates its earlier direction that YEC and YECL must provide a complete COS study and rate design with their next GRA.[8] The COS is to include updated studies on allocators, and will look at the feasibility of direct assigning assets, where applicable to certain rate classes. Further, the Board expects to see justification on the allocation of transmission assets.

In addition, the Board questions the rationale of defining the CSTP project as one of diesel displacement in light of YEC's comments that the project is to serve system requirements[9]. The Board would like to explore the COS evidence in this regard when it is filed in YEC's next GRA.

Therefore, until such time as a decision is rendered in the next GRA, the Board will accept Rate 39 on an interim basis as proposed by YEC. The interim Rate Schedule 39 will be applicable throughout Yukon. Due to the concerns expressed about the sufficiency of the current COS presented by YEC, the Board is not prepared to accept Section 3.5 of the PPA. The Board does not consider that there should be a link between Board approved rates which are deemed fair, just, reasonable and within the public interest (based on accepted COS principles) and the security provisions to protect Yukon ratepayers. The practice in Yukon is to follow cost causation for COS purposes as a fundamental building block to proper rate design. Minto and any other customer can take comfort in knowing that the regulatory environment in Yukon is based on standardized practices.

The Minimum Take-or Pay Amount is intended to protect Yukon ratepayers when there is significant investment in new facilities. The Take-or-Pay Amount is partially driven by

[7] UCG-YEC-1-15.
[8] Report to Executive Commissioner Yukon Energy Corporation 20-Year Resource Plan, page 50.
[9] YEC Argument, pages 11-12, inclusive.

the requirement to serve the Minto load, and of which Minto is expected to receive significant benefit. Based on regulatory practice in the Yukon, the Board's view is that Yukon rates are stable and built based on sound practice and a link to the Minimum Take-or Pay provision is not necessary to provide stable rates to Minto. Further, the Board agrees with UCG that Minto should be treated the same as all other customers in terms of any risk associated with regulated rates.

2. Low Grade Ore Processing Secondary Energy Rate

Section 4.1.3 of the Application presented the Low Grade Ore Processing Secondary Energy Rate (Rate Schedule 35). This is an interruptible rate and is to only be supplied from surplus hydro to Industrial Primary customers (who are supplied under Rate Schedule 39). As defined, this rate is to be limited to the processing of low grade copper ore. YEC proposes that unlike Rate Schedule 32 (Secondary Energy), where the rate is adjusted quarterly (based on changes in heating oil prices), Rate Schedule 35 will remain fixed. YEC indicated that energy use under this rate would not be separately metered, but it would rely on reporting from such customers to determine appropriate charges. Energy purchased under Rate 35 will not contribute to Whitehorse-Aishihik-Faro (WAF) winter peak or require the use of diesel generation.

In argument YEC summarized the concerns raised in the interrogatory process about Rate 35 as follows:

1) Concerns on how use of Rate 35 would be measured and audited
2) How this rate would impact other secondary energy users on the WAF grid
3) Would there be sufficient surplus energy available to other industrial customers[10]

YEC, in YUB-YEC-1-11(2), indicated that appropriate auditing and control measures are not currently in place for accurate measurement of Rate 35 usage, but described what those measures would likely involve.[11] YEC stated that auditing and control measures would be required before Minto could use this rate. In addition, reporting to enable YEC to determine which portion of the recorded Demand and Energy in any billing month that relates to Rate 35 is a prerequisite before YEC will allow usage of Rate 35. YEC submitted that these were sufficient safeguards to allow approval of Rate Schedule 35.

YEC addressed the second concern by stating that service to Rate 32 customers precedes service to Rate 35. Having a rate available such as Rate 35 provides such benefits as:

- Less water at dam sites spilled and wasted
- Incremental revenues to YEC
- Economic Processing of Low Grade Ore[12]

For the third point, YEC stated that Rate 35 would not be immediately applicable to other potential mine customers but would consider rewording some of the terms in Rate

[10] YEC Argument, p 9.
[11] YEC Argument, page 10 - footnote 31.
[12] YEC Argument, page 11

Schedule 35 to allow availability to other mines.[13] Additional firm mine loads concurrent with the Minto load implied that surplus hydro would not be available and hence Rate 35 would not be available.

UCG submitted that a cost-based rate should be used for secondary energy, and that any final decisions on this proposed rate should be delayed until the filing of the next GRA.

Mr. Percival recommended that "...any and all large industrial electrical customers can have an equal opportunity to purchase such seasonally available surplus hydro power on a non-discriminatory and non-favored basis."[14]

YECL requested that the approval of Rate Schedule 35 be deferred until the audit and control measures have been determined. This position was supported by UCG in reply.

In reply, YEC stated it "sees no reason for the Board to defer approval of Rate Schedule 35, but is willing to report to the Board with any proposed auditing methodology developed between YEC and Minto in order to ensure that it is reasonable and that fulfils the requirements of Rate Schedule 35. It is noted that not approving Rate Schedule 35 as it is currently set out at this time would require that both Parties to the PPA agree to an amendment."[15]

Views of the Board

The three issues with respect to Rate Schedule 35 are:

1) The quantum of the interruptible rate
2) The ability to measure the quantity of interruptible energy consumed
3) The broader applicability of the rate

Upon review of the negotiated rate, the Board observes that it is close to the level set for Rate 32. This does provide some comfort to the Board, as Rate 32 is a rate previously approved by the YUB. However, as discussed under s. 1 (Firm Mine Rate), the Board is concerned about the lack of a complete COS study by YEC and YECL. The Board has the same concerns with respect to Rate 35 and therefore will only approve Rate 35 on an interim basis. For the next GRA (Phase II), the Board directs both YEC and YECL to provide their electronic COS models and to distinctly show costs as being related to generation, transmission and distribution. Further, generation costs are to be separated based on each generation type (i.e. hydro, diesel, wind etc.).This will enable testing of costs to serve all rate classes, including Rate 35.

For the second issue, the Board is persuaded by the arguments of the Intervenors that insufficient systems are in place to accurately measure usage for Rate 35. Should Minto pursue Rate 35, proposed audit and control measures and reporting requirements must

[13] YCS-YEC-1-2(d)
[14] Percival Argument, page 2.
[15] YEC Reply, page 28.

be established between YEC and Minto, and then YEC is to file these with the Board. YEC is not to implement Rate Schedule 35 until such approval has been granted.

Finally, the Board is persuaded by the reply of YEC that it is willing to amend the terminology for Rate Schedule 35 if and when other industrial loads present opportunities for use of such a rate. Generic wording, instead of wording specific to one customer, is a preferred approach for rate schedules. Therefore, the Board directs YEC to amend the wording for Rate Schedule 35 at such time as the opportunity arises for other industrial loads to make use of Rate 35.

3. Peak Shaving Rate Option

The Peak Shaving Rate Option was described in section 4.1.2 of the Application and further in Schedule C of the PPA (Attachment E). The concept for this option is that, by providing a specified credit on the firm demand billing rate, Minto is provided incentive to limit its ability to affect peak winter loads on the WAF system. The winter peak contract load can be no less that two-thirds of the mine's maximum firm contract load.

In argument, YEC stated "that peak shaving, as proposed in the PPA, is a DSM [demand-side management] measure that should help to avoid the need for diesel fuel by contributing to a reduction of peak winter load requirements on WAF if, and when, sufficient additional mine loads are added to the WAF system."[16]

The Peak Shaving Rate Option was supported by Mr. Percival.

Views of the Board

The Board supports DSM measures that are beneficial to Yukon ratepayers. The Peak Shaving Rate Option is seen as a measure to manage peak winter demand. The Board accepts YEC's evidence that peak demand increases by 400 kW per degree Celsius when temperatures are below -24 to -44 degrees Celsius. Given these factors, the Board approves the Peak Shaving Rate Option as applied for. YEC and Yukon ratepayers will benefit from this option if it lowers the need to plan for and run peaking diesels.

4. Mine Net Revenue Account (MNRA)

YEC requested approval of provisions respecting the MNRA as set out in Section 3.6 of the PPA. The position of YEC is that "this deferral account, which continues to address annual Mine Net Revenue at least for so long as Minto continues to provide the YEC Security, is one of the key measures to ensure that there are no adverse rate impacts on other ratepayers in Yukon due to the PPA".[17]

Mine Net Revenue (MNR) is described as:

[16] YEC Argument, page 9.
[17] YEC Application to Approve Minto PPA, page 3.

> Mine Net Revenue in each fiscal year equals Minto Power Bills (plus any take-or-pay payment) less incremental YEC costs in the year (i.e., incremental YEC expenses and return on rate base in that year due to the supply of Electricity to Minto by YEC), including any added WAF diesel generating costs, lost income due to displaced interruptible secondary sales, incremental amounts due to the CS Project or the Mine Diesels, or other incremental costs resulting form the PPA.[18]

YEC requested that the MNRA not form part of YEC's earnings in that year and stated it will invest the amounts in the account at 6.5 percent interest per annum. When the amount equals or exceeds the CSTP Stage One Undepreciated Capital Cost, YEC will use the accrued MNRA to reduce the YEC regulated rate base.

The intent of the MNRA is to shield YEC rate base and Yukon ratepayers from any rate impact due to mine operations. In argument, YEC stated that the MNRA addresses rate instability during and after the mine life due to a variety of factors including instability caused by temporary events, increasing incremental YEC costs related to mine load, the eventual loss of Mine revenue and the need for other ratepayers to pay for the remaining Stage One CSTP undepreciated capital costs[19]. The recent Government of Yukon announcement that it will provide $10 million in funding for the CSTP[20] is expected to enhance ratepayer benefits and reduce ratepayer risks, although YEC noted this will not eliminate risk.

UCG likened the MNRA to the previously proposed Income Stabilization Trust (IST) and noted that the Board deemed such an account as unnecessary and did not approve it.

Mr. Percival agreed with UCG that the need for the MNRA had not been adequately established. Mr. Percival characterized the account as "a fund that will be used at some future date for further utility investments in infrastructure[21]."

On page 6 of his reply argument, Mr. Percival also noted that with the Government of Yukon's commitment of up to $10 million toward the CSTP, there is no need for the MNRA. His position was that YEC ratepayer risks would be substantially reduced if YEC collected the customer contribution from Minto up front.

YECL took the position that the PPA does not guarantee "no adverse impact to ratepayers"[22] and in the end the MNRA promotes rate stability over intergenerational equity. YECL continued by stating that parallels drawn with the Faro mine are overstated as the energy consumption at the Faro mine represented 40 percent of Yukon energy, whereas Minto's consumption will only represent 12 percent[23].

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[18] YEC Application to Approve Minto PPA, page 14.
[19] YEC Argument, page 22.
[20] April 2, 2007, letter from the Minister of Energy, Mines and Resources to the Chair of the Board, Yukon Energy Corporation.
[21] Percival Argument, page 5.
[22] YECL Argument, page 12.
[23] YECL Argument, page 13.

YECL in its reply stated it would prefer to see benefits concurrent with costs and future rate impacts addressed at the time they occur. YECL went on to argue that the mine is only viable as long as commodity prices are high. With the proposed MNRA, ratepayers would not see the benefit of the $10 million YTG funding until such time as the MNRA is disposed.

In reply, YEC acknowledged that the MNRA promotes rate stability but disputed that intergenerational equity was being greatly sacrificed. YEC added that the definition of incremental costs was broad enough to include all reasonable incremental costs and recognized the Board's jurisdiction and mandate to control the MNRA and ensure the benefits are retained for all ratepayers.

YEC disagreed with the IST analogy proffered by UCG, as UCG's argument did not account for the ratepayer rate stability risks outlined in the Application. YEC reiterated these points in reply to Mr. Percival and said that there is no basis to say that the account will be used only for future investment in infrastructure.

Views of the Board

The Board acknowledges that for regulatory purposes utilities are sometimes required to deviate from Generally Accepted Accounting Principles (GAAP) and that deferral accounts are sometimes required within the regulatory arena. In general, deferral accounts are required when there is a certain level of uncertainty around specific elements. It may be that a price cannot be determined until after a prolonged period of time or a quantity cannot be determined until a final reconciliation occurs. Deferral accounts are sometimes set up due to an unwillingness of a utility to take on forecast risk for specific elements of their revenue requirement.

The MNRA does not take on any of these characteristics. On the surface, the MNRA appears to violate the revenue recognition criteria of GAAP. The Board is of the view that for the MNRA, based on the above criteria, there is no justification to deviate from GAAP. While the Board recognizes that the MNRA is designed to increase rate stability, the Board is persuaded by the position of Mr. Percival that, with the Government of Yukon contribution to the project, the need for the MNRA to reduce ratepayer risk is minimal. The Board does not advocate a policy of deferring revenues or costs outside of the appropriate recognition period for the purpose of keeping rates stable. Nor is the Board supportive of the YEC proposed option of using the fund for future investment projects[24]. The Board does support the view that revenues collected from rates should be applied to the COS that derived those rates. Hence if the revenues exceed the revenue requirement, then the rates should be reduced. As the Board does not consider there to be adequate justification for the MNRA, nor does it consider that the MNRA is required, the MNRA is denied.

[24] YUB-YEC-1-6(2): "The account does provide, however, for its use to fund annual Incremental YEC costs that the Board approves to include in revenue requirements of YEC for the CS Project and potentially other future generation projects".

5. Capital Cost Contribution

The PPA requires that Minto contribute $7.2 million to the construction of the CSTP plus the actual costs for the Mine Spur. The terms of the Capital Cost Contribution are:

- Mine spur contribution to be paid in equal blended monthly payments of interest at 7.5 percent per year and principal over the first 7 years of YEC service.
- Carmacks-Minto Landing Capital Costs Contribution of $7.2 million to be paid in equal monthly payments of interest at 7.5 percent per year for the first 4 years of YEC service, and in equal blended monthly payments of interest and principal over the next 3 years of YEC service.[25]

The PPA contained other provisions based on in-service date, service interruption, new mine loads and reserve levels.[26]

YEC stated that during the negotiations, it was apparent that without YEC financing for the customer capital cost contribution, the Mine would not connect to the grid.[27] In negotiating this aspect, YEC used an existing precedent from Newfoundland (Duck Pond) for financing customer capital cost contributions and enhanced the provisions found in that example with further security provisions.

UCG in argument said that any customer contribution should be flexible and reconcile to actual costs[28]. UCG also questioned the estimate, provided on a cost per kilometer $/km basis, for calculating Minto's contribution.

Mr. Percival noted three issues with respect to the Capital Cost Contributions:

1. Reasonableness of the contribution and methods of calculation.
2. Fixed amount of contribution versus fixed percentage of contribution.
3. Risk and prudence of financing the customer capital cost contribution[29].

With respect to the first point, Mr. Percival considered accurate cost estimates of the project to be necessary to determine the appropriateness as to the quantum of the costs. For the second point Mr. Percival submitted that the Board reserve judgment on the quantum or set the customer contribution as a fixed percentage of the costs. If the YUB approves the financing of the customer contribution, Mr. Percival argued the Board would be setting a precedent, with an unacceptable level of risk to YEC and its ratepayers.

[25] YEC Application to Approve Minto PPA, page 13.
[26] PPA, pages 22-23 inclusive.
[27] YUB-YEC-1-34
[28] UCG Argument, page 12.
[29] Percival Argument, page 3.

YECL had considerable comment in its argument, questioning the quantum of the capital contribution.[30] YECL stated it would expect that, in an instance where a fixed customer contribution is proposed, a detailed design estimate would be available to support the estimated capital cost of the project and the fixed contribution proposal.

YECL in its reply reiterated that the quantum of the contribution ($7.2 million) has not been sufficiently supported, and stated "YECL remains of the view that the level of capital actually spent on facilities should drive the appropriate customer contribution".[31]

Not having detailed engineering completed, in YECL's view, has increased the risks as opposed to having mitigated the risks. YECL did not oppose having customer contributions based on the least costly technically feasible alternative but argued Minto should share in the construction risk of the transmission line.

YECL agreed with UCG and Mr. Percival that an upfront contribution does not shift risk to YEC and Yukon ratepayers. YECL and UCG submitted that Minto's inability to obtain conventional financing for its contributions should be seen as a significant risk, and YEC should not assume this risk. YECL concluded by stating that if the Board approves YEC's financing of the contribution, then it should follow the Duck Pond example and receive blended principal and interest payments upon commencement of service. YECL also suggested that a broader principle should be developed, specifically, a policy for maximum utility investment (MUI) for industrial customers, as such a policy would lead to consistency.

Mr. Percival shared the UCG view that to mitigate ratepayer risks, Minto should front all costs for its contributions to the transmission line, the Mine Spur and decommissioning costs. Mr. Percival reiterated his points that the contribution should not be a fixed amount but rather a fixed percentage and based upon actual costs.

YECL, UCG and Mr. Percival all were of the view that YEC's proposal to finance Minto's contribution should not be accepted.

YEC stated that approval of the PPA is a requirement for continued work on the CSTP. YEC disputed all assertions made by YECL regarding the MUI. Other than the Mine Spur, YEC claimed that the CSTP was a system extension and would therefore be a cost shared by all ratepayers.

As to the quantum of the amount, in reply, YEC de-linked separated the amount of the contribution from any regulatory requirement, stating it was a negotiated amount based on the mutual interests of the parties. Other than the Mine Spur, the CSTP is planned to serve system requirements[32] and other customers and as such would not require any customer contribution.

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[30] YECL Argument, pages 2-3.
[31] YECL Reply, page 3.
[32] The CSTP is to primarily connect the two grids (WAF and M-D), provide grid access to local first Nations customers as well as serve new loads. (YEC Reply, page 13).

YEC rejected YECL's and Mr. Percival's arguments pertaining to YEC's financing of the capital cost contributions and restated its points in relation to the Duck Pond precedent, Minto not otherwise willing to connect to the grid, and other security enhancements from its argument.

Views of the Board

The Board agrees with Mr. Percival's observation that capital cost contributions can be separated into three issues:

i. Reasonableness of the Contribution and Methods of Calculation
ii. Fixed Amount of Contribution versus Fixed Percentage of Contribution
iii. Risk and Prudence of Financing the Customer Capital Cost Contribution

i. Reasonableness of the Contribution and Methods of Calculation

Based on the forecast of costs presented by YEC in Schedule 1 (page 4) of its Application, the Board is satisfied with the quantum of the contribution to the CSTP as it exceeds the contribution level based on the MUI model. The fact that Minto will be responsible for 100 percent of the costs of the Mine Spur further supports this position. The Board accepts all the points brought forward by YEC in response to YUB-YEC-1-7. The determination of the $7.2 million for the CSTP contribution representing the mid-point cost estimate for a 35 kV line for service from Carmacks to Minto Landing is a prudent estimate to recover the cost of the additional transmission facilities to provide service to Minto. In essence, by using this minimum plant estimate and the costs as forecast, YEC is not making any investment in transmission facilities to serve Minto.

ii. Fixed Amount of Contribution Versus Fixed Percentage of Contribution

In its argument, YEC stated that the CSTP is a system project to serve system requirements, provide service to other customers and hence it would not normally require any customer contribution. Yet the economics for this project are driven by new load, namely the addition of Minto. If a connection to Minto was not to happen, the project would not proceed. As a result, the Board views the CSTP as a hybrid - a project to supply new load and a project to serve system requirements.

The Board has considered the positions of the Intervenors and YEC with respect to the quantum of the contribution by Minto. In general, given the highly inflationary nature of the construction industry, the Board prefers to see a contribution based on a fixed percentage versus a fixed amount. Noting that the Board views this project as a project to supply new load and a project to serve system requirements, the Board is of the view that the contribution to the CSTP should be indexed to the detailed cost estimates for the line. That is, if the final tendered cost exceeds the high estimate as shown in Schedule 1 of the Application, then the contribution should be indexed for the equivalent

construction of a 35 kV line for the appropriate segments accordingly. To be clear, for example, if the final tendered costs exceed the high estimate by 10 percent, then the contribution by Minto to the CSTP should increase by 10 percent.

With respect to MUI, the Board is of the view that the arguments presented by YECL have merit. The Board would like to see a consistent approach when it comes to determining levels of investment by utilities into new facilities. The Board directs both YEC and YECL to review and refine their investment policies for industrial customers and to include recommendations within their next GRA, which is expected to be filed by October 31, 2007. The policies should clarify to potential industrial customers what the utility will invest in new facilities and provide consistency in the approach when constructing facilities to serve new loads.

Based on the YEC response to YUB-YEC-1-7, the Board is persuaded that the approach used to calculate the portion of the CSTP that is funded by Minto is appropriate. The method is described as follows:

> In the context of the above ESR terms and conditions, the PPA in effect assigns to Minto 100% of the estimated costs of the facilities needed to be constructed to serve the Mine in the event that all such facilities were to be built solely to serve the Mine at 35 kV from Carmacks to the Mine, i.e., YEC is not proposing any utility investment be planned toward the expected costs for such an extension[33].

Nonetheless, based on the foregoing, if the costs of the project exceed the high estimate, the Board directs that the contribution by Minto for a 35 kV equivalent transmission line be adjusted accordingly. While this could increase the contribution required from Minto, any increase is expected to be significantly less than the $18 million in benefits Minto will receive from grid connection. Given these benefits, the Board would not expect Minto would consider it a prudent investment decision to walk away from the PPA.

iii. Risk and Prudence of Financing the Customer Capital Cost Contribution

While each case must be decided on its merits, the Board generally does not consider the utility financing of customer contributions to be appropriate. This activity presents a different and higher risk structure to Yukon ratepayers. The costs for such agreements (for example, legal, financial and management due diligence costs) bring about increased costs that may be more appropriately handled by entities that are in the business of financing, rather than being handled by a regulated utility. The only precedent cited for this (Duck Pond)

[33] YUB-YEC-1-7, page 3 of 4.

deviates materially from this circumstance in that payment of the contributions commenced when the service was connected.

In line with the position that Stage 1 of the CSTP is partially driven as a system requirement, this part falls outside of the MUI concept advocated by YECL. Hence, the Board accepts that Minto is willing to provide development funding to see the project go forward. The quid pro quo Minto will receive for this development funding includes potential benefits in excess of $18 million from reduced energy costs and financing for the Mine Spur. The calculation of this $18 million in savings is based on an expected mine life of nine years. If the mine life were extended, the savings to Minto would be even greater.

The Board views the receipt of $7.2 million in development funding in exchange for providing financing for approximately $3.8 million of Mine Spur costs as an arrangement that is beneficial to Yukon ratepayers over the long term.

However, the Board views providing this type of funding as being beyond the scope of regulated activities of a utility and imposing an additional level of risk on ratepayers that the Board does not consider appropriate and is not prepared to accept. The Board is only prepared to approve this section of the PPA if any losses YEC may suffer due to the financing of the contributions are on account of YEC shareholders, that is, any losses incurred will not be allowed into YEC's revenue requirement. The Board is concerned about the level of risk associated with this financing and is of the view that this condition is necessary to protect ratepayers.

The Board reiterates that it does not generally consider utility financing of customer contributions to be appropriate, and YEC should not have the expectation that such an arrangement in the future would be approved.

6. Take-or-Pay and YEC Security

On page 3 of its Application YEC seeks approval of provisions respecting the Minimum Take-or Pay Amount and the YEC Security as set out in Part 6 of the PPA.

These provisions are discussed on pages 15 and 16 of the Application. Section 6.2 of the PPA provides that Minto will pay YEC a minimum aggregate amount of $24 million for Grid Electricity regardless of the amount of Grid Electricity actually delivered by YEC. Provisions exist for minimum cumulative annual payments averaging $3 million per year. The terms are subject to the Firm Mine Rate as described in Section 3.5 and availability of Grid Electricity as described in Section 6.3.

The YEC security involves a charge over all assets of Minto, including the mine, only subordinate to the Current Bank Financing. This YEC Security is to cover the payment of the Capital Cost Contribution plus any interest outstanding, the Minto Power Bills, the Minimum Take-or-Pay obligations, the Decommissioning Cost Payment and Minto

Payments to Caterpiller.[34] Discharging the YEC Security can only occur when Sections 5.2, 11.2(b) and the Minimum Take-or-Pay obligations have been satisfied.

In argument, YEC identified the normal risks associated with projects of this magnitude and the PPA specific risks. It further identified the risk issues as follows:

- The issues and rationale related to YEC financing the Minto Capital Cost Contribution
- Minto's Minimum Take-or-Pay obligations
- The security that Minto will provide YEC for its Capital Cost Contribution
- The level and duration of Minto's firm purchase power commitments and the risk of Minto defaulting.[35]

YEC acknowledged that not all PPA related risks can be avoided or completely mitigated. The financing of the Capital Cost Contribution and the possibility of early shutdown of the Mine are risks that cannot be fully covered. YEC's position is that the risk of this event happening is extremely low and therefore should not prevent the PPA from proceeding nor the project from going ahead.

YEC consistently maintained that without YEC financing of the Capital Cost Contribution, Minto would not agree to interconnect to the grid. The position of YEC was summarized as follows:

> In the end, YEC's agreement to finance Minto's capital cost contribution was based on Minto's special circumstances, the overall magnitude of expected ratepayer benefits related to the PPA, and the negotiated terms and conditions established in the PPA to protect YEC and YEC ratepayers. Although it is not without risk, YEC strongly believes that the ability to facilitate a major infrastructure development for the Yukon (interconnection of the MD and WAF grids) using YEC's surplus hydro especially given Minto's commitment to contribute $7.2 million to the capital costs of the CS Project presented an exciting opportunity for YEC and Yukon ratepayers.[36]

UCG had concerns about the relationship between the Minimum Take-or-Pay Amount, the YEC Security, and the connection to the Firm Mine Rate. In argument, UCG submitted that there was no justification for extinguishing the Take-or-Pay Amount in the event the Firm Mine Rate changes to the detriment of Minto: "That the savings may be less then projected do not mitigate the need for security related to the Take or Pay Amount by YEC in order to make the Project feasible (sic)."[37] In reply, UCG stated that Minto's inability to find conventional financing for its Capital Cost Contribution should be viewed as an indication of significant risk.

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[34] YEC Application to Approve Minto PPA, page 16.
[35] YUB-YEC-1-14 and YUB-YEC-1-32.
[36] YEC Argument, page 20.
[37] UCG Argument, page 13.

Mr. Percival's position was that if the Customer Cost Contribution was received up front, then Minimum Take-or-Pay provisions would not be necessary. It was also Mr. Percival's submission that the level of security held by YEC was inadequate and under distressed conditions, and YEC's position is tantamount to being virtually unsecured. Mr. Percival was of the view that as YEC is a regulated public utility, not a financial institution, the YUB should not approve YEC's taking on such risks.

YECL noted that based on Table D-1 of the Application, the Net Present Value (NPV) of the cost savings to Minto are estimated at $18.7 million. If there should be a material change to Minto's cost savings due to a change in the Firm Mine Rate or the underlying COS principles and methods in Schedule E, YECL noted that the Minimum Take-or-Pay Amount is reduced to offset the loss of cost savings and the YEC Security no longer provides security for the Minimum Take-or-Pay amount. Further, YECL stated that should Minto realize increased savings, no benefit was conferred to YEC or Yukon ratepayers.

YEC in its reply pointed out that only under Force Majeure conditions is the Mine released from its Take-or-Pay obligation.

Views of the Board

As discussed in s. 5 of this decision, the Board agrees with the views of the Intervenors that by not collecting the customer Capital Cost Contribution up front, that YEC and ratepayers face increased risk. The Board also agrees that the Minimum Take-or-Pay Amount should not be tied to the Firm Mine Rate as discussed in s.1 of this Decision.

In response to YUB-YEC-2-1, YEC submitted:

> The primary purpose of the Direct Agreement from YEC's perspective is to provide certainty to YEC and its ratepayers, regarding Macquarie Bank's and YEC's respective rights when it comes to each Party's security interest.

The response further stated:

> Under the Direct Agreement, Minto has agreed under Article 2.3 to a subordinated position to that of the Finance Parties; however, under 2.4 it is recognized that YEC shall retain the priorities that may be accorded to YEC by the Miner's Lien Act (sic) from time to time with respect to (a) the amount owing for any electricity delivered to Minto by YEC under the PPA and (b) the amount of any portion of the Capital Cost contribution (as defined in the PPA) which is due and owing by Minto to YEC under the PPA and interest thereon which is due and owing by Minto to YEC under the PPA.

It was YEC's position that as long as the mine remains viable using electricity delivered by YEC, YEC and its ratepayers are protected. YEC is satisfied that the Direct Agreement is an acknowledgement by the Macquarie Bank of the priority of YEC claims through the *Miners Lien Act*.

With the exception of YEC's not receiving up-front the customer Capital Cost Contribution, the Board is satisfied with the Security and Direct Agreement that YEC has put in place. Although not a guarantee, the Board finds the security measures put in place by YEC, such as the Direct Agreement, the Minimum Take-or-Pay Amount, and security as afforded by the *Miners Lien Act* are reasonable.

7. YEC Purchase of Diesel Units

Page 10 of YEC's PPA Application states:

> The PPA requires YUB approval of provisions respecting the YEC purchase of the four Diesel Units (each with a continuous rating of at least 1.6 MW) as set out under Part 10 of the PPA for $2.24 million, with YEC to provide payments to Minto in this regard on the same basis as Minto's Mine Spur Capital Costs Contribution payments, i.e. in equal blended monthly payments of interest and principal over the first seven years of YEC service.

YEC stated the benefits to the WAF system and to the Mine associated with the YEC acquisition of the Diesel Units are as follows:

- The units provide a comparatively low cost addition to WAF peak winter capacity (at a price not exceeding $350 per kW, the cost is competitive with the Mirrlees life Extension Project) at a time when YEC is actively examining options to enhance WAF firm winter peak capacity.
- The units provide added security to YEC and Minto as regards reliable supply at the Mine; in YEC's case, the purchase payment arrangements for this asset enhance YEC's security with regard to the Minto obligation to pay the Mine Spur Capital Cost Contribution.
- When WAF diesel operation is required, YEC operation of at least two of the Diesel Units at the Mine Site (especially for baseload operation) is expected to be cost effective (due to the minimization of line losses and related additional diesel generation requirements).
- In the near term these units provide cost effective contingency protection until such time as other potential major mine loads (Carmacks Copper) as well as capacity supply options are better clarified.[38]

Part 10 of the PPA describes the Conditions of Assignment, how payments for the Diesel Units are to occur, how the Diesel Units will operate and who is responsible for the operation of the Diesel Units, under what conditions the Diesel Units can be removed from the Mine Site and the closing of the Sale of the Diesel Units.

[38] YEC Application to Approve Minto PPA, page 11.

UCG took the position that if YEC were to assume ownership of the Diesel Units, their future deployment should not be limited to the WAF grid. More generally, Mr. Percival and UCG questioned the need for the units in light of the Government of Yukon's commitment to provide funding for the Aishihik Third Turbine development. Mr. Percival submitted that in light of the Government of Yukon's announcement the need to acquire units from Minto was no longer necessary and there were other more viable options available.

Mr. Percival disagreed with the purchase of the Diesel Units. His position was that if Minto provided its customer contribution up front then additional security would not be necessary. YECL also argued this point. Mr. Percival further stated that if Minto failed "in its spur line obligations, it is unlikely additional winter peaking will be necessary on the WAF grid."[39]

YECL took the position that YEC has not provided an appropriate business case to support the purchase of the Diesel Units, nor had YEC confirmed whether the Diesel Units were already "used equipment" prior to their use at the Minto mine. YECL further commented that YEC has not provided evidence to support that the price for the Diesel Units is indeed competitive. Further, YEC should not be financing the Minto customer contribution in which case the security argument about Minto's obligations is moot. YECL also argued that YEC provided no evidence to support the statement the line loss reductions will offset other incremental costs.

In reply, YEC noted UCG-YEC-2-14 and YUB-YEC-1-8 provided evidence as to the reasonableness of the purchase price and submitted that section 10.2 of the PPA provides safeguards to YEC with respect to the condition of the Diesel Units. YEC further commented that these diesel units would rank high in the stacking order reflecting cost effective operations. With respect to UCG's argument, YEC affirmed that the Diesel Units are mobile and could be moved or sold at any time after the terms and conditions set out in section 10.5 of the PPA are satisfied[40]. YEC generally rejected the premises of Mr. Percival's arguments and suggested that there was no evidence on the record to support Mr. Percival's position.

Views of the Board

With respect to some of the concerns expressed about the purchase of the Diesel Units, the Board is of the view that section 10.2 of the PPA provides adequate protection for YEC and Yukon ratepayers as to the condition of the units. The Board accepts that the price for the units as determined in the PPA and as further noted in UCG-YEC-2-14 and YUB-YEC-1-8 is reasonable. The Board also accepts the terms as to the mobility of the units. However, the Board is not convinced the units are needed. Other than a parenthetic notation late in the Resource Plan process, YEC has not demonstrated a need for the units nor provided an adequate business case supporting this option. Given

[39] Percival Argument, page 6.
[40] YEC Reply, page 32.

the new capacity planning criteria employed by YEC, YEC has not furnished evidence that these units are needed based on those criteria, nor where this capacity addition stacks with the other projects identified within the Resource Plan.

Further, the new funding available for the third turbine at Aishihik from the Government of Yukon also brings into question the need for the units and whether they would be a least cost option. The Board agrees with YECL that no evidence has been offered to support the statement that line loss reductions will offset other incremental costs. The Board also agrees with Mr. Percival and UCG's argument that if YEC did not agree to finance the customer contribution from Minto, the use of the units as security would not be necessary. In the event that YEC had to use the units as security for collection from Minto, it is questionable that the units would be in the condition stated in section 10.2 as under those circumstances the units are more likely to be in a distressed condition. Based on the foregoing, the Board does not accept the purchase of the Diesel Units as part of the PPA.

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

8. Decommissioning Costs

The PPA requires YUB approval of all Decommissioning Costs for the removal of the spur servicing the Minto mine to be incurred by YEC. YEC estimates these costs to be 25 percent of the capital costs to construct the spur. An Accrued Decommissioning Fund account will be set up by YEC and the final amount will be adjusted to actuals based on Section 11.2(c) of the PPA.

The Decommissioning Cost Payment will be paid to YEC by Minto:

- When Minto pays the outstanding balance of the Capital Cost Contribution under Section 5.2(d) at the end of the fourth year of service by YEC; or
- Within 180 days after Minto otherwise pays the outstanding balance of the Capital Cost Contribution; or
- In any event on or before the date on which Minto provides notice of the Commercial Operation Cessation Date.[41]

The PPA contains terms for YEC to collect any shortfall in decommissioning costs in excess of those in the fund from Minto; or conversely if the amount in the fund exceeds the actual decommissioning costs, that amount will be refunded to Minto.[42]

Mr. Percival commented that without knowing what the detailed construction costs of the line are, it is difficult to determine what the salvage costs will be. His estimate was that the salvage costs would be approximately 35 percent of the costs of constructing

[41] Section 11.2 of PPA.
[42] Section 11.3 of PPA.

the spur line. Mr. Percival suggested the terms of the PPA be revised to reflect his estimate and that the salvage costs be either collected up front or in four equal annual installments commencing at the end of the first year of service.

YEC summarized its position on Decommissioning Costs as follows:

> The ultimate aim of the decommissioning provisions under Section 11 of the PPA is to ensure that Minto pays all costs required to decommission the full Mine Spur and that at the time of decommissioning these costs have accrued in a fund and are available to pay the total cost of decommissioning after the Mine shuts down and YEC commences decommissioning activities. As noted in UCG-YEC-1-9 (4) the YEC Security provisions under section 6.5 of the PPA cover the decommissioning cost payment and the YEC Security cannot be discharged until that payment has been paid in full pursuant to section 11.2(b) of the PPA.[43]

YEC submitted that there was no basis for the Board to accept the 35-percent estimate for salvage costs from Mr. Percival. YEC stated that the 25-percent estimate for decommissioning costs was derived from its last depreciation study which set salvage costs for transmission components.[44] YEC stated that it was able to secure a one-time $850,000 Decommission Cost payment that would be placed in to an Accrued Decommissioning Fund and invested at 6.5 percent per annum and allowed to compound until such time as decommissioning costs were incurred. Further, there is a provision for a final true-up between Minto and YEC when all decommissioning costs are finally determined.[45]

Views of the Board

The Board recognizes that it is difficult to precisely determine the decommissioning costs when construction costs for the Minto Spur have not been fully determined. Given that the actual decommissioning costs cannot be determined at this time, the Board is satisfied that through Section 11 of the PPA, YEC has provided sufficient safeguards to ensure that Minto is responsible for all decommissioning costs. Further, the Board finds the set-up and use of the Accrued Decommissioning Fund to be an acceptable method to provide for these future salvage costs and that the liability of each party (YEC and Minto) is clearly set out in the final reconciliation. Regarding the decommissioning costs, the Board accepts YEC's percentage of 25 percent over that proposed by Mr. Percival as YEC's estimate is based on a prior depreciation study that set salvage costs. Therefore the Board approves the provisions respecting Decommissioning costs as set out in Part 11 of the PPA.

[43] YEC Argument, page 35.
[44] YECL-YEC-1-19.
[45] YEC Application to Approve Minto PPA, page 16.

9. Other Matters

Through the course of the proceeding additional matters arose:

a) Capacity Planning Criteria

Based on YEC's response to YECL-YEC-1-2, YECL stated that there is a misunderstanding between YEC and the Board with respect to YEC's capacity planning criteria. YECL noted that if YEC purchases the Minto diesel units, Minto will no longer have onsite backup supply, and so the Minto load should be included in the N-1 and LOLE criteria. YECL notes that this would require new generation sooner under the criteria. YECL submitted that these consequences need to be considered prior to the PPA moving forward. YECL sought clarification on whether the LOLE includes or excludes industrial load (Minto). YECL's understanding is that industrial load is not included in the N-1 criteria.

YEC responded stating that serving Minto at the firm loads provided in the PPA will have no impact on YEC planning capacity requirements under either the LOLE or N-1 criteria. The LOLE criteria included industrial loads and the N-1 criteria did not. Minto is to retain emergency back-up diesel generation units at the mine. YEC summarized its position as follows:

- As per the Resource Plan submission, the WAF system is designed to incorporate mine loads and the LOLE criteria is based on the principle that the system will be planned to ensure reliable service to all customers including mines and other industrials:
  - The LOLE criteria is comparable to criteria in other Canadian grid systems, and it ensures that all firm loads (including industrial customers such as Minto) receive reasonable utility-grade supply from the system.
  - The N-1 is included as an added "emergency criteria" to address the seriousness of sustained outages in Yukon of a critical system component (eg., the Aishihik transmission) during the period of peak winter loads; it is calculated to include firm loads, excluding major industrial loads. The Resource Plan noted that major industrial loads in Yukon (i.e., mines) "typically" have their own on-site diesel generation for emergency purposes.
- As reviewed in YECL-YEC-1-2, under the above criteria, mines will be served as firm customers (not as interruptible customers). Because secondary energy sales customers are interrupted based on lack of surplus hydro capability, they are interruptible customers and therefore are not taken into account in N-1.
- The PPA was negotiated based on YEC's currently adopted capacity planning criteria as reviewed above, and the following points are noted:
  - The service to the mine provided by YEC under the Firm Mine Rate is intended to be firm service that would be provided to Minto in all

hours of the year, whether from hydro or form diesel, to a utility standard (long-term average LOLE of two hours per year).

- The four diesel Units that Minto will use at the Mine until Commencement of Delivery by YEC, when Grid Electricity will be provided by YEC, will not at any time be considered "emergency backup" generation supply at the Mine. Minto will at all times have approximately 500 kW of additional backup power (of the type assumed in the Resource Plan Hearing) at the Mine to meet needs in emergency circumstances.[46]

Views of the Board

The Board notes that in s.3.2 of the YUB Report on the Resource Plan it states:

> Therefore, the Board recommends that, in order to ensure that no new generating capacity is added for the purpose of ensuring reliable supply to major industrial customers and to ensure consistency with the N-1 criterion, major industrial loads should not be included in the LOLE calculation.

The Board considers that the recommendation made in that Report speaks for itself and no further clarification is required.

b) Material Adverse Impact to Minto Savings

YECL noted that Minto's forecast cost savings (NPV) are estimated at $18.7 million. In argument, YECL requested the Board direct YEC and Minto to develop a more balanced approach to the factors affecting the Minto savings.[47]

YEC responded that the Take-or-Pay obligation and the YEC security is removed only if the Board materially alters the terms and conditions of the PPA, increases Rate 39 based on a COS that differs form the methods used in Schedule E, and either action materially adversely affects the cost savings to Minto from grid connection.

Views of the Board

The Board is not persuaded by the views of YECL. COS is the foundation upon which rates are based. It is cost causation that will determine a rate and not the deemed, perceived, or actual benefit to the recipient.

However, the Board has already determined that the COS provided by YEC is insufficient. The Board will not approve a rate structured to provide a certain level of benefit to any customer; rates are to be based on cost causation. As discussed in s. 1 of this decision, the Board has only approved the Firm Mine Rate on an interim basis, pending YEC's next GRA, in which a COS study will be filed.

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[46] YEC Reply pages 4-5.
[47] YECL Argument, page 14.

c) Rate Modifications

Rider F

YECL stated that in accordance with Section 6(1) and Section 8 of OIC 1995/090 that Rider F should continue to apply to all rate classes. For the 2008 rate, YECL did state that this rider should be set to $0.0 as Rate 39 already contains current diesel price information.

YEC responded that it was only seeking approval for the 2008 rate and that the rate could be amended later.

Views of the Board

The Board agrees with YECL. For consistency, the Board directs that a Rider F be included for Rate 39 and that for 2008 the rider charge be set to $0.0 for rate class 39.

Billing Demand

Mr. Percival requested the demand charge be increase to $16.00/kV.A from $15.00/kV.A. He also requested that the summer ratcheting provision be re-inserted into Rate Schedule 39.

YEC responded that there was no COS basis to change the demand rate and that the ratchets were applicable to system peak (winter months).

Views of the Board

The Board agrees with the position of YEC that the ratchets are intended to cover system peaks and that there is no current basis to change the demand rate. However, the Board agrees with Mr. Percival that these issues should be addressed in YEC's next GRA.

d) Applicability of Rates to YECL Service Territory

UCG and YECL stated that according to s. 6(1) of OIC 1995/090, rates must apply to all customers in the Yukon, so Rate 39 must apply to both utilities.

YEC acknowledged the comments of YECL and UCG but determined that currently there is only one planned Rate Schedule 39 customer (a YEC customer). If another such customer were to connect in YECL territory, then the rate schedule could then be modified accordingly.

Views of the Board

While the Board accepts that currently there is only one Rate 39 customer, given the direction in s. 6(1) of OIC 1995/090, the Board directs YEC to change the wording in Rate Schedule 39 accordingly.

C. Conclusion

The Board acknowledges that the PPA has not been approved as applied for and directs YEC to revise the PPA based on the foregoing and file the revision with the Board by May 31, 2007. However, given the upcoming Board hearing directed by the Government of Yukon on the CSTP that starts May 15, 2007, the Board requests that YEC endeavor, by May 9, 2007, to reach an agreement in principle with Minto on the changes required by the Board in order for the Board to approve the PPA, and advise the Board of the status by that date.

D. Summary of Board Findings

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1.0 Until such time as a decision is rendered in the next GRA, the Board will accept Rate 39 on an interim basis as proposed by YEC. The interim Rate Schedule 39 will be applicable throughout Yukon. Due to the concerns expressed about the sufficiency of the current COS presented by YEC, the Board is not prepared to accept Section 3.5 of the PPA.

2.0 Based on regulatory history, there is sufficient assurance to Minto that Yukon rates are stable and built upon sound practice, and therefore a link to the Minimum Take-or Pay provision is not necessary.

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

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

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

6.0 The Board directs YEC to amend the wording for Rate Schedule 35 when such an opportunity arises.

7.0 The Board approves the Peak Shaving Rate Option as applied for.

8.0 As the Board does not consider there to be adequate justification for the MNRA, nor is it required, the MNRA applied for is denied.

9.0 The Board is satisfied with the quantum of the contribution to the CSTP as it exceeds the contribution level based on the MUI model. That Minto will be responsible for 100 percent of the costs of the Mine Spur further supports this position. The Board accepts all the points brought forward by YEC in response to YUB-YEC-1-7. The determination of the $7.2 million for the CSTP contribution representing the mid-point cost estimate for a 35 kV line for service from Carmacks to Minto Landing is a prudent estimate to recover the cost of the additional transmission facilities to provide service to Minto. The Board prefers to see a contribution based on a fixed percentage versus a fixed amount. Noting that the Board views this project as a hybrid — a project to supply new load and a project to serve system requirements — the Board is of the view that the contribution to the CSTP should be indexed to the detailed cost estimates for the line. That is, if the final tendered cost exceeds the high estimate as shown in Schedule 1 of the Application, then the contribution should be indexed for the equivalent construction of a 35 kV line for the appropriate segments accordingly. To be clear, if the final tendered costs exceed the high estimate by 10 percent, then the contribution by Minto to the CSTP will increase by 10 percent.

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

11.0 If YEC suffers any losses due to the financing of the contribution, such losses shall be on account of YEC shareholders. While each case must be decided on its merits, the Board generally does not consider the utility's financing of customer contributions to be appropriate.

12.0 The Board views the receipt of $7.2 million in development funding in exchange for providing financing for approximately $3.8 million of Mine Spur costs as an arrangement that is beneficial to Yukon ratepayers.

13.0 As discussed in s. 5 of this decision, the Board agrees with the views of the Intervenors that by not collecting the customer Capital Cost Contribution up front, that YEC and ratepayers face increased risk. The Board also agrees that the Minimum Take-or-Pay Amount should not be tied to the Firm Mine Rate as discussed in s.1 of this Decision.

14.0 Other than not receiving upfront the customer Capital Cost Contributions, the Board is satisfied with the Security and Direct Agreement that YEC has put in place. Although not a guarantee, the security measures such as the Direct Agreement, the Minimum Take-or-Pay Amount, and security as afforded by the *Miners Lien Act*, put in place by YEC are reasonable.

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

16.0 The Board approves the provisions respecting Decommissioning costs as set out in Part 11 of the PPA. The Board accepts the estimated percentage of 25 percent for decommissioning costs as it is based on a prior study.

17.0 The Board recommends that, in order to ensure that no new generating capacity is added for the purpose of ensuring reliable supply to major industrial customers and to ensure consistency with the N-1 criterion, major industrial loads should not be included in the LOLE calculation.

18.0 The Board agrees with YECL and, for consistency, the Board directs that a Rider F be included for Rate 39 and that for 2008 the rider charge be set to $0.0 for rate class 39.

19.0 The Board agrees with the position of YEC that the ratchets are intended to cover system peaks and that there is no current basis to change the demand rate. However, the Board agrees with Mr. Percival that these issues should be addressed in YEC's next GRA.

20.0 The Board confirms the direction of s. 6(1) of OIC 1995/090 and directs YEC to change the wording in Rate Schedule 39 accordingly.

Attachment B – YEC Annual Transmission Facilities Costs

Line #	Description	Cost ($)
	Transmission Facilities costs as of end of 2008:	
1	Total assets at cost	1,455,125
2	Accumulated depreciation	294,939
3=1-2	Net book value at yr end	1,160,186
4	Annual depreciation	29,723
	Estimated Transmission Facilities costs at end of 2009 and end of 2010, assuming no new assets:	
5=3-4	Projected Net Book value at end of 2009	1,130,463
6=5-4	Projected Net Book value at end of 2010	1,100,740
7=(5+6)/2	Projected Net Value at mid yr 2010	1,115,602
	Based on YUB approved return (debt and equity cost at 6.56% blended) on rate base for 2009, plus depreciation, the annual owner costs for this line for	
8=4	Depreciation	29,723
9=7*6.56%	Return at 6.56%	73,183
10=8+9	Total Annual Cost	102,906
11=10/12months	**Cost per month**	**8,576**
8,576*0.85	**Alexco Fixed Charge**	**7,289**

REFERENCE: Alexco PPA, Application, Page 4

PREAMBLE:

The PPA Fixed Charge of $7,289/month ($87,468 per annum) assigns to Alexco 85% of YEC 2010 annual owner costs (depreciation and return) related to the defined Transmission Facilities primarily developed in the past to serve industrial customers in the District (i.e. UKHM).

and

The proposed 85% share as agreed in the PPA is based on NEB 1985 NCPC Report finding re: Faro mine which the YUB subsequently retained to set the fixed charge for the Faro mine under Rate Schedule 39.

QUESTION:

a) Please provide and cite all Board decisions where the Board specifically approved the 85% allocation of annual costs to Faro.

b) What was the Faro share, at the time of annual retail load (both demand and energy)?

c) What is the expected Alexco share of annual retail load (both demand and energy) of the Mayo-Dawson system?

d) How does the direct cost allocation of 85% of the costs (Faro mine) reasonably reflect the mine's share of the load on the line (approximately 96.8%)?

e) On an initial forecast basis (both load and costs), of the total costs (fixed and variable), what percentage of those total costs will be captured by Alexco?

f) Please list all factors that differ for the Alexco situation from those that existed at the time for Faro.

ANSWER:

(a)

The original justification of the 85% direct cost allocation to the Faro Mine was provided in the 1985 NEB Report in relation to the CAMC mine. See response to UCG-YEC-1-4 for a copy of Chapter 7 of this Report where this matter was addressed in section 7.3.4.2. The response to UCG-YEC-1-4(d) provides the NEB's rationale for the cost allocation to the CAMC mine.

Previous YUB decisions where this precedent was accepted are reviewed in response to YUB-YEC-1-3(a), which also provides the relevant excerpts. In summary, these precedents are as follows:

- **1992 Report on Cost of Service and Rate Design** - In the 1992 COS and Rate Design Review, the Companies relied upon the rationale provided by the NEB to determine the proportion of this asset to be assigned specifically to the industrial class (i.e., the Faro mine). It was noted during the 1992 COS and Rate Design review that "inasmuch as the Whitehorse/Faro transmission line was constructed specifically for the purpose of servicing the Faro mine operated by Cyprus Anvil, a substantial portion of the cost of the line should be allocated to the industrial class" (at page 26). At page 29 of the Report the Board recommended that the appropriate method of allocating transmission costs is to specifically assign 85% of the costs of the Whitehorse/Faro line to Curragh, and to allocate all remaining transmission costs to all customer classes including Curragh, on the basis of demand at the time of system peak.

- **Order 1993-8** - The Board determined that there were no changes in circumstances that warrant changes to the cost of service or rate design principles from those established in the 1992 Cost of Service hearing and that that methodology and rate design proposed by the Companies was appropriate.

- **Order 1996-7** - In 1996/97 GRA, the then current Faro mine owner (Anvil Range Mining or ARM) argued that as a new company, it should not be subject to the specific cost allocations applied in the past, noting the transmission line was not designed specifically for ARM, is fully depreciated and the rate level should

therefore reflect the current cost of the line. The Companies at that time argued that the vintage of the customer was irrelevant to the COSS and that there were no changes in circumstances to justify a review or revision of the methodology from that established in the 1992 Report. The Board in 1996 agreed that this allocation conforms to similar practices in Canada and the assignment of 85% specifically to the industrial rate class was based on usage and not related to the vintage of the customer since in the absence of the mine load the line would not have been built (see page 4-5 of Order 1996/7).

(b) and **(c)**

As reviewed in the recent 2009 Phase II hearing, in relation to the 1996/97 COS it was noted that the Faro Mine was approximately 43% of the energy on the overall Yukon system and 29.99% of demand on the overall Yukon system. Such shares had no bearing on the NEB report recommendation in 1985 regarding fixed transmission charge allocation to the Faro mine, i.e., that recommendation was based on the Faro mine share of the load on the relevant transmission segment (from Whitehorse to Faro) for which the fixed costs were being allocated to the Faro mine.

Based on Mayo Dawson approved forecast loads for 2009 (see Tab 2 of YEC 2008/2009 GRA) and Alexco loads per the PPA, the Alexco loads are expected to approximate one third of the Mayo Dawson system energy sales and demand. Such shares had no bearing on the PPA determination of the Alexco Fixed Charge i.e., that charge was determined as set out in Attachment B to the PPA Application, and as reviewed in response to YUB-YEC-3(b), based on the Alexco share of the load on the relevant transmission segment (from Mayo to Keno) for which the fixed costs were being allocated to the Alexco facilities.

(d)

Page 4 of the September 28, 2010 Application letter notes the proposed 85% share was agreed to between YEC and Alexco as a fair allocation of annual costs of the line to the industrial customer based on past Yukon precedent established for the treatment of Faro mine.

For the Faro mine, the NEB noted in its report in 1985 that the mine's share of the line annual costs prior to 1985 (in 1983/84) had approximated 96.8%, which was understood to reflect the mine's share of load on the line. After considering this information, the NEB recommended that 85% of the annual cost be assigned specifically to the Faro Mine and that the remaining 15% be rolled in with the pooled costs to be allocated to all customer classes (including industrial) based on their respective demands, i.e., the NEB noted that "The 85% figure for CAMC [the Faro Mine] reflects the fact that, under this arrangement, CAMC would also be assigned its share of the pooled costs."

Alexco's estimated share of the load on the Mayo-Keno line is 98%, which for all practical purposes appears to reflect the Faro Mine actual share of the Whitehorse Faro line load in 1983/84. However, as in the Faro Mine case reviewed by the NEB in 1985, it is understood that under any future COS determination the Alexco mine would also be assigned its share of the pooled costs.

(e)

The proposed Fixed Charge sets out the share of forecast fixed costs for the specified transmission facilities that Alexco would pay (i.e., 85%). YEC does not have a similar forecast of variable costs for this line segment - and, based on the earlier Faro Mine precedent, it would not be appropriate to include variable costs in this Fixed Charge.

(f)

Please see response to YECL-YEC-1-4(d) and (j). Unlike the circumstances surrounding the Whitehorse to Faro line built to service CAMC in 1969, there is no related agreement between Alexco and the Government of Canada or any other government - however, in Alexco's case, there is a specific agreement on this matter between the utility and Alexco, as well as the history of the relevant line having been built in the past specifically to supply mine activities in the Keno district. At the time of the NEB review leading to its1985 report the Faro mine in fact was closed - in contrast, today the Alexco mine and mill are operating.

REFERENCE: Alexco PPA, Application, Page 5

PREAMBLE:

Under the Alexco PPA Capital Costs are to be paid by Alexco for all Mine Facilities Spurs that YEC agrees to develop to provide grid service to the Mine Facilities as well as for YEC's costs to negotiate and conclude the PPA (and such costs are to be fully paid shortly after Commencement of Delivery to the relevant Mine Facilities).

QUESTION:

a) Have the Capital Costs been paid by Alexco since the Commencement of Delivery was expected to occur in October 2010?

b) If the Capital Costs have not been paid as of the date of the responses to these information requests, who is responsible for the working capital costs of the Mine Facilities Spurs until such time as the Capital Costs are paid?

ANSWER:

(a)

YEC has invoiced Alexco for 50% of the estimated Capital Costs as provided for in Section 5.1 of the PPA, and this invoice was paid by Alexco according to the PPA stipulated terms. During December YEC will finalize the Capital Costs and invoice Alexco for the remaining portion. See also response to LE-YEC-1-4(a) and (b).

(b)

As part of its internal accounting processes, YEC charges AFUDC (Allowance for Funds Used During Construction) towards all open work orders, and this charge will become part of the final Capital Cost to be paid by Alexco.

REFERENCE: **Definition of Costs to be Paid by Alexco [Section 1.1(j)], Attachment A-6**

QUESTION:

a) Do the costs and expenses reasonably incurred to conclude the PPA with Alexco include all the costs associated with this regulatory proceeding?

b) Are the costs referred to in (a) above to be included at the Board scale of costs?

ANSWER:

(a) and **(b)**

No. Costs for regulatory review of the PPA are considered regulatory costs of Yukon Energy. YEC will apply for Board approval of costs for the preparation and review of the PPA Application as part of the costs awards process for the current proceeding. As such, these costs will be subject to the Board scale of costs.

REFERENCE: **Schedule of Payment of Capital Costs by Alexco [Part 5, Section 5.1(a-d)], Attachments A-18 and A-19**

QUESTION:

a) Do the costs defined in Part 5, section 5.1(a-d) include a working capital component?

ANSWER:

(a)

Yes, as part of its internal accounting processes YEC charges AFUDC (Allowance for Funds Used During Construction) towards all open work orders, and these costs will become part of the final Capital Cost to be paid by Alexco.

REFERENCE: **Alexco PPA, Application, Page 7 – Payments for Future Decommissioning Costs for the Mine Facilities Spurs**

PREAMBLE:

Alexco will make Decommissioning Cost Payments (based on the Estimated Decommissioning Costs) towards this account to be deposited into the account by YEC upon payment and invested at 6.5% interest per annum to fund YEC's regulated rate base during the Term under Part 11.

QUESTION:

a) Does YEC see this investment as an equity component or a debt component in its capital structure?

ANSWER:

(a)

This investment is treated as an offset to rate base thus can be considered 60% debt and 40% equity (assuming that this capital structure continues to apply to YEC). In practice, such payments would reduce the rate base amount otherwise funded by debt and equity.

REFERENCE: **Alexco PPA, Attachment A-7, Section 1.1(m) Commercial Operation Date**

QUESTION:

a) What is the Commercial Operation Date?

ANSWER:

(a)

The Commercial Operation Date for the Initial Mine Facilities (i.e., the first date on which Alexco actually received Grid Electricity from YEC for a combined Electric Demand at the Points of Delivery in excess of 1,000 kW) is November 1, 2010.

REFERENCE: **Alexco PPA, Attachment A-7, Section 1.1(o)**
Decommissioning Costs

QUESTION:

a) Do Decommissioning Costs include costs with respect to the inspection of the restored sites and any related regulatory costs?

ANSWER:

(a)

Yes, Decommissioning Costs include all YEC costs reasonably required to remove such parts of the Mine Facilities Spurs to be decommissioned after a Mine Facilities Shut Down Date as YEC may at that time require to be decommissioned, including all such costs associated with removal of all equipment, salvage, site restoration, monitoring, and inspection of the restored sites and all directly related regulatory costs.

REFERENCE: Alexco PPA, Attachment A-10, Section 1.1(mm) Interest

QUESTION:

a) Please provide an example of the documentation used to determine the interest rate as defined in (mm) of 1.1 Definitions in Part 1 Definitions and Interpretation.

ANSWER:

(a)

YEC has not issued external debt for some time. As such, in recent YEC experience the interest rate has been based on what YEC could secure from TD Canada Trust. Documentation in this regard relates to discussion and email correspondence.

REFERENCE: **Alexco PPA, Attachment A-14, Section 3.3 Initial Activities — Initial Mine Facilities**

QUESTION:

a) Please confirm the dates for the commissioning of the Initial Mine Facilities.

ANSWER:

(a)

The PPA does not provide for notification to YEC by Alexco as to any "commissioning dates" for the Initial Mine Facilities. Under section 3.3 of the PPA, provision is made for Alexco to provide written notice to YEC of the Mine Facilities Operation Date (i.e., the date on which Alexco wishes the commercial operation for that Mine Facility to occur) for the Initial Mine Site and for the Initial Mill Site. Although written notice was not necessarily provided, YEC understood from Alexco that the Mine Facilities Operation Date for both the Initial Mine Site and the Initial Mill Site had occurred by November 1, 2010, even though commercial operation of the Mill was to occur November 3rd.

As regards the commencement of delivery of Grid Electricity by YEC, the Initial Mill Site started to receive Grid Electricity on October 6, 2010.

The Initial Mine Site has been an existing Point of Delivery long before the PPA and did not require commissioning related to the PPA.

REFERENCE: **Alexco PPA, Attachment A-21, Section 7.2 Metering — Testing**

PREAMBLE:

If a meter is found not to be functioning within the prescribed limit of error, the Electricity purchased will be determined under the Act.

QUESTION:

a) Please provide further explanation to the above statement and support it with a numerical example.

ANSWER:

(a)

The provisions of section 7.2 provide for testing of meters, and the referenced sentence addresses what will occur in the event that such tests determine that a meter is not functioning within the prescribed limit of error.

Under standard Yukon Energy procedures, if a meter was found to be reading low resulting with a lower bill, then the utility would first identify the error to the customer and attempt to reach an agreement with the customer to remedy the error. If the two parties are unable to agree, then either party can register a complaint with Measurement Canada who will inspect the meter in dispute and confirm its accuracy. Both parties are informed of their findings. In either event, regardless as to whether the error reduced or increased the bill, the customer's bill will be adjusted back to the time when the error can be reasonably estimated. When the initial start of the error cannot be estimated, then the start to the error is deemed to be three months before the meter test or the installation date of the meter, whichever occurred later.

As an example, if the meter was reading 5% low for three months for both demand and energy, then the three previous months' bill would be reviewed and adjusted. The monthly energy amount would be increased by 5%, the monthly metered demand would be increased by 5% and the bill would be recalculated. There would be an adjustment

identified for the energy portion of the bills and there may be an adjustment made for the demand charges, if the corrected demand exceeded the existing billing demand for those months. The customers would be required to pay the difference in the three months previous bill and the corrected bill.

REFERENCE: **Alexco PPA, Attachment B-1 — YEC Annual Transmission Facilities Costs**

QUESTION:

a) Please provide the source for the actual 2008 transmission costs and the estimated transmission costs to the end of 2009 and 2010.

b) Please reconcile the transmission costs amounts to the amounts approved in YEC's 2008-2009 GRA.

c) Will Alexco derive any benefits from the completion of the second stage of the Carmacks-Stewart Transmission Project (CSTP)?

d) If so, should any residual costs of the CSTP Stage 2 be included I the fixed costs under this PPA?

ANSWER:

(a) and **(b)**

The source data for the YEC Annual Transmission Facilities Costs was the Actuals for 2008. Data to this type and detail is not included in GRA filings. The data relied upon is provided as Attachment 1 to this response.

(c) and **(d)**

No. Alexco is not deriving direct benefits from completion of CSTP Stage 2. Alexco is commencing service as an industrial customer prior to completion of this line and interconnection of the grids, and is being served through the existing 69 kV Mayo-Keno line via a Mine Facilities Spur that the mine is fully funding.

The CSTP Stage 2 line is expected to be fully funded by Federal and YDC contribution payments. Benefits will occur for ratepayers through reduction in YEC diesel generation costs otherwise required without connection of the two existing grids.

Asset #	GL Code	Gl Desripton	Amount Dec 31, 2008	Ending Accum. Dep 2008	rate	Annual Deprec	
290	20.140006.300	Poles and fixtures	328,856.38	94,189.86	2.00	6,577.13	
803	20.140006.300	Poles and fixtures	24,028.74	4,182.51	2.00	480.57	
1074	20.140006.300	Poles and fixtures	28,519.52	4,162.32	2.00	570.39	
1165	20.140006.300	Poles and fixtures	209,170.07	29,074.76	2.00	4,183.40	
1674	20.140006.300	Poles and fixtures	123,673.73	11,724.79	2.00	2,473.47	
4461	20.140006.300	Poles and fixtures	75,021.60	3,376.09	2.00	1,500.43	
7399	20.140006.300	Poles and fixtures	43,044.24	-	2.00	860.88	Asset was added at 12/31/2008
7430	20.140006.300	Poles and fixtures	19,754.56	-	2.00	395.09	Asset was added at 12/31/2008
7370	20.140009.605	Communication Equipment	20,677.62	-	5.00	1,033.88	Asset was added at 12/31/2008
291	20.140006.402	Overhead Conductors/Poles	241,985.37	88,814.62	2.00	4,839.71	
804	20.140006.402	Overhead Conductors/Poles	287,160.90	50,920.60	2.00	5,743.22	
879	20.140006.402	Overhead Conductors/Poles	53,231.89	8,493.21	2.00	1,064.64	
Total Plant In Service			1,455,124.62	294,938.76		29,722.82	
			net y/e 2008	1,160,185.86			