BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-42-05

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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 to Amend 2005 Rates

BEFORE: R.H. Hobbs, Chair) May 5, 2005

O R D E R

WHEREAS:

A. In a 2005 Revenue Requirements Application dated December 17, 2004 ("the Application"), Pacific Northern Gas (N.E.) Ltd. ["PNG(N.E.)"] applied for approval to increase the rates in the Fort St. John/Dawson Creek and Tumbler Ridge Divisions on an interim and final basis, effective January 1, 2005, pursuant to Sections 89 and 58 of the Utilities Commission Act; and

B. The Application proposed to increase the delivery rates to all customers primarily as a result of increases in cost of service and gas cost for sales customers; and

C. On December 7, 2004, PNG(N.E.) filed its Fourth Quarter 2004 Report ("the Report") on gas supply costs and Gas Cost Variance Account ("GCVA") balances which requested an increase in the Gas Supply Charges for the Fort St. John/Dawson Creek Division effective January 1, 2005, based on the November 24, 2004 natural gas forward prices. PNG(N.E.) proposed that no changes be made to Gas Supply Charges for the Tumbler Ridge Division; and

D. The Report projected a significant credit balance in the Fort St. John/Dawson Creek GCVA at December 31, 2004; and

E. Commission Order No. G-115-04 approved interim rate changes in the delivery charges for all rate classes of customers as filed in the Application, and permanent Gas Supply Charges and GCVA rate rider for the Fort St. John/Dawson Creek Division, all effective January 1, 2005; and

F. PNG(N.E.) in its Application for the Fort St. John/Dawson Creek Division proposed a $239,000 revenue deficiency (excluding Company Use Gas) and for the Tumbler Ridge Division proposed a $25,000 revenue deficiency (excluding Company Use Gas); and

G. Commission Order No. G-115-04 also established a written hearing process to review the Application; and

H. On December 17, 2004 Pacific Northern Gas Ltd. ("PNG"), filed its 2005 PNG Revenue Requirements Application ("the PNG Application") and an application to recapitalize PNG under an income trust ownership structure ("the Income Trust Application"); and

I. Commission Order No. G-15-05 established an oral hearing process to review the Income Trust Application and the appropriate capital structure under the PNG Application and the Income Trust Application; and

J. The Company filed a revision on February 18, 2005 ("the Revised Application") that significantly reduces the original Application revenue deficiency for each of the two divisions. The Revised Application proposes a revenue sufficiency (excluding Company Use Gas) of $64,000 in the Fort St. John/Dawson Creek Division and a revenue deficiency (excluding Company Use Gas) of $3,000 in the Tumbler Ridge Division; and

K. The Commission has reviewed the Application and the Revised Application and the evidence adduced thereon, all as set forth in the Reasons attached as Appendix A.

NOW THEREFORE the Commission orders as follows:

1. The Revised Application is approved subject to the directions contained in the Reasons attached as Appendix A to this Order.

2. The revised Fort St. John/Dawson Creek Division revenue sufficiency (excluding Company Use Gas) of $64,000 and the revised Tumbler Ridge Division revenue deficiency (excluding Company Use Gas) of $3,000, as filed in the schedules accompanying PNG(N.E.)'s Revised Application are not approved.

3. PNG(N.E.) is directed to file an amended Summary of Rates and Bill Comparison schedule conforming to the terms of the Reasons attached as Appendix A to this Order, along with a method for refunding excess payments back to customers.

4. PNG(N.E.) is to provide, subject to timely filing, amended Gas Tariff Rate Schedules in accordance with this Order.

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

DATED at the City of Vancouver, in the Province of British Columbia, this 6th day of May 2005.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

Attachments

PACIFIC NORTHERN GAS (N.E.) LTD.
2005 REVENUE REQUIREMENTS APPLICATION

REASONS FOR DECISION

1.0 INTRODUCTION

1.1 Background

Pacific Northern Gas (N.E.) Ltd. [“PNG(N.E.)”, “Company”, “Utility”] 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 northeastern British Columbia. The Fort St. John/Dawson Creek (“FSJ/DC”) Division receives natural gas from the 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.

1.2 The Application

In a 2005 Revenue Requirements Application dated December 17, 2004 (“the Application”), PNG(N.E.) applied for approval to increase the rates in the Fort St. John/Dawson Creek and Tumbler Ridge Divisions on an interim and final basis, effective January 1, 2005, pursuant to Sections 89 and 58 of the Utilities Commission Act (“the Act”). The Application proposed to increase the delivery rates to all customers primarily as a result of increases in the cost of service and gas cost for sales customers.

PNG(N.E.) filed its Fourth Quarter 2004 Report on gas supply costs and Gas Cost Variance Account (“GCVA”) balances (“the Report”), which requested an increase in the Gas Supply Charges for the Fort St. John/Dawson Creek Division effective January 1, 2005 based on the November 24, 2004 natural gas forward prices. PNG(N.E.) proposed that no changes be made to Gas Supply Charges for the Tumbler Ridge Division.

On December 17, 2004 PNG filed its 2005 PNG Revenue Requirements Application (“the PNG Application”) and an application to recapitalize PNG under an income trust ownership structure (“the Income Trust Application”).

Commission Order No. G-115-04 approved interim rate changes in the delivery charges for all rate classes of customers as filed in the Application, and permanent Gas Supply Charges and GCVA rate rider for the Fort St. John/Dawson Creek Division, all effective January 1, 2005. PNG(N.E.) in its Application for the Fort St. John/Dawson Creek Division proposed a $239,000 revenue deficiency (excluding Company Use Gas) and for the Tumbler Ridge Division proposed a $25,000 revenue deficiency (excluding Company Use Gas).

The Company filed a revision on February 18, 2005 ("the Revised Application") that significantly reduces the original Application revenue deficiency for each of the two divisions. The Revised Application proposes a revenue sufficiency (excluding Company Use Gas) of $64,000 in the Fort St. John/Dawson Creek Division and a revenue deficiency (excluding Company Use Gas) of $3,000 in the Tumbler Ridge Division.

The Commission notes that the Tab Application section of the Application should have been more comprehensive. The application section should indicate the content of the order requested including a summary of all approvals sought by the Company. **The Commission directs PNG(N.E.) to provide a comprehensive application section in each future application outlining all approvals sought from the Commission.**

The Commission notes that, due to the lack of cross-referencing and supporting schedules, the financial information in the schedules is difficult to trace from one schedule to the next. For the convenience of the Commission and the intervenors, the Company should in its next filing provide cross-referencing between schedules and include any relevant supporting schedules.

The Commission directs PNG(N.E.) to file the approved 2005 full financial schedules in accordance with the directions contained herein. The financial schedules will be formatted to include columns for approved 2005, Revised Application, and actual 2004 figures.

1.3 The Written Hearing Process

On December 21, 2004 Commission Order No. G-115-04 established a written hearing process to review the Application. Interventions were received from the British Columbia Public Interest Advocacy Centre on behalf of the BC Old Age Pensioners' Organization, Council of Senior Citizens' Organizations of B.C., Federated Anti-Poverty Groups of B.C., Senior Citizen's Association of B.C., End Legislated Poverty, and the Tenants Rights Action Coalition (collectively known as "BCOAPO"). The B.C. Ministry of Energy and Mines, Terasen Gas Inc., Avista Energy Canada Inc., the Peace River Regional District, and Mr. Dave Turchanski also intervened.

After a series of information requests and responses, a submission was received from BCOAPO on February 24, 2005. In the submission, BCOAPO claims that PNG(N.E.)'s Revised Application that was filed on February 18, 2005 was not received by BCOAPO until February 21, 2005. BCOAPO submits that PNG(N.E.) used the timing of the update to avoid responding in a meaningful way to both Commission and intervenor information requests.

The Commission notes that the series of information requests and the timing and delivery of updates did provide limited time for review by intervenors. The Commission also notes that, although the timing and delivery was poor, the Company did endeavour to be responsive to Commission and intervenor information requests. PNG(N.E.) should ensure that all registered intervenors receive on the same day any filings submitted to the Commission in accordance with the Document Filing Protocols.

BCOAPO submits that it is premature to consider the Revised Application, until decisions on the Income Trust Application and the PNG Application have been issued. The Company acknowledges that the Income Trust Application could affect PNG(N.E.)'s cost of capital, but argues that the recapitalization of PNG as an income trust would not affect any other 2005 test year cost of service items applicable to PNG(N.E.), or how PNG allocates shared costs to PNG(N.E.) (Reply Argument, p. 3). PNG(N.E.) submits that the Commission should not delay in making its decision on PNG(N.E.)'s Application and proposes a deferral account to record any difference in shared service costs (Reply Argument, p. 4).

The Commission concludes that a decision by the Commission for the Revised Application should proceed without delay. The proposed shared service deferral account is addressed later in section 4.8.

2.0 LOAD FORECAST

PNG(N.E.) submitted updated load forecast numbers as part of its Revised Application, for FSJ/DC (Exhibit B-7, Tab Application, FSJ/DC, p. 3 and Tab Rates, FSJ/DC, p. 7) and TR (Exhibit B-7, Tab Application, TR, p. 3 and Tab Rates, TR, p. 5). The methodology for the updated load forecast values appears to have remained the same as that used in the original application and further explained in information request ("IR") responses. The update incorporated year end 2004 actual rather than projected deliveries.

2.1 Fort St. John

<u>Residential</u>

PNG(N.E.) forecasts deliveries of 1,094,047 GJ to its residential customers in Fort St. John. This value is the product of the test year weighted average customer count and the test year average use per account (Exhibit B-1, Tab Application, FSJ/DC, pp. 17-20; Exhibit B-7, Tab Rates, FSJ/DC, p. 7).

The weighted average customer count for the 2005 test year is 8,325. This equals the residential customer count at December 31, 2004 plus the forecast net customer additions multiplied by a 30 percent equivalence factor (Exhibit B-2, BCUC IR 14.1; Exhibit B-7, Tab Rates, FSJ/DC, p. 7). The test year average use per account is 131.4 GJ and is calculated as the mid-point between the normalized 2004 actual use per account and the linear trend 2005 figure (Exhibit B-1, Tab Application, FSJ/DC, p. 18; Exhibit B-7, Tab Application, FSJ/DC, p. 3 and Tab Rates, FSJ/DC, p. 7).

The approach used to establish both weighted average customer count and average use per account is the same as that approved by the Commission for the 2004 test year. The approach was deemed appropriate in light of the marked change in residential use per account in recent years and the establishment of a Rate Stabilization Adjustment Mechanism ("RSAM") account for PNG(N.E.). The Commission is of the view that these factors remain relevant for the 2005 test year.

No intervenors objected to PNG(N.E.)'s proposal in this regard.

The Commission accepts the 2005 deliveries forecast of 1,094,047 GJ for PNG(N.E.)'s residential customers in Fort St. John.

<u>Small Commercial</u>

PNG(N.E.) forecasts deliveries of 768,436 GJ to its small commercial customers in Fort St. John. This value is the product of the test year weighted average customer count and the test year average use per account (Exhibit B-1, Tab Application, FSJ/DC, pp. 17-20; Exhibit B-7, Tab Rates, FSJ/DC Application, p. 7).

The weighted average customer count for the 2005 test year is 1,386. This equals the small commercial customer count at December 31, 2004 plus the forecast net customer additions multiplied by a 35 percent equivalence factor (Exhibit B-2, BCUC IR 14.1; Exhibit B-7, Tab Rates, FSJ/DC, p. 7), and adjusted for customers that switched from the small commercial rate class to the large commercial rate class (Exhibit B-2, BCUC IR 14.4; Exhibit B-7, Tab Application, FSJ/DC, p. 3). It is unclear from the description in the Revised FSJ/DC Application whether all of the six indicated customers that switched were in Fort St. John. However, the Commission assumes that based on the response in BCUC IR 14.4, that all six customers are in fact in the Fort St. John area and are the primary cause of the change in forecast usage for the small commercial and large commercial classes between the original and Revised FSJ/DC Applications.

The test year average use per account is 554.1 GJ and is calculated as the mid-point between the normalized 2004 actual use per account and the linear trend 2005 figure, both of which include the effect of removing the use for the reclassified customers (Exhibit B-1, Tab Application, FSJ/DC, p. 18; Exhibit B-7, Tab Application, FSJ/DC, p. 3 and Tab Rates, FSJ/DC, p. 7).

The approach used to establish both numbers is consistent with that used for the 2005 residential forecast deliveries accepted by the Commission as described above, and is based on the same methodology approved for the small commercial forecast deliveries by the Commission for the 2004 test year.

The Commission accepts the 2005 deliveries forecast of 768,436 GJ for PNG(N.E.)'s small commercial customers in Fort St. John.

Large Commercial

PNG(N.E.) forecasts deliveries of 197,150 GJ to its large commercial customers in Fort St. John (Exhibit B-7, Tab Rates, FSJ/DC, p. 7). The forecast is based on a review of historical deliveries and expected use in 2005 based on discussions with these customers. PNG(N.E.) considers that this is an appropriate methodology given how few customers are in this class (Exhibit B-1, Tab Application, FSJ/DC, p. 21). This number also takes into account six small commercial customers that were reclassified as large commercial customers as their actual 2004 deliveries were greater than 5,500 GJ (Exhibit B-7, Tab Application, FSJ/DC, p. 3).

The Commission accepts the 2005 deliveries forecast of 197,150 GJ for PNG(N.E.)'s large commercial customers in Fort St. John.

Small Industrial

PNG(N.E.) forecasts deliveries of 161,901 GJ to its small industrial customers and 1,277,799 GJ to its transportation service customers. PNG(N.E.) bases its small industrial load forecast on a review of historical deliveries and expected use in 2005 based on discussions with these customers (Exhibit B-1, Tab Application, FSJ/DC, p. 21), which is the same approach applied in respect of the large commercial customer forecast, described above.

The Commission accepts the 2005 deliveries forecast of 161,901 GJ and 1,277,799 GJ for PNG(N.E.)'s Fort St. John small industrial and transportation service customers, respectively.

2.2 Dawson Creek

Residential

PNG(N.E.) forecasts deliveries of 618,719 GJ to its residential customers in Dawson Creek. This value is the product of the test year weighted average customer count and the test year average use per account (Exhibit B-1, Tab Application, FSJ/DC, pp. 17-20; Exhibit B-7, Tab Rates, FSJ/DC, p. 7).

The weighted average customer count for the 2005 test year is 5,083. This equals the residential customer count at December 31, 2004 plus the forecast net customer additions multiplied by a 30 percent equivalence factor (Exhibit B-2, BCUC IR 14.1; Exhibit B-7, Tab Rates, FSJ/DC, p. 7). The test year average use per account is 121.7 GJ and is calculated as the mid-point between the normalized 2004 actual use per account and the linear trend 2005 figure (Exhibit B-1, Tab Application, FSJ/DC, p. 19; Exhibit B-7, Tab Rates, FSJ/DC, p. 7).

The approach used by PNG(N.E.) for the Dawson Creek residential 2005 deliveries forecast is the same as that accepted by the Commission for the Fort St. John residential forecast as noted above.

The Commission accepts the 2005 deliveries forecast of 618,719 GJ for PNG(N.E.)'s residential customers in Dawson Creek.

Small Commercial

PNG(N.E.) forecasts deliveries of 475,451 GJ to its small commercial customers in Dawson Creek. This value is the product of the test year weighted average customer count and the test year average use per account (Exhibit B-1, Tab Application, FSJ/DC, pp. 17-20; Exhibit B-7, Tab Rates, FSJ/DC, p. 7).

The weighted average customer count for the 2005 test year is 707. This equals the small commercial customer count at December 31, 2004 plus the forecast net customer additions multiplied by a 35 percent equivalence factor (Exhibit B-2, BCUC IR 14.1; Exhibit B-7, Tab Rates, FSJ/DC, p. 7). The test year average use per account is 673.4 GJ and is calculated as the mid-point between the normalized 2004 actual use per account and the linear trend 2005 figure (Exhibit B-1, Tab Application, FSJ/DC, p. 18; Exhibit B-7, Tab Rates, FSJ/DC, p. 7).

The approach used by PNG(N.E.) for the Dawson Creek small commercial 2005 deliveries forecast is the same as that accepted by the Commission for the Fort St. John small commercial forecast as noted above.

The Commission accepts the 2005 deliveries forecast of 475,451 GJ for PNG(N.E.)'s small commercial customers in Dawson Creek.

Large Commercial

PNG(N.E.) forecasts deliveries of 198,400 GJ to its large commercial customers in Dawson Creek. The forecast is based on a review of historical deliveries and expected use in 2005 based on discussions with these customers. PNG(N.E.) considers that this is an appropriate methodology given how few customers are in this class (Exhibit B-1, Tab Application, FSJ/DC, p. 21; Exhibit B-7, Tab Rates, FSJ/DC, p. 7). This is the same approach accepted by the Commission with respect to the large commercial customer forecast for Fort St. John, described above.

The Commission notes that there is a significant increase in forecast deliveries for this customer class in the Revised FSJ/DC Application relative to the original Application, which forecast 162,098 GJ for this rate class (Exhibit B-1, Tab Rates FSJ/DC, p. 7). The Revised FSJ/DC Application provides no explanation as to whether the change is due to customer reclassifications, or simply that the actual 2004 usage was higher than originally projected and how this was incorporated into the revised forecasting process.

As directed in Commission Order No. G-71-04 in respect of PNG(N.E.)'s 2004 Rate Application, the Commission again directs PNG in future applications to explicitly identify the cause of any data variations between application years and between application iterations.

Based on the assumption that the numbers provided in the Revised FSJ/DC Application reflect the method proposed by PNG(N.E.) in the Application, the Commission accepts the 2005 deliveries forecast of 198,400 GJ for PNG(N.E.)'s large commercial customers in Dawson Creek.

<u>Small Industrial</u>

PNG(N.E.) forecasts deliveries of 81,500 GJ to its small industrial customer in Dawson Creek, based on a review of historical deliveries and expected use in 2005 based on discussions with the customer (Exhibit B-1, Tab Application FSJ/DC, p. 21; Exhibit B-7, Tab Rates, FSJ/DC, p. 7). This forecast is subject to an Industrial Customer Deliveries Deferral Account ("ICDDA") to record any variance between forecast and actual margin. The account was initially established to mitigate a high degree of variation and uncertainty in the load forecast of this customer. The 2004 forecast of 130,000 GJ was markedly higher than the Commission's approved 2003 forecast of 50,000 GJ and actual 2003 deliveries of 81,565 GJ (Commission Order No. G-71-04, p. 7 of Appendix A). The 2004 projected consumption in the original application was 87,963 GJ (Exhibit B-1, Tab Application FSJ/DC, p. 21) and the actual 2004 consumption was 95,060 GJ (Exhibit B-3, BCOAPO IR 10c).

As described above in respect of the revised forecast for the Dawson Creek large commercial class, it appears the 2005 forecast deliveries for that rate class were increased from the original application to reflect 2004 actual rather than projected deliveries. However, the small industrial forecast did not change in the Revised FSJ/DC Application as a result of the 2004 actual being higher than projected. The 2005 forecast consumption in the original application was equal to 93 percent (81,500 GJ/87,963 GJ) of the projected 2004 consumption.

The Commission is of the view that the 2005 forecast for the small industrial customer should reflect the actual 2004 consumption, and on that basis approves a modified forecast of 93 percent of 95,060 GJ, or 88,400 GJ.

Commission Order No. G-71-04 on page 7 of Appendix A states that the Commission expects to examine the need for continued use of the Industrial Customer Deliveries Deferral Account ("ICDDA") at PNG(N.E.)'s next revenue requirements hearing. Given the significant variance between the forecast and actual 2004 consumption, it appears that the load continues to be difficult to forecast; therefore the Commission directs PNG(N.E.) to continue to apply the ICDDA to variances between the forecast and actual margin of its small industrial customer in Dawson Creek in 2005.

2.3 Tumbler Ridge

<u>Residential</u>

PNG(N.E.) forecasts deliveries of 79,393 GJ to its residential customers in Tumbler Ridge. This value is the product of the test year weighted average customer count and the test year average use per account (Exhibit B-1, Tab Application, TR, p. 16; Exhibit B-7, Tab Rates, TR, p. 5).

The weighted average customer count for the 2005 test year is 1,046. This equals the residential customer count at December 31, 2004 plus the forecast net customer additions multiplied by a 30 percent equivalence factor (Exhibit B-2, BCUC IR 14.1; Exhibit B-7, Tab Rates, TR, p. 5). The test year average use per account is 75.8 GJ and is calculated as the mid-point between the normalized 2004 actual use per account and the linear trend 2005 figure (Exhibit B-1, Tab Application, TR, p. 17; Exhibit B-7, Tab Application, TR, p. 3 and Tab Rates, TR, p. 5).

The approach used by PNG(N.E.) for the Tumbler Ridge residential 2005 deliveries forecast is the same as that accepted by the Commission for the Fort St. John and Dawson Creek residential forecasts as noted above.

The Commission accepts the 2005 deliveries forecast of 79,393 GJ for PNG(N.E.)'s residential customers in Tumbler Ridge.

Small Commercial

PNG(N.E.) forecasts deliveries of 28,279 GJ to its small commercial customers in Tumbler Ridge. This value is the product of the test year weighted average customer count and the test year average use per account (Exhibit B-1, Tab Application, TR, p. 16; Exhibit B-7, Tab Rates, TR, p. 5).

The weighted average customer count for the 2005 test year is 60. This equals the small commercial customer count at December 31, 2004 plus the forecast net customer additions multiplied by a 35 percent equivalence factor (Exhibit B-2, BCUC IR 14.1). The test year average use per account is 471.3 GJ and is calculated as the mid-point between the normalized 2004 actual use per account and the linear trend 2005 figure (Exhibit B-1, Tab Application, TR, p. 17; Exhibit B-7, Tab Rates, TR, p. 5).

The approach used by PNG(N.E.) for the Tumbler Ridge small commercial 2005 deliveries forecast is the same as that accepted by the Commission for the Fort St. John and Dawson Creek small commercial forecasts as noted above.

The Commission accepts the 2005 deliveries forecast of 28,279 GJ for PNG(N.E.)'s small commercial customers in Tumbler Ridge.

Large Commercial

PNG(N.E.) forecasts deliveries of 30,400 GJ to its large commercial customers in Tumbler Ridge (Exhibit B-7, Tab Rates, TR, p. 5). The forecast is based on a review of historical deliveries and expected use in 2005 based on discussions with these customers (Exhibit B-1, Tab Application, TR, p. 18). This is generally the same forecasting approach accepted by the Commission with respect to the large commercial customer forecast for Fort St. John and Dawson Creek, described above.

The forecast includes expected consumption by a new large commercial customer that commenced taking service in the summer of 2004. This explains why the 2005 forecast is significantly higher than the 2004 forecast of 18,400 GJ for this rate class (Exhibit B-1, Tab Application TR, p. 18).

The Commission accepts the 2005 deliveries forecast of 30,400 GJ for PNG(N.E.)'s large commercial customers in Tumbler Ridge.

Small Industrial Transportation Service

PNG(N.E.) forecasts deliveries of 580,000 GJ to its small industrial transportation service customer in Tumbler Ridge (Exhibit B-7, Tab Rates, TR, p. 5).

Actual consumption by this customer in 2004 was 593,457 GJ. The five year average from 2000 to 2004 was 587,873 GJ, and the four year average from 2001 to 2004 was 593,476 GJ (Exhibit B-2, BCUC IR 15.1).

BCOAPO in its February 24, 2005 submission is of the view that the forecast should be adjusted upwards to 593,000 GJ to be consistent with the historical four year average level (Exhibit C4-3, p. 3). In PNG(N.E.)'s reply the Utility considers the 580,000 GJ forecast to meet the probability criteria in regard to the high and low figures over the 2000 to 2004 period (Reply Argument, p. 10).

The Commission determines that the appropriate forecast is 593,000 GJ for the small industrial transportation service deliveries in Tumbler Ridge.

3.0 CAPITAL EXPENDITURES

3.1 Fort St. John/Dawson Creek

Total capital additions in 2005 are forecast to be $1,752,000 before construction overheads (Exhibit B-7, Tab 2, FSJ/DC, p. 2). This includes an expenditure of $278,000 for the replacement of five vehicles, as well as a vessel to improve the safety and efficiency of odorant delivery from central Fort St. John to rural locations. The replacement of the vehicles is in accordance with PNG's replacement policy of 7 years or 160,000 km whichever comes first (Exhibit B-2, BCUC IR 18.1).

Major Projects in the Capital Additions Budget of $1,752,000 (Exhibit B-2, BCUC IR 20.1)	
Regulator Station Modification	$110,000
Removal of Underground Dresser fittings	$346,000
Mains/Services/Meters/Regulators for customer additions	$264,000
Replacement of Beta Polyethylene pipe	$211,000
Replacement of Transportation Equipment	$278,000
Miscellaneous System Improvements	$125,000

The Commission accepts the capital addition forecast.

3.2 Tumbler Ridge

Total capital additions in 2005 are forecast to be $134,000 before construction overheads (Exhibit B-7, Tab 2, TR, p. 2). The installation of fire and gas detection equipment will provide an early warning of the presence of a fire, or unsafe environment. Plant and Station improvements are designed to improve safety measures for hazardous products.

Major Projects in the Capital Additions Budget of $134,000 (Exhibit B-2, BCUC IR 21.1)	
Annual Processing Plant Turnaround	$51,000
Fire and Gas Detection System	$41,000
Plant and Station Improvements	$23,000

The Commission accepts the capital addition forecast.

3.3 Transfers to Capital

PNG(N.E.) proposes that 18.78 percent of overhead should be allocated to capital projects for Fort St. John/Dawson Creek Division (Exhibit B-1, Tab Application, FSJ/DC, p. 12) and 3.15 percent for Tumbler Ridge Division (Exhibit B-1, Tab Application, TR, p. 12). The percentage of overheads allocated to capital projects is based on the forecast labour in capital projects divided by total labour. The transfer to capital rate has declined from 2001 to 2005, but capital additions have not. The Company explained that the proportion of labour in a capital project does not increase with the value of the project, especially if contractors are utilized (Exhibit B-3, BCOAPO IR 7a); therefore capital transfers can decline while the value of capital projects are rising.

The Commission accepts the capitalized overhead rate of 18.78 percent for the Fort St. John/Dawson Creek Division and 3.15 percent for the Tumbler Ridge Division.

4.0 EXPENSES

4.1 Company Use Gas: Fort St. John/Dawson Creek

The Company Use Gas component is made up of blowdowns and losses, line heater consumption, office space heating and Unaccounted for Gas. For 2005, these are projected to be in a reasonable range of total gas deliveries. The 2005 Company Use Gas is forecast to be a 0.69 percent loss in the Fort St. John/Dawson Creek Division (Exhibit B-2, BCUC IR 12.1). The 2005 projected cost of Company Use Gas is based on the forecast of gas prices on the November 24, 2004 forward gas strip and the projection of the quantity of gas PNG(N.E.) expects to purchase for company use. The Unaccounted for Gas loss in 2005 is forecast to be a 0.25 percent loss (Exhibit B-2, BCUC IR 12.1).

The Commission accepts this level of Company Use Gas and its components, including the Unaccounted for Gas which is within reasonable limits considering past years.

4.2 Company Use Gas: Tumbler Ridge

The amount of Company Use Gas is forecast to be about 60,018 GJ or 8.33 percent of total gas deliveries in 2005 for the Tumbler Ridge Division (Exhibit B-2, BCUC IR 12.1). This is made up of process plant fuel and line heaters at a level of 1.32 percent. The CNRL share of the process plant fuel is 5.46 percent and PNG(N.E.) has hired a consultant to investigate the high losses in this area. The Unaccounted for Gas losses are forecast to be 1.55 percent (Exhibit B-2, BCUC IR 12.1).

The Commission accepts the Company Use Gas percentage and finds that the Unaccounted for Gas losses to be in an acceptable range. However, a component of Company Use Gas from the CNRL share of the process plant fuel percentage is unacceptably high. In reaction to this, PNG has hired a consultant to investigate this problem and the Commission agrees that this is an appropriate response at this time.

4.3 Operating, Maintenance, and Administrative and General ("OMA&G") Costs

BCOAPO, in its February 24, 2005 submission, expressed concern about the level of cost per customer increases since 2002 for OMA&G expenses, excluding Company Use Gas and shared service costs (Exhibit C4-3, p. 3).

PNG(N.E.) in its reply summarized the filed evidence for the gross operating (net of company use gas), maintenance, and administrative and general costs (Reply Argument, pp. 5-8). The Fort St. John/Dawson Creek Division OMA&G costs since 2000 have increased annually by an average of 2.2 percent. The Tumbler Ridge Division operating and administrative and general costs since 2000 have increased annually by an average of 3.8 percent. Maintenance costs for the Tumbler Ridge Division were not provided in the filed evidence and not included in the calculation. PNG(N.E.) considers the cost increases for FSJ/DC and TR to be reasonable. The Utility maintains that BCOAPO did not provide any compelling justification for any disallowance of costs (Reply Argument, p. 8).

The Commission finds that the historical level of gross OMA&G cost increases for PNG(N.E.) is reasonable.

Maintenance Expense for Fort St. John/Dawson Creek

BCOAPO indicated that, given the historical average in prior years, the maintenance expense for the Fort St. John/Dawson Creek Division should be more consistent with 2000 to 2003 average of $235,000 as opposed to the forecast of $266,000 (Exhibit C4-3, p. 3). PNG(N.E.) explained that the 2005 test year amount was based on an assessment of the maintenance work that needs to be completed, including an increase in expenditures for right-of-way slashing (Reply Argument, p. 9).

The Commission finds that the applied for 2005 test year maintenance expense for the Fort St. John/Dawson Creek Division is appropriate to maintain safe and reliable service.

4.4 Uncollectible Accounts

Fort St. John/Dawson Creek Account 718 – Uncollectible Accounts increased from $47,000 in Decision 2004 to $125,000 in 2005 test year, an increase of $78,000 or 166 percent. The $125,000 is based on a bad debt allowance provision of 0.43 percent. The average actual five year bad debt experience for FSJ/DC is 0.50 percent (Exhibit B-2, BCUC IR 4.0).

In the Revised Application, the Tumbler Ridge Division bad debt allowance provision was changed from 0.44 percent to 0.25 percent. The revised TR Account 718 – Uncollectible Accounts is $4,300 for 2005 (Exhibit B-3, BCOAPO IR 17b).

The Commission accepts, for Account 718 – Uncollectible Accounts, the forecast costs of $125,000 for the Fort St. John/Dawson Creek Division and $4,300 for the Tumbler Ridge Division.

4.5 Customer Billing

PNG(N.E.) explained in detail that the costs in Account 713 – Customer Billing are direct costs payable primarily to third party service providers under contracts that are competitive. Also, the Utility noted that the contracts underlying the costs have been properly entered into, having regard to the principle of seeking the best service at the most economical price (Exhibit B-6, BCUC IR 7.1). PNG(N.E)'s response to BCUC IR 7.1 also included the response to BCOAPO IR 4 which requested justification for certain cost items, including justification for the increased cost of the customer information system ("CIS"). PNG(N.E.)'s response in BCUC IR 7.1 provided information about the nature of the service contract for the CIS, but did not specifically provide reasoning for the increased 2005 unit cost.

In the Revised Application, the Utility reviewed in detail the customer billing cost as a result of responding to information requests. As a result, FSJ/DC Account 713 – Customer Billing decreased by $72,000 while Account 711 – Customer Contracts increased by $13,000 (Exhibit B-7, Tab Application, FSJ/DC p. 2). Similarly, TR Account 713 decreased by $14,000 and Account 711 increased by $1,000 (Exhibit B-7, Tab Application, TR p. 2).

BCOAPO's submission considers the up-to-date competitive bidding as an outstanding issue and submits that the Utility has not provided the business cases to support the need for database management improvements, justified by employee cost savings or reduction of bad debt (Exhibit C4-3, p. 5). PNG(N.E.) argues that it has provided a comprehensive explanation of what costs are incurred and how the competitive bidding process is applied. The Utility does not consider it reasonable to obtain competitive bids every year for existing multi-year term contracts (Reply Argument, p. 14).

The Commission finds that PNG(N.E.) has filed an acceptable explanation of its customer billing costs by detailed cost item. **The Commission accepts the revised customer billing costs in the Revised Application for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions.**

4.6 Audit, Legal and Consulting Fees: Fort St. John/Dawson Creek

PNG(N.E.) forecasts $22,000 for audit, legal and consulting fees in the Fort St. John/Dawson Creek Division (Exhibit B-7, Tab 1, FSJ/DC, p. 5). The Utility explained that, due to higher standards of corporate reporting required by various regulatory agencies, audit fees are projected to increase by $2,000 and legal fees by $3,000 from Decision 2004 (Exhibit B-3, BCOAPO IR 13b). In its February 24, 2005 submission, BCOAPO argues that the proposed increase in audit and legal fees is excessive. BCOAPO suggests that, if the increase is granted, the $5,000 should be added to the actual 2004 cost of $15,000 and not the 2004 Decision amount of $17,000 (Exhibit C4-3, p. 3).

The Commission agrees that the increases in audit and legal fees are reasonable. **The Commission accepts the $22,000 forecast in audit, legal and consulting fees for the Fort St. John/Dawson Creek Division.**

4.7 Allocation of Insurance Expense

PNG(N.E.) proposes to change the basis of allocation of insurance costs by PNG to PNG(N.E.) in 2005. Prior to 2005, property and commercial liability insurance were allocated on the basis of a fixed percentage and there was no allocation of Director's and Officer's insurance. Beginning in 2005, PNG(N.E.) proposes to allocate property insurance premiums on the basis of replacement value, adjusted for estimated risk of claims; commercial liability premiums on the basis of customer count; Director's and Officer's premiums on the basis of net income; and fiduciary insurance premiums on the basis of employee count (Exhibit B-1, Tab Application, FSJ/DC, p. 9 and Tab Application, TR, p. 9).

The Utility believes that there are a number of factors that determine the commercial liability premium. The Utility's insurance broker confirmed that it was equitable to use customer count for the allocation of commercial liability premiums. PNG(N.E.) notes that, while the potential magnitude of a liability claim would be much larger for a large transportation service customer relative to a residential customer, the risk of a claim is expected to be much lower given the safety practices and awareness of the large transportation customers (Exhibit B-8, BCUC IR 29.4). The Utility does not believe that there is a strong relationship between net plant-in-service and general commercial liability premiums (Exhibit B-8, BCUC IR 29.5).

The submission from BCOAPO states that its only issue is the allocation of the commercial liability portion of the insurance cost based on customer count. BCOAPO submits that the use of an allocator that reflects length of the network system or a volumetric allocator is more reasonable. Also, BCOAPO submits that a change in the insurance allocation methodology at this point should not be carried out until the application to recapitalize as an income trust is resolved (Exhibit C4-3, p. 4). In its reply to BCOAPO, PNG(N.E.) estimates that use of kilometers of installed pipe would result in an almost identical allocation of commercial liability insurance premiums as compared to using customer count as the allocator. The Utility considers the use of system volumes as the allocation methodology for commercial liability insurance premiums as unjustified and not supported by its past claims history. Also, PNG(N.E.) submits that it is not necessary for the Commission to delay approving the proposed allocation of insurance premiums (Reply Argument, p. 12).

The Commission agrees that a delay in the proposed allocation of insurance premiums is not warranted. **The Commission accepts PNG(N.E.)'s proposed allocation of insurance premiums, except for the allocation of commercial liability premiums.**

The Commission finds that commercial liability premiums are based on a number of factors, such as expected frequency and severity of loss. **The Commission directs that commercial liability premiums are to be allocated on the basis of both customer count and net plant-in-service, weighted equally.**

4.8 Shared Service Deferral Account

BCOAPO submits that it is premature to consider PNG(N.E.)'s Revenue Requirement Application until the decisions on both the Income Trust Application and the PNG Application have been issued (Exhibit C4-3, p. 1). PNG(N.E.) argues that the recapitalization of PNG under an income trust ownership structure could affect PNG(N.E.)'s cost of capital, but would not affect any other 2005 test year cost of service items applicable to PNG(N.E.). However, PNG(N.E.) agrees that the Commission's decision on the PNG Application could affect the shared service charges by PNG to PNG(N.E.). Therefore, the Utility proposes a deferral account for PNG(N.E.) to record the difference in the shared service cost calculation that may arise as a result of the Commission's decision on the PNG Application (Reply Argument, p. 4).

The Commission approves the proposed shared service deferral account to record the difference in shared service costs to PNG(N.E.) arising from the Commission's Decision on the PNG Application. Any deferral balance at year end 2005 is to be fully amortized in the following year.

4.9 Negative Depreciation Provision in Account 484: Fort St. John/Dawson Creek

The Company stated, in the Application for the Fort St. John/Dawson Division, that the $168,000 decrease in depreciation from 2004 to 2005 included a one time credit adjustment of $54,000 pertaining to transportation equipment that was over-depreciated in 2004 (Exhibit B-1, Tab Application, FSJ/DC, p. 13). In the Utility's information response, it stated that in 2004, the accumulated depreciation for Account 484 – Transportation Equipment was over-depreciated beyond the gross plant balance, resulting in a net credit balance of $54,000 at the end of 2004 (Exhibit B-2, BCUC IR 9.1). This is evidenced in the Application's financial schedules that show gross plant of $1.415 million and accumulated depreciation of $1.469 million for the forecast 2004 year end balance (Exhibit B-1, Tab 2, FSJ/DC, pp. 2-3). However, in the Revised Application the revised 2004 year end balances for Account 484 are $1.390 million gross plant and $1.451 million accumulated depreciation (Exhibit B-7, Tab 2, FSJ/DC, pp. 2-3). Also, the 2005 depreciation provision for this account was revised to $61,000 from $54,000. Since the 2004 plant continuity schedules were not provided, it is unclear how the difference arose. PNG(N.E.) proposes to reverse the over-depreciation charge with a negative depreciation provision in 2005. In the Revised Application, plant additions of $278,000 in 2005 for Account 484 (Exhibit B-7, Tab 2, FSJ/DC, p. 2) eliminate the net credit balance in the account by year end 2005.

The Commission denies PNG(N.E.)'s request to record a negative $61,000 depreciation provision in the Fort St. John/Dawson Creek Account 484. The Commission directs that the depreciation provision be set at zero for FSJ/DC Account 484 – Transportation Equipment in 2005. The Commission notes that the Utility should monitor its plant accounts to ensure that each account is not over-depreciated in the year. Also, the Utility in future applications should include plant continuity schedules in its application and updates.

4.10 Other Post-Retirement Benefits

Commission Order No. G-71-04 directed PNG(N.E.) to follow the allowed treatment of other post-retirement benefits consistent with the Decision on PNG's 2004 Revenue Requirements Application. The PNG Decision of July 29, 2004 conditionally approved the proposed expensing of post-retirement costs. Subsequently, Commission Letter L-6-05 confirmed that PNG's option for a Retirement Compensation Arrangement ("RCA") was in accordance with the Commission's direction.

PNG(N.E.) indicated that the Utility was in the process of creating and funding the RCA and would reflect the funding in its February 18, 2005 update for the contribution of funds to the RCA trust and its impacts to other working capital and tax expense (Exhibit B-2, BCUC IR 24.1). The Revised Application removed the allowance in other working capital (Exhibit B-7, FSJ/DC and TR, Tab 2, p. 11) and adjusted tax expense to reflect the RCA funding.

4.11 Deferral Account for Unaccounted for Gas

PNG(N.E.) requests approval of a deferral account to record the difference between budgeted Unaccounted for Gas and actual Unaccounted for Gas losses/gains. The exaggerated gain and loss swings in the PNG-West Division Unaccounted for Gas account necessitated the set-up of a deferral account. In 2004, PNG-West was expected to have an Unaccounted for Gas gain; therefore a deferral account with a 0.45 percent band was not considered necessary (PNG Decision July 29, 2004). However, the Commission allowed the deferral account without a band and indicated that this will be reviewed again in the 2005 PNG Revenue Requirements Application.

BCOAPO disagrees with a deferral account which shifts additional risk to rate payers. However, it considers the forecast Company Use and Unaccounted for Gas percentages for 2005 to be reasonable. These factors are consistent with past percentages with the exception of 2004 (Exhibit C4-3, p. 4).

PNG(N.E.) submits that it is strongly motivated to take steps to reduce Unaccounted for Gas losses to maintain its rates as low as possible. If this is not done, the Utility suggests the Commission could discontinue its approval of the deferral account. As an example, PNG(N.E.) has taken action to remedy the situation by alerting employees to high unaccounted for gas losses in 2004. It also has measurement personnel checking large volume metering equipment to ensure accuracy. In addition to these measures, a consultant was engaged to review the gas accounting function in all of the PNG service areas with an emphasis on the Fort St. John/Dawson Creek system (Exhibit B-3, BCOAPO IR 11b and c).

The Commission denies the application for a deferral account that would record the difference between budgeted Unaccounted for Gas and actual Unaccounted for Gas losses/gains because PNG(N.E.) should be at risk for Unaccounted for Gas.

4.12 Deferral Studies

The Tomslake study was undertaken in 1997 to review the economics of providing gas service to the Tomslake area near Dawson Creek. It was determined that customer contributions required for the construction of the distribution system were too high. Upon review, PNG(N.E.) believes that no substantial new developments are likely to occur in the future. Given that the economics of providing gas service to Tomslake are unlikely to change, PNG(N.E.) proposes the amortization of the entire $7,000 after-tax cost of the study in 2005 (Exhibit B-2, BCUC IR 22.3).

The Commission accepts the $7,000 deferral amortization of the Tomslake study in 2005 for the Fort St. John/Dawson Creek Division.

4.13 Interest Deferral Account

In its Application, PNG(N.E.) indicated that it will continue to record the difference between the actual and forecast short term interest expense, arising as a result of differences in interest rates, in the Interest Deferral Account (Exhibit B-1, FSJ/DC Application, p. 15 and TR Application, p. 14).

The Commission accepts the continuation of the Interest Deferral Account.

4.14 Property Tax Deferral Account

PNG(N.E.) requests continuance of deferral account treatment for property tax variances (Exhibit B-2, BCUC IR 8.2).

The Commission accepts the continuation of the Property Tax Deferral Account.

4.15 Damage Due to Terrorist Act Deferral Account

Fort St. John/Dawson Creek

As in 2004, PNG(N.E.) FSJ/DC is unable to obtain insurance coverage for “Terrorist Acts” and is requesting the continued approval of a deferral account to record costs that would be incurred should FSJ/DC suffer any damage due to a terrorist act (Exhibit B-1, Tab Application, FSJ/DC, p. 9).

Tumbler Ridge

As in 2004, PNG(N.E.) TR is unable to obtain insurance coverage for “Terrorist Acts” and is requesting the continued approval of a deferral account to record costs that would be incurred should PNG(N.E.) TR suffer any damage due to a terrorist act (Exhibit B-1, Tab Application, TR, p. 10).

The Commission approves the continuation of a deferral account to record costs incurred to repair damage caused by a terrorist act.