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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-22-03

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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 2003 Revenue Requirements

BEFORE:	P. Ostergaard, Chair	)	
	R.D. Deane, Commissioner	)	
	K.L. Hall, Commissioner	)	March 27, 2003
	R.H. Hobbs, Commissioner	)	

O R D E R

WHEREAS:

A. In a 2003 Revenue Requirements Application dated November 29, 2002 (the "Application"), and in a revision dated February 24, 2003 (the "Revised Application"), Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek and Tumbler Ridge Divisions) ["PNG (N.E.)"] applied to increase the Gas Delivery Charge and Gas Supply Cost components in rates on an interim and final basis, effective January 1, 2003, pursuant to Sections 91 and 58 of the Utilities Commission Act (the "Act"); and

B. The Application and Revised Application proposed to increase the Gas Delivery Charge to all customers as a result of increases in the cost of service and decreased deliveries to most customer classes and also proposed to increase the Gas Supply Cost based on the November 22, 2002 and February 5, 2003 forward gas price strip; and

C. By Commission Order No. G-92-02, the Commission approved:

- Interim increases in the Gas Delivery Charge for all classes of customers, effective January 1, 2003, subject to refund with interest, based on the 2003 Revenue Requirement except for the requested increase in the Tumbler Ridge Division's common equity component,
- Interim increases in the Gas Supply Cost as set out in the Application, and
- An interim increase to $0.30/GJ for the Tumbler Ridge Division's Gas Cost Variance Account ("GCVA") rider.

The Commission also directed PNG (N.E.) to make an interim change to the GCVA rider for the Fort St. John/Dawson Creek Division that would amortize the projected December 31, 2003 GCVA balance for the Fort St. John /Dawson Creek Division over 2003; and

D. A timetable for a written hearing process was set by Order No. G-92-02; and

E. The Commission has reviewed the Application and 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 Commission has reduced the 2003 revenue deficiency from $307,000 to approximately $220,000 for the Fort St. John/Dawson Creek Division and from $190,000 to approximately $131,000 for the Tumbler Ridge Division, as filed in the schedules accompanying PNG (N.E.)'s Revised Application and adjusted in the Reasons attached as Appendix A to this Order.

2. The interim increases in the Gas Supply Cost and GCVA riders for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions are confirmed as permanent.

3. The approved rates for the Gas Delivery Charge for the Fort St. John/Dawson Creek Division are less than the interim rates which have been in effect since January 1, 2003. PNG (N.E.) FSJ/DC Division is 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. The approved 2003 revenue deficiency and the resulting rates for the Gas Delivery Charge for the Tumbler Ridge Division are greater than the revenue deficiency used to derive the interim rates which have been in effect since January 1, 2003. The interim rates will be set as permanent from January 1 to March 31, 2003.

   PNG (N.E.) Tumbler Ridge Division is directed to recover the remainder of the approved forecast 2003 revenue deficiency over the nine-month period from April 1 to December 31, 2003. The remainder referred to above is defined as being the approved forecast 2003 revenue deficiency less the amount already recovered during the period from January 1 to March 31, 2003.

   PNG (N.E.) Tumbler Ridge Division is 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.

5. PNG (N.E.) is to comply with the directions contained in the Reasons attached as Appendix A to this Order.

6. The Commission will accept, subject to timely filing, amended Gas Tariff Rate Schedules in accordance with this Order.

7. 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 27th day of March 2003.

BY ORDER

Original signed by:

Robert H. Hobbs
Commissioner

Attachment

PACIFIC NORTHERN GAS (N.E.) LTD.
2003 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"). Duke Energy Corporation ("Duke") owns 100 percent of the voting common shares and about 40 percent of the non-voting common shares of PNG.

PNG (N.E.) serves about 16,000 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 transmission pipeline system and the Williams Energy (Canada) Inc. West Stoddart pipeline. The Tumbler Ridge ("TR") Division obtains all its raw gas supply from Canadian Natural Resources Limited ("CNRL") and operates its own small gas processing plant.

The parent company, PNG, delivers natural gas to about 24,000 customers, including to 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. In turn, some services are provided to PNG by Duke through an Administrative Services Agreement.

In 2000 PNG and PNG (N.E.) began restructuring their operations in an effort to reduce operating costs. Gas price volatility continues to affect customer consumption in both service areas. The continued economic downturn in northwestern British Columbia and the viability of certain large industrial customers present ongoing challenges for PNG.

1.2 The Applications

On November 29, 2002, PNG (N.E.) applied to the British Columbia Utilities Commission (the "BCUC"), the "Commission") for approval to amend rate schedules for its FSJ/DC Division and its TR Division effective January 1, 2003 on an interim basis pursuant to Section 91 of the Utilities Commission Act (the "Act") and on a permanent basis pursuant to Section 58 of the Act (the "Applications").

The Applications requested increases in the gas delivery component of rates, which result primarily from reduced (compared to the 2002 Decision) forecast deliveries in 2003. For the TR Division the increase is also driven by the proposed increase in the deemed common equity component of capital structure from 36 percent to 40 percent.

The Applications also sought Commission approval of a residential/small commercial customer deliveries deferral account commencing with the 2003 test year. PNG (N.E.) proposed to call this account "RSAM", which is consistent with the terminology used for the same account by BC Gas Utility Ltd. ("BC Gas").

Forecast increases in gas supply charges for 2003 were also reflected in the Applications. For the purposes of these Applications, the gas supply cost recovery rates were recalculated using PNG (N.E.)'s gas cost flow through model updated to reflect the 2002/2003 gas supply price changes with PNG (N.E.)'s gas suppliers and the forward gas price strip as of November 22, 2002.

On February 24, 2003 PNG (N.E.) submitted revisions (the "Revised Applications") to its original Applications, dated November 29, 2002. These revisions incorporated new and updated information that resulted in changes such as higher depreciation expense and decreases in sales.

The revisions also reflected several changes for calculation errors and omission of data that resulted in changes in income tax expense, lower operating expenses and a decrease in the return on rate base due to a higher contribution in aid of construction amount and a revised cash working capital methodology.

The overall impact of the above revisions caused a net decrease of $40,000 (from $347,000 to $307,000) in the 2003 revenue deficiency for the FSJ/DC Division. For the TR Division, the revisions resulted in a net increase of $60,000 in the 2003 revenue deficiency, increasing it from $130,000 to $190,000.

1.3 The Written Hearing Process

Interventions were received from the British Columbia Public Interest Advocacy Centre ("BCPIAC") on behalf of the Consumers Association of Canada (BC Branch) et al. ("CAC (BC) *et al.*") and from the Peace River Regional District ("PRRD"). After a series of information requests and responses, submissions were received from both Intervenors on February 28, 2003. The PRRD agreed with the general conclusions of CAC (BC) *et al*. and also expressed its concern with the magnitude of the rate increases requested by PNG (N.E.). In addition, the PRRD submitted that the request for rate increases comes at a time when natural gas costs are rapidly rising and that this has a particularly severe impact on customers in the communities served by PNG (N.E.), given the northern climate and the resulting amount of natural gas consumed.

PNG (N.E.) filed its Final Argument on March 7, 2003.

2.0 REVENUE STABILIZATION ADJUSTMENT MECHANISM

PNG (N.E.) applied for a deliveries deferral account that is similar in structure to the Revenue Stabilization Adjustment Mechanism ("RSAM") used by BC Gas. PNG (N.E.) proposed that if the consumption of gas by residential and small commercial customers varies from the consumption levels used to establish rates, then the variance in delivery margin would be placed in a deferral account. The Utility would continue to bear the risk in the forecast of the number of customers.

The Utility said that it is seeking approval for the RSAM because of the difficulty in forecasting. The difficulty is caused by a combination of factors such as economic conditions, gas price volatility and unusual weather patterns (BCPIAC IR No. 1, Q. 5b, p. 9). PNG (N.E.) proposed that for the 2003 test year, the year-end balance of the RSAM would be amortized over a one-year period (BCPIAC IR No. 1, Q. 5c, p. 10). The Utility proposed a RSAM for each of the two distribution system divisions, FSJ/DC Division and TR Division.

CAC (BC) *et al*. submitted that the establishment of RSAM would result in reduced risk to the Utility's shareholders and a corresponding transfer of risk to customers. It did not object to the establishment of a RSAM but argued for a 25 basis points reduction in equity risk premiums. CAC (BC) *et al.* submitted that an adjustment to the Utility's risk premiums to reflect the lowered risk is a condition for its support of the RSAM [CAC (BC) *et al.* Argument, p. 2].

PNG (N.E.) submitted that the RSAM is in the best interests of all parties [PNG (N.E.) FSJ/DC Division Argument, p. 5].

The Commission accepts PNG (N.E.)'s application for the RSAM in 2003. The RSAM deferral accounts for the FSJ/DC and TR Divisions will be the same as the RSAM mechanism reached in the Negotiated Settlement for the PNG 2003 Revenue Requirements Application and approved by Order No. G-14-03. The reduced forecast risk as a result of the establishment of the RSAM accounts will be considered in Section 7.0.

3.0 LOAD FORECAST

3.1 Fort St. John

3.1.1 Residential Customers (RS 1) Load Forecast

PNG (N.E.) forecast sales of 1,100,415 GJ to its residential customers in 2003. The forecast was based on monthly weighted averages of an estimated annual consumption of 136.4 GJ per customer and a weighted average number of 8,068 customers.

The weighted average number of customers of 8,068 was derived from the actual 8,020 customers as recorded at the end of 2002 and an expected 159 customer additions during the course of the test year. Since new customers are added throughout the year, PNG (N.E.) has assumed that the new customers on the system have a weighted average requirement of 30 percent of full-year customers. Most new home completions occur in the fall. When this 30 percent equivalence factor is taken into account, the real impact is an increase of 48 full-year customers, resulting in a weighted average of 8,068 customers.

The use per account forecast of 136.4 GJ is the midpoint between the normalized 2002 figure of 134.3 GJ and the 1992-2002 linear trend projection of 138.5 GJ for the test year. Despite the projected increase in Gas Supply Charge for 2003 to $6.899/GJ from the 2002 Gas Supply Charge of $4.412/GJ (Revised Applications, FSJ/DC Division, Tab Rates, p. 4), the Utility has not made any reference to the possible impact the Gas Supply Charge increase may have on the 2003 use per account forecast.

CAC (BC) *et al.* submitted that the use per account forecast methodology is appropriate especially if the RSAM is approved. On the customer additions, CAC (BC) *et al*. observed that PNG (N.E.) had not included possible additions from reattachments of shut-off services to the residential and commercial customer accounts [CAC (BC) *et al.* Argument, p. 2].

PNG (N.E.) submitted that its use per account forecast methodology is reasonable in view of its request for approval for a RSAM account in 2003. Without a RSAM, it argued that its delivery forecast would need to be reduced to a level that is consistent with the lower gas consumption of customers in 2001 and 2002 [PNG (N.E.) FSJ/DC Division Argument, p. 5].

The Commission accepts the PNG (N.E.) forecast of use per account of 136.4 GJ and is satisfied that the Utility has considered the net effect of service removals/reattachments separately from customer additions due to new construction and new main extensions.

The Commission accepts the forecast of 1,100,415 GJ for Fort St. John residential customers.

3.1.2 Small Commercial Customers (RS 2) Load Forecast

PNG (N.E.)'s small commercial deliveries forecast for 2003 is 819,634 GJ, based on monthly weighted averages of an annual estimated use per account of 619.9 GJ/year and a weighted average number of 1,322 customers.

The weighted average number of 1,322 customers was based on the actual year-end 2002 record of 1,316 customers and an expected addition of 15 customers during 2003, or the equivalent of an increase of six full-year customers. The actual year-end 2002 figure has already taken into account the movements between small and large commercial customers.

The Utility's reclassification of 11 RS 2 customers to the RS 3 class and four RS 3 customers to the RS 2 class has caused downward pressure to the average use per account in the RS 2 customer class in 2002 (Revised Applications, FSJ/DC Division, pp. 3-4). PNG (N.E.)'s forecast of 619.9 GJ/year was based on the midpoint of the actual normalized 623.2 GJ/year for 2002 and the linear trend projection of 616.6 GJ/year for 2003.

CAC (BC) *et al.* submitted that the Utility's methodology is appropriate especially if the RSAM account is approved.

The Commission accepts the deliveries forecast of 819,634 GJ for Fort St. John small commercial customers.

3.1.3 Large Commercial Customers (RS 3) Load Forecast

PNG (N.E.) forecast that the 2003 level of consumption would be 167,700 GJ based on discussions with customers.

The actual deliveries to the large commercial customers in 2002 totaled 179,227 GJ compared to 93,130 GJ in 2001. Before the reclassification of the net movement of seven customers from the RS 2 class to the RS 3 class, the projected consumption level for 2002 was 106,036 GJ (BCUC IR No. 1, Q. 7.2, p. 14).

CAC (BC) *et al.* argued that the forecast for large commercial customers should be increased to the 2002 actual consumption level because past experience indicates that customers who were asked to project their forecast gas use had a tendency to underestimate their actual use [CAC (BC) *et al.* Argument, p. 3].

The Commission sets the consumption level for Fort St. John large commercial customers at 179,000 GJ, a level comparable to 2002.

3.1.4 Small Industrial Customers Load Forecast

PNG (N.E.) forecast gas deliveries of 151,500 GJ to small industrial customers and gas deliveries of 1,200,800 GJ to the transportation service customers based on discussions with those customers. No Intervenor commented on these forecasts.

The 2003 deliveries forecasts by PNG (N.E.) are reasonably close to the actual deliveries recorded in 2002.

The Commission accepts the deliveries forecasts to the Fort St. John small industrial and transportation service customers.

3.2 Dawson Creek

3.2.1 Residential Customers (RS 1) Load Forecast

PNG (N.E.) forecast sales to residential customers of 645,673 GJ in 2003. The figure was based on weighted monthly averages of an estimated annual use per account 128.3 GJ/year and a weighted average of 5,033 customers.

The actual number of customers at the end of 2002 was 5,024 and PNG (N.E.) forecast 29 additions over the test year. Using the 30 percent equivalence factor, the real impact is an increase of nine full-year customers, thus giving a weighted average of 5,033 customers for the test year. PNG (N.E.) has employed a consistent methodology for all the temperature-sensitive customers in both Fort St. John and Dawson Creek. The use per account of 128.3 is the midpoint between the actual normalized 125.1 GJ and the linear trend projected 2003 figure of 131.5.

The submission of CAC (BC) *et al.* on sales volume forecast is applicable to both Fort St. John as well as Dawson Creek. CAC (BC) *et al.* does not object to the forecasting methodology used by PNG (N.E.), especially if the RSAM is approved.

The Commission accepts the deliveries forecast of 645,673 GJ for the Dawson Creek residential customer class.

3.2.2 Small Commercial Customers (RS 2) Load Forecast

PNG (N.E.) forecast that the gas sales to small commercial customers would be 463,480 GJ for 2003. This was based on monthly weighted averages of an estimated annual use rate of 682.6 GJ/year and a weighted average number of 679 customers in 2003.

There were 677 small commercial customers as at year-end 2002 after the reclassification of three RS 2 customers to the large commercial customer class, RS 3 (Revised Applications, FSJ /DC Division, p. 3). PNG (N.E.) forecast an increase of two full-year customers or a weighted average of 679 customers for 2003. The forecast 682.6 GJ/year average use per customer is the midpoint between the normalized 2002 use rate of 679.2 GJ and the linear trend projected 2003 rate of 685.9 GJ.

CAC (BC) *et al.* submitted that the methodology is appropriate especially if a RSAM is approved.

The Commission accepts the deliveries forecast of 463,480 GJ for the Dawson Creek small commercial customer class.

3.2.3 Large Commercial Customers (RS 3) Load Forecast

PNG (N.E.) forecast deliveries of 137,400 GJ to large commercial customers based on discussions with customers. The actual deliveries in 2002 were 148,875 GJ after taking into account the movement of three RS 2 customers to the RS 3 customer class.

CAC (BC) *et al.* argued that the forecast for large commercial customers should be increased to the 2002 actual consumption level because past experience indicates that customers who were asked to project their forecast gas use had a tendency to underestimate their actual use [CAC (BC) *et al.* Argument, p. 3].

The Commission sets the gas deliveries for Dawson Creek large commercial customers at 148,000 GJ, a level that is comparable to the 2002 deliveries.

3.2.4 Small Industrial Customers Load Forecast

Dawson Creek has only one small industrial customer, the Louisiana Pacific board plant. In 2002 the Industrial Customer Deliveries Deferral Account ("ICDDA") was in place to record any variance on the forecast margin. The forecast deliveries of 50,000 GJ in 2003 is based on a customer survey and compares to deliveries of 38,169 GJ in 2002. No comment was received from Intervenors on this forecast.

The Commission accepts the Dawson Creek small industrial load forecast and directs the Utility to continue to use a deferral account to record the variances between forecast and actual margin.

3.3 Tumbler Ridge

3.3.1 Residential Customers (RS 1) Load Forecast

PNG (N.E.) forecast deliveries of 89,800 GJ to the residential class in 2003 based on monthly weighted averages of an estimated annual consumption of 85.1 GJ/year and a weighted average number of 1,055 customers.

The actual number of customers at the end of 2002 was 1,060, a loss of ten customers since 2001. PNG (N.E.) forecast a continuation of the decrease, which would result in a net loss of 16 customers over the course of the test year, or a loss of 5 full-year residential customers. The forecast use per account in 2003 is 85.1 GJ/year, which is the midpoint between the actual normalized 82.1 GJ/year recorded in 2002 and the linear trend projected 2003 figure of 88.1 GJ/year.

CAC (BC) *et al*. submitted that it would be appropriate for PNG (N.E.) to use the same methodology for TR Division as it has for FSJ/DC Division, especially if a RSAM is approved.

The Commission notes that the normalized average use per account in 2002 in TR Division had not experienced a rebound from the low 2001 level, unlike the rebound experienced in FSJ/DC Division when the price per GJ declined in 2002 (Revised Applications, FSJ/DC Division, Tab Application, p. 13; Revised Applications, TR Division, Tab Application, p. 13). The Utility has not provided further information on the cause of the 2002 decrease in average use that could assist in the forecasting. Instead, PNG (N.E.) argued that without RSAM, the delivery forecast would need to be reduced to a load consistent with the 2001 and 2002 deliveries [PNG (N.E.), TR Division Argument, p. 5].

The Commission is concerned that forecasting made without the support of market information because of an over reliance on the deferral account mechanism could lead to a significant build-up in the RSAM balance. The Commission expects PNG to provide more forecast analysis in future applications even though a RSAM is in place.

The Commission accepts the PNG (N.E.) forecast methodology for TR Division on the basis that the economy in Tumbler Ridge is in transition and reliable market information is not currently available. The 89,800 GJ deliveries forecast is accepted for the purpose of establishing a margin revenue forecast.

3.3.2 Small Commercial Customers (RS 2) Load Forecast

The actual normalized deliveries to small commercial customers in 2002 were 30,323 GJ. PNG (N.E.) forecast sales of 30,758 GJ for the test year, based on a forecast average use per account of 460.4 GJ/year and a weighted average number of 67 customers.

The actual number of customers at the end of 2002 was 68. After taking into consideration the movement of one RS 2 customer to the RS 3 class, PNG (N.E.) forecast the 2003 weighted average number of customers at 67. The forecast average use rate is a midpoint between the normalized 2002 average rate of 450.2 GJ/year and 470.5 GJ/year from the linear trend projected figure for 2003.

The Commission notes that Fort St. John and Dawson Creek had each recorded an increase in average use per account in 2002 from the 2001 level despite the downward pressure exerted by the customer migration from RS 2 to RS 3 whereas Tumbler Ridge had recorded a further decline in 2002 (Revised Applications, FSJ/DC Division, Tab Application, p. 13; Revised Applications, TR Division, Tab Application, p. 13). The Utility has not provided reasons for the significant decrease in margin in the Revised Applications and the Commission is concerned that PNG (N.E.) may be relying too heavily on the establishment of RSAM in its forecast. The Commission expects the Company to provide more details on market information in future applications even with a RSAM.

The Commission accepts the PNG (N.E.) forecast methodology for TR Division on the basis that the economy in Tumbler Ridge is in transition and reliable market information is not currently available. The 30,758 GJ deliveries forecast is accepted for the purpose of the margin revenue forecast.

3.3.3 Large Commercial Customers (RS 3) Load Forecast

The deliveries forecast for large commercial customers is 23,800 GJ, after accounting for the movement of one small commercial customer to the RS 3 rate class in 2002. No Intervenor commented on the Utility's forecast. The 2003 forecast is comparable to the 2002 actual level of deliveries of 20,134 GJ.

The Commission accepts the Tumbler Ridge large commercial (RS 3) deliveries forecast.

3.3.4 Industrial Transportation Service Load Forecast

There is only one industrial transportation service customer -- Canadian Natural Resources Limited. PNG (N.E.) revised its original forecast of deliveries from 540,000 GJ to 586,000 GJ in the Revised Application. The revised forecast was based on the average annual deliveries for the period 2000 to 2002.

The Commission accepts the Tumbler Ridge industrial transportation service customer forecast of 586,000 GJ.

4.0 REVENUE REQUIREMENTS

4.1 Cost of Gas

The core market gas supply cost and the Gas Cost Variance Account ("GCVA") are reviewed in a separate quarterly review process. In March 2003 an examination of Gas Supply Charges for core sales, the Company Use Gas component of Delivery Charges, and the GCVA riders was conducted. Based on current forward natural gas prices further increases, effective April 1, 2003, were approved by Commission Order No. G-20-03.

4.1.1 <u>Fort St. John/Dawson Creek Division</u>

The interim rates approved by Order No. G-92-02 included an increase to Gas Supply Charges effective January 1, 2003. This was based on the November 22, 2002 forward natural gas price strip. The proposed Gas Supply Charge increases (Applications, FSJ/DC Division, Tab Rates p. 7) for Residential (RS 1), Small Commercial (RS 2), Large Commercial (RS 3) and Small Industrial (RS 4) classes are \$1.338/GJ, \$1.255/GJ, \$1.213/GJ and \$1.073/GJ, respectively. The increase was made interim pending resolution of demand charge allocations between PNG and PNG (N.E.).

The interim increases in Gas Supply Charges are confirmed and the demand charge allocations between PNG and PNG (N.E.) are accepted.

4.1.2 <u>Tumbler Ridge Division</u>

The interim Gas Supply Charges increase effective January 1, 2003 and approved by Order No. G-92-02 was based on the November 22, 2002 forward price strip (Applications, TR Division, Tab Rates, p. 5).

The interim increase in Gas Supply Charges of \$1.202/GJ is confirmed.

4.2 Company Use Gas Cost and Unaccounted for Gas Losses

4.2.1 Fort St. John/Dawson Creek Division

Commission Order No. G-92-02 approved, on an interim basis, an increase of $.004/GJ for the Company Use Gas Cost Supply Charge (Applications, FSJ/DC Division, Tab Rates, p. 7), based on volume and the November 22, 2002 forward strip.

The Commission accepts the interim increase in Company Use Gas Cost of $.004/GJ.

4.2.2 Tumbler Ridge Division

Commission Order No. G-92-02 approved on an interim basis an increase of $.035/GJ for the Company Use Gas Cost Supply Charge (Applications, TR Division, Tab Rates, p. 5). The Company's Revised Applications changed the forecast of Company Use gas to reflect the higher unaccounted for gas loss in 2002, and requested approval of a deferral account to record the difference between actual and forecast 2003 unaccounted for gas losses.

The interim increase in Company Use Gas Cost of $.035/GJ is accepted effective January 1, 2003 based on volume and the November 22, 2002 forward strip. The use of the increased forecast of unaccounted for gas loss is approved effective April 1, 2003. A deferral account to record the difference between actual and budgeted 2003 unaccounted for gas losses is also approved.

4.3 Shared Services

PNG (N.E.) receives an allocation from PNG for the cost of various shared services (e.g. customer care, engineering, administration). The bases for allocation include:

- a fixed percentage based on historical time study,
- an employee count and,
- a customer count.

In the 2003 Negotiated Settlement dated February 21, 2003 and approved by Order No. G-14-03 dated March 12, 2003, PNG agreed to:

- review the operating and maintenance ("O&M") accounts to be included in the cost pool for allocation as the organization of the Care Centre evolves and in any case at the time of its next revenue requirement application, and

- update the historical time study used as the base to derive the fixed allocation percentage before submitting its next revenue requirement application.

In its submission of February 28, 2003, CAC (BC) *et al.* agreed that this review is appropriate and is prepared to accept the 2003 shared service allocations to PNG (N.E.) given these issues can be addressed in the next revenue requirement application.

The Commission accepts the 2003 shared services costs.

4.4 O&M Expenses other than Shared Services

4.4.1 Fort St. John/Dawson Creek Division

PNG (N.E.) forecasts that expenses (excluding the Shared Services portion) in Account 713 Customer Billing will increase from the Decision 2002 amount of $244,000 (Revised Applications, FSJ/DC Division, Tab 1, p. 3) to $303,000 (Revised Applications, FSJ/DC Division, Tab 1, p. 3) in the 2003 test year, a 24 percent increase. These expenses are primarily incurred for outside services obtained from Enlogix and from Customer Information Systems ("CIS") Communications.

The cost per customer in the 2003 test year is $19.96 ($303,000/15,179 average number of customers for 2003), which is $3.61 or about 22 percent higher than the cost of $16.35 ($244,000/14,922 average number of customers) allowed in the 2002 Decision.

The evidence filed for this proceeding does not provide sufficient support for the above increases. For example, it is not fully evident whether the above increases are driven by price increases for the existing levels of service, an increase in the level of existing services, the addition of new types of services or a combination.

The Commission considers that a one-year increase of about 22 percent in the cost per customer for Customer Billing expenses (excluding the Shared Services portion) over the level allowed in the 2002 Decision is excessive.

In the absence of full justification for the requested increase the Commission will allow a cost per customer of $17.00 (based on the Decision 2002 amount of $16.35 plus a provision for inflation). The total 2003 expense (excluding the Shared Services portion) in Account 713 Customer Billing is reduced from $303,000 to $260,000 ($17.00 x 15,179 average number of customers for 2003) or $43,000.

In its next revenue requirement application PNG (N.E.) FSJ/DC Division should present evidence that fully demonstrates the underlying causes for the requested increases. To the extent that these are driven by increased costs for outside services (e.g. Enlogix), the Company is encouraged to present evidence showing that the incumbent service providers are still competitive compared to other market service providers.

4.4.2 Tumbler Ridge Division

PNG (N.E.) forecasts that expenses (excluding the Shared Services portion) in Account 713 Customer Billing will increase from the Decision 2002 amount of $20,000 (Revised Applications, TR Division, Tab 1, p. 3) to $35,000 (Revised Applications, TR Division, Tab 1, p. 3) in the 2003 test year, a 75 percent increase. These expenses are primarily incurred for outside services obtained from Enlogix and from CIS Communications.

The cost per customer in the 2003 test year is $31.11 ($35,000/1,125 average number of customers), which is $13.28 or about 74.5 percent higher than the cost of $17.83 ($20,000/1,122 average number of customers) allowed in the 2002 Decision.

The evidence filed for this proceeding does not provide sufficient support for the above increases. For example, it is not fully evident whether the above increases are driven by price increases for the existing levels of service, an increase in the level of existing services, the addition of new types of services or a combination.

The Commission considers that a one-year increase of about 74.5 percent in the cost per customer for Customer Billing expenses (excluding the Shared Services portion) over the level allowed in the 2002 Decision is excessive.

In the absence of full justification for the requested increase the Commission will allow a cost per customer of $18.50 (based on the Decision 2002 amount of $17.83 plus a provision for inflation). The total 2003 expense (excluding the Shared Services portion) in Account 713 Customer Billing is reduced from $35,000 to $21,000 ($18.50 x 1,125 average number of customers for 2003) or $14,000.

In its next revenue requirement application PNG (N.E.) TR Division should present evidence that fully demonstrates the underlying causes for the requested increases. To the extent that these are driven by increased costs for outside services (e.g. Enlogix), the Company is encouraged to present evidence showing that the incumbent service providers are still competitive compared to other market service providers.

5.0 RATE BASE

5.1 Capital Expenditures

5.1.1 Fort St. John/Dawson Creek Division

The difference between the 2002 actual amount spent and the 2003 forecast is approximately $17,000 or 0.8 percent (BCPIAC IR No. 1, Q. 2a, p. 2). Two vehicles were to be replaced at a cost of $87,500 (BCUC IR No. 1, Q. 17, p. 24).

It is the Commission's view that the forecast capital expenditures are within a reasonable range. The allowed forecast capital expenditures of $2,002,500 have been adjusted downward by $43,500 to reflect the replacement of only one vehicle.

5.1.2 Tumbler Ridge Division

CAC (BC) *et al.* indicated in its February 28, 2003 submission that the forecast capital expenditures were high in relation to the amount spent over the last five years. CAC (BC) *et al.* suggested that this could be reduced to a level closer to 2002 actuals. The capital expenditures in 2003 are expected to be about $129,000 which is $32,000 over 2002 actual costs (BCPIAC IR No. 1, Q. 2b, p. 12).

Capital expenditures are affected by a number of factors such as the specific projects to be undertaken, customer attachments and the inflation rate. Therefore, analyzing historic capital expenditure data to develop a trend may not always be appropriate.

The Commission accepts the Tumbler Ridge capital expenditure forecast of $129,000.

5.2 Deferral Accounts – GCVA Riders

5.2.1 Fort St. John/Dawson Creek Division

Order No. G-92-02 approved a GCVA rider of $0.119/GJ as an interim rate effective January 1, 2003.

This interim increase is now confirmed.

5.2.2 Tumbler Ridge Division

Order No. G-92-02 approved an interim increase to the GCVA rider of $.15/GJ to $.30/GJ.

This interim increase is now confirmed.

5.3 Methodology for determination of Cash Working Capital

In its Revised Applications, the Utility changed the methodology for calculating the cash working capital component of rate base. This change caused a decrease in the cash working capital component of rate base. The methodology used is the same as the one approved by the Commission in PNG's 2003 Negotiated Settlement (Order No. G-14-03).

The Commission accepts PNG (N.E.)'s revised methodology for calculating the cash working capital component of rate base.

6.0 INCOME TAXES

In the Applications, income tax expense was incorrectly calculated. The Revised Applications corrected the error, which then in part, caused the revenue deficiency for the TR Division to increase to $190,000. This amount exceeds the revenue deficiency of $124,000 used to set the interim rates approved by Commission Order No. G-92-02.

Intervenors did not comment on the correction and change in income tax expense.

The Commission accepts the corrections made to the calculation of income tax expense in the Revised Applications. However, the Commission is concerned about the impact of this correction and the increase caused to rates for customers of the TR Division. To mitigate this impact on rates in the test year 2003, the Commission directs PNG (N.E.) TR Division to amortize the accumulated balance of deferred income taxes so as to completely offset the increase in income tax expense caused by the correction.

7.0 RETURN ON EQUITY ("ROE") AND CAPITAL STRUCTURE

7.1 Fort St. John/Dawson Creek Division

The provision for the return on equity in PNG (N.E.)'s application for the FSJ/DC Division is based on a 9.92 percent allowable rate of return and a deemed common equity ratio of 36 percent.

The deemed equity component of 36 percent is unchanged from 2002 and the Utility has not applied to change the equity component of the capital structure. The allowable rate of return is based on the Commission's automatic ROE formula that in 2003 sets 9.42 percent as the benchmark rate for low-risk utilities, plus a 50 basis point (0.50 percent) risk premium that the Commission has allowed the FSJ/DC

Division of PNG (N.E.) in 2002. The Company has not applied to change the risk premium in the 2003 test year.

CAC (BC) *et al*. commented that PNG (N.E.)'s proposal to establish a RSAM amounts to a transfer of risk from shareholders to ratepayers, and therefore should result in a downward adjustment to the Utility's risk premium. It submitted that a 25 basis points reduction would be appropriate [CAC (BC) *et al.* Argument, p. 2].

PNG (N.E.) argued that, even with the establishment of a RSAM, its FSJ/DC Division continues to be at least 50 basis points riskier than the low-risk utility such as BC Gas. An example cited by the Utility is its small size relative to BC Gas, which makes it susceptible to customer movement in the boom and bust economy of the oil patch in northeastern British Columbia. Another example cited is that the RSAM, as applied to FSJ/DC Division, would only cover 82 percent of the Division's gross margin compared to over 90 percent for BC Gas [PNG (N.E.), FSJ/DC Division Argument, p. 5].

The Commission agrees with PNG (N.E.) that the size of the FSJ/DC Division makes this distribution system riskier than BC Gas, and this resulted in the awarding of a 50 basis points premium during the previous year. With the implementation of RSAM for the test year, there will be a tangible risk reduction for the Utility's shareholders in the form of 82 percent of the Division's gross margin revenue (Revised Applications, FSJ/DC Division, Tab Rates, p. 6) being covered by a deferral account mechanism. The Commission notes that the RSAM for BC Gas covers approximately 84 percent of its total gross margin revenue.

The Commission determines that the establishment of a RSAM should be accompanied by a reduction of 10 basis points in the equity risk premium from 50 to 40 basis points, the same reduction the Commission determined for BC Gas when its RSAM was introduced (Return on Common Equity Decision, June 10, 1994, p. 31).

7.2 Tumbler Ridge Division

PNG (N.E.) has applied for an increase in the common equity component from 36 percent to 40 percent. It submitted that deeming the common equity at 40 percent is consistent with the Commission's practice to allow the Utility to earn a just return on its invested capital (BCUC IR No. 1, Q. 23, p. 28).

PNG (N.E.) has not applied for any change to its current equity risk premium of 75 basis points (0.75 percent). Its provision for the return on common equity in the Application is 10.17 percent (75 basis points plus the low-risk benchmark rate of 9.42 percent) on a deemed 40 percent common equity component. The interim rates approved by Order No. G-92-02 to be effective January 1, 2003 did not reflect the requested increase in the equity component of the capital structure.

The impact of the applied-for increase in equity thickness would be about a $5,000 increase in revenue requirement (Revised Applications, TR Division, Tab Application, p. 3).

CAC (BC) *et al.* argued that the Utility has not provided sufficient evidence to justify an increase given the common equity components of other natural gas utilities and PNG. It also requested a reduction to the risk premium by 25 basis points as a result of the lowered risk due to the establishment of a RSAM [CAC (BC) *et al*. Argument pp. 2-3].

PNG (N.E.) submitted that it is a small utility with a risk profile that justifies the need for a 40 percent common equity ratio [PNG (N.E.), TR Division Argument, p. 4]. At the same time, PNG (N.E.) argued that its risk premium should remain at 75 basis point after the implementation of the RSAM on the basis of its small size of just over 1,100 customers and that the RSAM applies to only 68 percent of the gross margin revenue for TR Division [PNG (N.E.), TR Division Argument, p. 5].

The Commission determines that the equity risk premium of the TR Division should be reduced by 10 basis points from 75 to 65 basis points to reflect the reduced risk profile as a result of RSAM. The allowable rate of return on equity for 2003 will be 10.07 percent.

The Commission determines that there is insufficient evidence to support a change to the equity thickness of the TR Division and denies PNG (N.E.)'s application for an increase in the deemed equity ratio to 40 percent from 36 percent.