IN THE MATTER OF

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)
and
(Tumbler Ridge Division)

2012 REVENUE REQUIREMENTS

DECISION

November 9, 2012

Before:

C.A. Brown, Commissioner

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EXECUTIVE SUMMARY

This is a decision pursuant to an application to the British Columbia Utilities Commission (Commission) by Pacific Northern Gas (N.E.) Ltd. [PNG (N.E.)] pursuant to sections 58-61 and 89-90 of the *Utilities Commission Act* for approval of PNG (N.E.)'s 2012 forecasted Revenue Requirements to increase rates. This is to support a forecasted 2012 revenue deficiency for PNG (N.E.) Fort St. John/Dawson Creek approximately $0.100 million comprised of a net decrease in cost of service of $0.081 million and a decrease in margin of $0.181 million, and a forecasted revenue deficiency for PNG (N.E.) Tumbler Ridge of approximately $0.246 million comprised of a net increase in cost of service of $0.310 million offset by an increase in margin of $0.064 million. (Exhibit B-3, p. 2; Exhibit B-4, p. 2) This would have the following impacts on the various classes of ratepayers within PNG (N.E.):

- A 1.3 percent increase in the annual bill for Fort St. John residential customers
- A 1.4 percent increase in the annual bill for Fort St. John small commercial customers
- A 1.4 percent increase in the annual bill for Dawson Creek residential customers
- A 1.8 percent increase in the annual bill for Dawson Creek small commercial customers
- A 12.7percent increase in the annual bill for Tumbler Ridge residential customers
- A 11.1 percent increase in the annual bill for Tumbler Ridge small commercial customers

PNG (N.E.) cites the following reasons as the main driver for the rate increase: lower gross margin, higher cost of service, and the increasing cost of its pension obligation.

The proceeding was conducted as a written hearing. There were two registered interveners, the Peace River Regional District and the British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO) [recent name change to British Columbia Pensioners' and Seniors' Organization] of which BCOAPO filed substantial submissions.

Several key issues emerged during the proceeding. The Panel has addressed these issues in the decision, which include: the impact of adopting US Generally Accepted Accounting Principles and the rising cost of shared services. Pension issues have been dealt with in more detail in the Pacific Northern Gas Ltd. 2012 Revenue Requirements Decision.

The Commission Panel has reviewed and considered PNG (N.E.)'s requests and has approved the 2012 Revenue Requirements Application, subject to the directives contained within the Decision. The significant directives include:

- PNG (N.E.) is to amortize its Plant Gains and Losses Deferral Account over five years instead of PNG (N.E.)'s proposed ten year period. In future revenue requirements applications PNG (N.E.) is also to provide an assessment of each new addition to the Plant Gains and Losses Deferral Account.
- Some of PNG (N.E.)'s requested treatments for pensions and other non-pension post retirement benefits (NPPRB) were not approved. If PNG (N.E.) wishes to reapply to the Commission for recovery in rates in 2013 for any of the pension/NPPRB items then PNG (N.E.) is to file a separate comprehensive pension application.

The 2012 permanent rates will be lower than the 2012 interim rates therefore PNG (N.E.) is directed to submit an amended Schedule of Rates and Bill Comparison that conforms to the directions in the Reasons for Decision.

1.0 INTRODUCTION

1.1 Background

Pacific Northern Gas (N.E.) Ltd. [PNG (N.E.), Utility, and Company] is a wholly owned subsidiary of Pacific Northern Gas Ltd. (PNG) and serves customers in the Fort St. John, Taylor, Dawson Creek, Pouce Coupe, and Tumbler Ridge areas of north eastern British Columbia. The Fort St. John/Dawson Creek (FSJ/DC) Division receives natural gas from the Spectra Energy (formerly Duke Energy) Gas Transmission pipeline system and the Canadian Natural Resources Limited (CNRL) pipeline. The Tumbler Ridge (TR) Division obtains all its raw gas supply from CNRL and operates its own small gas processing plant.

The parent company, PNG, delivers natural gas to customers, including large industrial operations, in a region west of Prince George to tidewater at Kitimat and Prince Rupert. PNG's head office is in Vancouver. Customer service and administrative functions for both PNG and PNG (N.E.) are supported from a regional office in Terrace. Although PNG (N.E.) has construction, operation, and maintenance staff located in its service territory, PNG provides PNG (N.E.) with most of its administrative, support, and gas supply services.

PNG (N.E.) received British Columbia Utilities Commission (Commission) approval to use US Generally Accepted Accounting Principles (US GAAP) for regulatory accounting and reporting purposes for the period January 1, 2012 to December 31, 2014 (see Order G-168-11). This is PNG (N.E.)'s first Revenue Requirements Application under US GAAP.

PNG (N.E.) invoices customers for their services in the following categories: a Basic Monthly Charge, a Delivery Charge, a Company Use Rate Rider, a Revenue Stabilization Adjustment Mechanism Rate Rider, a Commodity Charge, and a Gas Cost Variance Account Rate Rider. The subject of this Application does not include Commodity Charge or the Gas Cost Variance Account Rate Rider.

PNG (N.E.)'s 2011 Revenue Requirements was reviewed through a Negotiated Settlement Process (NSP) and the Negotiated Settlement Agreement (NSA) approved by the Commission (see Commission Order G-93-11). Item 44 of the 2011 NSA provided that PNG (N.E.) should prepare its 2012 Revenue Requirements Application (2012 RRA), in the anticipation of a public hearing process, rather than an NSP.

1.2 The Application and Approvals Sought

PNG (N.E.) filed for approval of its 2012 Revenue Requirements Application on November 30, 2011, to increase, among other things, its delivery rates pursuant to sections 58 to 61 of the *Utilities Commission Act* (*UCA*, the Act). PNG (N.E.) FSJ/DC forecasted a 2012 revenue deficiency of approximately $0.331 million comprised of a net increase in cost of service of $0.121 million offset by a decrease in margin of $0.210 million. (Exhibit B-1, Tab Application, p. 3) PNG (N.E.) TR forecasted a 2012 revenue deficiency of approximately $0.323 million comprised of a net increase in cost of service of $0.342 million offset by an increase in margin of $0.019 million.

PNG (N.E.) also requested refundable interim relief pursuant to sections 58 to 61, 89 and 90 of the Act, to allow PNG (N.E.) to amend its rates on an interim basis, effective January 1, 2012. The Commission approved the delivery rates and the Revenue Stabilization Adjustment Mechanism (RSAM) rider set forth in the Application on an interim and refundable basis, effective January 1, 2012 (see Order G-208-11). The Commission also established a Preliminary Regulatory Timetable for Intervener registration and a Workshop to review the issues in the Application.

The Peace River Regional District (PRRD) and the British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO – recently changed to British Columbia Pensioners and Seniors Organization) registered as Interveners in this proceeding.

In response to a Commission letter dated January 4, 2012, which requested submissions regarding the appropriate review process for the Application and comments on a draft Regulatory Timetable, the Commission received submissions from PRRD and PNG (N.E.), supporting a written hearing process while BCOAPO submitted that a written process may be appropriate but it reserved the right to re-assess its position at the conclusion of the evidentiary stage. All parties supported the filing date for Information Requests (IRs) to occur after PNG (N.E.) filed updates to the Application.

The Commission considered the submissions received and established an Amended Regulatory Timetable for the preliminary review of the Application (see Order G-13-12, dated February 7, 2012). The timetable provided for two rounds of Commission and Intervener IRs followed by submissions regarding any further process for the review of the Application. A placeholder schedule for written argument was also specified.

On March 15, 2012, PNG (N.E.) filed updates to the 2012 RRA (the 2012 RRA and the updates to the 2012 RRA are collectively referred to as the Application) to reflect the impact of the year end 2011 figures on the forecast 2012 cost of service. PNG (N.E.) FSJ/DC forecasts a 2012 revenue deficiency of approximately $0.100 million comprised of a net decrease in cost of service of $0.081 million and a decrease in margin of $0.181 million. (Exhibit B-3, p. 2) PNG (N.E.) TR forecasted a 2012 revenue deficiency of approximately $0.246 million comprised of a net increase in cost of service of $0.310 million offset by an increase in margin of $0.064 million. (Exhibit B-4, p. 2)

After the completion of the evidentiary phase of the proceeding, PNG (N.E.) applied on September 13, 2012, to the Commission pursuant to sections 44.2(1)(b) and 52 of the Act for approval to:

(i) construct a new Dawson Creek Operations Centre on vacant property presently owned by PNG (N.E.) at 1805 – 98 Avenue, Dawson Creek for an estimated cost of $1,017,000; and

(ii) dispose of the facilities comprising the existing Dawson Creek office building and land at 1208 – 102 Avenue, Dawson Creek (Existing Operations Centre) (Dawson Creek Operations Centre Application).

(Dawson Creek Operations Centre Application, September 13, 2012 letter)

The Dawson Creek Operations Centre Application also noted that the 2012 RRA included planned capital expenditures of $421,000 for the reconstruction of a significant block wall and grade beam at the Existing Operations Centre. (Dawson Creek Operations Centre Application, p. 4) It is anticipated that the planned construction of the Dawson Creek Operations Center and the corollary disposal of the existing property will impact this Application.

1.3 The Written Hearing Process

After the evidentiary stage, the Commission received further submissions on process from PNG (N.E.), BCOAPO and the PRRD in response to the Commission's request, in accordance with Order G-12-12. Each of the submissions supported a written hearing for the review of the Application.

The Commission considered the submissions received, and determined that a written public hearing process should be established to review the Application and revised the Regulatory Timetable for Final Arguments in Order G-67-12.

2.0 REGULATORY AND POLICY FRAMEWORK

PNG (N.E.) applies to the Commission for Revenue Requirements approval, pursuant to sections 58-61 and 89-90 of the *UCA*. Section 59 (1)(a) of the Act provides that a public utility must not make, demand, or receive an "unjust, unreasonable, unduly discriminatory or unduly preferential rate" for its services. The *UCA* further provides that the Commission Panel has sole discretion to determine whether a rate is unjust or unreasonable, or whether there is undue discrimination, preference, prejudice or disadvantage respecting a rate (s. 59(4)). Specifically, the *UCA* sets out the parameters for rate setting, providing that a rate is unjust or unreasonable if it is more than a fair and reasonable charge for service of the nature and quality provided by the utility (s. 59(5)(a)) or if it is "insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property" (s. 59(5)(b)).

In terms of the regulatory policy underlying a revenue requirements application, the Panel emphasizes that rates must be fair, just, and reasonable, and must not discriminate nor grant preferences among ratepayers within a class. To be fair and reasonable, the Panel considers the interest of protecting the public in a monopolistic environment in securing fair, reasonable and stable rates, while also allowing the utility an opportunity to earn a reasonable rate of return on its investment.

3.0 SALES VOLUME FORECASTS

The ability to forecast the number of customers and the customer usage rate is an integral part of Revenue Review Applications (RRA). This section sets out the Applicant's sales forecasts and the assumptions and risks inherent in those forecasts, with a view to determining whether the forecasts are reasonable.

PNG (N.E.) submitted updated load forecast numbers as part of its Revised Application for the FSJ/DC and TR divisions. (Exhibit B-3, Tab Rates, pp. 6-21; Exhibit B-4, Tab Rates, pp. 1-10) The methodology for the updated load forecast values appears to have remained the same as that used in the original Application. (Exhibit B-1) The updated Application for PNG (N.E.) Fort St. John/Dawson Creek and Tumbler Ridge divisions reflect the impact of actual year end 2011 figures on the forecast 2012 cost of service and other adjustments. (Exhibit B-3; Exhibit B-4)

PNG (N.E.) FSJ/DC provided additional load forecast data (Exhibit B-8) and analysis in its responses to IRs from Commission staff and BCOAPO that included extensive historical data and time-series analysis in support of its Application. This data included annual year-end average customer counts and normalized use per account based on twelve years of historical data from the Fort St. John and Dawson Creek areas.

Sales customer volume forecasts are provided to anticipate the natural gas that PNG (N.E.) purchases and/or delivers on behalf of its customers. For PNG (N.E.), sales customers represent 67 percent of the deliveries, with the remaining 33 percent being delivered to customers who purchase their own gas and pay PNG (N.E.) only for transportation on its system.

PNG (N.E.)'s load forecast for 2012 projects a gross margin of $13.4 million (Exhibit B-3, p. 13; Exhibit B-4, p. 6) of which approximately 88 percent relates to sales deliveries, and 12 percent relates to transportation deliveries. PNG (N.E.) FSJ/DC is forecasting approximately a 4.4 percent increase in sales customer deliveries and a 6.1 percent decrease in transportation deliveries for forecast 2012 compared to the 2011 actual volumes. (Exhibit B-9, FSJ/DC, BCUC 1.51.1; Exhibit B-12, FSJ/DC, BCUC 2.76.2.1)

On a consolidated basis for all customer classifications and service regions, PNG (N.E.) is forecasting relatively little change in Terajoules (TJ) usage. Actual 2011 gas deliveries were 5.285 TJ as compared to expected usage in 2012 of 5.322 TJ, representing less than 1 percent change in overall energy demand. Although the net change in energy usage for the 2012 forecast is small, fluctuations among individual rate classes are significant, in some cases with variations of 69 percent compared to 2011 actual deliveries.

3.1 Fort St. John

The Fort St. John region has applied for rates based on projected sales volumes of 2,120,402 GJ and transportation volumes of 923,800 GJ. (Exhibit B-3, Tab Rates, p. 11) The Fort St. John region accounts for approximately 62 percent of the total gross margin for the PNG (N.E.) region. The remaining 38 percent of gross margin is derived from gas sales and transportation services in the Dawson Creek and Tumbler Ridge regions. (Exhibit B-3, Tab Rates, p. 13; Exhibit B-4, Tab Rates, p. 4)

Residential

PNG (N.E.)'s residential load forecast is based on the forecasted number of customers and their forecasted use of gas. For 2012, the residential load forecast is 1,028,162 GJ, which is a function of a forecasted average count of 9,652 customers and a normalized use per customer of 106.5 GJ/year. (Exhibit B-3, Tab Rates, p. 11) The 9,652 customer forecast was determined forecasting the 73 net customer additions to the year-end 2011 customer count by taking the difference between the average of the 2012 month end customer count and the 2011 year-end customer count. (Exhibit B-9, p. 71) The 106.5 GJ/year is closely based on a first order regression of historical use per account data.

Commission Determination

The Commission Panel has considered PNG (N.E.)'s forecast methodology. The load forecasting approach applied by PNG (N.E.) for residential customers is consistent with the methodology applied in previous applications. The level of forecast confidence that may be placed on gas deliveries for 2012 is affected by the Applicant’s forecasting track record in previous years. To the extent that the Applicant’s historical forecasts are accurate, the Commission Panel may place a high degree of reliance on those forecasts.

The Commission reviewed, PNG (N.E.)’s forecasting track record for the period 2006 to 2011, for FSJ/DC. The average forecast error for Residential Sales is 2.6 percent above actual with an 80 percent bias of over forecasting energy demand. The magnitude of the forecast error is relatively small (2.6 percent) but the bias (80 percent) is significant, which may suggest that it is systemic in nature. (Exhibit B-12, FSJ/DC, BCUC 2.76.1; 2.76.2.1) The Commission Panel encourages the Application to review its forecasting methodology for future periods.

The Commission accepts that forecasting energy demand is inherently difficult due to a multitude of variables that are outside of the control of PNG (N.E.). **For the 2012 forecast the Commission Panel accepts PNG (N.E.)’s forecast weighted average residential customer count of 9,652 and forecast use per customer of 106.5 GJ/year resulting in a residential load forecast of 1,028,162 GJ in Fort St. John.**

Small Commercial

PNG (N.E.) forecasts deliveries of 727,135 GJ to its small commercial customers in Fort St. John. This is based on the product of the 2012 test year weighted average customer count and the 2012 test year average use per account. (Exhibit B-3, Tab Rates, p. 11)

PNG (N.E.) estimated 4 net customer additions to the 2012 test year, bringing the total customer count to 1,591 by taking the difference between the average of the 2012 month end customer count and the 2011 year-end customer count. (Exhibit B-9, FSJ/DC, BCUC 50.5) The use per account estimate of 457.0 GJ/year is closely based on a first order regression of historical normalized use per account data.

Commission Determination

PNG (N.E.)'s forecast of 727,135 GJ has been derived using a consistent methodology to that applied in previous Applications. On a consolidated basis for FSJ/DC over the six-year period 2006 to 2011, PNG (N.E.)'s Small Commercial forecasts have had a 70 percent bias of over-forecasting energy demand by 3.7 percent. The magnitude of the forecast error is moderate (3.7 percent) but the bias (70 percent) is significant. (Exhibit B-12, FSJ/DC, BCUC 2.76.1)

The Commission accepts that forecasting energy demand is inherently difficult due to a multitude of variables that are outside of the control of PNG (N.E.). **For the 2012 forecast the Commission Panel accepts PNG (N.E.)'s Small Commercial gas deliveries of 727,135 GJ in Fort St. John.**

Large Commercial

PNG (N.E.) forecast that the 2012 level of consumption would be 136,050 GJ, is based on a review of historical deliveries and expected use in 2012, based on discussions with these customers. (Exhibit B-3, Tab Rates, p. 11)

The Large Commercial sales forecast in 2012 in the Fort St. John region is 22,093 GJ less than in 2011, which represents a 14 percent decrease in sales volume. (Exhibit B-9, FSJ/DC, BCUC 1.51.1, p. 73) There is no specific reason for the decrease. PNG (N.E.) relies on forward-looking projections from their Large Commercial customers that involves confidential business information on a customer-by-customer basis. Due to the relatively small customer base, the volatility in sales volumes from one year to the next is not uncommon.

The decrease in the Fort St. John region is offset by an increase in the Dawson Creek region by 22,229 GJ, leading to slightly higher sales volume in the consolidated FSJ/DC region. On a consolidated basis, the 2012 deliveries forecast by PNG (N.E.) are reasonably close to the actual deliveries recorded in 2011.

Commission Determination

The Commission Panel accepts the 2012 deliveries forecast of 136,050 GJ for PNG (N.E.)'s Large Commercial customers in Fort St. John.

<u>Small Industrial</u>

PNG (N.E.) 2012 forecast gas deliveries of 229,055 GJ to Small Industrial customers based on discussions with those customers, and represent a 69 percent increase over 2011 gas deliveries of 135,705 GJ. (Exhibit B-9, BCUC 1.51.1) The reason for the large increase is due to the addition of two new customers, which accounts for 108,306 GJ of the increase. (Exhibit B-1, Tab Application FSJ/DC, p. 33)

Commission Determination

The Commission Panel accepts the 2012 deliveries forecast of 229,055 GJ for PNG (N.E.)'s Small Industrial customers in Fort St. John.

<u>Industrial and Commercial Transportation Service</u>

PNG (N.E.) is forecasting deliveries of 923,800 GJ to its Industrial and Commercial Transportation Service customers in 2012, which represents a reduction of 203,200 GJ (approximately 18 percent), compared to NSP 2011. (Exhibit B-3, Tab Rates, p. 11) Actual 2011 Industrial and

Commercial Transportation Service deliveries were 1,107,200 GJ. (Exhibit B-9, BCUC 1.51.1) The reason for the reduction in transportation service has been attributed to reduced demand by Rate Schedule 6 and other transportation service customers in the Fort St. John region.

Commission Determination

The Commission Panel accepts the 2012 deliveries forecast of 923,800 GJ for PNG (N.E.)'s Industrial and Commercial Transportation Service customers in Fort St. John.

3.2 Dawson Creek

PNG (N.E.) Dawson Creek region has applied for rates based on projected sales volumes of 1,259,132 GJ and transportation volumes of 32,100 GJ. Approximately 98 percent of the gross margin in the Dawson Creek district is derived from sales, with the remaining 2 percent from transportation service. The Dawson Creek region accounts for approximately 29 percent of the total gross margin for PNG (N.E.), with the balance resulting from the Fort St. John and Tumbler Ridge districts. (Exhibit B-3, Tab Rates, p. 11)

<u>Residential</u>

PNG (N.E.)'s Dawson Creek residential load forecast of 602,484 GJ is based on an average count of 5,782 customers and normalized use of 104.2 GJ/year. The 5,782 customer forecast is based on a projection of 58 additional customers in 2012. The 104.2 GJ/year is closely based on a first order regression of historical use per account data. (Exhibit B-3, Tab Rates, p. 11)

The load forecasting approach applied by PNG (N.E.) in the Dawson Creek region is consistent with the methodology applied in previous Applications. Based on the most recent six years of data, the average forecast error for Residential Sales is 2.6 percent above actual with an 80 percent bias of over forecasting energy demand. The magnitude of the forecast error is relatively small (2.6 percent) but the bias (80 percent) is significant, which suggests that it is systemic in nature. (Exhibit B-12, FSJ/DC, BCUC 2.76.1)

Commission Determination

The Commission accepts that forecasting energy demand is inherently difficult due to a multitude of variables that are outside of the control of PNG (N.E.). **For the 2012 forecast the Commission Panel accepts PNG (N.E)'s forecast weighted average residential customer count of 5,782 and forecast use per customer of 104.2 GJ/year resulting in a residential load forecast of 602,484 GJ in Dawson Creek.**

<u>Small Commercial</u>

PNG (N.E.) forecasts 2012 deliveries of 436,048 GJ to its small commercial customers in the Dawson Creek region. (Exhibit B-3, Tab Rates, p. 11) PNG (N.E.) estimated 12 net customer additions in the 2012 forecast, bringing the total customer count to 848 by taking the difference between the average of the 2012 month end customer count and the 2011 year-end customer count. (Exhibit B-9, FSJ/DC, BCUC 1.50.5) The use per account estimate of 514.0 GJ/year is broadly based on a first order regression of historical normalized use per account data.

PNG (N.E.)'s forecast of 727,135 GJ has been derived using a methodology that is consistent with previous applications. Since consistency does not necessarily ensure accuracy, Commission IRs reviewed the historical accuracy of PNG (N.E.)'s Small Commercial forecasts. (Exhibit B-12, FSJ/DC, BCUC 2.76.1- 2.76.2.1) On a consolidated basis for FSJ/DC over a six-year period from 2006 to 2011, PNG (N.E.)'s Small Commercial forecasts have had a 70 percent bias of over-forecasting energy demand by 3.7 percent. The magnitude of the forecast error is moderate (3.7 percent) but the bias (70 percent) is significant, which suggests that it is systemic in nature.

Commission Determination

The Commission accepts that forecasting energy demand is inherently difficult due to a multitude of variables that are outside of the control of PNG (N.E.). **For the 2012 forecast the Commission Panel accepts PNG (N.E.)'s Small Commercial Customer load forecast of 436,048 GJ in Dawson Creek.**

Large Commercial

PNG (N.E.) forecast that the 2012 level of consumption would be 179,100 GJ is based on a review of historical deliveries and expected use in 2012 based on discussions with these customers.
(Exhibit B-3, Tab Rates, p. 11)

The Large Commercial sales forecast in 2012 in the Dawson Creek region is 22,229 GJ more than in 2011, which represents a 14 percent increase in sales volume. (Exhibit B-9, FSJ/DC, BCUC 1.51.1) There is no specific reason for the increase. PNG (N.E.) relies on forward looking projections that involve confidential business information. Due to the relatively small customer base, the volatility in sales volumes from one year to the next is typical.

Commission Determination

The Commission Panel accepts the 2012 deliveries forecast of 179,100 GJ for PNG (N.E.)'s Large Commercial customers in Dawson Creek.

Small Industrial

PNG (N.E.) 2012 forecast gas deliveries of 41,500 GJ to Small Industrial customers in the Dawson Creek region (Exhibit B-3, Tab Rates, p. 11), is based on discussions with those customers, and represents a 22 percent (11,544 GJ) decrease to the 2011 gas deliveries of 53,044 GJ. (Exhibit B-9, FSJ/DC, BCUC 1.51.1) Volatility in gas deliveries from one year to the next is typical given the small customer base for Small Industrial customers in the Dawson Creek region. On aggregate, the reduction of 11,544 GJ does not have a material impact on 2012 forecast PNG (N.E.) revenue requirements.

Commission Determination

The Commission Panel accepts the 2012 deliveries forecast of 41,500 GJ for PNG (N.E.)'s Small Industrial customers in Dawson Creek.

Commercial Transportation Service

PNG (N.E.) is forecasting deliveries of 32,100 GJ to its Dawson Creek Commercial Transportation Service customers in 2012 (Exhibit B-3, Tab Rates, p. 11), which represents a reduction of 6,300 GJ (16 percent), compared to NSP 2011. The reason for the reduction in transportation service has been attributed to reduced use per account among transportation service customers in the Dawson Creek region.

Commission Determination

The Commission Panel accepts the 2012 deliveries forecast of 32,100 GJ for PNG (N.E.)'s Commercial Transportation Service customers in Dawson Creek.

3.3 Tumbler Ridge

The approach used by PNG (N.E.) for the Tumbler Ridge region 2012 test year deliveries forecast is the same as that accepted by the Commission for the Fort St. John and Dawson Creek forecasts as noted above.

During the Application process the sales volumes and revenues forecasted were revised to reflect updated information. (Exhibit B-4)

The Tumbler Ridge region has applied for rates based on projected sales volumes of 186,702 GJ and transportation volumes of 800,000 GJ. (Exhibit B-4, Tab Rates, p. 5) The gross margin required to meet the proposed revenue requirement for the Tumbler Ridge region for 2012 is approximately 75 percent from sales, and 25 percent from transportation deliveries. (Exhibit B-4, Tab Rates, p. 4)

<u>Residential</u>

Residential Customer forecasted gas volumes for the 2012 test year of 96,605 GJ were based on a projection of 1,094 customers and a normalized average use per account of 88.3 GJ/year. (Exhibit B-4, Tab Rates, p. 5)

The Actual 2011 use per account was 87.9 GJ/year. (Exhibit B-7) The forecast 2012 use per account of 88.3 GJ/year is 3 percent higher than the 85.7 GJ per year used under the 2011 NSP, but is consistent with the normalized use per account linear trend in the region. PNG (N.E.) is projecting two additional residential customers for 2012. The increase in use per account and customer count results in higher energy sales of approximately 3,016 GJ. This represents an overall increase in energy sales of 3.2 percent as compared to 2011. (Exhibit B-7)

Commission Determination

The Commission Panel accepts the 2012 gas deliveries forecast of 96,605 GJ for PNG (N.E.)'s Residential customers in Tumbler Ridge.

<u>Small Commercial</u>

Small Commercial Customer forecasted volumes for 2012 of 47,597 GJ are based on a projection of 104 customers and a normalized average use per account of 460 GJ/year. (Exhibit B-4, Tab Rates, p. 5)

The Actual 2011 use per account was 445.4 GJ/year. (Exhibit B-7) The forecasted 2012 test year use per account of 460 GJ/yr is approximately 2 percent higher than the 450.1 GJ per year, used under the 2011 NSP, but is in keeping with the normalized use per account linear trend in the region. PNG (N.E.) is projecting two additional small commercial customers for 2012. (Exhibit B-1, Rate Application TR, p. 28)

The overall impact of the increase in use per account and new customer additions results in an increase of approximately 3,908 GJ energy sales, representing an 8.9 percent increase in demand in this customer group as compared to the 2011 actual. (Exhibit B-9, TR, BCUC 1.32.1)

Commission Determination

The Commission Panel accepts the 2012 gas deliveries forecast of 47,597 GJ for PNG (N.E.)'s Small Commercial customers in Tumbler Ridge.

<u>Large Commercial</u>

The Actual 2011 Large Commercial customer use per account was 31,441 GJ/year. (Exhibit B-7) Large Commercial customer forecasted gas volumes for 2012 of 42,500 GJ are based on customer projections and represent a 32.8 percent (10,500 GJ) increase over 2011 NSP. The 10,500 GJ increase in energy demand represents a slight increase of 1.1 percent of the total energy demand for the Tumbler Ridge region in 2012 and therefore does not have a material impact on the Application.

Commission Determination

The Commission Panel accepts the 2012 gas deliveries forecast of 42,500 GJ for PNG (N.E.)'s Large Commercial customers in Tumbler Ridge.

<u>Industrial Transportation Service</u>

The Actual 2011 Industrial Transportation Service customer use per account was 868,954 GJ/year. (Exhibit B-7) PNG (N.E.) forecasts gas deliveries of 800,000 GJ to CNRL, the only customer in the Industrial Transportation Service customer class in Tumbler Ridge (Exhibit B-1, Tab Application, p. 29), which is the same as under NSP 2011. PNG (N.E.) relies upon projections from CNRL in formulating 2012 deliveries to this rate class.

PNG (N.E.) is requesting Commission approval to continue the Dawson Creek Industrial Deliveries deferral account for variance between actual deliveries and forecast deliveries in 2012.

Commission Determination

The Commission Panel accepts the 2012 gas deliveries forecast of 80,000 GJ for PNG (N.E.)'s Industrial Transportation Service in Tumbler Ridge. The panel also approves the continued use of the Dawson Creek Industrial Deliveries Deferral Account, as requested in the Application.

3.1.3 Rate Stabilization Adjustment Mechanism Amortization

Historically PNG (N.E.)'s RSAM rate rider has been amortized over a three year period, effectively spreading short term rate impacts over three years. Therefore, the current RSAM balance is comprised of cumulative balances from 2009, 2010 and 2011. In the Application PNG (N.E.) has requested to change the amortization period from three years to one year, resulting in the 2011 year-end balance being fully amortized in 2012. PNG (N.E.) states that a one year amortization period is necessary as US GAAP requires a maximum amortization period of 24 months following the end of the annual period in which the amounts were recognized; therefore, the 2009 balance has to be fully amortized by the end of the 2012 under US GAAP. For 2013 and subsequent forecasts, PNG (N.E.) plans to request approval of a 24 month amortization period. (Exhibit B-3, p. 7; Exhibit B-4, p. 6)

The final approved RSAM rate rider for PNG (N.E.) FSJ/DC in 2011 was a debit of $0.05/GJ (charge to ratepayers). The current approved interim 2012 RSAM under a three year amortization period is $.015/GJ (charge to ratepayers). (Exhibit B-1, Tab Rates FSJ/DC, p. 20) The applied for updated RSAM under a one year amortization period is $0.165/GJ (charge to ratepayers). (Exhibit B-3, Tab Rates, p. 20)

The final approved RSAM rate rider for Tumbler Ridge in 2011 was a debit of $0.30/GJ (charge to ratepayers). The current approved interim 2012 RSAM under a three year amortization period is $.193/GJ (charge to ratepayers). (Exhibit B-1, Tab Rates TR, p. 10) The applied for updated RSAM under a one year amortization period is $0.297/GJ (charge to ratepayers). (Exhibit B-4, Tab Rates, p. 10)

Commission Determination

The Commission approved PNG (N.E.)'s use of US GAAP for regulatory accounting and reporting purposes for the period January 1, 2012 to December 31, 2014 (see Order G-168-11). Given that a one year amortization is required under US GAAP **the Commission Panel approves a one year amortization period for the 2011 year end RSAM balance** in order to allow PNG (N.E.) to fully amortize the balance in 2012.

4.0 UNACCOUNTED FOR GAS

Fort St. John/Dawson Creek

The 2011 NSA provided that PNG (N.E.) must forecast Unaccounted for Gas (UAF) losses at 1 percent of deliveries and to record up to 1.5 percent UAF in the UAF volume deferral account without further approval from the Commission. (Order G-93-11, NSA 2011, Item 12) UAF volumes have fluctuated in both positive (losses) and negative (gains) from year to year with a trend in the last two years to increasing losses.

Table 4-1 - Unaccounted for Gas FSJ/DC

in GJ	Reference	Year				
		2008	2009	2010	2011	2012
Unaccounted for gas gain(-)/loss - Forecast	Exhibit B-9, BCUC 1.48.3	48,092	47,373	46,565	44,329	43350
Unaccounted for gas gain(-)/loss - Actual	Exhibit B-9, BCUC 1.48.3	-40,410	-39,166	100,633	111,939	
Total Deliveries	Exhibit B-3, Tab 1, p.1, Line 7	4803000	4916000	4345000	4246000	4335000
UAF as a Percentage of Total Deliveries		-0.84%	-0.80%	2.32%	2.64%	
Note: 2012 Forecast calculated based on 1% of Total Deliveries						

In 2011, PNG (N.E.) reported a UAF loss of 2.45 percent that was outside the one percent band, and applied to the Commission to record the full variance in the deferral account. The Commission approved PNG (N.E.)'s request (Order G-25-12). It should be noted there is a minor discrepancy between the UAF percentage calculated in the table above for 2011 and what was requested by PNG and approved by Order G-25-12 for UAF losses in 2011.

In the Application PNG (N.E.) has not requested any changes to treatment of UAF used in the previous test year nor has anything come to the Commission's attention that would cause it to make a change to this decision. Therefore the Commission continues to allow PNG (N.E.) FSJ/DC to forecast UAF volume at 1 percent of deliveries and to record a UAF volume of up to 1.5 percent of deliveries in the UAF volume deferral account with seeking further Commission approval.

<u>Tumbler Ridge</u>

The 2011 NSP, approved by Commission Order G-93-11, allowed the Tumbler Ridge region to forecast a zero percent UAF gas loss and to record up to 1.0 percent UAF loss in the UAF gas volume deferral account without further Commission approval. PNG (N.E.) is seeking no change to the UAF treatment for 2012 and reports a very slight decreasing trend over the past several years.

For 2010 and 2011 Tumbler Ridge did not have to seek further Commission approval to report UAF losses over 1 percent. The table below shows the historical reporting of actual UAF losses for Tumbler Ridge.

Table 4-2 - Unaccounted for Gas TR

Tumbler Ridge Unaccounted for Gas

	2006	2007	2008	2009	2010	2011
Company Use:						
Unaccounted for gas	-0.83%	-0.44%	-0.34%	-1.04%	-0.42%	-0.46%

(Exhibit B-9, TR BCUC 1.30.3.1)

In its Application PNG (N.E.) has not requested any changes to treatment of UAF used in the previous test year nor has anything come to the Commission's attention that would cause it to make a change to this decision. Therefore the Commission continues to allow PNG (N.E.) TR to forecast UAF volume at zero percent of deliveries and to record a UAF volume of up to 1.0 percent of deliveries in the UAF volume deferral account for Tumbler Ridge with seeking further Commission approval.

5.0 SERVICE QUALITY INDICATORS

PNG (N.E.) reports on a set of Service Quality Indicators (SQIs) as part of each RRA. The SQIs were agreed to by PNG (N.E.), Interveners and Commission staff in Order G-40-09 (2009 NSA) and were reported on in the Application and updated in Exhibit B-9. They are considered important indicators of the continuing service quality provided by PNG (N.E.) but are not binding on the Utility.

Table 5.1 – FSJ/DC Service Quality Indicators

Description	2011	2010	2009	2008
Number of emergency calls	451	473	544	465
Average response time per call (in minutes)	19.5	20	17.5	18
Calls with response time over 40 minutes	32	21	24	20
Underground leaks	26	9	8	13
Reportable Environmental Incidents	1	1	0	0
Lost Time Injury Frequency Rate	0	0	0	4.02
Customer Complaints to BCUC**	0	1	1	0

**Information reflects the Commission's March 31 fiscal year end (i.e. data for 2010 is from April 1, 2010 to March 31, 2011). (Exhibit B-9, FSJ/DC, BCUC 1.45.1)

Table 5.2 – TR Service Quality Indicators

Description	2011	2010	2009	2008
Emergency calls	11	12	12	4
Average response time per call (in minutes)	20.5	20.5	11	18
Calls with response time over 40 minutes	5	1	3	1

**Information reflects the Commission's March 31 fiscal year end (i.e. data for 2010 is from April 1, 2010 to March 31, 2011). (Exhibit B-9, TR, BCUC 1.21.1)

In response to IRs on the deteriorating statistics for number of calls with response times over 40 minutes and number of underground leaks, PNG (N.E.) stated that:

> "…variation in the data is in part a function of the small sample size and unique circumstances surrounding each incident. However, a contributing factor to the number of calls with a response time in excess of 40 minutes was one of the Tumbler Ridge employees experienced a long term illness, removing him from the workforce, which negatively impacted [PNG (N.E.)]'s response time in certain circumstances. The Tumbler Ridge personnel resources have now returned to a full complement. In addition 13 of the calls with a response time over 40 minutes were from rural customers in the Fort St. John, Dawson Creek and Toms Lake areas. The driving distance, road conditions and the time the call was received are all factors which can affect the response time.

> The number of underground leaks has varied from historical levels primarily due to the material failure of a specific underground service tee fitting which was installed in Tumbler Ridge during the original installation of the system. During the completion of leak survey activities in Tumbler Ridge during 2011, 16 leaks were discovered at the location of the fitting in question. All of the leaks were discovered in one particular area and all were repaired."
> (Exhibit B-9, FSJ/DC, BCUC 1.45.2)

PNG (N.E.) does not distinguish its SQIs between the FSJ/DC and TR divisions since it believes that the sample size for all divisions is already small and separating the divisions to show data independently would exacerbate the small sample problem and lead to potentially erroneous conclusions while providing no valuable insight into on-going service quality. (Exhibit B-12, FSJ/DC, BCUC 2.64.1)

The Commission accepts PNG (N.E.)'s SQI for 2011 and accepts the explanations for the Applicant's inability to meet 2011 metrics on calls with response times over 40 minutes and underground leaks and recognizes that one year of statistics does not confirm a trend. However, the Commission will look forward to receiving next year's improved statistics for SQIs.

6.0 OPERATING AND MAINTENANCE

6.1 Operating and Maintenance Expenses

Fort St. John/Dawson Creek

The actual 2011 PNG (N.E.) FSJ/DC Operating and Maintenance (O&M) expenses were $4.294 million and $0.47 million respectively before transfers to capital and not including Company Use Gas, which is recovered at cost from customers. PNG (N.E.) FSJ/DC seeks approval of O&M forecast expenses of $4.680 million and $0.438 million respectively for the 2012 budget. (Exhibit B-3, Tab 1, p. 2) This is an increase of $385,000 and decrease of $32,000 respectively over the actual 2011 figures; or approximately 7.4 percent on the combined O&M budget. Wages for labour and supervision account for approximately 40 percent of the total O&M budget and include a bargaining agreement labour wage increase of 3.5 percent over 2011.

The majority of the maintenance expense increase from 2011 NSA can be attributed to what PNG (N.E.) FSJ/DC calls a forecasting error in 2011 where no costs were forecast for follow-up investigative digs for the close interval surveys performed. PNG (N.E.) FSJ/DC report actual 2011 expenses for this purpose were $128,000. (Exhibit B-9, BCUC 1.13.1) This resulted in actual 2011 maintenance expenses of $470,000. Forecast 2012 maintenance expenses (including follow-up investigative digs) are $438,000. (Exhibit B-3, Tab 1, p. 4) The operating expense increase comes from increases to the shared service costs reflecting the increased labour rate and pension expense and from a forecast for Uncollectable Accounts. (Exhibit B-1, Tab Application, p. 7)

6.1.1 Close Interval Surveys

Close Interval Surveys (CIS) are a process used to identify the corrosion that may have occurred in pipelines. As a component of its pipeline integrity management plan, PNG (N.E.) FSJ/DC employs third party contractors for much of this activity. (Exhibit B-9, FSJ DC, BCUC 1.5.2.1) The issue was pursued in information request where PNG (N.E.) FSJ/DC identified that the 2011 bid process for close interval survey activity resulted in lower costs by $149,000 than expected (Exhibit B-9, FSJ/DC, BCUC 1.5.1) while still completing all work planned (Exhibit B-9, FSJ/DC, BCUC 1.5.1.1). In response to further information requests, PNG (N.E.) FSJ/DC provided the following table:

FSJ/DC *Close Interval Surveys*

Year	No. of km Surveyed	No. of Close Interval Surveys	Forecast Contractor Expense	Actual Contractor Expense
2010	103	17	$156,000	$88,000
2011	46	8	$198,000	$60,000
2012	57	6	$180,000	----
2013	N/A	N/A	N/A	N/A

(Exhibit B-12, FSJ/DC, BCUC 2.57.1)

As identified, the actual costs in both 2010 and 2011 were well below forecast. PNG (N.E.) FSJ/DC further explains that: "The forecast 2012 expense of $180,000 includes $94,000 to perform an in-line inspection of the 6 inch diameter lateral providing service to Dawson Creek." (Exhibit B-12, FSJ/DC, BCUC 2.57.2) The in-line inspection is a new activity/expense. In the 2011 PNG (N.E.) RRA, PNG (N.E.) FSJ/DC stated that it does not perform in-line inspection on it facilities. [2011 PNG (N.E.) RRA, BCUC 1.6.1]

In the 2011 PNG (N.E.) RRA proceeding, PNG (N.E.) FSJ/DC explained the significant increase in forecast contractor costs for 2011 over 2010 was due to the number of CIS planned for 2011 being greater than 2010. However, this explanation is not supported by the number of actual CIS contracts in 2010 and 2011. [2011 PNG (N.E.) RRA, BCUC 1.6.1.1]

The BCOAPO also raises this issue in its Final Argument and proposes reducing the amount for Account 665 from $180,000 to $168,000. (BCOAPO Final Argument, p. 4)

PNG (N.E) FSJ/DC in its Reply Submission, respectfully disagrees with BCOAPO's position by arguing that one cannot make a direct comparison of the cost for these activities from one pipe section to another or from one year to another, as this type of work is site specific. [PNG (N.E.) Reply Submission, p. 3]

Commission Determination

The Commission Panel accepts the 2012 forecast cost of service related to maintenance expenses.

The Commission Panel does not accept the 2012 forecast operating expenses. The Commission Panel notes that PNG (N.E.)'s response to IRs respecting contractor charges lacked the detail necessary for the Panel to fully understand the variance issues respecting operating expenses. The Applicant has overestimated the cost of close interval surveys in the past and has not been forthcoming in its inspection plans and responses. **The Commission Panel is reducing the 2012 budget for close interval surveys and contractor expenses to $120,000.** This figure, arrived at by using 2011 actual expenses of $60,000 plus $60,000 for the in-line inspection, which is a more reasonable figure, based on PNG (N.E.)'s record of over-estimating these costs, and based on a similar amount of CIS to be surveyed in 2012 as 2011.

PNG (N.E.) FSJ/DC is directed to provide a comprehensive pipeline asset integrity plan and report broken down by activity and cost function covering the current year and forward looking two years. The report should be updated annually and filed no later than 60 days following the end of year. Actual results and costs should be discussed and compared to planned activities and costs in the report. The goal of this filing is to provide clarity and confidence in these important activities from a planning and budgeting perspective and hopefully improve the transparency and efficiency of future RRA proceedings.

<u>Tumbler Ridge</u>

The actual 2011 PNG (N.E.) TR O&M expenses were $704,000 and $118,000 respectively before transfers to capital and not including Company Use Gas, which is recovered at cost from customers. PNG (N.E.) TR has forecast $743,000 of operating expenses and $154,000 of maintenance costs for the 2012 test year. (Exhibit B-4, Tab 1, p. 2) This is a forecast increase of $39,000 and $36,000 respectively over 2011 actual figures; or approximately 9.1 percent on the combined O&M budget. Wages for labour and supervision account for approximately 35 percent of the total O&M budget and include a bargaining agreement labour wage increase of 3.5 percent over 2011.

The majority of the operating expense increase from actual 2011 can be attributed to the necessity to do close interval surveys on PNG (N.E.) TR's transmission line ($43,000). (Exhibit B-1, Tab Application TR, p. 5) The majority of the maintenance expense increase from actual 2011 can be attributed to investigative dig activities ($41,000) to follow-up on the results of close interval surveys, the majority of which are contractor charge estimates. (Exhibit B-1, Tab Application TR, p. 6)

PNG (N.E.) TR explains that this will be the first year it performs close interval surveys and follow-up investigative digs on its Tumbler Ridge transmission line, as a baseline requirement to meet the Oil and Gas Commission's adopted Canadian Standards Association (CSA) Z662-11 standard for its own Integrity Management Plan, with future inspection requirements determined from this baseline activity. (Exhibit B-9, TR, BCUC 1.8.1, 1.8.1.1, 1.8.1.3)

In its Final Argument the BCOAPO raises the same issue of PNG (N.E.) TR over estimating contractor expenses as was raised for FSJ/DC and proposes reducing the amount of $43,000 for close interval survey expenses (Account 665 Pipelines) to $14,000 or 1/3 based on the over-estimate of PNG (N.E.) for FSJ/DC for this contractor expense. (BCOAPO Final Argument, p. 5)

In its Reply Submission PNG (N.E.) provides evidence that the specific section of line to be surveyed in 2012, located between Tumbler Ridge processing plant and the community of Tumbler Ridge, is an area that is heavily forested and with mountainous terrain. The forecast cost of $43,000 accounts for the reduced productivity due to the terrain and additional clearing needed.
[PNG (N.E.) Reply Submission, p. 4]

Commission Determination

The Commission Panel notes BCOAPO's concerns regarding the Close Interval Survey estimate of $43,000 which accounts for nearly all of the increase in over NSP 2011 and the PNG (N.E.) history of over-estimating contractor expenses for this activity. **The Panel is reducing the budget for pipeline operations (Account 665 Pipelines) by $14,000 to $68,000 from the $82,000 forecast for Account 665. The Panel is also reducing the budget for pipeline maintenance (Account 865 Pipelines) by $9,000 or one third of the estimated $26,000** for contractor charges for follow-up investigative digs **for the same reasons.**

7.0 ADMINISTRATIVE AND GENERAL EXPENSES

7.1 Fort St. John/Dawson Creek

PNG (N.E.) FSJ/DC seeks approval of its forecast 2012 administrative and general expenses of $1.846 million before transfers to capital, which is an increase of $39,000 or 2.2 percent over the actual 2011costs of $1.807 million. (Exhibit B-3, Tab 1, p. 2) The specific issues are outlined in the administrative and general expense categories below.

7.1.1 Labour

Actual labour costs for the Bargaining Unit Performance/Incentive Pay exceeded the budgeted amounts by 25 percent in 2010, and 28 percent in 2011 (Exhibit B-9, FSJ/DC, BCUC 1.3.1) PNG (N.E.) FSJ/DC states that Bargaining Unit employees exceed all of the goals in 2010 and 2011 due to strong performance against the plan measures. The budgeted amounts reflect the target award for achieving 100 percent of the goal. When goals are exceeded, the award is greater than the target. In each of those years, some or all of the goals were exceeded due to strong performance against the plan measures. The award level is capped at 150 percent of target. (Exhibit B-12, FSJ/DC, BCUC 2.55.1)

Commission Determination

The Bargaining Unit employees' ability to exceed all of the goals in both 2010 and 2011 could be a trend. If Bargaining Unit employees exceed all of the goals in 2012, PNG (N.E.) should provide a detailed description of the Performance/Incentive Pay program and explain why all of the goals are being consistently exceeded in the next Revenue Requirements Application.

The Commission Panel is concerned with the lack of evidence that shows whether the incentive program has been successful. The real question is what is the incentive targets of the bonus plan and how does it connect with a corporate strategy that is aligned with the interests of the ratepayer? **The Commission Panel orders the Applicant to provide the following, for the next RRA: details of the Performance/Incentive Pay program, for 2012 and 2013; an analysis of how that incentive program incents behaviour that benefits the ratepayer and an analysis of how each successive incentive pay challenge invites an employee to stretch.**

7.1.2 Audit, Legal and Consulting fees

PNG (N.E.) FSJ/DC seeks approval of its forecast 2012 audit, legal and consulting fees of $109,000 compared to the 2011 NSA amount of $57,000, an increase of $52,000 or 91.2 percent over the 2011 NSA. (BCOAPO Final Argument, para. 16, p. 3) The Applicant suggests that $29,000 of the increase is comprised of $4,900 for legal fees and $24,000 expert consultant fees. (Exhibit B-9, FSJ/DC, BCUC 1.20.1) There is no breakdown of the remaining $23,100 of the $52,000 increase.

PNG (N.E.) FSJ/DC notes that audit fees were budgeted at $78,000 in 2010 and incorrectly budgeted at $54,000 in 2011. (Exhibit B-1, Tab Application FSJ/DC, p. 10) Actual 2010 and 2011 PNG (N.E.) FSJ/DC audit fees were $71,000 and $62,000 respectively. (Exhibit B-9, FSJ/DC, BCUC 1.21.1)

BCOAPO notes that for the period 2008-2011 inclusive, the average actual amount booked into this account was $65,750 and submits that $95,000 is appropriate for 2012, consisting of the average historical cost of $65,750 plus $4,800 for outside legal expenses plus $24,000 for expert evidence. (BCOAPO Final Argument, paras. 18 and 20, pp. 3-4)

PNG (N.E.) states that the increase in audit, legal and consulting also includes an allocation of $9,500 for actuarial services fees and $4,000 for general legal services which were not allocated to PNG (N.E.) in prior years but were fully borne by PNG. PNG (N.E.) respectfully submits that it should fully recover these allocated costs. [PNG (N.E.) Reply, para. 5, p. 2]

Commission Determination

The Panel concurs with BCOAPO and approves $95,000 in audit, legal and consulting fees for the 2012 forecast, for PNG (N.E.) FSJ/DC.

7.2 Shared Services from Parent

PNG (N.E.) reimburses its parent company, PNG West, for shared services. PNG (N.E.) FSJ/DC Division's contribution to Shared Service costs has increased from $1.685 million in 2008 to $2.233 million proposed for 2012. (Exhibit B-1, Tab Application FSJ/DC, p. 11; Exhibit B-9, FSJ/DC, BCUC 1.23.1) The PNG (N.E.) TR Division portion of Shared Services grew from $123,000 in 2008 to $153,000 proposed for 2012. (Exhibit B-1, Tab Application TR, p. 8; Exhibit B-4, Tab 1, pp. 3, 5) The specific issues are outlined in the following benefit loading and shared service allocation categories.

7.2.1 Rising costs of benefits

The 2012 forecast of FSJ/DC Division's Shared Services costs included a benefit cost of $504,000. This has increased over the compared to actual 2011 NSA costs of $480,000. (Exhibit B-9, FSJ/DC, BCUC 1.23.1) Prior to 2011, benefit loadings were determined by the dividing total benefit costs (Account 725) by total labour costs. Effective 2011, benefit load factors are now determined on a bottom-up basis, identifying benefits and their specific cost relative to average compensation for each group of employees. (Exhibit B-9, FSJ/DC, BCUC 1.23.2) The 2012 forecast of TR Division's Shared Services costs included benefit costs of $36,000 compared to actual 2011 costs of $33,000. (Exhibit B-9, TR, BCUC 1.13.1)

Benefit Load Factors

Group	Benefit Load Factors	
	Test Year 2012	**NSP 2011**
Executive	51.6%	57.4%
Non-Bargaining Unit	28.5%	30.6%
Bargaining Unit - West	54.1%	50.1%
Bargaining Unit - NE	45.1%	42.9%

(Exhibit B-9, FSJ/DC, BCUC 1.23.2)

The Benefit Load Factor Table shows that some benefit loads are over 50 percent. PNG (N.E.) states that pensions are the main driver of benefit cost increases, but the cost of other benefits have also increased. PNG (N.E.) suggests that changes to interest rates and investment returns which drive pension costs, are also beyond PNG (N.E.)'s ability to control. In addition, PNG (N.E.) states that pension costs are of a cyclical nature such that plans can go from a surplus to a deficit and back to a surplus over different market cycles. Higher prescription drug costs, dental fee guide costs and savings plan company contribution (due to the employer matching schedule) as wages increase and employees obtain additional company service also impact benefit costs. (Exhibit B-12, FSJ/DC, BCUC 2.58.2)

The PRRD expressed concerns regarding the impact of increasing employee benefit costs and pension expenses on customers of PNG (N.E.). In addition, the PRRD encouraged PNG (N.E.) to continue to examine how it can keep such increases as low as possible and to mitigate the impact on customers. (PRRD Final Argument, p. 1)

Regarding the increase in benefits costs, BCOAPO states that it expects that, a smaller discount factor and deteriorating investment portfolio returns can result in significant increases in this component of the charges. Furthermore, BCOAPO submits that it is heartened by PNG (N.E.)'s response to BCUC 2.58.2 which includes the statement that PNG (N.E.) is "examining how some benefit plan costs may be reduced due to the acquisition by AltaGas and the potential economies of scale that this may bring." BCOAPO requests that the Commission direct PNG (N.E.) to report back regarding the outcome of this examination in its next rates filing. (BCOAPO, Final Argument, para. 15, p. 3; Exhibit B-12, FSJ/DC, BCUC 2.58.2)

PNG (N.E.) states that it appreciates concerns raised by the PRRD in its final argument regarding cost increases and the impact these may have on residents and businesses in the Northeast service territory. In addition, PNG (N.E.) states that the issues raised by the PRRD are not dissimilar to those noted by BCOAPO in its final argument. PNG (N.E.) submits that the issues of cost increases in excess of inflation, increased employee benefits and pension costs and the rate increase proposed for the Tumbler Ridge Division have been adequately addressed in the evidence submitted in this proceeding. [PNG (N.E.) Reply Argument, para. 16, p. 5]

Commission Determination

PNG (N.E.), like most utilities, provides defined benefit pensions to its executives that are at no cost to the executive. They make no contributions to the annual funding and most all of the cost is collected from ratepayers (The Commission has not allowed portions of the incentive pay to be funded by ratepayers).

The response to BCUC 1 23.2 identified that the Benefit Loading for the Executive is now over 50 percent of salary. (Exhibit B-9, FSJ/DC, BCUC 1.23.2) The issue of Benefit Loading was pursued in IR No. 2 and the response to BCUC 2.58.1 identifies that almost $100,000 of an executive's total benefit relates to funding of their "free "pensions". Another $13,000 relates to other post employment benefits and the Employee saving plan. (Exhibit B-12, FSJ/DC, BCUC 2.58.1)

In recent years, many employers have moved away from defined benefit pensions to defined contribution plans. The reduced actuarial discount rates and various accounting changes have driven up the cost of funding defined benefit plans.

The Panel recognizes that the Interveners have raised significant concerns regarding the rising benefit costs; however, the Panel considers that there is insufficient evidence to decide this issue in this Application. The issue is part of a broader nation-wide concern for the rising cost of total compensation. **In the next RRA PNG (N.E.) is to bring forth evidence on alternatives for addressing strategies for total compensation, including the rising benefit costs and cost recovery from ratepayers.** In the Panel's view, this issue should be addressed on a broader basis and the Commission could require other utilities to address this issue in a generic review.

7.2.2 Rising Total Shared Service Allocation to PNG (N.E.)

Although the details of the Shared Service charges are reviewed in detail in the PNG Application and Decision, the total Shared Service allocation to PNG (N.E.) has been an issue in each RRA for the last several years. PNG (N.E.) FSJ/DC Division has seen its share of the pool of Shared Service costs rise from $1,685,000 in 2008 to $2,233,000 proposed for 2012. (Exhibit B-1, Tab Application, p. 11; Exhibit B-9, BCUC 1.23.1) This 33 percent increase over 4 years is the result of rising Shared Service costs and increasing allocations to PNG (N.E.) FSJ/DC Division as that utility has had increased customers and gas sales while PNG has stagnated. PNG (N.E.) FSJ/DC states that "…there are increased labour costs in the Test Year due to general compensation increases, as well as increase benefit loads due to increased pension costs and inflation of other benefits cost elements." (Exhibit B-9, BCUC 1.7.1)

> "Due to a shift in customer numbers, there has been an increase in costs allocated on this basis, from 44.8% under NSP 2011 to 45.2% for Test Year 2012. This was offset in part by a decrease in costs allocated based on employee count, dropping from 22.5% under NSP 2011 to 21.9% for Test Year 2012." (Exhibit B-9, FSJ/DC, BCUC 1.7.1)

The PNG (N.E.) TR Division share of Shared Services grew from $123,000 in 2008 to $153,000 proposed for 2012. (Exhibit B-1, Tab Application FSJ/DC, p. 8; Exhibit B-4, Tab 1, pp. 3, 5)

BCOAPO states that the 2012 forecasted costs for PNG (N.E.) FSJ/DC customer billing (Account 713) are $433,000, representing a 9.1 percent increase over actual 2011 costs of $397,000 and a

45 percent increase over actual 2008 costs of $299,000. (BCOAPO Final Argument, paras. 9-10, p. 2) Furthermore, BCOAPO notes that the 3.5 percent collective agreement increase forms part of a 10.5 percent customer billing labour increase (a $21,000 increase) that is three times the size of the collective agreement increase. BCOAPO submits that the labour cost component should limited to an increase of 3.5 percent. (BCOAPO Final Argument, para. 14, pp. 2-3; Exhibit B-9, FSJ/DC, BCUC 1.7.1)

The allocation methodology has been in place for several years and is the same for this year's Application as applied under NSP 2011. As part of NSP 2011, PNG agreed to undertake a new cost allocation study in 2012 to be filed with the Commission in the Fall of 2012 (Shared Services Study). On September 19, 2012 PNG and PNG (N.E.) requested approval to file the Shared Services Study as part of the PNG 2013 RRA. Commission Letter L-62-12 approved the request.

The Commission Panel acknowledges the Applicant's commitment to undertaking the new cost allocation study in 2012, and looks forward to receiving the new cost allocation study this Fall as part of the PNG 2013 RRA.

7.3 Transfers to Capital

PNG (N.E.) requests approval to calculate transfers to capital, transferring overhead to capital projects, which will impact the rate of return received by PNG (N.E.) for its rate base. The requested approval seeks to calculate transfer to capital in accordance with the capital overhead allocation methodology approved under the 2011 NSA, as amended for refinements to the methodology as noted. [PNG (N.E.) FSJ/DC, para. 57; PNG (N.E.) TR, para. 66] Item 2 of the 2011 NSA accepted the overhead capitalization rates recommended in the 2010 Overhead Capitalization Study. In addition, PNG (N.E.) agreed to apply the same capitalization overhead rates for rate setting purposes as it does for external financial reporting purposes once International Financial Reporting Standards (IFRS) are adopted. (Order G-93-11, Appendix A, p. 4)

PNG (N.E.) FSJ/DC forecast 2012 transfers to capital of $302,000. (Exhibit B-3, p. 3)

PNG (N.E.) TR forecast 2012 transfers to capital at $25,000. (Exhibit B-4, p. 3)

PNG (N.E.) used the capital overhead allocation methodology approved under the 2011 NSA to calculate the transfers of budgeted 2012 operating, administrative and general expenses to capital in the Application. PNG (N.E.) also confirms that it is using the same capitalization overhead rates for both rate setting purposes and for external reporting purposes. The Application also notes that the benefits loading associated with field personnel were included under “Transfers to Capital – Operating Expenses” in 2011 NSA are included “Transfers to Capital – Administrative and General Expenses” for 2012, as all employee benefits are included under BCUC Account 725 Employee Benefits. (Exhibit B-1, Tab Application FSJ/DC, p. 12; Tab Application TR, p. 9)

Commission Determination

Given that PNG (N.E.) has used the capital overhead allocation methodology approved under the 2011 NSA, **the Commission Panel approves PNG (N.E.)’s requests to calculate transfers to capital in accordance with the capital overhead allocation methodology approved under the 2011 NSA, as amended for refinements to the methodology for 2012 as noted in the Application.**

8.0 RATE BASE

8.1 2012 Forecast Capital Additions

Fort St. John/Dawson Creek

PNG (N.E.) FSJ/DC originally forecast $3.468 million in capital addition projects for 2012 to manage growth and sustainment activities. (Exhibit B-1, Tab Application FSJ/DC, pp. 21-24) In its updated application PNG (N.E.) FSJ/DC increased the capital additions forecast to $4.471 million (including overheads) to reflect the installation of a new service extension to the community of Wonowon, BC. In its response to BCUC 1.28.1, PNG (N.E.) FSJ/DC discovered an error in its Application that increased its forecast cost of new service additions from $378,000 to $756,000, a difference of $387,000. Further, the Applicant clarified that a modelling error had occurred, and reported a corrected amount of $4,561,000 (including overheads). (Exhibit B-9, FSJ/DC, BCUC 1.30.3)

Plant in Service Additions Account Details 2012

Major 2012 Capital Projects (larger than $50,000)	Budgeted Cost Excluding Overhead	Budgeted Cost Including Overhead	Plant in Service Account #
Wonowon extension	$679,000	$731,000	475/467/471/477
Lineheater Replacement	110,000	120,000	467
Lineheater Replacement	59,000	65,000	467
Repair Ops. Centre wall	421,000	481,000	472
Lowering HP line	75,000	82,000	465
Mechanical coupling removal	320,000	347,000	475
Meters New/replacements	167,000	167,000	478
PE 2306 replacement	225,000	244,000	475
Lineheater Replacement	59,000	65,000	467
Upgrade Pressure Reducing Stn.	64,000	70,000	467
Install station alarms	68,000	74,000	467
Services	378,000	415,000	473
Mains	143,000	155,000	475
Distribution syst. Improvement	230,000	249,000	475
Mobile Equipment	169,000	169,000	484
Work Equipment	66,000	66,000	485
*Other	980,000	1,061,000	
Total	**$4,213,000**	**$4,561,000**	

**Note: Other includes 2011 carryover projects totaling $341,000.*

(Exhibit B-9, FSJ/DC, BCUC 1.30.3)

Included in the Capital Additions planned for 2012 was the repair/replacement of a wall for the 40 year-old Dawson Creek Operations Centre for a forecast cost of $421,000. Subsequent to the closing of the evidentiary record for this Proceeding, the Applicant has submitted a separate application to replace the existing 40 year-old Dawson Creek Operations Centre with a new facility.

Tumbler Ridge

PNG (N.E.) TR has included $190,000 in 2012 forecast Capital Additions compared with $384,000 in 2011. (Exhibit B-1, Tab Application TR, p. 20) The planned capital expenditures reflect sustaining activities including replacement meters ($27,000), annual plant turn-around ($63,000) and additional safety and security projects.

Commission Determination

The Commission Panel accepts the Applicant's Capital Additions forecast for 2012 less the amount of $421,000 for the repair of the Dawson Creek Operations Centre. The construction of the replacement operations centre was reviewed in a separate Proceeding and approved by Commission Order G-160-12. **The Commission Panel directs PNG (N.E.) to include the 2012 costs for the repair of the Dawson Creek Operations Centre in a non-rate base, interest bearing deferral account. The amortization period and dollar value of the deferral account will be addressed as part of PNG (N.E.)'s next Revenue Requirements Application.**

While the Commission Panel accepts the balance of the Capital Additions Planned for 2012 as reasonable, the Panel refers the Applicant to Section 8.2 of the PNG 2012 RRA Decision (Order G-130-12) and directs PNG (N.E.) to use more rigorous reporting and variance analysis processes to reduce errors and omissions for Capital Additions forecasting and cost control and to provide a more fulsome reporting for the next Revenue Requirements Application.

9.0 DEPRECIATION

This section deals with depreciation methodology, related deferral accounts, recovery of gains and losses, and accounting for negative salvage value.

9.1 Depreciation Policy and Depreciation Adjustment Deferral Account

Depreciation Policy

In its Applications, PNG [N.E.) seeks approval to return to the historical methodology of recording depreciation on additions to plant and equipment commencing the year following when the addition was placed into service, as permitted under US GAAP. [PNG (N.E.) FSJ/DC, para. 59; PNG (N.E.) TR, para. 67]

The 2011 NSA provides that PNG (N.E.) adopt a policy of commencing amortization in the period when an asset is put into use in order to comply with IFRS requirements. At that time, PNG (N.E.) had not applied to the Commission for the adoption of US GAAP and was in the process of preparing to adopt IFRS. (Order G-93-11, Appendix A, p. 7)

Then, PNG (N.E.) applied to the Commission to adopt US GAAP. Accordingly, in 2011, PNG (N.E.) did not adopt the above noted depreciation policy for financial reporting purposes; instead it maintained its old policy to begin amortizing assets in the year following the placement into use which is in accordance with US GAAP. (Exhibit B-1, Tab Application FSJ/DC, p. 18; Tab Application TR, p. 15)

PNG (N.E.) received consent to adopt US GAAP instead of IFRS for regulatory and security reporting purposes for a three year period of 2012-2014 in Commission Order G-168-11. (Exhibit B-12, FSJ/DC BCUC 2.72.1; TR, BCUC 2.42.1) Both methods of depreciation are acceptable for regulated utilities under US GAAP and under PNG’s Canadian GAAP approach in 2011; however the 2011 approved method to commence depreciation in the period the asset was put in service is the only acceptable method under IFRS. (IFRS standards, IAS 16)

Depreciation Adjustment Deferral Account

PNG (N.E.) set the 2011 rates based on depreciation commencing in the period the assets were put in service. This policy was not applied for financial reporting accounting purposes, resulting in depreciation for reporting purposes that were $47,730 lower for PNG (N.E.) FSJ/DC and $8,000 lower for PNG (N.E.) TR than the depreciation recovered in rates. In order to return the excess depreciation expense to ratepayers, PNG (N.E.) FSJ/DC and TR are seeking approval of a new 2011 Depreciation Adjustment Credit Deferral Account. PNG (N.E.) FSJ/DC and TR are requesting to place the credits of $47,730 and $8,000 respectively within this account, creating a process for a refund to ratepayers. PNG (N.E.) FSJ/DC and TR are also requesting to fully amortize the balance of this account in 2012. [PNG (N.E.) FSJ/DC Final Submission, para. 59, p. 15; PNG (N.E.) TR Final Submission, para. 67, p. 16; Exhibit B-1, Tab Application FSJ/DC, p. 18; Tab Application TR, p. 15]

Commission Determination

The Commission Panel notes that as IFRS was not adopted, PNG (N.E.) is not required to commence depreciation on additions at the time the assets are placed into service. Instead, as permitted under US GAAP, PNG may continue to amortize assets in the year following when additions are placed into service. The Commission previously approved such treatment and the Panel believes this methodology allows for more accurate forecasting. Therefore **the Commission Panel approves PNG (N.E.)'s request to commence depreciation in the following year an asset is placed into service, as allowed under US GAAP and consistent with PNG (N.E.)'s prior accounting practices. The Commission Panel also approves the Applicant's request to establish a 2011 Depreciation Adjustment Credit Deferral Account to be fully amortized in 2012.**

9.2 Plant Gains and Losses Deferral Account

In the Application, the FSJ/DC Division is requesting:

- approval to refund a plant gain credit of $238,000 from 2010 (updated from the 2011 NSA forecast credit of $264,000) in rates; (Exhibit B-1, Tab Application FSJ/DC, p. 16)
- approval to amortize the Plant Gains and Losses Deferral Account over a ten year period. (Exhibit B-1, Tab Application FSJ/DC, p. 16)

PNG (N.E.) TR is requesting:

- approval to refund the 2010 plant gain credit of $15,000 (updated from the 2011 NSA forecast credit of $30,000) in rates; (Exhibit B-1, Tab Application TR, p. 13)
- approval to amortize the Plant Gains and Losses Deferral Account over a ten year period. (Exhibit B-1, Tab Application FSJ/DC, p. 13)

The Panel will address each of the above noted requests individually and will then discuss the future reporting requirements and treatment of Plant Gain and Losses Deferral Account and negative salvage.

The Uniform System of Accounts Prescribed for Gas Utilities stipulates that there shall be no charge or credit to income from plant retirement or disposition. Any gains or losses, costs of removal and salvage values are charged to accumulated depreciation. (2012 PNG RRA, BCUC 1.43.19) However, with Commission approval, the Uniform System of Accounts does allow for gains or losses, costs of removal and salvage values, including extraordinary plant losses, to be recorded in a deferral account. (2012 PNG RRA, BCUC 2.130.1)

As part of the 2011 RRA negotiations PNG (N.E.) requested Commission approval to establish a new Plant Gains and Losses rate base deferral accounts for each of FSJ/DC and TR. The December 31, 2009 credit balances (i.e. $264,000 in FSJ/DC and $30,000 in TR) were recorded to these rate base deferral accounts to reflect the over depreciation of assets that had been retired and remained in plant, property and equipment. However, the request was withdrawn in the amendments to the Application, but restored during negotiations. The parties agreed to PNG (N.E.)'s restored request provided that no amortization could be taken in 2011. Furthermore, the parties did not consider PNG (N.E.)'s ability to refund the balance in a future period nor did they discuss whether the dollar values were properly determined. "The parties agreed that the recoverability, amortization period and dollar value of the deferral account balances would be addressed as part of PNG (N.E.)'s next revenue requirements application." (Order G-93-11, 2011 NSA)

The year-end 2011 balance in this deferral account is a credit of $207,000 for FSJ/DC and credit of $13,000 for TR; both items represent amounts owed to the ratepayer. [Exhibit B-3, Tab 2, PNG (N.E.), Tab 2, p. 9; Exhibit B-4, Tab 2, PNG (N.E.), Tab 2, p. 9]

9.2.1 Losses on Plant Assets - 2010

As part of the 2011 NSA, PNG (N.E.) was approved to place the above referenced credit balances of $264,000 (later updated to $238,000) and $30,000 (later updated to $15,000) respectively in the Plant Gains and Losses Deferral Account. The parties did not consider PNG (N.E.)'s ability to recover the balances in a future period nor did they discuss whether the sum of the net book values (NBV) of the individual assets as compared against the NBV of the entire asset class amounted to a credit of $238,000 for FSJ/DC and a credit $15,000 for TR. The dollar value of the deferral account, the recoverability, and the amortization period are the subject of this Application. None of the $238,000 credit for FSJ/DC and $15,000 credit for TR was recovered (amortized) in 2011. (Exhibit B-1, Tab Application FSJ/DC, p. 16; Tab Application TR, p. 13)

PNG (N.E.) indicates that these gains and losses occurred because the depreciation rates accorded to these assets were too high. (Exhibit B-1, Tab Application FSJ/DC, p. 15)

In the Application, PNG (N.E.) submits that the amounts are recoverable as they represent prudently incurred costs and is proposing to commence amortization on this account to allow PNG (N.E.) to recover these losses through rates. (Exhibit B-9, BCUC 1.40.2, 1.41.3)

Commission Determination

The Commission Panel finds that separating these items from the asset sub-ledger continues to be a transparent method to track gains and losses and is allowed under the Uniform System of Accounts. **The Commission Panel accepts that the $238,000 and $15,000 credit balances for FSJ/DC and TR represents the difference between actual experience and estimates for depreciation rates and salvage values for 2010 and approves PNG (N.E.)'s ability to recover these balances in rates.** The appropriate depreciation rate is discussed as a separate issue below.

9.2.2 Amortization Period

2011 additions to the Gains and Losses Deferral Account were $30,000 for FSJ/DC and $3,000 for TR. (Exhibit B-3, Tab 2, p. 8; Exhibit B-4, Tab 2, p. 8)

PNG (N.E.) FSJ/DC and TR are seeking Commission approval to amortize the balance in the Plant Gains and Losses Deferral Account over ten years (Exhibit B-1, Tab Application FSJ/DC, 16; Tab Application TR, p. 13), stating that this is the current approved amortization period for the extraordinary gains and losses also recorded in this account. (Exhibit B-9, FSJ/DC, BCUC 1.40.5)

The 2012 PNG RRA Decision directed PNG to amortize the Plant Gains and Losses Deferral Account over 5 year instead of PNG's proposed 10 year period.

Commission Determination

Given that the 5 year amortization period approved in the 2012 PNG RRA Decision will result in a larger credit to ratepayers in 2012 than under a ten year amortization period, **the Panel directs PNG (N.E.) to amortize the Plant Gains and Losses Deferral Account over five years** instead of PNG (N.E.)'s proposed ten year period.

9.2.3 Future Reporting Requirements and Treatment

PNG (N.E.) seeks approval of the creation of a Plant Gains and Losses Deferral Account, to enable PNG to track more accurately its property, plant and equipment assets, instead of maintaining a balance in its plant accounts for assets that are no longer in existence. (Exhibit B-1, Tab Application FSJ/DC, p. 15; Tab Application TR, p. 13) Both treatments are permitted under the Commission's Uniform System of Accounts.

In the Application, PNG (N.E.) states that the Plant Gains and Losses account it currently used to record:

- extraordinary plant losses; (Exhibit B-1, Tab Application FSJ/DC, p. 15; Tab Application TR, p. 13)
- gains and losses from the disposition of assets in the ordinary course of business; and (Exhibit B-1, Tab Application FSJ/DC, p. 15; Tab Application TR, p. 13)
- costs incurred when assets are taken out of service. (Exhibit B-9, BCUC 1.42.1)

The 2012 PNG RRA Decision approved the creation of a Plant Gains and Losses Deferral Account. (2012 PNG RRA Decision, p. 44)

Commission Determination

The Panel approves the creation of a Plant Gains and Losses Deferral Account, to report gains and losses in a transparent manner and to use this deferral account to track these items. This is easier than the alternative of having any gains or losses, costs of removal and salvage values being charged to accumulated depreciation. Further this preferred practice is consistent with other utilities regulated by the Commission.

However, **in future Revenue Requirement Applications PNG (N.E.) is directed to provide an assessment of each new addition to the Plant Gains and Losses Deferral Account in order for the Commission to determine the cause of the gain/loss and to allow the Commission to evaluate PNG (N.E.)'s current depreciation rates. Any requested addition must be allocated between extraordinary plant losses, gains/losses on ordinary disposal, costs incurred when assets are taken out of service and any salvage value; further, PNG (N.E.) is to track the balance in the account based on these components and clearly disclose this information in its future Revenue Requirements Applications.**

10.0 DEFERRAL ACCOUNTS

10.1 IFRS/US GAAP Deferral Account

PNG (N.E.) is requesting approval to amortize the 2011 year-end balance in the joint IFRS/US GAAP Conversion Cost Deferral Account over three-years ended in 2014. [PNG (N.E.) Final Argument, pp. 15, 17]

In the PNG US GAAP decision (see Order G-168-11, section 4) PNG (N.E.) was directed to seek approval for the amortization period and recoverability of the IFRS Deferral Account and to address the disposition of the previously incurred IFRS conversion costs. In this Application, PNG (N.E.) seeks approval to amortize the 2011 year-end balance in the joint IFRS/US GAAP Conversion Cost Deferral Account over a three-year period ended in 2014. Consistent with PNG's US GAAP application, total conversion costs expected by PNG Consolidated in 2011 are $250,000 and 2012 are $150,000. These amounts have been included as additions to the deferral account in their respective years and allocated to each of PNG and PNG (N.E.) based on rate base. (Exhibit B-1, Tab Application FSJ/DC, p. 16; Tab Application TR, p. 14) PNG (N.E.) considers three years to be appropriate given this is the initial period of time over which PNG will initially apply US GAAP pending further review in 2015. (Exhibit B-1, Tab Application FSJ/DC, p. 16; Tab Application TR, p. 14)

The 2012 PNG RRA Decision approved the PNG request to amortize the joint IFRS/US GAAP Conversion Cost Deferral Account over a three-year period, beginning in 2012. (2012 PNG RRA Decision, p. 47)

Commission Determination

Given the consistency between the requested amortization period and the period of adoption of the new accounting standards and the approval for PNG to amortize the joint IFRS/US GAAP Conversion Cost Deferral Account over a three-year period**, the Commission Panel approves the request to amortize the joint IFRS/US GAAP Conversion Cost Deferral Account over a three-year period, beginning in 2012.**

11.0 CAPITAL STRUCTURE AND RETURN ON CAPITAL

For 2012 PNG (N.E.) is not requesting changes to the rate of return on equity and the deemed common equity thickness agreed to under 2011 NSA. Furthermore, PNG (N.E.) submits that a higher rate base level is the major reason for higher common equity and return on equity in Test Year 2012 compared to the 2011 NSA. (Exhibit B-1, Tab Application FSJ/DC, p. 20)

12.0 PENSIONS AND OTHER NON-PENSION POST RETIREMENT BENEFITS

PNG presented the 'Non-Pension Post Retirement Benefits and Pension Plan' (NPPRB) portion of the PNG 2012 RRA on a consolidated basis combining the requests and balances for both PNG and its wholly owned subsidiary PNG (N.E.).

To be consistent with the presentation of the Pension and Other Non-Pension Post Retirement Benefits in the Application, the Panel addressed these requests on a consolidated basis in the PNG 2012 RRA Decision.

Commission Determination

As a result the determinations regarding Pension and Other Non-Pension Post Retirement Benefits for PNG (N.E.) are included in the PNG 2012 RRA Decision on pp. 53-64 and will not be repeated.

13.0 ERRATA

PNG (N.E.) also discovered a coding error in its rate application as $11,543 of data lines expenses was miscoded and allocated to Dawson Creek instead of Tumbler Ridge which has resulted in higher expenses in customer billing (Account 713) for PNG (N.E.) FSJ/DC. This will be corrected in the final submission to the Commission. (Exhibit B-9, BCUC 1.10.1)

The actual 2011 expenses for PNG (N.E.) FSJ/DC pipeline maintenance (Account 865) exceeded those forecast primarily due to a forecasting error. Although the cost of close interval surveys for 2011 were budgeted in Account 665, inadvertently no costs were forecast for the follow-up investigative digs. Actual expenses incurred for this purpose in 2011 were $128,000. (Exhibit B-9, FSJ/DC, BCUC 1.13.1)

When updating narrative for the PNG (N.E.) FSJ/DC planned 2012 capital additions modelling, an error was discovered in the tabulation of transfers to capital, the correct information was shown in the Exhibit B-9, FSJ/DC BCUC 1.30.3. (Exhibit B-9, FSJ/DC BCUC 1.30.3)

An error was discovered in the 2012 forecast cost of new service additions. The $378,000 figure for 2012 shown in the original application will be corrected to $756,000. (Exhibit B-9, BCUC 1.28.1) The Commission Panel notes that this error will have an impact on the final approved rate.

Commission Determination

The Commission Panel directs PNG (N.E.) to correct these errors when it files its final regulatory schedules following the release of the Commission's decision on this Application.

14.0 SUMMARY OF COMMISSION DECISION AND DETERMINATIONS

This Summary is provided for the convenience of readers. The content of this directive list is not inclusive of all decisions and determinations made throughout the reasons for decision. Where directives are listed below, additional context may be provided through the reasons for decision. Where any discrepancy or confusion may arise due to lack of context, the determinations made within the reasons for decision shall prevail.

No.	Directive	Page
1.	**For the 2012 forecast the Commission Panel accepts PNG (N.E.)'s forecast weighted average residential customer count of 9,652 and forecast use per customer of 106.5 GJ/year resulting in a residential load forecast of 1,028,162 GJ in Fort St. John.**	9
2.	**For the 2012 forecast the Commission Panel accepts PNG (N.E.)'s Small Commercial gas deliveries of 727,135 GJ in Fort St. John.**	10
3.	**The Commission Panel accepts the 2012 deliveries forecast of 136,050 GJ for PNG (N.E.)'s Large Commercial customers in Fort St. John.**	11
4.	**The Commission Panel accepts the 2012 deliveries forecast of 229,055 GJ for PNG (N.E.)'s Small Industrial customers in Fort St. John.**	11
5.	**The Commission Panel accepts the 2012 deliveries forecast of 923,800 GJ for PNG (N.E.)'s Industrial and Commercial Transportation Service customers in Fort St. John.**	12

6.	**For the 2012 forecast the Commission Panel accepts PNG (N.E)'s forecast weighted average residential customer count of 5,782 and forecast use per customer of 104.2 GJ/year resulting in a residential load forecast of 602,484 GJ in Dawson Creek.**	13
7.	**For the 2012 forecast the Commission Panel accepts PNG (N.E.)'s Small Commercial Customer load forecast of 436,048 GJ in Dawson Creek.**	14
8.	**The Commission Panel accepts the 2012 deliveries forecast of 179,100 GJ for PNG (N.E.)'s Large Commercial customers in Dawson Creek.**	14
9.	**The Commission Panel accepts the 2012 deliveries forecast of 41,500 GJ for PNG (N.E.)'s Small Industrial customers in Dawson Creek.**	15
10.	**The Commission Panel accepts the 2012 deliveries forecast of 32,100 GJ for PNG (N.E.)'s Commercial Transportation Service customers in Dawson Creek.**	15
11.	**The Commission Panel accepts the 2012 gas deliveries forecast of 96,605 GJ for PNG (N.E.)'s Residential customers in Tumbler Ridge.**	16
12.	**The Commission Panel accepts the 2012 gas deliveries forecast of 47,597 GJ for PNG (N.E.)'s Small Commercial customers in Tumbler Ridge.**	17
13.	**The Commission Panel accepts the 2012 gas deliveries forecast of 42,500 GJ for PNG (N.E.)'s Large Commercial customers in Tumbler Ridge.**	17
14.	**The Commission Panel accepts the 2012 gas deliveries forecast of 80,000 GJ for PNG (N.E.)'s Industrial Transportation Service in Tumbler Ridge. The panel also approves the continued use of the Dawson Creek Industrial Deliveries Deferral Account, as requested in the Application.**	18
15.	**The Commission Panel approves a one year amortization period for the 2011 year end RSAM balance.**	19
16.	**The Commission Panel accepts the 2012 forecast cost of service related to maintenance expenses.**	25
17.	**The Commission Panel does not accept the 2012 forecast operating expenses.**	25
18.	**The Commission Panel is reducing the 2012 budget for close interval surveys and contractor expenses to $120,000.**	26
19.	**PNG (N.E.) FSJ/DC is directed to provide a comprehensive pipeline asset integrity plan and report broken down by activity and cost function covering the current year and forward looking two years. The report should be updated annually and filed no later than 60 days following the end of year.**	26

20.	**The Panel is reducing the budget for pipeline operations (Account 665 Pipelines) by $14,000 to $68,000 from the $82,000 forecast for Account 665. The Panel is also reducing the budget for pipeline maintenance (Account 865 Pipelines) by $9,000 or one third of the estimated $26,000 for the same reasons.**	27
21.	**The Commission Panel orders the Applicant to provide the following, for the next RRA: details of the Performance/Incentive Pay program, for 2012 and 2013; an analysis of how that incentive program incents behaviour that benefits the ratepayer and an analysis of how each successive incentive pay challenge invites an employee to stretch.**	29
22.	**The Panel concurs with BCOAPO and approves $95,000 in audit, legal and consulting fees for the 2012 forecast, for PNG (N.E.) FSJ/DC.**	30
23.	**In the next RRA PNG (N.E.) is to bring forth evidence on alternatives for addressing strategies for total compensation, including the rising benefit costs and cost recovery from ratepayers.**	33
24.	**The Commission Panel approves PNG (N.E.)'s requests to calculate transfers to capital in accordance with the capital overhead allocation methodology approved under the 2011 NSA, as amended for refinements to the methodology for 2012 as noted in the Application.**	35
25.	**The Commission Panel accepts the Applicant's Capital Additions forecast for 2012 less the amount of $421,000 for the repair of the Dawson Creek Operations Centre.**	37
26.	**The Commission Panel directs PNG (N.E.) to include the 2012 costs for the repair of the Dawson Creek Operations Centre in a non-rate base, interest bearing deferral account. The amortization period and dollar value of the deferral account will be addressed as part of PNG (N.E.)'s next Revenue Requirements Application.**	37
27.	**While the Commission Panel accepts the balance of the Capital Additions Planned for 2012 as reasonable, the Panel refers the Applicant to Section 8.2 of the PNG 2012 RRA Decision (Order G-130-12) and directs PNG (N.E.) to use more rigorous reporting and variance analysis processes to reduce errors and omissions for Capital Additions forecasting and cost control and to provide a more fulsome reporting for the next Revenue Requirements Application.**	37
28.	**The Commission Panel approves PNG (N.E.)'s request to commence depreciation in the following year an asset is placed into service, as allowed under US GAAP and consistent with PNG (N.E.)'s prior accounting practices. The Commission Panel also approves the Applicant's request to establish a 2011 Depreciation Adjustment Credit Deferral Account to be fully amortized in 2012.**	39

29.	**The Commission Panel accepts that the $238,000 and $15,000 credit balances for FSJ/DC and TR represents the difference between actual experience and estimates for depreciation rates and salvage values for 2010 and approves PNG (N.E.)'s ability to recover these balances in rates.**	42
30.	**The Panel directs PNG (N.E.) to amortize the Plant Gains and Losses Deferral Account over five years.**	43
31.	**The Panel approves the creation of a Plant Gains and Losses Deferral Account, to report gains and losses in a transparent manner and to use this deferral account to track these items.**	43
32.	**In future Revenue Requirement Applications PNG (N.E.) is directed to provide an assessment of each new addition to the Plant Gains and Losses Deferral Account in order for the Commission to determine the cause of the gain/loss and to allow the Commission to evaluate PNG (N.E.)'s current depreciation rates. Any requested addition must be allocated between extraordinary plant losses, gains/losses on ordinary disposal, costs incurred when assets are taken out of service and any salvage value; further, PNG (N.E.) is to track the balance in the account based on these components and clearly disclose this information in its future Revenue Requirements Applications.**	44
33.	**The Commission Panel approves the request to amortize the joint IFRS/US GAAP Conversion Cost Deferral Account over a three-year period, beginning in 2012.**	45
34.	**As a result the determinations regarding Pension and Other Non-Pension Post Retirement Benefits for PNG (N.E.) are included in the PNG 2012 RRA Decision on pp. 53-64 and will not be repeated.**	46
35.	**The Commission Panel directs PNG (N.E.) to correct these errors when it files its final regulatory schedules following the release of the Commission's decision on this Application.**	47

Dated at the City of Vancouver, in the Province of British Columbia, this 9th day of November 2012.

Original signed by:

____

C.A. Brown
Commissioner

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-168-12

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek and Tumbler Ridge Divisions)
for Approval of its 2012 Revenue Requirements
for the PNG (N.E.) Service Area

BEFORE: C.A. Brown, Commissioner November 9, 2012

O R D E R

WHEREAS:

A. On November 30, 2011, the Pacific Northern Gas (N.E.) Ltd. [PNG (N.E.)] Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) Divisions filed with the British Columbia Utilities Commission (Commission), its 2012 Revenue Requirements Application (RRA, Application) to among other things, amend its delivery rates pursuant to sections 58 to 61 of the *Utilities Commission Act* (Act);

B. The Applicant, PNG (N.E.), also sought refundable interim relief pursuant to sections 58 to 61, 89 and 90 of the Act to allow PNG (N.E.) to amend its rates on an interim basis, effective January 1, 2012, pending the hearing of the Application and orders subsequent to that hearing, on the basis that on January 1, 2012, PNG (N.E.)'s rates would otherwise no longer be fair, just and not unduly discriminatory. Commission Order G-208-11 approved for PNG (N.E.) the delivery rates and the Rate Stabilization Adjustment Mechanism riders set forth in the Application on an interim basis, effective January 1, 2012. The Order also established a Preliminary Regulatory Timetable, a Workshop to review the issues in the Application, and invited registered Interveners to make submissions regarding the appropriate and formal review process for the Application;

C. By letter dated January 4, 2012, the Commission proposed a draft regulatory timetable for the review of the Application and requested submissions regarding the draft regulatory timetable. In accordance with Commission Order G-208-11, a Workshop was held on January 12, 2012;

D. The Peace River Regional District (PRRD) and PNG (N.E.) submissions dated January 27, 2012 and January 31, 2012, supported a written hearing process for the review of the Application. The British Columbia Old Age Pensioners' Organization *et al*. (BCOAPO) [recently changed to British Columbia Pensioners' and Seniors' Organization] submission dated January 31, 2012, stated that a written process may be appropriate for the review of the Application, but it reserved the right to re-assess its position at the conclusion of the evidentiary stage. All Parties supported delaying the filing date of Information Request (IR) No. 1 until after PNG (N.E.) filed its updated Application;

E. On March 15, 2012, PNG (N.E.) filed an Updated Application which forecasted revenue deficiencies of $100,000 for the FSJ/DC Division and $246,000 for the TR Division (Updated Application and the RRA are collectively referred to as the "Application"), down from $331,00 for the FSJ/DC Division and $323,000 for the TR Division in the Application filed on November 30, 2011;

F. Commission Order G-12-12 established an Amended Regulatory Timetable for the review of the Application that included a request for Intervener submissions regarding the format of the proceeding following PNG (N.E.)'s responses to the second round of IRs and a draft written argument schedule;

G. The Commission received submissions from PNG and the PRRD on May 18, 2012 and the BCOAPO on May 25, 2012, supporting a written hearing process for the review of the Application. Commission Order G-67-12 established a written hearing process for the review of the Application;

H. The Commission has considered the Application, the evidence and the written Arguments as set forth and discussed in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission for the reasons stated in the Decision, orders as follows:

1. Pursuant to sections 59 to 61 of the Act, the Commission does not approve the 2012 revenue deficiency of approximately $100,000 for FSJ/DC and $246,000 for TR, as filed in the schedules accompanying PNG (N.E.)'s Application.

2. PNG (N.E.) is directed to resubmit its financial schedules incorporating all the adjustments as outlined in the Decision, within 30 days of this Order.

3. If the 2012 permanent rates are less than the interim rates, PNG (N.E.) is to refund to customers the difference in revenue with interest at the average prime rate of the principal bank with which PNG (N.E.) conducts its business. If the 2012 permanent rates exceed the interim rates, PNG (N.E.) is to include the difference between the interim and approved rates in a non-rate base deferral account to be amortized in 2013.

4. PNG (N.E.) will file, on a timely basis, amended Gas Tariff Rate Schedules in accordance with this Order.

. . . /3

5. PNG (N.E.) will inform all affected customers of the final rates by way of a customer notice.

6. PNG (N.E.) is directed to comply with all other directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 9th day of November 2012.

BY ORDER

Original signed by:

C.A. Brown
Commissioner

Excerpts of *Utilities Commission Act*

Discrimination in rates

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

LIST OF ACRONYMS

2011 RRA	PNG's 2011 Revenue Requirements Application
2012 RRA	2012 Revenue Requirements Application
BCOAPO	British Columbia Old Age Pensioners' Organization *et al.*
CIS	Close Interval Surveys
CNRL	Canadian Natural Resources Limited
Commission, BCUC	British Columbia Utilities Commission
CSA	Canadian Standards Association
DBRS	Dominion Bond Rating Service
DC	Dawson Creek
FSJ	Fort St. John
IFRS	International Financial Reporting Standards
IRs	Information Requests
NBV	net book values
NPPRB	non-pension post-retirement benefits
NSA	Negotiated Settlement Agreement
NSP	Negotiated Settlement Process
O&M	Operating and Maintenance
PNG	Pacific Northern Gas Ltd.
PNG Consolidated	PNG and its wholly owned subsidiary PNG (N.E.) (collectively referred to as PNG Consolidated)
PNG (N.E.), the Utility, the Company	Pacific Northern Gas (N.E.) Ltd.
PRRD	Peace River Regional District
RRA	Revenue Review Applications
RSAM	Revenue Stabilization Adjustment Mechanism
SQI	Service Quality Indicators
the Application	the 2012 RRA and the updates to the 2012 RRA are collectively referred to as the Application
***UCA*, the Act**	*Utilities Commission Act*
TJ	Terajoules

TR	Tumbler Ridge
UAF	Unaccounted for Gas
US GAAP	US Generally Accepted Accounting Principals

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Pacific Northern Gas (N.E.) Ltd.
2012 Revenue Requirements Application

LIST OF EXHIBITS

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter and Order G-208-11 dated December 7, 2011 - Establishing a Preliminary Regulatory Timetable and Workshop
A-2	Letter dated January 4, 2012 – Request for comments and Draft Regulatory Timetable
A-3	Letter and Order G-12-12 dated February 7, 2012 – Amended Regulatory Timetable
A-4	Letter dated April 11, 2012 - Commission Information Request No. 1 for the Fort St. John/Dawson Creek Division
A-5	Letter dated April 11, 2012 - Commission Information Request No. 1 for the Tumbler Ridge Division
A-6	Letter dated May 9, 2012 – Commission Information Request No. 2 for the Fort St. John/Dawson Creek Division
A-7	Letter dated May 9, 2012 - Commission Information Request No. 2 for the Tumbler Ridge Division
A-8	Letter dated May 28, 2012 – Order G-67-12 Revised Amended Regulatory Timetable
A2-1	Letter dated May 14, 2012 - Commission Staff Submitting from the PNG-West 2012 Revenue Requirements Proceeding - PNG Response to BCUC Information Request No. 1 dated March 20, 2012

Exhibit No.	Description
APPLICANT DOCUMENTS PNGNE	
B-1	**PACIFIC NORTHERN GAS (N.E.) LTD. (PNGNE)** Letter dated November 30, 2011 - 2012 Revenue Requirements Application
B-2	Letter dated January 31, 2012 – PNGNE Comments on Draft Regulatory Timetable
B-3	Letter dated March 15, 2012 – PNGNE Submitting Updates on Fort St. John/Dawson Creek division Regulatory Schedules
B-3-1	Letter dated March 20, 2012 – PNGNE Submitting Updates on Fort St. John/Dawson Creek division Regulatory Schedules Corrected pages
B-4	Letter dated March 15, 2012 – PNGNE Submitting Updates on Tumbler Ridge Division Regulatory Schedules
B-4-1	Letter dated March 20, 2012 – PNGNE Submitting Updates on Tumbler Ridge Division Regulatory Schedules Corrected pages
B-5	Letter dated March 23, 2012 – PNGNE Submitting System Line Map
B-6	Letter dated March 23, 2012 – PNGNE Submitting Organization Charts
B-7	Letter dated March 23, 2012 – PNGNE Submitting Tumbler Ridge Division Customer Load Forecast Data
B-8	Letter dated March 23, 2012 – PNGNE Submitting Fort St. John/Dawson Creek Division Customer Load Forecast Data
B-9	Letter dated May 1, 2012 - PNGNE Submitting Response to BCUC IR No. 1
B-9-1	Letter dated May 1, 2012 – PNGNE Submitting CONFIDENTIAL Response to BCUC IR No. 1
B-10	Letter dated May 1, 2012 - PNGNE Submitting Response to BCOAPO IR No.1
B-11	Letter dated May 18, 2012 - PNGNE Submitting Comments on Proceeding Format
B-12	Letter dated May 18, 2012 - PNGNE Submitting Response to BCUC IR No. 2
B-13	Letter dated May 18, 2012 - PNGNE Submitting Response to PRRD IR No. 2

Exhibit No.	Description
B-14	Letter dated May 18, 2012 - PNGNE Submitting Response to BCOAPO IR No. 2

INTERVENER DOCUMENTS

C1-1	**PEACE RIVER REGIONAL DISTRICT (PRRD)** Letter dated December 15, 2011 – Request for Intervener Status by Carolyn MacEachern
C1-2	Letter dated January 27, 2012 – PRRD Submitting Comments on the Regulatory Process
C1-3	Letter dated May 10, 2012 – PRRD Submitting Information Request No. 2
C1-4	Letter dated May 18, 2012 - PRRD Submitting Comments on Proceeding Format
C2-1	**BRITISH COLUMBIA OLD AGE PENSIONERS ORGANIZATION ET AL (BCOAPO)** Letter dated January 9, 2012 – Request for Intervener Status by Eugene Kung
C2-2	Letter dated January 31, 2012 – BCOAPO Submitting Comments on the Regulatory Process
C2-3	Letter dated April 18, 2012 - BCOAPO Submitting Information Request No.1 Fort St. John/Dawson Creek Division
C2-4	Letter dated April 18, 2012 - BCOAPO Submitting Information Request No.1 Tumbler Ridge Division
C2-5	Letter dated May 10, 2012 - BCOAPO Submitting Information Request No. 2 to PNG (N.E.) Tumbler Ridge
C2-6	Letter dated May 10, 2012 - BCOAPO Submitting Information Request No. 2 to PNG (N.E.) FSJ/DC
C2-7	Letter dated May 25, 2012 - BCOAPO Submission on the Format of the Proceeding

INTERESTED PARTY DOCUMENTS

LETTERS OF COMMENT