SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-57-02

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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.
for Approval of 2002 Revenue Requirements

BEFORE:	P. Ostergaard, Chair	)	
	P.G. Bradley, Commissioner	)	July 31, 2002
	N.F. Nicholls, Commissioner	)	

O R D E R

WHEREAS:

A. In a 2002 Revenue Requirements Application dated November 30, 2001, and in revisions dated April 22, 2002, collectively referred to as the "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 component in rates on an interim and final basis, effective January 1, 2002, pursuant to Sections 91 and 58 of the Utilities Commission Act (the "Act"); and

B. The 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

C. Forecast changes in gas supply charges for 2001/02 were reflected in the Application but are separately determined by the Commission; and

D. On December 19, 2001, PNG (N.E.) applied pursuant to Section 50 of the Act for approval of a $4.5 million long-term loan from PNG. This filing was included in the Commission's review of the Application; and

E. On January 8, 2002 participants at the Pre-hearing Conference established by Order No. G-132-01, requested that a written public hearing process into the PNG (N.E.) Application be established. A timetable for a written hearing process was set by Order No. G-4-02; and

F. By Commission Order No. G-149-01, the Commission approved interim increases in the Delivery Charges for all classes of customers, effective January 1, 2002, subject to refund with interest, based on

…/2

the 2002 Revenue Requirement except for the requested increases in the common equity component and an increase in Tumbler Ridge's risk premium in the rate of return on common equity; and

G. The Commission has reviewed the 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 revenue deficiency to approximately $213,000 for the Fort St. John/Dawson Creek Division and to approximately $61,000 for the Tumbler Ridge Division, as filed in the schedules accompanying PNG (N.E.)'s April 22, 2002 Revision to the Application and adjusted in the Reasons attached as Appendix A to this Order.

2. Since the approved rates are less than the interim rates which have been in effect since January 1, 2002, PNG (N.E.) 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.

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

4. The Commission will accept, 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 *31st* day of July 2002.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

Attachment

PACIFIC NORTHERN GAS (N.E.) LTD.
2002 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"). Westcoast Energy Inc. ("Westcoast") owns 100 percent of the voting common shares and about 40 percent of the non-voting common equity 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 Division receives natural gas from the Duke Energy Gas Transmission ("Duke") pipeline system and the Williams Energy (Canada) Inc. West Stoddart pipeline. The Tumbler Ridge Division obtains all of 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 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 Westcoast 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 has affected customer consumption in both service areas. The economic downturn in northwestern B.C. and the viability of large industrial customers present challenges for PNG. In the PNG (N.E.) service area, regional economic conditions are more favourable, although the Quintette Mines Ltd. (“Quintette”) coal mine at Tumbler Ridge closed in 2000 and the mine's contract with PNG (N.E.) ended in late 2001.

1.2 The Applications

On November 30, 2001 PNG (N.E.) applied to the British Columbia Utilities Commission ("BCUC", "Commission") for approval to amend rate schedules for its Fort St. John/Dawson Creek Division and its Tumbler Ridge Division effective January 1, 2002 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 "Application").

The Application requested increases in the gas delivery component of rates, increases to the deemed common equity component of capital structure and, for the Tumbler Ridge Division, an increase in the equity risk premium.

Forecast changes in gas supply charges for 2001/02 were reflected in the Application but are separately determined by the Commission on a quarterly basis. PNG (N.E.) applied for significant cost of gas decreases, resulting in a net decrease in 2002 rates to sales customers.

On December 19, 2001 PNG (N.E.) also applied under Section 50 of the Act for Commission approval of a $4.5 million long-term loan from PNG. The Commission determined that this application should be reviewed as part of the 2002 Rate Application proceeding.

On April 22, 2002 PNG (N.E.) submitted revisions to its Application to incorporate new, updated and corrected information. For the Fort St. John/Dawson Creek Division, PNG (N.E.) calculates the revised revenue deficiency to be $1.0 million. For the Tumbler Ridge Division, the revised revenue deficiency is $142,000.

1.3 Commission Orders

Commission Order No. G-132-01 established a Pre-hearing Conference to deal with both the Application and a separate revenue requirements application from PNG. Participants at the Pre-hearing Conference requested that a written public hearing process into the Application be established, and by Order No. G-4-02 the Commission set out a Regulatory Agenda and Timetable.

Commission Order No. G-149-01 approved an interim rate increase in the delivery charge for all classes of customers, subject to refund with interest. The interim rate increases were based on the 2002 Revenue Requirements, excluding the requested increases in the common equity component of the capital structure and in the risk premium in the rate of return on common equity.

1.4 The Written Hearing Process

Interventions were received from the Peace River Regional District ("PRRD") and from the BC Public Interest Advocacy Centre on behalf of the Consumers Association of Canada (BC Branch) et al. ("CAC (BC) *et al*."; "BCPIAC"). After a series of information requests and responses, submissions were received from both intervenors. PNG (N.E.) filed its Final Argument on May 23, 2002.

2.0 LOAD FORECAST

2.1 Load Forecast Methodology

As a result of the significant drop in gas deliveries experienced in 2001, PNG (N.E.) opted to depart from its previous load forecast methodology in favour of a technique that is more dependent on judgment. First, PNG (N.E.) forecast the number of accounts based on discussions with service area personnel. Second, it calculated a historical average use per account to 2000, and compared this figure with the estimated 2001 use per account. The forecast use for 2002 was then obtained by adjusting the 2001 figure on the assumption that there would be partial recovery to the historical average. The recovery was estimated to be one-third of the difference for the residential sector and one-quarter of the difference for the commercial sector.

PNG (N.E.) provided additional market data and analysis in its responses to Information Requests from BCUC staff and CAC (BC) *et al*. and from an exercise in time-series analysis that PNG (N.E.) undertook as a result of a public hearing process on the concurrent application by PNG. The data included annual year-end and weighted average customer counts and normalized use per account going back over ten years in most of the market segments. The time-series analyses were carried out using both single and multiple regression analysis and their results were presented along with accompanying statistical tests of significance.

2.2 Fort St. John

2.2.1 <u>Residential Load Forecast</u>

PNG (N.E.)'s residential load forecast of 1,153,950 GJ is broadly based on a weighted average count of 7,831 customers and normalized use of 147.4 GJ/year (Tab 1, p. 3). The weighted average of 7,831 was derived from the end-October 2001 count of 7,816 customers at year-end and a projected increase of

49 customers during 2002 to reach 7,865 customers. Because new customers are added throughout the year, an assumption that the new customers on the system have a weighted average requirement of 30 percent of full year customers was adopted by PNG. The 147.4 GJ was based on PNG (N.E.)'s judgment of reduced consumption.

CAC (BC) *et al*. argued that the judgment was arbitrary and that the subsequent statistical analysis is not sophisticated enough for forecasting. CAC (BC) *et al*. argued for a 10-year use figure of 153.5 GJ based on 1992 - 2001 average use per account data (BCPIAC IR 1, p. 8) as the best estimate for 2002 use given that there was no evidence of a downward trend prior to 2001. The Commission accepts the recommendation of CAC (BC) *et al*. of 153.5 GJ as the best estimate of 2002 use, in part due to the significant reduction in burner tip rates this year. As part of the historical average use approach, the Commission incorporated the actual 2001 year-end customer count of 7,893 (BCUC IR 1, Question 1.1) to forecast the 2002 count. Based on PNG (N.E.)'s own field research which projected a net increase of 49 customers during 2002, this would imply approximately 15 additional weighted average customers, and a 2002 weighted average of 7,908 customers.

The Commission sets the expected gas deliveries at 1,213,878 GJ (153.5 GJ x 7908).

2.2.2 Commercial Load Forecast

PNG (N.E.)'s commercial load forecast of 1,020,769 GJ is broadly based on a weighted average of 1,279 accounts and average use of 797.9 GJ (Tab 1, p. 4). Out of this total, PNG (N.E.) forecasts 123,500 GJ for its large commercial customers and the remaining 897,269 GJ for its small customers.

PNG (N.E.) based its 2002 estimated average use per account on the average use per account for the years 1998 to 2000 and the estimate for 2001. Due to the recent moderation in gas prices, PNG (N.E.) increased the 2001 estimate by one quarter of the difference to obtain its 2002 forecast.

PNG (N.E.) estimated the sales to all commercial customers, then estimated the sales to large commercial customers based on a review of historical deliveries to individual customers and on information obtained from service area personnel. Estimated sales to small commercial customers were then derived as the difference between the two.

No intervenor commented on this forecast or its methodology in the final submissions.

The Commission has adopted the average use per account based on the historical average given that there was no evidence of a discernible trend. The Commission accepts the concern of PNG (N.E.) over the pre-1999 figures for Fort St. John and therefore adopted the average of the 1999 to 2001 normalized sales (BCUC IR 1, Question 1.3.2), estimated at 837.0 GJ/year for 2002.

In order to incorporate the most recent data available, the Commission has used the actual 2001 year-end customer count of 1,298 (BCUC IR 1, p. 3) to forecast the 2002 number of commercial customers. PNG (N.E.) indicated that there would be a net addition of 15 customers during 2002 (Tab 1, p. 4), and on this basis a 2002 weighted average of 1,303 customers is estimated.

The Commission sets the expected commercial gas deliveries at 1,090,611 GJ (837.0 GJ x 1303 customers).

The Commission, in the Reasons for Decision (the "2001 Decision") on the 2001 Revenue Requirements Application ("2001 Application"), had expressed concern over PNG's method of disaggregation if movement between rate classes was not expected. In the Response to BCUC IR 1, Question 1.4, PNG (N.E.) indicated that there had been no switching between RS2 and RS3 and that none is expected to occur in 2002.

In the absence of available data on normalized use per account for large and small commercial customers, the Commission retains the 2001 market shares for the two segments and sets the deliveries at 119,324 GJ for large customers and 971,287 GJ for small customers.

The Commission expects PNG (N.E.) to improve its documentation and presentation of empirical evidence in future applications.

2.2.3 Industrial Load Forecast

PNG (N.E.) forecasts industrial sales and transportation deliveries in 2002 at 1,239,000 GJ based on discussions between service area personnel and customer representatives. Actual deliveries in 2000 and 2001 were 1,417,694 GJ and 1,239,862 GJ respectively. The forecast is close to the actual deliveries in recent years and incorporates customer expectations.

The Commission accepts PNG (N.E.)'s industrial load forecast for Fort St. John.

2.3 Dawson Creek

2.3.1 Residential Load Forecast

PNG (N.E.)'s residential load forecast of 643,606 GJ is broadly based on a weighted average of 4,986 customer accounts and normalized use of 129.1 GJ/year. The actual 2001 year-end number of accounts is 4,993 and actual normalized use per account is 119.2 GJ (BCUC IR 1, Question 1.6).

PNG (N.E.) provided additional time-series analysis and estimated the average use per account for 2002 as 130.5 GJ/year. CAC (BC) *et al*. suggested either adopting the subsequent regression analysis performed by PNG (N.E.) but identifying the effects of outliers or, alternatively, using the long-term average use rate. The Commission accepts the regression equation which forecasts 130.5 GJ for 2002. In order to incorporate the most recent available data, the Commission used the actual 2001 year-end customer count of 4,993 to forecast the 2002 number of accounts. PNG (N.E.) indicated in the Application that the customer count would remain stable in 2002 (Tab 1, p. 6).

The Commission sets the total residential gas deliveries at 651,587 GJ (130.5 GJ x 4,993 customers).

2.3.2 Commercial Load Forecast

PNG (N.E.)'s commercial load forecast of 580,312 GJ is broadly based on a weighted average customer count of 686 and average use per account of 845.6 GJ/year. Out of this total, PNG forecast deliveries at 125,200 GJ for large customers and the remaining 455,122 GJ for small customers. The actual 2001 year-end number of accounts is 693 and normalized use per account is 791.8 GJ/year.

No intervenor commented on this forecast or methodology in the final submissions.

In the absence of any evidence of a trend from the discrete annual data provided by PNG (N.E.) in its responses to information requests, the Commission adopts the 1995-2001 historical average of normalized use per account of 850.2 GJ as the value for 2002. In order to incorporate the most recent available data, the Commission has updated the actual 2001 year-end count of 693 to project the 2002 number of accounts. Based on PNG's own market view of a net addition of five accounts in 2002, this implies a 2002 weighted average of 695.

The Commission sets the total commercial gas deliveries at 590,889 GJ (850.2 GJ x 695 customers).

As noted above with respect to the Fort St. John commercial forecasts, the Commission is concerned with the inherent weakness in the methodology in disaggregating the forecast into large and small commercial customers. **In the absence of a load projection for the small commercial class, the Commission retains the market shares for the two segments and sets the deliveries at 127,818 GJ for the large customers and 463,071 GJ for the small customers.**

2.3.3 Industrial Load Forecast

The Louisiana Pacific board plant is the only industrial rate class customer. It is forecast to consume 51,000 GJ of gas in 2002. PNG (N.E.) also predicted that the veneer plant, which could consume as much as 25,000 GJ, is unlikely to proceed in 2002. The customer's consumption of gas in 2001 was 34,987 GJ.

The Commission accepts PNG (N.E.)'s forecast as a conservative estimate, subject to the Industrial Customer Deliveries Deferral Account that has been in place since last year.

2.3.4 Industrial Customer Deliveries Deferral Account ("ICDDA")

Commission Letter No. L-33-01 approved a 2001 Dawson Creek Industrial Customer Deliveries Deferral Account and in 2002 a $57,000 after-tax debit balance in the deferral account is amortized into rates. PNG (N.E.) is proposing that this deferral account be discontinued in 2002 as PNG (N.E.) has a high degree of confidence in 2002 forecast deliveries to this customer class (Tab Application, pp. 7, 9-10). No intervenor comments were received on this issue.

The Commission has approved a conservative industrial load forecast for 2002 and considers that this deferral account should continue to record variances between forecast and actual margin.

2.4 Tumbler Ridge

2.4.1 Residential Load Forecast

PNG (N.E.)'s residential load forecast of 91,894 GJ of gas deliveries for 2002 is broadly based on a 1,054 weighted average customer count and 87.2 GJ/year of normalized use per account (Tab 1, p. 3).

PNG (N.E.) based its estimates on the 2001 normalized use per account plus one third of the difference between that and the average for the years 1993-2000. PNG (N.E.) submitted that there is insufficient data to perform any regression analysis. The actual 2001 year-end number of accounts is 1,071 and the average normalized use per account is 84.0 GJ/year (BCUC IR 1, Question 12.1).

The Commission is cognizant of the possible change in the demographics and gas consumption volume in this service area resulting from the loss of Quintette as a major employer. The Commission believes that the historical average of 1995 to 2001 or 91.5 GJ/year is the best estimate of average use per account for 2002 because there is no discernible trend. Adopting PNG (N.E.)'s projection of a reduction of 16 accounts in 2002, and the same relationship for account losses as for additions (the weighted average is 30 percent of the yearly additions or losses), the Commission estimates a loss of five weighted average accounts. Using the actual 2001 year-end number of accounts of 1,071 and subtracting five weighted average accounts produces 1,066 total weighted average residential customers in 2002.

The Commission sets the total residential gas deliveries at 97,539 GJ (91.5 GJ x 1,066 customers).

2.4.2 Commercial Load Forecast

PNG (N.E.)'s forecast of 48,778 GJ of gas deliveries is broadly based on a projected weighted average customer count of 67 and an average normalized use of 733.0 GJ/year. The actual 2001 year-end customer count is 69 (BCUC IR 1, Question 12.2).

Given that there was no discernible trend from the historical data provided by PNG (N.E.) in its information response, the Commission believes that the historical average between 1995-2001 is appropriate as a basis for calculating an estimated average use per account. Using that data yields an average use per account of 747.7 GJ/year. The Commission accepts PNG (N.E.)'s forecast for 2002 of 67 weighted average accounts.

The Commission sets the total gas deliveries at 50,096 GJ (747.7 GJ x 67 customers).

PNG (N.E.) has not disaggregated the commercial load forecast into small commercial sales (RS2) and large commercial sales (RS3) in the Application. **PNG (N.E.) is directed to separately forecast the load for small customers or project the deliveries to small customers based on its latest market share in total commercial gas deliveries.**

2.4.3 Industrial Load Forecast

Quintette

Quintette discontinued operations in October 2000 and is currently engaged in reclamation activities. As a result of an unbudgeted contract termination payment of $217,411 received in 2002, PNG (N.E.) refunded this amount to customers based on their 2001 consumption. The forecast of 12,635 GJ for 2002 is based on the heating load of 12,378 GJ recorded in 2001 for its facilities.

The Commission accepts this forecast.

Canadian Natural Resources Limited ("CNRL")

PNG (N.E.) stated that consumption for CNRL in 2000 and 2001 was in the 525,000 GJ to 550,000 GJ range and, based on discussions with CNRL, forecast 2002 deliveries of 500,000 GJ (BCUC IR 1, Question 12.3).

The Commission considers that the forecast should be at the mid-point of consumption in the past two years, and sets the forecast at 537,500 GJ.

3.0 REVENUE REQUIREMENTS

3.1 Shared Services

PNG (N.E.) states that the closure of the local offices in Fort St. John, Dawson Creek and Tumbler Ridge in 2000 has resulted in an increased level of administrative and general services provided from its parent company, PNG (FSJ/DC Tab Application, p. 6; Tumbler Ridge Tab Application, p. 6). The Commission finds that the 2000 reorganization and the outsourcing of services from PNG (N.E.) to PNG and to Enlogix for customer billing has made the comparison of 2002 operating, maintenance and administrative and general expenses to 2001 and prior years difficult.

In argument, the PRRD submits that "While PNG (N.E.) states that its more detailed review of the shared service allocation methodology has resulted in a more accurate (and increased) allocation of costs to PNG (N.E.) from PNG, it gives very little detail on the methodology it used at the time of the reorganization in late 2000, and the methodology it is using in this application to justify the increase."

The Commission considers that the tracking of shared services to the divisions of PNG (N.E.) could be improved by PNG identifying the gross cost of the shared services it provides to PNG (N.E.) and the shared services that PNG obtains externally from Westcoast and Enlogix. PNG should provide supporting calculations that demonstrate how the gross cost of the shared services is allocated to the divisions of PNG (N.E.) according to the allocation bases of time spent and customer count identified in PRRD IR 1, page 2. The tracking would also be improved if the shared service allocation to PNG (N.E.) identified the operating, maintenance and administrative and general accounts of PNG (N.E.) that would record these shared services and the corresponding amounts. Future applications should be supplemented by a comparison of the shared service allocation to the divisions of PNG (N.E.) for the prior year.

The tracking of allocated services from Enlogix to PNG (N.E.) would be improved if the services provided and the cost of the services were identified individually. Increased costs in the current year, such as postage or courier fees, would allow a comparison to the fees charged in the past year.

The Commission concludes that PNG (N.E.) has not substantiated its proposed increases to shared service costs. The Commission must approximate a fair allocation for efficient operations based on past information and the overall impact on associated accounts. The adjustments made by the Commission in Section 3.2 reflect adjustments to both allocated shared service costs and locally incurred costs.

3.2 Expenses

PNG (N.E.) attributed the increase in 2002 operating expenses in the Fort St. John and Dawson Creek Division to third party expenditures. In the Tumbler Ridge Division, expenses are forecast to increase due to an increased allocation from PNG for shared service costs of engineering, drafting, warehousing, measurement and corrosion services.

3.2.1 <u>Fort St. John/Dawson Creek</u>

The mains and services operating expenses in account 675 are forecast to be $235,000 in 2002 compared to 2001 actual costs of $147,000. This increase may result from reduced capital expenditures since plant additions are forecast to decrease in 2002 to $2.06 million compared to 2001 actual of $2.263 million. The operating expenses transferred to capital in account 689 are forecast to decrease to $173,000 compared to a 2001 actual of $205,000 (Tab 1, p. 10).

The Commission considers that the decrease in capital projects may result in fewer costs transferred from operating expenses to capital. In 2001, the actual combined total of accounts 675 and 689 was $352,000 and the Commission considers that a 2002 combined total of $360,000 is reasonable. With a combined provision of $360,000, the 2002 allowance for account 675 is $187,000 and for account 689 is $173,000.

The customer billing costs in account 713 allowed by the 2001 Decision were $507,000 or approximately $34 per customer. These operating expenses are forecast to increase to $677,000 or about $46 per customer in 2002 due to two additional Customer Care Centre employees ($60,000), increased postage and courier costs (Enlogix: $31,000; Canada Post: $4,000), telephone and data line costs ($25,000), training and development ($20,000), data clean-up fee ($20,000) and stationery costs ($10,000). PNG (N.E.) states that no additional services are provided in 2002 compared to 2001 but attributes the cost increase to increased costs in the Customer Care Centre and a more accurate shared service allocation (BCUC IR 1, p. 16).

The Commission accepts that the additional employees and the increased telephone and data line costs are necessary to handle customer billing and account enquiries above the amount provided in the 2001 Decision. Recovery of the increased postage cost from Canada Post is necessary. The Commission considers that a cost per customer of $46 is excessive and that a cost per customer of approximately $40 per customer should be achievable. The Commission considers that a 2002 provision for customer billing costs of $600,000 is appropriate.

In its 2001 Application, PNG (N.E.) forecasted Administrative expenses in account 721 of $464,000. This included annual cost reductions of $499,000 resulting from the closure of offices in Fort St. John and Dawson Creek, offset by an increase in shared service costs of $150,000 for the costs of the Customer Care Centre in Terrace. PNG (N.E.) expected these annual cost savings of $349,000 would continue. PNG (N.E.) stated that the reorganization focused on the administrative and customer accounting activities and there were no outside field workers or emergency response personnel positions impacted (2001 Application, BCUC IR 1, pp. 1-2).

The Administrative expenses in account 721 are forecast to increase to $580,000 in 2002 compared to $464,000 allowed in the 2001 Decision and 2001 actual expenditures of $315,000 (Tab 1, p. 12). PNG (N.E.) attributes the cost increases to the closure of offices in Fort St. John and Dawson Creek in 2000 and the opening of the Customer Care Centre in Terrace. The Utility stated that in 2001 the Customer Care Centre costs allocated to PNG (N.E.) included only estimated labour and benefits, while in 2002 all Customer Care costs are included in the allocation (PRRD IR 1, p. 2).

In its argument, PRRD considers that the customers of PNG (N.E.) are receiving a lower level of customer service at an increased cost and requests that the allocation to PNG (N.E.) be proper, fair and reflect the cost of actual services. CAC (BC) *et al*.'s argument submits that the BCUC should take a close look at customer costs in the PNG hearing before approving intercorporate allocations to PNG (N.E.).

The list of services provided from PNG to PNG (N.E.) appears to be similar for each year from 1999 to 2002 (BCUC IR 1, p. 15). The average number of customers served in the 2001 Decision and 2001 actual was 14,893 and in the 2002 test year is forecast by PNG (N.E.) as 14,864 (BCUC IR 1, p. 16). It appears that the administrative services provided to PNG (N.E.) in 2001 are similar to the services required in 2002. The Commission accepts that the actual 2001 costs of $315,000 might be understated by only including labour and benefits.

The Commission considers that the 2002 allowance for providing administrative services under account 721 should be based on the 2001 Decision provision of $464,000 adjusted for inflation and the change in the average number of customers. The Application includes an inflation forecast of 2.25 percent and the Commission's adjustments in the load forecast sections increased the number of customers by 84 in the residential class and 33 in the commercial class. The Commission establishes a 2002 provision in account 721 of $477,000 (($464,000/14,893) x (14,864+84+33) x 1.0225).

PNG (N.E.) is forecasting Fiscal and Corporate Expenses of $45,000 in account 728 for 2002. The actual 2001 expenditures were $35,000 compared to the allowance of $45,000 in the 2001 Decision (Tab 1, p. 12). The 2001 expenses were lower than forecast due to approximately $4,000 of budgeted public relations expenditures not being made and fewer requests for donations (BCPIAC IR 1, p. 32).

The Commission considers that PNG (N.E.) should be capable of providing the same level of cost control in 2002 as in 2001 and therefore will allow a 2002 provision of $35,000 in account 728.

3.2.2 Tumbler Ridge

The total operating expense in 2002 of $452,000 is consistent with the actual operating expenses incurred from 1999 to 2001. **The Commission considers that most of the variation in actual operating expenses from 1999 to 2002 appears to be related to changes in the cost of company use gas; therefore, the 2002 forecast is accepted.**

Maintenance expenses of $58,000 were forecast for 2002 but, in argument, CAC (BC) *et al.* noted that the actual 2001 expenses incurred were $15,000 and considers that the amounts forecast for 2002 may not be needed or spent. **The Commission finds that the 2002 forecast of maintenance expenses for the Tumbler Ridge Division is consistent with actual expenses incurred in 1999 and 2000 and accepts the 2002 forecast.**

The total actual administrative and general expenses were $97,000 in 2001 and the 2002 forecast has increased to $129,000. The Utility attributes the cost increases to the closure of the office in Tumbler Ridge in 2000, increased services provided by PNG and an increased allocation of costs from the Customer Care Centre in Terrace. **The Commission considers that the closure of the Tumbler Ridge local office should have resulted in costs savings compared to the 1999 actual administrative and general expenses of $101,000 and therefore considers that a provision of $97,000 is reasonable for 2002.**

3.3 Financing

The 2002 long term debt cost of the Fort St. John/Dawson Creek Division has increased as a result of a new long-term loan of $4.5 million from PNG to PNG (N.E.) and due to a proposal that PNG and PNG (N.E.) increase the interest rate in an existing $8 million loan.

On January 1, 2002 PNG loaned the Fort St. John/Dawson Creek Division of PNG (N.E.) $4.5 million until January 15, 2011 at a rate equal to PNG's $12 million RoyNat financing plus 0.05 percent. The interest rate under the $12 million RoyNat financing is variable and PNG (N.E.) has requested a deferral account to record variations between the actual and forecast interest rate. The Utility states that the funds from this Series 2010 Debenture will be used to finance capital expenditures in 2001 and 2002. No intervenors commented on this loan arrangement. **The Commission approves the $4.5 million loan arrangement and the requested interest rate deferral account as filed effective January 1, 2002.**

The $8 million loan involves a 1996 interest rate swap arrangement maturing on June 10, 2004 that was approved by Commission Order No. G-53-96 and initiated by a previous parent company of PNG (N.E.). PNG assumed responsibility for the swap arrangement when it acquired the utility serving the Fort St. John service area. Effective January 1, 1997, PNG entered into a loan agreement with the Fort St. John utility that stipulated an interest rate of 8.45 percent per annum (BCUC IR 2, pp. 48-51).

PNG (N.E.) described the swap arrangement as a long-term loan at a fixed rate of 7.7 percent plus fees, for an all-in cost of 8.45 percent that is financed by PNG through short-term debt. PNG states that its risk premium has increased and it is incurring an all-in cost on short-term debt of 10.7 percent, but under the current loan arrangement is only receiving 8.45 percent from PNG (N.E.) (BCUC IR 2, p. 44).

PNG and PNG (N.E.) are proposing to enter into a new loan agreement to replace the current loan agreement. The new loan agreement would mature on June 10, 2004 and bear a fixed interest rate of 7.75 percent including a 0.05 percent fee from PNG to PNG (N.E.) plus PNG's risk premium on short-term debt, currently 3 percent, for an all-in cost of 10.75 percent. If PNG's risk profile was to improve, then the savings would be passed on to PNG (N.E.) (FSJ/DC Tab Application, p. 9).

Intervenors commented on the $8 million loan. CAC (BC) *et al*. considers that if PNG failed to make provision for changing circumstances in its original loan agreement, it should be for the account of PNG and in particular its shareholder rather than the customers of PNG (N.E.). CAC (BC) *et al*. submits that the terms of the agreement established by Order No. G-53-96 should remain in force for the period established by the Order. PRRD submitted that the Commission should ensure that PNG (N.E.) is charged the appropriate interest rate on the $8 million loan from PNG.

The Commission agrees with CAC (BC) *et al.* that the terms of Order No. G-53-96 are obligations inherited by PNG that should be honoured. The Commission considers that the January 1, 1997 loan agreement between PNG and PNG (N.E.) is consistent with the approval given by Order No. G-53-96 and fixes the all-in interest cost to PNG (N.E.) at 8.45 percent until June 10, 2004.

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

4.1 <u>Fort St. John/Dawson Creek</u>

PNG (N.E.) has based its Application on an ROE of 9.63 percent based on a 50 basis point (0.50 percent) risk premium added to the 2002 allowed ROE of 9.13 percent for a low risk benchmark utility (Tab Application, p. 4). In this respect, the Application proposes no change to the currently approved ROE for this division, which is 50 basis points above that of the low risk utility.

PNG (N.E.) has applied to increase the allowed common equity component to 40 percent from 36 percent to reflect the risk profile of a small utility operating in an area of the economic boom and bust cycles associated with the oil and gas industry. PNG (N.E.) submits that the small size of the customer base is a risk as well (Tab Application, pp. 4 and 8). This increase in the equity component of the capital structure results in a $43,000 increase in the revenue requirement (Tab Application, p. 8). The actual common equity component is 36.29 percent (Tab 5, p. 1).

Interim rates approved by Order No. G-149-01 did not include the requested increases in the equity component for both divisions and the requested increase in the ROE for the Tumbler Ridge Division. At that time, the Commission found that PNG (N.E.)'s submissions requesting the increases were incomplete, and stated that it would consider the matter in the proceeding to be established for PNG (N.E.).

No intervenor commented directly on the ROE or capital structure for this division.

PNG (N.E.) has provided virtually no evidence to support its contention that the currently approved equity component of the deemed capital structure for this division is too low. The Commission also notes that the ICDDA was established in 2001 to record the difference between forecast and actual deliveries to Dawson Creek industrial customers. The existence of the ICDDA reduces the risk to PNG (N.E.) that industrial revenues in Dawson Creek may vary from those forecast. Although PNG (N.E.) has recommended that the deferral account be discontinued for 2002, the Commission has not approved the elimination of the ICDDA as set out in Section 2.3.4.

The Commission finds that there is insufficient evidence to support approval of a higher equity component for the Fort St. John/Dawson Creek Division and denies PNG (N.E.)'s application for an increase.

4.2 Tumbler Ridge

PNG (N.E.) has applied for an ROE of 10.63 percent based on a risk premium of 150 basis points over the low risk benchmark utility. The proposed risk premium, if approved, would be an increase of 75 basis points. PNG (N.E.) has stated that the increase is needed to reflect the uncertainty of Tumbler Ridge's future without its major employer Quintette operating. PNG (N.E.) also cites the small size of the community, with just over 1000 customers, as an additional risk factor (Tab Application, p. 4).

PNG (N.E.) has applied to increase the deemed common equity component from 36 to 45 percent for the same reason as it has asked to increase the risk premium (Tab Application. p. 4). The actual equity component in 2001 was 27.4 percent (Tab 5, p. 1). The impact of both the ROE increase and the increased equity thickness is a $10,000 increase in the revenue requirement (Tab Application, p. 7).

No intervenor commented directly on the ROE or capital structure for Tumbler Ridge.

PNG (N.E.) has provided almost no evidence to support its contention that the current ROE and equity component approved for this division is inappropriate, and has not provided any evidence to tie its current market environment to any specific risk premium or equity thickness. In spite of the closure of the Quintette mine, it is unclear if the degree of uncertainty has increased sufficiently to support a higher risk premium and thicker equity structure. Circumstances for natural gas distribution in Tumbler Ridge have now stabilized after the closure of the mine.

The Commission determines that there is insufficient evidence to support a change to the current risk premium and equity thickness of the Tumbler Ridge Division, and denies PNG's application for increases to the equity component of its capital structure and its return on that equity component.

5.0 SAFETY AND EMERGENCY RESPONSE

In its May 25, 2001 PNG Decision, the Commission expressed concern that customers had the perception of reduced safety and that customers were unaware of the existence of the emergency response telephone number.

In reply to BCUC IR 1, Question 10.3, PNG (N.E.) outlined a number of actions it has taken in order to respond to this issue:

a) The emergency phone number has been advertised in all local papers in December, 2000 and January, 2001.
b) Signs at the entrance to local field offices identify an emergency number.
c) All calls to the 1-800 Customer Inquiry number first hear a message identifying the emergency number.
d) Emergency contact information is in all local telephone books.
e) All customer bills now show the emergency response number.
f) All emergency responders (e.g. police, fire, etc.) have been advised of the new contact information.
g) Pipeline marker signs and regulating facilities have had the new 1-800 number added to the signage.
h) Bill inserts showing all contact information have been included with bills starting December 2001.

PNG (N.E.) maintains emergency response staff in Fort St. John, Dawson Creek and Tumbler Ridge. All emergency staff train annually and at least one employee is on 24-hour standby in each district. In addition, there is coordination with local fire departments that includes training in gas awareness, response to emergencies (such as blowing gas) and knowledge of PNG's Corporate Emergency Response Plan.

PNG (N.E.) indicated that emergency calls fall into three broad categories of third party damage, outside gas odours and inside gas odours. Calls averaged 13 per week in 2001. Although the response time was not tracked, PNG (N.E.) estimates that typical emergency calls would be responded to within 15 minutes if they are in the vicinity of the three main communities. The response time could reach 40 minutes for a distant rural customer (BCUC IR 1, Question 10.1).

PNG (N.E.) indicated that all emergency calls are responded to with equal priority. The Company is unaware of any situation that took more than 40 minutes for a first responder to arrive. However, there may have been situations that took longer than 40 minutes for the gas to be turned off if construction equipment was required (BCUC IR 1, Question 10.2).

In its May 1, 2002 submission, the PRRD indicated that in its view PNG (N.E.) should track the length of time to respond to emergency calls. It is also of the view that customer satisfaction to emergency response should be monitored as it is a very important component of customer service.

The Commission expects PNG (N.E.) to monitor its response to emergency calls for both the length of time it takes to have a company representative at the scene and the time it takes to shut off the gas line.