IN THE MATTER OF

PACIFIC NORTHERN GAS LTD.

2002 REVENUE REQUIREMENTS APPLICATION

DECISION

July 31, 2002

Before:

Peter Ostergaard, Chair
Nadine F. Nicholls, Commissioner
Paul G. Bradley, Commissioner

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1.0 INTRODUCTION

1.1 Background

Pacific Northern Gas Ltd. ("PNG", the "Utility", the "Company") delivers natural gas to about 24,000 customers, including large industrial operations, in a region extending west of Prince George to tidewater at Kitimat and Prince Rupert. PNG's pipeline connects with the Duke Energy Gas Transmission ("Duke") pipeline at Summit Lake north of Prince George. A wholly-owned subsidiary, Pacific Northern Gas (N.E.) Ltd. ["PNG (N.E.)"], serves customers in the Fort St. John, Dawson Creek, and Tumbler Ridge areas of northeastern British Columbia.

PNG's head office is in Vancouver. Westcoast Energy Inc. ("Westcoast") owns 100 percent of the voting common shares and about 40 percent of the non-voting common equity of PNG. The customer service and administrative functions of both PNG and PNG (N.E.) are now supported from a regional office in Terrace. In 2000 PNG began to restructure its operations in an effort to reduce operating costs in response to gas price volatility, difficult regional economic conditions, and the closure or imminent closure of some of its industrial customers' facilities.

1.2 The Applications, Commission Orders, and the Public Hearings

1.2.1 PNG's Initial Application

On November 30, 2001 PNG and PNG (N.E.) filed for approval of their 2002 Revenue Requirements Applications (the "Applications") pursuant to Sections 91 and 58 of the Utilities Commission Act (the "Act", the "UCA"). The Applications sought to increase rates on an interim and final basis effective January 1, 2002. By Order No. G-132-01 the Commission held a Pre-hearing Conference on the Applications in Vancouver on January 8, 2002 with video-conferencing links in Terrace and Dawson Creek, to address procedural matters. Order No. G-132-01 also established a regulatory timetable for the public review of the PNG Application and scheduled the commencement date for an oral public hearing into the PNG Application for March 6, 2002 in Terrace.

On December 5, 2001 counsel for Eurocan Pulp and Paper Co. Ltd. ("Eurocan") objected to PNG's request for an interim rate increase and the inclusion of an increased risk premium and common equity component in calculating the interim rate increase. Counsel for Methanex Corporation ("Methanex") raised a similar objection. On December 11, 2001 PNG provided a response to Eurocan's objection, noting that the Commission may grant interim relief under Section 89 of the Act and included a summary of the evidence on capital structure and rate of return on common equity.

On December 19, 2001 by Order No. G-149-01 the Commission approved for PNG and PNG (N.E.) interim rate increases in the delivery charges subject to refund with interest. The interim rate increases were based on the November 30, 2001 Revenue Requirements Application except for requested increases in the common equity portion of the capital structure and increases in risk premium. The Commission found that the initial submissions by PNG and PNG (N.E.) for interim increases to these two components were incomplete. The Commission stated it would consider these matters through the course of the scheduled public hearing for PNG and the proceeding to be established for PNG (N.E.).

On February 25, 2002 PNG submitted revisions to its November 30, 2001 Revenue Requirements application that included several changes to its projected 2002 cost of service. In these reasons, unless the context dictates otherwise, the term "PNG Application" refers to the 2002 Revenue Requirements Application dated November 30, 2001 (Exhibit 1) as amended by the February 25, 2002 revisions (Exhibit 1A).

1.2.2 Gas Supply Costs and Delivery Charges

The rate structure for PNG's residential, commercial and small industrial customers who buy gas from PNG is comprised of a monthly fixed charge, a delivery charge, and a gas supply charge. Beginning in early 2001, changes to the gas supply charge have been reviewed quarterly by the Commission in a process that is separate from the annual determination of delivery charges. The cost of providing service in 2002 to PNG's customers, excluding the commodity cost of gas, was examined through the oral public hearing process, and the resulting revenue deficiency is to be recovered through an increase in the delivery charge component of the rates.

Included in the PNG Application was a request for reductions to gas supply charges and changes to the Gas Cost Variance Account ("GCVA") riders effective January 1, 2002 due to lower forward gas market prices and reduced forecast gas supply costs for 2002. On December 11, 2001 PNG filed its Fourth Quarter 2001 Report on current and projected GCVA balances and future gas acquisition costs and revenues, consistent with the guidelines set out in Commission Letter No. L-5-01.

Order No. G-136-01 approved the Gas Supply Charges and GCVA riders effective January 1, 2002. Consistent with Commission guidelines, PNG was directed to file, by 15 business days prior to the start of each calendar quarter, an update on GCVA balances and expected gas costs and revenue for the following 12 months. PNG is to request rate changes where forecast gas costs (including the GCVA balance at the start of the period) and revenue differ by more than 5 percent.

The proposed changes to gas supply charges and GCVA riders reduced total gas commodity charges by about 27 percent. The corresponding reduction to the annual bills of typical residential and commercial customers was approximately 16 percent. A reduction to the gas supply charge and the implementation of a GCVA rider of $1.802/GJ was approved for customers of PNG's propane grid in Granisle reducing propane charges by about 15 percent and lowering the annual bill of a typical Granisle residential customer by approximately 11 percent.

On March 18, 2002 PNG filed its First Quarter 2002 Report on GCVA balances and future gas acquisition costs and revenue. The Report projected GCVA credit balances of $2,988,652 for core market sales and $965,630 for company use gas as of February 28, 2002. PNG noted the volatility in gas prices and its inability to hedge gas purchases, and recommended that no reductions be made at that time to the gas commodity charges in rates. The Commission determined that the significant GCVA credit balances should be returned to customers. Order No. G-19-02 approved, effective April 1, 2002, a reduction in the company use gas charge and a GCVA credit rider calculated to repay the GCVA credit balances over the next 12 months of deliveries.

1.2.3 Methanex Load Retention Rate Application

The Methanex methanol plant at Kitimat historically accounted for over two-thirds of the volume transported on the PNG system and 45 percent of PNG's operating margin. In May 2000, Methanex announced that it would close its Kitimat plant for an initial period of 12 months beginning July 1, 2000. The plant reopened in July 2001.

On December 21, 2000 Methanex applied to the Commission for a load retention rate. This Methanex application was added to the proceedings for the 2001 Revenue Requirements Application of PNG. The Commission's May 25, 2001 Decision (the "2001 Decision") and Order No. G-51-01 denied Methanex's December 21, 2000 application and indicated that an appropriate load retention rate would be no less than $0.46/GJ for a contract commencing on July 1, 2001. This figure was based on the value of existing contract commitments that would be replaced by any new agreement, with adjustments to account for absorption of variable costs and the greater of the opportunity cost of capacity or the value of rate base reduction. In the 2001 Decision, the Commission encouraged PNG and Methanex to negotiate a new rate for Methanex that would be beneficial to PNG, Methanex and other customers.

In an application dated September 28, 2001 ("the Methanex Application") Methanex complained to the Commission that negotiations with PNG were not progressing and that it would not be possible to negotiate a long-term load retention rate with PNG without further Commission involvement. Methanex requested that the Commission immediately make PNG's rates to Methanex interim and order a rate of $0.46/GJ, adjusted for payments made since July 1, 2001. PNG provided comments on the Methanex Application and noted that it would soon be filing a Revenue Requirement Application for 2002.

Based on its review of the submissions by Methanex and PNG, the Commission by Order No. G-127-01 required the Methanex Application for a load retention rate to be reviewed coincident with PNG's 2002 Revenue Requirements Application and made PNG's rates to Methanex interim effective October 1, 2001.

1.2.4 The Public Hearing and PNG's Revised Application

The oral public hearing began March 6, 2002 in Terrace. After three days of evidence the hearing adjourned to continue in Vancouver, concluding on March 11, 2002. The Commission ordered a schedule for written final argument, commencing with filings by PNG and Methanex on March 28, 2002.

On March 20, 2002 PNG and Methanex entered into a Memorandum of Agreement ("MOA") to terminate their existing agreements for firm transportation and interruptible gas sales service and to replace those agreements with a new agreement effective November 1, 2002. The new agreement, if approved, would result in the withdrawal of the Methanex Application. On March 27, 2002 PNG submitted revisions (Exhibit 1B) to its Application to reflect the impact of the MOA, which included changes to the revenue deficiency, effective November 1, 2002. The delivery charge to residential customers would rise by approximately 20 percent and for small commercial customers it would rise by about 16 percent. This would be offset by a small additional decrease in the gas supply charge. When combined with the approved gas commodity decreases, the revised average annual residential bill would decrease by about 10 percent and the average annual small commercial bill would decrease by about 11 percent (Exhibit 1C, p. 4).

Given the impact of the terms of the MOA on the PNG and Methanex Applications before the Commission, PNG's March 27, 2002 application also requested postponing the filing of final argument and approving a revised oral public hearing and argument schedule. PNG proposed an amended regulatory timetable that included the resumption of the public hearing on April 17, 2002. By Order No. G-20-02 the Commission postponed the filing of final argument, and requested intervenors to advise the Commission whether they consented to PNG filing the revised application, and to state their position on PNG's proposed timetable.

On April 2, 2002 intervenor comment letters were received from the Consumers' Association of Canada (BC Branch) and others ("CAC (BC) *et al.*"), West Fraser Timber Co. Ltd., Canadian Forest Products Co. Ltd. and Eurocan (the "Forest Companies"), and Alcan Primary Metal Group ("Alcan"). CAC (BC) *et al.* consented to PNG's filing of the revised application and considered the proposed timetable generally acceptable. The Forest Companies objected to the new application as being incomplete, considered there was insufficient time in PNG's proposed timetable, and raised additional issues. Alcan did not object to PNG's filing of the revised application but submitted that the proposed hearing date should be delayed to allow for comments on the submission of the Forest Companies. On April 3, 2002 PNG provided written comments on the issues raised by the Forest Companies.

The Commission considered that intervenors should be allowed to comment on the issues raised by the Forest Companies before deciding on a revised hearing and argument schedule. Order No. G-23-02 requested that intervenors provide written comments, if any, on the issues raised by the Forest Companies and allowed PNG to supplement the comments made in its April 3, 2002 submission. By April 19, 2002 the Forest Companies were to reply to the written comments of intervenors and PNG.

The Commission reviewed the submissions from intervenors and PNG and addressed them in Reasons for Decision issued on April 23, 2002. By Order No. G-31-02 a regulatory timetable was established to review PNG's revised application, culminating in a public hearing in Vancouver beginning May 27, 2002.

On May 16, 2002 PNG submitted further revisions (Exhibit 1C) to its Application in the form of new schedules reflecting the lower equity risk premium associated with the MOA. In these Reasons, unless the context dictates otherwise, the term PNG's "Revised Application" refers to the PNG application as amended on March 27, 2002 and May 16, 2002.

The May 27, 2002 public hearing ended that afternoon. A new schedule for written final argument was established, concluding with PNG and Methanex filing replies on July 5, 2002.

2.0 PNG / METHANEX MEMORANDUM OF AGREEMENT AND METHANEX APPLICATION

2.1 Methanex Application

PNG currently provides firm natural gas transportation service to Methanex under three long-term contracts. The largest of these, with a demand of 44 MMcf/d, expires on October 31, 2002. The remaining two contracts for 2 MMcf/d and 11 MMcf/d expire on October 31, 2003 and October 31, 2009, respectively (Exhibit 5, PNG Submission, p. 1). Methanex accounts for the largest share of PNG's load, currently comprising about 75 percent when in full operation. Most of the gas delivered to Methanex is feedstock to the methanol manufacturing process. Methanex has other plants in offshore locations that enjoy lower gas prices (T3: 431; T5: 728).

The Methanex Application filed on September 28, 2001 requested that the Commission immediately make the existing Methanex rate interim and establish a long-term load retention rate based on the findings in the 2001 Decision (Exhibit 5, p. 1). The requested load retention rate would be based on the \$0.46/GJ rate found in the 2001 Decision adjusted downward to recognize payments made during the three months following July 1, 2001 and the reduced present value of Methanex's obligation to PNG (Exhibit 5, p. 4). The proposed load retention rate firm demand charge would be \$0.27/GJ with a minimum monthly charge equal to the firm demand charge times 64,000 GJ/d times the number of days in the month (Exhibit 6, Schedule A).

The proposed firm load retention rate demand charge of \$0.27/GJ is based on:

- the present value of Methanex's remaining obligations of \$0.17/GJ;
- an interruptible credit of \$0.02/GJ;
- the greater of the capacity value or rate base reductions estimated at \$0.10/GJ; and
- an increased (non-gas) variable cost of \$0.02/GJ.

Under the load retention rate proposal, Methanex would supply sufficient company use gas to move its gas volumes (Exhibit 6, Schedule A).

The amount required for a buyout of the agreement would be based on the present value of the remaining obligations at the time of the buyout reduced by \$0.09/GJ for variable costs that would not be incurred, and by \$0.07/GJ for the opportunity cost of the pipeline capacity which could be returned to other customers (Exhibit 5, p. 4).

2.2 PNG / Methanex Memorandum of Agreement

On March 27, 2002 PNG filed a revision (Exhibit 1B) to the PNG Application to reflect the impact of the MOA (Exhibit 34). The MOA contemplates a new long-term firm transportation service agreement ("New Contract") that consolidates the three agreements that currently cover deliveries to the Kitimat methanol/ammonia complex. The New Contract would be for a seven-year term from November 1, 2002 to October 31, 2009 (Exhibit 1B, p. 3).

The firm transportation rate under the New Contract would be \$0.50/GJ applied to a contract demand of 1614 10^3m^3 (thousand cubic metres) converted to GJ using the heat content applicable to deliveries at Summit Lake. At the current heat rate of 38.4 $GJ/10^3m^3$ the daily demand would be approximately 62,000 GJ. The New Contract would generate annual revenues of \$11,315,000 per year to be paid as a fixed annual demand charge regardless of actual deliveries. The prepaid deficiency volume provisions under the old agreements would no longer apply and Methanex would forego delivery of prepaid deficiency volumes (worth about \$1.4 million) that remained under the two small existing contracts (Exhibit 34; Exhibit 1B, pp. 3-4).

The interruptible rate would be \$0.32/GJ, which is approximately the same as applied to Methanex under the old agreements, but it would apply only to deliveries in a month that exceed the daily contract demand times the number of days in the month. The rates under the New Contract would be fixed for the term of the contract except for government levies applied to the transportation of gas (Exhibit 34).

Methanex would not pay a company use gas charge to PNG, but would supply a portion of PNG's company use gas equal to 4 percent of the deliveries to Methanex. Moreover, under the Unit Demand Charge Uplift provision of the MOA, PNG would share in the profits of the Kitimat methanol facility when the methanol/gas price differential is greater than \$80 US per tonne for more than three months (Exhibit 1B, pp. 3-4).

Methanex would be able to terminate the New Contract on six months notice and payment of specified amounts at the end of the notice period. During the notice period Methanex would continue to pay the monthly demand charge. Methanex stated that it would not enter into an agreement with PNG with a buyout schedule based on 100 percent of Methanex's contract volumes and a rate of \$0.46 (Exhibit 6A, BCUC Q. 10.2, p. 5)

2.3 Comparison of the PNG / Methanex Agreement to Alternatives

Because the largest of the existing Methanex contracts extends until November 2002, parties recognize that the impact of closure of the Methanex plant or the MOA would be greater in 2003 and subsequent years than in 2002. PNG stated during the hearing that the agreement with Methanex was required to keep the plant from closing and that it did not consider there was a realistic scenario under which Methanex would continue to be fully operating without a new contract (T5: 643-44, 683). In argument, PNG states that the MOA is the best possible arrangement that could be negotiated with Methanex and eliminates a significant uncertainty concerning the recovery of margin from Methanex after October 31, 2002 (PNG Argument p. 4).

PNG states that the impact on other customer rates arising from the MOA will be much less than if Methanex decided to shut down for a year or more. As shown in the table below, PNG's 2003 Gross Margin is higher with the New Contract in place than if Methanex closed, irrespective of the level of operation of Skeena Cellulose Inc. ("Skeena").

2003 Gross Margin ($)

	Skeena Not Operating	Skeena Operating at 1.63 PJ	Skeena Operating at 3.13 PJ
Methanex plant closes	$29,373,637	$31,727,428	$33,884,382
Methanex operates with New Contract	$37,156,544	$39,563,740	$41,788,937

(Extracted from Exhibit 2B, pp. 23-46).

Accordingly, comparing the possible revenue deficiency under various scenarios shows that the revenue deficiency is minimized by the MOA. Under the most pessimistic scenario, with both Methanex and Skeena taking no deliveries, PNG's revenue deficiency would be $11.9 million. Under a comparable scenario, with Methanex operating under the New Contract, but Skeena taking no deliveries, PNG's revenue deficiency would be $3.5 million. Under the most optimistic scenario, with Methanex operating under the New Contract and Skeena taking delivery of 3.13 PJ in 2003, PNG would show a slight revenue surplus of $720,000 (Exhibit 2B, pp. 22 and 43).

The MOA buyout provision is a payment schedule that is more generous than the buyout payments under the remaining two existing contracts (Exhibit 2B, p. 57; Exhibit 2C).

The above comparisons between scenarios with and without Methanex operating do not include any adjustment for potential reductions in PNG's rate base due to removal of assets that would no longer be required to serve Methanex. Considering the impact of the incremental revenues from those assets under the MOA, ratepayers are better off with the New Contract and the assets in place. The depreciated value in 2003 of the incremental facilities put in place to serve Methanex was estimated to be approximately $33 million (Exhibit 2B and 2C, BCUC IR 3 and 4, Q. 24.2; T5: 685-688). The incremental annual cost of those facilities would be approximately $6.15 million, whereas the annual incremental revenue from the New Contract would be approximately $11.3 million. On that basis, the assets which PNG put in place to serve Methanex show an annual incremental benefit to other customers under the New Contract of approximately $5.15 million (T5: 688).

Under the New Contract Methanex would be supplying a portion of company use gas in proportion to its actual deliveries, rather than paying a company use gas charge to PNG. PNG states that because of this change some of the gas price risk will be shifted to Methanex (Exhibit 1B, p. 4). PNG also stands to gain additional revenues if the market price of methanol exceeds the equivalent price of natural gas by $80 (USD) per tonne of methanol. PNG would defer any revenues received under the profit sharing mechanism related to the methanol/gas price differential for later disposition by the Commission (Exhibit 1B, p. 4).

PNG also amended its request for a higher equity risk premium from 150 basis points to 100 basis points as a result of the impact of the MOA with Methanex (T5: 721). The impact of the reduction in the requested risk premium is to reduce the total 2002 cost of service applied for by approximately $0.5 million (Exhibit 1C, p. 1).

Intervenors generally offered conditional support for the MOA. While Alcan does not oppose the MOA, it commented that its key concern was the lack of criteria for determining who is entitled to a load retention rate and who is not. Alcan argued that the Commission should clearly articulate in its reasons the criteria for approving a load retention rate. Alcan also argued that the Commission should reserve the right to publicly review the load retention rate in the New Contract every two years and should retain the right to terminate the New Contract on reasonable notice to Methanex. Alcan also expressed concern that the rates embedded in the New Contract would not be adjusted during the term of the New Contract and urged the Commission to include an inflation adjustment of 2 to 3 percent per year in the rate so that the real rates would remain relatively constant over the term of the New Contract. Alcan also argued that the Commission should not allow the New Contract to be assigned without the Commission's approval. Alcan further submitted that the New Contract should not be extended past 2009 without prior Commission approval and after a hearing. Finally, Alcan argued that PNG should bear some of the costs through disallowing some portion of costs or appraising PNG's rate base. Alcan noted that the former might not be permissible under the Act.

CAC (BC) *et al.* was the only intervenor to comment on Methanex's Application for a load retention rate. It argued that by entering into the negotiated MOA Methanex has clearly indicated that it does not need the rates in its load retention rate application to operate. CAC (BC) *et al.* argued that the Methanex Application should be rejected. With respect to the MOA, CAC (BC) *et al.* is skeptical of the purported long-term stability provided by the MOA to PNG's remaining ratepayers. It urged the Commission to consider not only the impact of the MOA on the Revised Application, but also the long-term impacts (CAC (BC) *et al.* Argument, p. 7).

The Forest Companies generally support approval of the load retention rate in the MOA if the subsequent reduction in revenues is not borne by the other customer classes. To the extent that approval of the load retention rate transfers the reduction in revenues from Methanex to other customers, the Forest Companies oppose approval.

Methanex supports approval of the MOA and states that if the Commission approves the MOA then it will be unnecessary for the Commission to rule on the merits of the Methanex Application. Methanex opposes changes to the MOA and argues that the agreement is a complete package and represents years of attempts to reach an agreement between PNG and Methanex. It states that changing even minor provisions of the MOA could lead to unraveling of the whole agreement (Methanex Reply Argument, p. 1). Methanex also states that it has no objection to a requirement that the Commission should retain the authority to approve any extension of the New Contract beyond 2009 (Methanex Reply Argument, p. 4).

Commission Findings

Most intervenors expressed some level of qualified support for the MOA but either with reservations related to the allocation of resulting reductions in revenue from Methanex or with suggestions for amendments to the MOA. The Commission accepts that the methanol plant would not remain viable at existing rates and therefore Methanex would not renew the existing contracts with PNG. In this circumstance, PNG has attempted to reach agreement with Methanex on a rate which is both higher than the other likely potential uses of the pipeline capacity and which is the maximum level that Methanex could afford to pay (T2: 387).

The evidence adduced in the hearing indicates that there are several reasons why the rates under the MOA are considerably more beneficial to other ratepayers than the rates under the alternatives, namely, the probable closure of the Methanex Kitimat plant or the load retention rate applied for by Methanex. The rates to other customers are lower than if Methanex ceased to be a customer of PNG (Exhibit 2B, Q. 17.1). The revenues to PNG from the New Contract will exceed the variable cost of serving Methanex and the contribution to PNG’s fixed cost is approximately double the cost of the rate base that might be removed if Methanex was no longer a customer (Exhibit 40; T5: 688).

The Commission finds that the MOA is consistent with the principles set out in its 2001 Decision. The firm rate under the MOA of $0.50/GJ is also higher than the minimum load retention rate identified by the Commission in its 2001 Decision. As noted by PNG, the MOA rates provide PNG with the opportunity to become more financially stable over the long-term (Exhibit 1B, p. 5). Alcan noted that Methanex represents approximately 75 percent of PNG's total load and that loss of that load could result in large rate increases to remaining customers and jeopardize PNG's financial integrity. No capital additions are anticipated, and incremental operating costs with Methanex continuing to take gas are minimal. Finally, if Methanex exercises the option to terminate the agreement, the buy-out provision in the MOA exceeds the present value of the obligations under the existing contracts with Methanex (Exhibit 2C).

The MOA is a negotiated rate between PNG and Methanex and the Commission is reluctant to direct amendments to the agreement. However, the Commission is concerned that assignment of the New Contract could lead to premature closure of the methanol plant. Such an occurrence would have adverse consequences for the Utility and its ratepayers. The lack of an inflation or cost escalation provision in the MOA adjustment was addressed in the hearing and PNG stated that, while it had been discussed in negotiations, the parties could not agree to include such a provision in the MOA (T5: 726-27). Methanex argues that the \$0.50/GJ firm rate in the MOA is a levelized rate that accounts for inflation (Methanex Final Argument p. 15).

The Commission approves the MOA between Methanex and PNG. PNG is required to submit an executed version of the New Contract for approval by the Commission to ensure that it is materially the same as the agreement contemplated by the MOA. The Commission also requires PNG to apply to the Commission for approval of any extension to the New Contract beyond 2009 or of any assignment of the New Contract to another entity. Any such application is to be filed in sufficient time for a review of the circumstances of PNG and Methanex or successor companies at that time, if the Commission determines that such a review is necessary.

2.4 Retroactivity of Rate Increases Arising from the MOA

The Forest Companies argued that PNG sought to recover the November/December 2002 revenue deficiency through an adjustment to rates applicable over all of 2002. In their view, the fact that rates were interim pending the Commission's Decision on a pending application does not give the Commission license to set rates that will apply in the prior period based on the new circumstance, as it was not part of the pending application (Forest Companies' Argument, p. 29). No other party addressed the issue in final argument.

The argument of the Forest Companies is similar to their April 2, 2002 submission to the Commission regarding PNG's Revised Application. At that time Methanex submitted that the rates proposed in the Revised Application are prospective, PNG's current rates are interim effective January 1, 2002 and circumstances that occur subsequent to the filing of a Revenue Requirements Application are matters that are proper and relevant for Commission consideration under Section 60 of the Act. PNG stated that its

2002 rates are currently interim and the suggestion of retroactivity was entirely without foundation in law. The Commission in the Reasons for Decision to Order No. G-31-02 directed parties to address the issue in Final Argument. As noted above, only the Forest Companies have done so.

The Commission considers that retroactive ratemaking applies to circumstances where permanent rates have been approved and one or more parties subsequently ask to have those rates reviewed and potentially changed. In the present situation, the rates have been interim effective January 1, 2002, except for Methanex, whose rates have been interim since October 1, 2001. There is no application to change the rates that were in effect prior to the time when they were made interim. **The Commission finds that it is lawful and in the public interest to take into consideration the existence and impacts of the MOA in establishing permanent rates to be charged by PNG.**

2.5 Revenue Deficiency Arising from a PNG / Methanex Agreement

In Exhibit 1B PNG states that the revised 2002 revenue deficiency is allocated to customers on the same basis as in Exhibit 1A, except for Methanex. PNG proposes that any additional revenue deficiency arising out of the MOA would be transferred to customers other than Methanex.

Various parties argue that, if the Commission approves the MOA, the revenue deficiency arising from the reduction in the Methanex rate should be borne by PNG shareholders rather than ratepayers.

CAC (BC) *et al.* argues that the Commission should not, in assessing the merits of the MOA, assume that the entire revenue shortfall arising from the agreement would be fully allocated to the remaining customers (CAC (BC) *et al.* Argument, p. 8). Alcan also argues that, in principle, PNG shareholders should bear some of the burden of the MOA rate. Nevertheless, Alcan notes that it may be difficult, in practice, to allocate some of the costs to PNG shareholders (Alcan Argument, pp. 5-6).

The Forest Companies submitted that the Commission can and should require PNG to absorb any reduction in revenue from Methanex resulting from the MOA. In their view, Section 60(1)(c) of the Act precludes the Commission from considering the Methanex rate when setting the rates of the other classes.

Additionally, the Forest Companies argued that the Commission must, under the Act, establish rates that provide the Utility an opportunity to earn a fair return on the <u>appraised value</u> of the property <u>used to provide service</u> (Forest Companies Final Argument, p. 10, their emphasis). They submitted that, as the earning power of the assets used to provide service to Methanex has declined, so too has the value of the plant used by PNG to provide service to Methanex diminished with the reduction of its earning power.

Consequently, the Forest Companies argued that the portion of the revenue deficiency created by the MOA should be borne by the PNG shareholders as the revenues received under the MOA constitute just and reasonable compensation for the assets used to serve Methanex.

PNG in reply argument responded that the Act requires the Commission to determine a fair and reasonable return and to set rates that allow PNG the opportunity to earn that return. PNG argues that there is no theoretical or practical basis for Eurocan's argument that Eurocan's rate should be determined in isolation from other customers because each customer is a separate class (PNG Reply Argument, p. 5). PNG also rejects the argument of the Forest Companies that there is a regulatory concept of "appraised value" other than original cost. PNG states that not only has the BCUC consistently adopted the original cost method for appraising rate base, but that the original cost method "…has been and is the accepted methodology used by regulators throughout North America to value rate base for rate making purposes." (PNG Reply Argument, p. 7). PNG also dismisses the Forest Companies' argument as being inherently circular (i.e. the value of the assets used to provide service is the basis for establishing the rate but the rate is used to determine the value).

Commission Findings

The Commission approved the MOA in Section 2.3 and determined that, compared to the alternative of Methanex closure, the MOA will provide the maximum likely revenue to PNG so as to minimize the revenue requirement from other customers. The issue addressed in this section is the extent to which the Commission will allow PNG to recover from customers other than Methanex the entire amount of any revenue deficiency resulting from the MOA.

The Commission notes that the allocation of the revenue reduction from Methanex to the other customers is consistent with previous actions of the Commission. Revenue requirement and rate design proceedings are done to allocate the total revenue requirement to all customer classes. The Commission has approved load retention rates in several instances and has never followed the methodology proposed by the Forest Companies. Bypass rates are treated in a similar manner as load retention rates, and revenue reductions from such rates are borne by other customers. Other customers benefit by the amount that the load retention rate is higher than a utility's variable cost of serving the load or the best other option for using the pipeline capacity.

The Forest Companies infer that the large overpayments in past years by Methanex benefited PNG shareholders when, in fact, they did not. Rates that generated revenue/cost ratios above 1.0 were applied to the overall revenue requirement and reduced the rates to other customers.

The Commission finds that the rates to all customer classes addressed in Section 9 of this Decision are fair and reasonable within the context of Section 59 of the Act. The rates to all customer classes remain affordable at this time. **The Commission denies the requests to reduce PNG's revenue requirement by an amount equivalent to the reduction in revenues from Methanex.**

3.0 MARGIN DEFERRAL ACCOUNTS AND LOAD FORECASTS

3.1 Margin Deferral Accounts

The 2001 Decision approved the continuation of the Industrial Customer Deliveries Deferral Account ("ICDDA") to record the difference between forecast and actual margin received from the large industrial customers of Methanex, the Skeena Cellulose pulp mill and Eurocan and approved PNG's request to include British Columbia Hydro and Power Authority ("B.C. Hydro") in the account. **The Commission approves the continuation of the ICDDA for 2002 for these four customers.**

Further discussion of the ICDDA occurs in Section 6.3 of this Decision.

3.2 Load Forecasts

3.2.1 Forecasting Methodology

As a result of the significant drop in gas deliveries in 2001, PNG opted to depart from its previous load forecasting methodology in favour of a technique that is more dependent on judgment (Exhibit 2, BCUC IR 1, p. 85). An express intent of the forecast approach adopted in the PNG Application was to correct the 15 percent over-estimation in 2001 (T2: 258).

For the residential and commercial classes of customers, PNG first forecast the number of accounts based on information provided by its service area personnel. Next, it calculated the historical average use per account from 1987 to 2000, and compared this figure with the estimated 2001 use per account. The forecast use for 2002 was then obtained by using the 2001 figure as a base and then assuming 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. For the small industrial customers, PNG's stated approach was to review the information supplied by customers in conjunction with data on historical and current deliveries (Exhibit 1, Tab 1, p. 9).

PNG provided additional market data and analysis in its Responses to Information Requests from BCUC Staff (Exhibit 2, Tab 1, pp. 73-90), Methanex (Exhibit 2, Tab 2, pp.13,16), the Forest Companies (Exhibit 2, Tab 3, pp. 1-3), CAC (BC) *et al. (*Exhibit 2, Tab 4, p. 7), and from an exercise in time-series analysis which PNG undertook as a result of the public hearing. The time-series analyses were carried out on normalized deliveries for the years 1988 to 2000 (Exhibit 28).

CAC (BC) *et al.* commented that PNG's forecast approach was "a clear and significant deviation from its standard practice in past years which was to base the use per account figure on regression analysis" (Final Argument, p. 9). Methanex urged the Commission to "take a more scientific view of use per customer than PNG has and base projected use for 2002 on a properly applied regression analysis rather than PNG's arbitrary estimates" (Methanex Argument, p. 9). The Forest Companies did not specifically address PNG's forecasting methodology but commented that PNG had not undertaken studies to ascertain if it would recover all of the lost market (Written Argument and Rebuttal, p. 33).

In its Reply Argument, PNG addressed only the load forecast results and did not provide further arguments to support the suitability of its forecast approach and methodology in deriving the sales forecast (Reply Argument, p. 14).

3.2.2 Load Forecast by Class of Customers

Residential Sector (Rate Schedule 1)

PNG's residential load forecast of 1,896,772 GJ is broadly based on a weighted average count of 19,926 customers and normalized use of 95.8 GJ/year (Exhibit 1, Tab 1, p. 4). The 2002 weighted average customer count of 19,926 was derived from the net decline of 790 customer accounts recorded as of the end of October 2001 and a projected small increase in customers during 2002 to reach 19,931 customers at year-end 2002. PNG further assumed that the end of October 2001 number of customers would be identical to the 2001 year-end count. If the 380 reconnections realized in November and December 2001 had been taken into account, the 2002 weighted average number should be 20,306 customers.

PNG decided not to update the 2002 weighted average number because the new input would not have made an impact on the forecast gas deliveries in PNG's forecast model (T2: 281).

CAC (BC) *et al.* noted that:

> "Based on the evidence on the record, it would be appropriate to base the residential use rate on the trendline (i.e., simple regression) using either time or price as the single explanatory variable. These approaches suggest that the use rate should be 99.7 or 99.8 GJ/account. Aside from being consistent with the statistical approach that has been used in previous years, a use rate in this range would appear to be reasonable given that the current price forecast suggests that the 2002 price of gas for residential customers will be lower than it has been for the past two years. It is quite reasonable to expect that customers will revert to something closer to their traditional use patterns than their extraordinarily low use rate in 2001, when commodity costs were very high, and very highly publicized." (Final Argument of CAC (BC) *et al.*, pp. 10-11).

The Commission accepts the argument of CAC (BC) *et al.* and determines that the regression of use per account against price provides a reasonable forecast for the 2002 average use per account at 99.8 GJ. The Commission finds that the 380 November and December reconnections should be incorporated into the forecast, leading to a revised 2002 weighted average of 20,306 customers.

The Commission sets the expected residential gas deliveries at 2,026,539 GJ (20,306 x 99.8 GJ).

PNG forecast propane deliveries of 22,196 GJ to the Granisle residential market for 2002 (Exhibit 1, Tab 1, p. 5). This forecast was based on an old data set. PNG revised the forecast to 23,197 GJ (Exhibit 2, Tab 2, p. 82).

The Commission accepts the revised forecast of 23,197 GJ for Granisle.

<u>Commercial Sector (Schedules 2, 3 and 4)</u>

PNG's commercial load forecast of 1,427,610 GJ is broadly based on a weighted average of 2,789 accounts and an average use of 511.9 GJ/year (Exhibit 1, Tab 1, p. 6; Exhibit 2A). PNG based its 2002 estimated average use per account on the average use per account for the years 1987 to 2000 and the estimate for 2001. Due to the moderation in gas prices, PNG increased the 2001 estimate by one quarter of the difference to obtain its 2002 forecast.

PNG subsequently provided three time-series analyses based on 1988 to 2001 normalized use per account. The first was a simple regression against time which yields 498.2 GJ/account, the second simple regression against price yields 523.3 GJ/account and the third was a multiple regression analysis against time and price that yields 543.1 GJ/year (Exhibit 28). During the hearing, PNG indicated that regression equations with R-squared values in the range of 0.59 to 0.80 are not ones on which it placed a great deal of confidence (T2: 256). The Commission considers that the general arguments by Intervenors for a more scientific view of use per customer are as applicable to the commercial sector as they are to the residential sector.

In the view of the Commission the ability of the regression equation to explain the variation in use per account over the years (the R-squared values) is not the only consideration in regression analysis. The statistical significance of the explanatory variable(s), the likelihood of establishing cause and effect between the independent variables and the dependent variable in light of the current gas market volatility and regional economic conditions, and the plausibility of the forecast results from the regression models should also be considered. **The Commission determines that the second simple regression analysis against price satisfies most of the factors under consideration and gives a reasonable forecast of 523.3 GJ/year.**

During the hearing, PNG indicated that the weighted average number of customer accounts for 2002 should be 2,848 instead of 2,789 if the Application had counted the reconnections in November and December of 2001 (T2: 282).

The Commission has incorporated the revised 2002 weighted average of 2,848 customers into the forecast. **The Commission sets the expected commercial gas deliveries at 1,490,358 GJ (2,848 x 523.3 GJ).**

<u>Seasonal Off-peak (Rate Schedule 6)</u>

Based on the expectations of the operators of the asphalt plants, PNG forecast consumption of 31,000 GJ for 2002 (Exhibit 1, Tab 1, p. 8). The six-year average (1995-2000) consumption for the sector is 34,068 GJ and the annual deliveries during 1999, 2000 and 2001 were noticeably lower at 30,537 GJ, 31,224 GJ and 30,184 GJ (Exhibit 2 BCUC IR 1, p. 74) respectively.

The Commission accepts PNG's forecast of seasonal off-peak deliveries.

<u>Natural Gas Vehicles (NGV) (Rate Schedule 7)</u>

The forecast for 33,900 GJ (Exhibit 1, Tab 1, p. 9) takes into account a marked decline in conversion levels, retirement of previously converted vehicles and minimal penetration of factory built NGV's in the region. The actual 2001 delivery was 34,704 GJ (Exhibit 2, BCUC IR 1, p. 24).

The Commission accepts PNG's forecast of NGV sales in 2002.

Small Industrial Sector (Rate Schedule 5 and Transport)

In the Application, PNG indicated that the small industrial deliveries projection was based on historical records as well as on a survey of customers (Exhibit 1, Tab 1, p. 9; T2: 285). Actual normalized deliveries in 2001 were 1,825,306 GJ, composed of 409,863 GJ in sales and 1,415,443 GJ in transportation (Exhibit 2, BCUC IR 1, p. 89). PNG also indicated in the hearing that it had not considered applying for a deferral account since historically the small industrial category has been the most consistent in deliveries among all customer classifications (T2: 288).

PNG forecast deliveries to small industrial customers in 2002 at 1,245,000 GJ, made up of 435,000 GJ in sales and 810,000 GJ in transportation deliveries (Exhibit 1, Tab 1, p. 9).

PNG argued that the significant reduction in 2002 deliveries compared to 2001 is reasonable because of the mid-2001 shutdown of Skeena sawmills in Terrace and Smithers as well as Slocan Forest Products converting to a waste wood burning dry kiln system (PNG's Final Argument, p. 14). PNG noted, however, that Slocan's conversion will not have a significant impact in 2002 because the minimum billing to Slocan will be effective until the end of October 2002 (Exhibit 1, Tab 1, p. 9). PNG also said that it is likely that Skeena will operate sometime in 2002 but that no deliveries have been forecast to its sawmills or pulp mill because of PNG's liquidity problem and the uncertainty about Skeena (T2: 288-290). PNG provided little evidence on other factors that could affect the behaviour of small industrial customers, such as changes in gas commodity and transportation costs, lumber markets, or the softwood lumber dispute, since the customer survey in mid-2001.

The Commission finds that PNG has provided insufficient evidence to support its forecast of a 32 percent reduction in small industrial deliveries from 2001 to 2002. The Commission considers a 10 percent reduction in deliveries from 2001 to be reasonable and cautiously below the seven-year average (1995-2001) deliveries of 1,726,661 GJ.

The Commission sets the expected small industrial deliveries at 1,642,775 GJ (1,825,306 x 0.9).

Large Industrial Sector

Methanex Corporation

As a result of the New Contract, the gross margin from Methanex has changed but the consumption projections remain at 24.7 PJ for 2002 (Exhibit 1C, p. 5). The 24.7 PJ would be composed of 22.63 PJ of firm deliveries and 2.07 PJ of interruptible deliveries. One of the terms of the New Contract is 100 percent take-or-pay for the 62,000 GJ/day or 22.63 PJ/year for the firm gas portion. The interruptible gas is the projected deliveries in excess of the contract demand.

The Commission accepts the interruptible gas forecast and determines that only this portion should be included in the 2002 ICDDA.

Skeena Cellulose

PNG forecast no deliveries to the Skeena Cellulose pulp mill for 2002 (Exhibit 1, Tab 1, p. 10) and Skeena indicated its understanding of PNG's conservative position (Exhibit 4B). Alcan submitted that a deferral account should be created for Skeena in the event that it returns to the PNG system in 2002 or 2003 (Alcan Argument, p. 6).

The Commission accepts PNG's forecast of no sales to Skeena in 2002 and determines that any variation in margin as a result of this forecast and any delivery margins resulting from a 2002 start-up be included in the 2002 ICDDA.

Eurocan Pulp and Paper Co. Ltd.

PNG forecast deliveries at 2,687,331 GJ for 2002 (Exhibit 1, Tab 1, p. 10). This forecast is based on input from Eurocan and is consistent with the 2001 actual deliveries.

The Commission accepts PNG's forecast and determines that the variation of actual deliveries from this forecast be recorded in the 2002 ICDDA.

Alcan

Alcan took deliveries of 991,406 GJ in 2001 (Exhibit 2, Methanex IR 1, p. 16). PNG's forecast for 2002 of 900,000 GJ was based on discussions with Alcan. PNG stated that there is a 50 percent probability of Alcan not achieving 900,000 GJ, and Alcan is not part of the industrial customer deliveries deferral account (T1: 65).

Methanex urged the Commission to use Alcan's actual 2001 level of 990,000 GJ as representative of anticipated sales for 2002 (Reply Argument, p. 14). PNG urged the Commission to adopt Alcan's views of its own requirements rather than those of Methanex (Reply Argument, p. 14).

The Commission considers that the market prospects and production levels for Alcan should be at least as good as in 2001. Therefore, the Commission sets the forecast for Alcan at 990,000 GJ for 2002.

B.C. Hydro

The B.C. Hydro generating station at Prince Rupert is not designed to operate for base load purposes. The Commission acknowledges PNG's argument that electricity prices since mid-2001 will not create the opportunity for this generating station to operate, except to avoid service interruptions.

The Commission accepts the 10,000 GJ projections for 2002 and determines that any variation in the margin should continue to be recorded in the 2002 ICDDA.

4.0 GAS SUPPLY COSTS

The core market gas supply cost and the GCVA are reviewed in a separate quarterly review process and were therefore not reviewed in detail in the hearing. Those reviews resulted in changes to rates effective January 1, 2002 (Order No. G-136-02), and April 1, 2002 (Order No. G-19-02). In the second quarter review this year there was no change to rates for July 1, 2002. The GCVA is impacted not only by core market gas cost changes, but also by Company Use and Unaccounted for Gas ("UAFG") deferral accounts.

4.1 Gas Commodity Cost Rate Changes

4.1.1 Gas Supply Cost Pass Through

The PNG Application included a request for reductions to gas supply charges and changes to GCVA riders which were revised by an application dated December 17, 2001. This application reflected lower forward gas market prices and reduced forecast gas supply costs for 2002. The GCVA records the extent to which the gas cost charge over-or-under recovers actual gas supply costs incurred by PNG. A GCVA rider is designed to recover or refund over time the expected balance in the GCVA. These changes had the effect of reducing gas commodity charges by about 27 percent, effective January 1, 2002.

The application also requested approval of a reduction to the Gas Supply Charge and the implementation of a GCVA rider of $1.802/GJ for customers of PNG's propane grid in Granisle. The changes would reduce total propane commodity charges by about 15 percent, effective January 1, 2002.

By Order No. G-136-01, the Commission approved reductions to the gas supply charge in PNG's natural gas and propane rates.

The 2002 first quarter review indicated that the Commission guidelines provided for a decrease in customer rates. As a result of Order No. G-19-02, the Commission approved a reduction effective April 1, 2002 in the company use gas charge and a GCVA credit rider. A second quarter review resulted in no change to rates at the end of June 2002.

4.1.2 Company Use Gas Cost Pass Through

The company use gas cost embedded in rates is $0.185/GJ ($6,159,147/33,229,073 GJ, Application, Tab Rates, p. 8). The decrease in company use gas costs is passed through to customers by applying a rate decrease of $0.059/GJ to deliveries in 2002. This is the difference between the unit company use gas cost rate of $0.244/GJ embedded in rates effective July 1, 2001 and the projected 2002 rate of $0.185/GJ. The delivery charge is then reduced to reflect this adjustment (Exhibit 2, CAC (BC) *et al.*, IR 1, p. 4). The unit cost of company use gas is expected to rise from $0.185/GJ to $0.229/GJ effective November 1, 2002 once Methanex begins supplying its own company use gas to PNG (Exhibit 1C, p. 6).

The GCVA Deferral Account has four components that reflect Company Use/UAFG and Unaccounted for Gas Volume Deferral:

- Company Use/UAFG Commodity – This is the deferral of the difference between the gas commodity price for company use gas embedded in rates and the actual commodity price per month determined through the GCVA model. The model allocates pooled commodity costs to the PNG and Fort St. John/Dawson Creek systems to determine the unit monthly gas commodity charge. The difference between the forecast and actual unit cost is applied to actual total company use and unaccounted for volumes. This component was a credit of $983,033 at the end of 2001. (Exhibit 2, p. 18; T3: 434-5).

- Company Use/UAFG Demand - The difference between the forecast and actual demand charges is deferred for future recovery from, or refund to, customers. At the end of 2001 this component was a debit balance of $10,203.

  The GCVA allocates actual demand charges to various customer classes and to customer use gas on a basis consistent with the gas supply flow through model. This model determines the forecast demand charges for each customer class.

- Unaccounted for Gas Volume Deferral - The difference between actual and forecast volumes of the UAFG deferral account is also reflected in the GCVA deferral account. This account is subject to a 0.2 to 0.7 percent company use volume band. Gas volumes outside this band are included as unaccounted for gas. This category is deferred on a cumulative monthly basis and the price applied to the variance is the blended annual budgeted price. The amount in this category at the end of 2001 was a credit of $206,924.

  PNG provided a table as part of Exhibit 33 showing unaccounted for gains and losses since 1991 (T3: 439). Orders No. G-67-93 and G-11-94 approved a deferral account for unaccounted for gas losses from fiscal 1992 and 1993 respectively.

  PNG’s records currently indicate a large gain in unaccounted for gas during 2000 and 2001 (Exhibit 1, Tab 1, p. 11). A consultant has been hired to complete a comprehensive review of this component and this analysis should have been completed in the second quarter of 2002. The Commission has yet to receive the report. If an adjustment is recorded by PNG for unaccounted for gains or losses from 1994 to the present, the adjustment will be recorded in the GCVA and will be passed through to customers. In the interim the Commission accepts PNG’s recommendation that a 0.4 percent factor continue to be used (Exhibit 2, BCUC IR 1, p. 103).

- Company Use Gas Volume Deferral – There is also a volume deferral account to record variances in all volumes of company use gas including the heating and compressor fuel. It was allowed for the first time in 2001 as a result of the uncertainty surrounding consumption by Methanex as well as a number of other customers (T: 437). This component has a credit of $354,613 at the end of 2001.

The effect of these four components was to reduce the GCVA from a 2001 opening debit balance of $987,230 by $1,534,367 to a 2001 closing credit balance of $547,137.

5.0 OPERATING, MAINTENANCE AND ADMINISTRATIVE EXPENSES

5.1 Operating Expenses

Total operating expenses for 2002 are expected to increase to $11.082 million compared to $8.518 million in the 2001 Decision. Most of the increase is due to the cost of company use gas since the 2002 forecast assumes that Methanex will be operating at normal volumes while the 2001 Decision expected the methanol plant to be shut down for the year. Other operating expenses, aside from company use gas, are expected to increase by approximately $470,000 from the 2001 Decision to the 2002 test year (Exhibit 1C, p. 9).

For 2002 PNG forecast cost increases above the levels allowed in the 2001 Decision or the 2001 actual costs in account numbers 688 (training), 713 (customer billing), 714 (credit and collections) and 718 (uncollectible accounts).

The 2001 Decision allowed $1.151 million in account 688 (training) but the 2001 actual costs were $812,000 and PNG has forecast 2002 costs of $998,000. PNG stated that the increase in training costs from 2001 actual to 2002 forecast is due to planned 2001 training that could not be completed (Exhibit 2, BCUC IR 1, Q. 7.12, p. 126). PNG explained that it couldn’t complete the 2001 training since it was dealing with the Customer Care Centre and customer issues (T3: 413-421).

The Commission considers that the 2001 Decision provided PNG with sufficient funds to complete the required training and it is not appropriate to increase the 2002 provision to fund training that was delayed from last year. The Commission approves a 2002 provision in account 688 (training) of $812,000.

Credit and collections in account 714 are forecast as $209,000 for 2002 compared to 2001 actual costs of $132,000 and an allowance of $190,000 in the 2001 Decision. The bad debt expense in account 718 is forecast as $200,000 compared to 2001 actual costs of $143,000 and a 2001 Decision allowance of $138,000 (Exhibit 1C, p. 9).

Methanex submitted that there is insufficient evidence to demonstrate why a $60,000 increase in bad debt expense is warranted for 2002 (Methanex Argument, p. 3). The Forest Companies and CAC (BC) *et al.* expressed a similar view. They considered that an increase in the 2002 bad debt expense above the actual 2001 level was unwarranted given the significant decrease in the commodity cost of gas and PNG's expectation to regain lost load from the core market (Forest Companies Argument, p. 30 and CAC (BC) *et al.* Argument, pp. 11-12).

PNG replied that it has numerous small sawmill operators that may be adversely affected by the softwood lumber dispute and that the higher bad debt provision allows for the higher likelihood of business failures and associated non-payment of gas bills (PNG Reply Argument, p. 10).

The Commission accepts that credit and collections may increase above the 2001 level as a result of the economic downturn and the softwood lumber dispute. However, the PNG tariff provides the Utility with protection through security deposits and customer disconnection procedures for non-payment that limits bad debt exposure.

The Commission approves a 2002 provision in accounts 714 and 718 totaling $328,000, which should provide PNG with an adequate allowance for credit and collections and uncollectible accounts.

PNG stated that the creation of the Customer Care Centre in 2000 resulted in cost savings of $1 million in operating wages and other operating expenses in 2002 compared to 2000 (Exhibit 2, Methanex IR 1, Q. 3A, p. 5). PNG also provided a comparison of the costs of providing customer care service costs from 1999 to 2002 that are summarized as follows:

	1999 Actual	2000 Actual	2001 Actual	2002 Forecast
Customer Care Costs	$ 1,228,634	$ 1,390,623	$ 2,275,905	$ 2,119,695
No. of Customers	23,388	23,588	39,230	38,721
Cost per Customer	$ 52.53	$ 58.95	$ 58.01	$ 54.74

PNG stated that the number of customers in the table above in 1999 and 2000 is for PNG only and that for 2001 and 2002 the number includes both PNG and PNG (N.E.) (Exhibit 2, BCUC IR 1, Q. 4.1, p. 72). PNG confirmed that the majority of the Customer Care Centre costs are recorded in accounts 711, 713 and 714 and that comparison of operating expenses for these services before and after the creation of the Customer Care Centre requires a review of this group of accounts. PNG stated that with the creation of the

Customer Care Centre, costs were reclassified within these accounts (T2: 263-268 and T3: 415-421).

The following table summarizes the actual and forecast costs in accounts 711, 713 and 714 and uses the number of customers per year from the preceding table (Exhibit 2, BCUC IR 1, Q. 7.6, p. 121):

	1999 Actual		2000 Actual		2001 Actual		2002 Forecast	
Account								
711-Customer Contracts	$	179,000	$	210,000	$	349,000	$	285,000
713-Customer Billing		769,000		803,000		696,000		957,000
714-Credit and Collections		200,000		255,000		132,000		209,000
Total	$	1,148,000	$	1,268,000	$	1,177,000	$	1,451,000
No. of Customers		23,388		23,588		39,230		38,721
Cost per Customer	$	49.09	$	53.76	$	30.00	$	37.47

The two preceding tables demonstrate that in 2002 the total expenses in accounts 711, 713 and 714 of $1.451 million represent about two-thirds of the total Customer Care Centre costs of $2.120 million. PNG also identified that the Customer Care Centre assets would involve depreciation expenses of $27,000 and return on rate base of $41,000 for 2002.

The Commission accepts the 2002 forecast of $285,000 in account 711 (customer contracts).

The 2001 Decision allowed for $754,000 in account 713 (customer billing) and PNG forecasts 2002 customer billing costs of $957,000. PNG attributed the increase to increased telecommunication costs ($56,000), two additional Customer Care Centre employees ($60,000), increased postage and courier ($15,000), data base clean-up fee ($20,000), office and IT supplies ($21,000) and employee expenses ($19,000) (Exhibit 1, Tab 1, p. 16).

In argument, Alcan observed that PNG applied for a 10 percent increase in its operating, maintenance, adminstrative and general costs, excluding company use gas costs ("O&M") from $11.6 million in 2001 Decision to $12.75 million for 2002. Alcan submits that it is incumbent on PNG to ensure that O&M costs increase at about the rate of inflation in 2002 and 2003. Alcan considers that even though the 2001 Decision assumed that Methanex would not operate in 2001, the provision for 2002 O&M costs should be $12.18 million representing 2 percent inflation and $350,000 to reflect the costs of Methanex taking gas in 2002 and beyond (Alcan Argument p. 8 and Exhibit 1C, p. 1).

The Commission accepts that the additional employees, increased postage and courier and the increased telecommunication costs are necessary to handle customer billing and account enquiries above the amount provided in the 2001 Decision. The Commission considers that a 2002 provision for customer billing costs of $885,000 is achievable and therefore appropriate ($754,000 + $60,000 + $15,000 + $56,000).

5.2 Maintenance Expenses

Total maintenance expense is expected to increase from $597,000 in 2001 to $952,000 in 2002 due to the inclusion of a compressor overhaul in 2002 expenses. In 2001 the unbudgeted compressor overhaul was recorded as part of the Methanex restart costs in an approved deferral account. **The Commission finds the 2002 forecast of maintenance expenses to be reasonable.**

5.3 Administrative and General Expenses

PNG provided five of its executives with retention bonuses in 2000 and 2001 to ensure the executives remained with the company during difficult financial times and avoid the Utility requiring protection under the Companies' Creditors Arrangement Act ("CCAA"). The bonuses were described in Exhibit 38 as being a percentage of the 2001 executives' base salary with total retention bonuses of $224,900 to be paid on July 31, 2002. PNG's president confirmed that these retention bonuses have been included in the 2002 Revenue Requirements (T5: 599-601).

Methanex submitted that PNG paid retention bonuses in 2001 that were included in the 2001 cost of service and that if PNG is in such dire circumstances to require repeated sizeable retention bonuses to be paid then it is inappropriate for PNG's customers to bear such costs. Methanex considers that PNG's shareholders should bear this burden (Methanex Argument, p. 3). The Forest Companies considered that PNG's shareholders were the principal beneficiaries of the restructuring without which PNG would have been rendered insolvent and the value of its shares dramatically reduced (Forest Companies Argument, pp. 31 and 42).

PNG replied that the retention bonuses were necessary to maintain a stable senior management team through PNG's financially challenging times which commenced in 2000 and which are continuing today (PNG Reply Argument, pp. 10-11).

The Commission agrees with Methanex that a retention bonus is not a normal expense that should be recovered in customer rates on a recurring basis. While stable management should

lead to lower cost service to customers, the Commission considers that a retention bonus for 2002 represents an unusual expense primarily for the benefit of shareholders. The Commission has reduced the 2002 provision of account 721 Administration by $224,900 to remove the retention bonuses from cost of service.

PNG is forecasting donations of $17,000 for 2002 compared to actual 2001 donations of $7,000. **The Commission has set a 2002 donation provision of $8,500.**

6.0 RATE BASE

The rate base is forecast to decline in 2002 to $137 million from $145 million in the 2001 Decision. This is due to the accumulated depreciation reducing net plant by $6.5 million plus plant additions increasing net plant by only $3.5 million and other items including deferred charges, working capital and customer contributions (Exhibit 1C, pp. 7 and 10).

6.1 Capital Expenditures

For 2002 PNG is forecasting capital additions of $3.5 million, including capitalized overhead of $1.2 million. As shown in the following table the significant capital expenditures excluding capitalized overhead for 2002 will total $2,009,000 and are broken down between transmission plant ($689,000) and distribution plant ($1,320,000) respectively (Exhibit 1, Tab 2, pp. 3-7).

Significant Projected 2002 Capital Expenditures

Capital Expenditure		**Amount**
Transmission Plant		
Unspecified mainline repairs		$ 187,000
Build road for right of way access		50,000
Annual mainline repair		60,000
Relocate Babine lateral		76,000
Additional cover for the Ridley Island 4in. Line		48,000
Solar unit controls		221,000
Replacement of generator at R3 compressor station		47,000
	Subtotal	$ 689,000
Distribution Plant		
Pipe, valve, fittings for service additions		$ 83,000
Distribution mains		240,000
Office equipment		57,000
Transportation equipment		144,000
Heavy transportation equipment		71,000
Tools and work equipment		129,000
Computer equipment		596,000
	Subtotal	$ 1,320,000
	Total	$ 2,009,000

The Commission approves the forecast total capital expenditures of $3.5 million including capitalized overhead.

6.2 Deferral Accounts

Unamortized deferred charges with a mid-year balance of $1.452 million are included in rate base for 2002 representing line break costs, stress corrosion cracking repairs, industrial customer deliveries deferral account, debenture redemption, refinancing costs and preliminary engineering studies.

6.3 Industrial Customer Deliveries Deferral Account (“ICDDA”)

The 2001 Decision approved the continuation of the ICDDA to record the difference between the 2001 forecast and actual margin received from the large industrial customers of Methanex, the Skeena Cellulose pulp mill and Eurocan and approved PNG’s request to include B.C. Hydro in the account. The ICDDA was also to record any variance between the forecast and actual company use gas costs that related to the margin variance in this account. By Order No. G-66-01, the Commission approved the recording in the ICDDA of PNG’s unbudgeted costs related to the restart of the methanol plant, subject to a prudency review.

For calendar year 2001, PNG recorded in the ICDDA margin variance items and non-margin items for a total net balance of $937,305 before tax ($529,577 after tax) as detailed in the following table extracted from Exhibit 26. The net balance in the ICDDA after tax would be amortized into rates in 2002 (Exhibit 1A, p. 36; Exhibit 1C, p. 1).

Margin Deferrals	Margin
Methanex	$ 113,257
Skeena Cellulose	1,331,920
Eurocan	570,554
B.C. Hydro	(3,055,179)
Total Margin Deferrals	(1,039,447)
Non-Margin Items	
Company Use Fuel Gas Avoided	(297,665)
Skeena Bad Debt Provision	1,509,458
Methanex Start Up	764,958
Total Deferral Before Tax	937,305
Total Deferral After Tax	$ 529,577

The ICDDA records the margin variance between the 2001 actual results and the 2001 Decision resulting from deliveries to the four large industrial customers. The 2001 margin variance for these four customers is a credit of $1,039,447 due to the high gas consumption of B.C. Hydro in 2001 more than offsetting the negative margin variance of the other three customers (Exhibit 26).

In calculating the margin variance for 2001 actual deliveries compared to forecast, PNG increased the 2001 Decision volumes for Methanex to reflect increased forecast deliveries from the restart of the methanol plant. PNG increased the 2001 forecast Methanex volumes from 18.5 PJ to 22.1 PJ representing firm volumes under the take-or-pay contracts and deficiency volumes, which were slightly above the actual 2001 deliveries (Exhibit 2A, BCUC IR 2, Q. 14.1, p. 8).

The 2001 Decision forecast deliveries to Skeena Cellulose of 3,400,000 GJ but as a result of Skeena shutting down operations in July 2001, the actual 2001 deliveries were 1,233,171 GJ. In calculating the 2001 Skeena Cellulose margin variance, PNG used the higher of the actual monthly volumes or the minimum monthly volumes to arrive at a deemed actual 2001 Skeena Cellulose delivery volume of 2,340,502 GJ (Exhibit 26; Exhibit 2A, BCUC IR 2, Q. 14.4, p. 15).

The Commission accepts the 2001 margin variance credit in the ICDDA of $1,039,447 before tax.

PNG has also recorded a credit of $297,665 in the ICDDA to reflect a lower than forecast company use gas cost. PNG forecasts the company use gas that will be needed for the deliveries in the test year. Company use gas costs are included in operating expenses and recovered from customers in the delivery charge. When industrial customers have lower actual deliveries than forecast such as Skeena Cellulose, the ICDDA records the margin variance and recognizes that less company use gas was required. The company use gas cost that is avoided due to these lower deliveries is recorded as a credit in the ICDDA and refunded to customers. **The Commission accepts the company use gas avoided credit of $297,665 in the ICDDA.**

PNG included a Skeena bad debt provision of $1,509,458 in the ICDDA. The Utility stated that historically industrial customers paid their bills in full. Therefore, PNG does not include a bad debt provision for industrial customers (T1: 122). PNG states that when Skeena shut down operations in July 2001 the customer was not paying its minimum monthly bills, and the bad debt reflects the minimum monthly bills from July to December 2001 (Exhibit 1, Tab 2, p. 16). The minimum monthly bills not paid by Skeena sawmill operations totalled $82,800 in deferred bad debt (Exhibit 2, BCUC IR 1, Q. 8.8, p. 137; T1: 124).

In 1997, the Commission approved the recovery of lost revenue from the former owners of Skeena Cellulose. In Letter No. L-53-97 to PNG the Commission stated that the closure of the Skeena mill was an extraordinary event that could not be reasonably foreseen and that PNG took prudent actions as the closure became evident. PNG applied for the 1997 deferral account in a timely manner on April 7, 1997 when Skeena obtained CCAA protection on March 3, 1997 (Exhibit 22).

PNG considers that requesting deferral account treatment of the Skeena bad debt is consistent with the 1997 deferral account treatment even though it did not file for deferral account treatment until the Revenue Requirements Application was filed on November 30, 2001. PNG stated that the 2001 Skeena bad debt could have been recorded in a separate deferral account (T1: 123). PNG doesn’t consider that it is requesting retroactive treatment and considers that the margin variance of the ICDDA could use the actual 2001 deliveries to Skeena and ignore the minimum bill provisions of the contract (T3: 447).

PNG did not propose a Skeena bad debt deferral account in the 2001 Revenue Requirements Application because it didn't expect that Skeena would be in a bad debt situation (T3: 450). PNG had ongoing discussions with the major shareholder of Skeena prior to the CCAA declaration and took comfort from those discussions (T3: 451). PNG put Skeena on notice a day or two before the CCAA declaration that PNG would be seeking a letter of credit or some form of prepayment (T3: 452). PNG filed a statement of claim with the trustee for $575,000 and expects to recover about 10 percent of the claim (T1: 184). Skeena terminated its contracts with PNG and PNG has increased its claim to the trustee to $4.3 million to reflect the minimum bill requirements to the end of the Skeena contract on November 1, 2002. PNG may go to court if the trustee rejects the revised claim (T5: 625-626).

PNG confirmed that it calculated the 2001 margin variance in accordance with the method described in Exhibit 2A, BCUC IR 2, Q. 14.3, p. 14 which does not specify that actual margin represents the higher of actual deliveries or the minimum bill. In the 2001 Decision, at pages 8 and 9, the Commission approved the continuation of the ICDDA, but did not specify that actual margin was to be the higher of actual deliveries or the minimum bill.

Methanex submits that the Skeena sawmills were not part of the ICDDA, the bad debt from those sawmills should not be recovered from customers and bad debt is part of the normal risk shareholders take on as owners (Methanex Argument, p. 6). The Forest Companies expressed a similar view (Forest Companies Argument, p. 31).

PNG replied that the closure of the Skeena sawmills is not a normal business risk any more than the closure of Skeena's pulp mill. PNG considers that when a customer continues to operate, fluctuation in delivery volumes is a business risk but when a customer ceases business and their revenue has been included for rate making purposes, the loss should be recoverable by the utility (PNG Reply Argument, pp. 11-12).

The Commission accepts that the actual margin to be used in the ICDDA for 2001 and 2002 is represented by the actual volumes delivered, in accordance with the definition from the PNG 2000 Revenue Requirements and Order No. G-37-00, Appendix A, page 2. The 2001 Decision approved the continuation of the ICDDA without modification to the derivation of margin variance. The Commission agrees with Methanex that the Skeena sawmills were not part of the ICDDA and should be excluded. The Commission accepts that the Skeena Cellulose bad debt of $1,426,658 (after removing the sawmill debts of $82,800) should be included in the ICDDA. PNG is to record any future recoveries of the Skeena Cellulose bad debt in the ICDDA for refund to the customers on a prospective basis.

The current definition of margin variance for the ICDDA provides PNG with protection against significant industrial forecast risk. In the next revenue requirements application, PNG is to present evidence regarding a change to the margin variance calculation whereby the actual margin is to represent the greater of the actual deliveries or the minimum monthly bill.

In the 2001 Decision, the deliveries to Methanex were 4,380,000 GJ on the assumption that the methanol plant would be shut down for the year but deliveries would continue to the ammonia plant. As a result of the significant decrease in forecast 2001 Methanex volumes, PNG did not budget for an annual compressor overhaul. After the 2001 Decision was issued, PNG was notified that Methanex would restart the methanol plant effective July 1, 2001. On June 12, 2001 PNG applied for recovery of the additional unbudgeted costs that it would incur in preparation for the restart of the methanol plant. By Order No. G-66-01, the Commission approved the recording of the forecast restart costs in the ICDDA subject to a prudency review. The costs of the restart were reported as $764,958 and additional information was provided on the prudency of these costs (Exhibit 1A, p. 40; Exhibit 2, BCUC IR 1, Q. 8.4 to 8.7.2; and 8.8).

The Forest Companies consider that Methanex's temporary departure from PNG is a shareholder risk and, therefore, the restart costs should be borne by PNG's shareholders (Forest Companies Argument, p. 40).

PNG replied that it was directed by the Commission to record the Methanex restart costs in the ICDDA subject to a prudency review. PNG stated that none of the parties challenged the prudency and necessity of the expenditures (PNG Reply Argument, p. 11).

The Commission accepts that the restart costs were prudently incurred and were necessary in order for PNG to resume deliveries to the methanol plant.

The Commission approves the one-year amortization of the approved margin variance and non-margin items in the ICDDA.

PNG is proposing that the Methanex volumes for interruptible deliveries under the MOA remain in the ICDDA (Exhibit 2B, BCUC IR 3, Q. 25.2, p. 73). Alcan submitted that in the event that Skeena returns to the PNG system in 2002 or 2003, the resulting revenue should be recorded in the ICDDA or another deferral account for refund to customers other than Methanex in 2003 or 2004 (Alcan Argument, p. 6).

The Commission accepts that the Methanex interruptible volumes should be included in the ICDDA. The calculation of ICDDA margin variance for the 2002 calendar year will compare the

actual 2002 deliveries to the 2002 forecast volumes included in this Decision for Eurocan, B.C. Hydro, Methanex interruptible volumes and Skeena Cellulose. Recovery of the 2002 ICDDA balance is to be reflected in PNG's revenue requirements on a prospective basis.

6.4 2002 Redemption Costs

Commission Order No. G-122-01 approved the refinancing of PNG's $12 million debenture and approved PNG's request for a deferral account to record the redemption premium, associated costs and the interest savings, subject to a prudency review.

PNG paid redemption costs totaling $620,000 before tax ($350,300 after tax) for the early redemption of the 2002 debenture. PNG estimated that the refinancing would result in interest savings of $410,000 for 2002 from the reduced cost of debt (Exhibit 1, Tab 2, p. 25). PNG is proposing amortization of these costs over one year in 2002 and states that under generally accepted accounting principles the costs should have been expensed in 2001 when the redemption occurred.

Methanex submits that based on a review of PNG's share price, it seems that PNG's shareholders were the primary beneficiaries of the restructuring and should accordingly pay a significant portion of the associated costs. Methanex considers that the remaining redemption costs should be recovered over the life of the new 2010 debenture rather than the proposed one-year amortization (Methanex Argument, p. 7).

PNG replied that none of the intervenors took issue with the prudency of the costs incurred by PNG to obtain its line of credit or finance its debenture balloon payment. PNG states that these costs were incurred in the ordinary course of business and should be paid by the customers in the same way as other prudently incurred costs of doing business. PNG considers that a one-year amortization will reduce PNG's short-term financing needs and minimize the cost base into 2003 (PNG Reply Argument, p. 11).

The Commission accepts the redemption costs of $350,300 after tax for inclusion in the schedule of deferred charges and recovery from customers in a one-year amortization in 2002.

6.5 Refinancing Costs

Commission Letter No. L-32-01 (Exhibit 23) approved the creation of a deferral account to record the costs to PNG of refinancing its operating line of credit. PNG is requesting recovery of refinancing costs of $642,459 before tax for the following: PNG's legal fees ($65,241), the Royal Bank's legal fees ($31,409), a legal advisor to the Special Committee of PNG's Board of Directors ($30,808), PNG's financial advisor ($510,000) and PNG's other expenses ($5,000) (Exhibit 1, Tab 2, p. 21). PNG confirmed that no allocation of these costs had been made to PNG's shareholders (Exhibit 2, BCUC IR 1, Q. 10.13, p. 184). On an after tax basis, the refinancing costs would total $362,989.

PNG acknowledged that a change occurred in its share prices following the 2001 Decision and the refinancing. PNG's President agreed that PNG's share price was $7 to $8 prior to the 2001 hearing and was about $13 in early March 2002 (T1: 177). Counsel for Methanex quoted the evidence of Ms. McShane, an expert witness for PNG, that PNG's share price was $10.12 on November 30, 2001 and $14.50 on March 11, 2002 (T4: 504). Ms. McShane commented that a possible explanation of the share price increase could be speculation that Duke may sell PNG (T4: 505-506).

PNG's President also confirmed that PNG's share price went from $8 to $11 in a few weeks on either side of November 1, 2001, around the time of the refinancing. PNG's President considered that PNG's shareholders benefited from the refinancing (T4: 574-575).

In argument PNG considered that the shareholders should not pay for the cost of obtaining debt financing when 100 percent of the debt is used for utility purposes, nor should they be responsible for the Utility's liquidity crisis in late 2000 and early 2001 resulting from high gas commodity costs (PNG Argument, p. 12).

Methanex suggested that PNG's refinancing costs should be recovered over the term of PNG's long-term financing plan instead of the one-year amortization period that PNG has proposed. Methanex also considers that the refinancing benefitted PNG's shareholders and PNG (N.E.) and both should also share in the refinancing costs (Methanex Argument, p. 6).

The Forest Companies consider that the cost of PNG refinancing its line of credit and arranging payment of the $12 million balloon payment on its long-term debt clearly benefits PNG's shareholders by the dramatic increase in PNG's share prices. If the Commission allocates some portion of the cost to customers, the costs should be amortized over a reasonable period (Forest Companies Argument, p. 31).

The Commission considers that the refinancing of PNG's operating line of credit was a very unusual circumstance necessitated, in part, to avoid the total collapse of PNG's share value if the $12 million balloon payment in July 2002 could not have been met. The costs of legal fees to PNG and the Royal Bank are normal costs which should be recovered. However, the Commission considers that the costs of a legal advisor to the Board of Directors should not have been necessary. This cost is denied. PNG would normally receive some external financial advice prior to placement of a significant debt issue, but the costs of the financial advisor to PNG's management are found to be excessive and are reduced by half to $255,000. **The Commission approves recovery of refinancing costs of $356,650 (before tax) and a one-year amortization into rates ($65,241 + $31,409 + $255,000 + $5,000).**

6.6 Preliminary Engineering Studies

PNG has undertaken a number of engineering studies and investigations which it wishes to recover in future rates.

6.6.1 Unbilled Revenue Collection Model

PNG hired a consultant to undertake a review in 2001 of the unbilled revenue collection model in PNG's Banner billing system. PNG originally forecast that this review would cost $5,000 (Exhibit 1A, p. 12) but an actual cost of $30,000 was incurred in 2001 (Exhibit 2, p. 139). PNG expects that it will be able to recover this expenditure from either the software provider or other users of the Banner billing system (T1: 119). Therefore at the present time PNG has not amortized the amount into rates (T1: 120).

6.6.2 Preliminary Engineering Studies – 2001 Decision

The 2001 Decision disallowed the recovery of costs for the engineering studies shown in the table below and directed PNG to reverse credit the after-tax funds that applied to the costs for the five studies (2001 Decision, pp. 26-27). PNG was to advance evidence as to why the cost of each study is properly a charge to ratepayers, why the costs were not expensed at the time, and why PNG did not request Commission approval of the expenditure.

Preliminary Engineering Studies	
Gas Distribution Expansion Project	$ 42,977
Liquified Natural Gas	84,941
Diagnose Methanex Heat Exchanger	10,202
Municipal Franchise Project	13,950
Wood Residue Power Generation Project	19,860
Total	$ 171,930

The PNG Application requests approval to amortize the preliminary engineering costs shown in the table above in 2002 rates. In PNG's opinion the common procedure has been for the Commission to accept the deferral account subject to a prudency test in the future. A significant expenditure would require regulatory approval prior to acceptance of the deferral account treatment. When expenditures are less than $100,000, accounts may be set up without Commission approval however they would be subject to a prudency review prior to being amortized (Exhibit 1, p. 27).

PNG argued that the studies, other than the Municipal Franchise Project, relate to capital projects which were directly related to the PNG system and which would have been regulated utility projects had they proceeded. PNG submitted that the southeast Alaska distribution project would have used transportation service through the PNG system and would have resulted in significant benefit to PNG's existing customers (PNG Final Argument, p. 13).

PNG further believes that one of the primary benefits of these projects would have been the spreading of the administrative costs over a larger customer base. PNG stated that if the Commission does not approve the recovery of these costs, it would be reluctant to explore the viability of any future potential projects. PNG argued that the cost of each study was modest in comparison to the potential benefits each project could have brought to PNG's customer base and should be approved for recovery from customers (PNG Reply Argument, p. 10).

The Forest Companies argued that customers pay the fixed costs of management to operate the utility and not to pursue business ventures. PNG does not allocate management or executive time to the projects in the preliminary engineering studies. The customers have to absorb the fixed costs of management as well as the out of pocket costs of unsuccessful projects. The Forest Companies argued that the Commission should require PNG's management personnel to keep track of their time on such ventures.

The Forest Companies are also of the opinion that there is a moral hazard. If a project is successful it may generate shareholder returns for PNG while if it is unsuccessful it is backstopped and paid for by PNG customers (Forest Companies' Argument, p. 38).

The Commission's reviews of the individual study costs follow in the sections below.

6.6.3 Gas Distribution Expansion Project

Studies were conducted in 1996 on the possibility of providing natural gas service to southeast Alaska. This project would have allowed for the better utilization of the PNG transmission system and reduced the level of overheads being allocated to the current PNG customers (Exhibit 1, p. 28).

In the Commission's view, the distribution system would be in Alaska and under an entirely different system of regulatory parameters. The Commission considers that the potential for this project was poor and the potential benefit to PNG customers was small. Therefore this investigation should have been undertaken through an independently structured non-regulated business and is not approved for deferral account treatment.

6.6.4 Liquified Natural Gas Study

PNG investigated high-pressure natural gas storage in large diameter pipeline sections, the barging and/or trucking of LNG and the possibility of an LNG plant in the Port Edward area (Exhibit 1, p. 27). The propane air plant in Prince Rupert was a concern and a backup energy source was possibly needed in the area.

An LNG plant was considered as a replacement and an outside consultant was retained to investigate the economics of a small plant. Potential markets in southeast Alaska were then investigated to justify a larger LNG plant for both energy security in Prince Rupert and Alaska (T1: 113). PNG did not adopt an LNG solution but did upgrade the transmission line between Terrace and Prince Rupert (T1: 114).

The Commission considers that the LNG plant was not a realistic option at the time the study was undertaken. The Commission does not believe an adequate business case existed to spend ratepayer funds on the project. Therefore the Commission does not accept this project for deferral account treatment.

6.6.5 Methanex Heat Exchanger

An engineering management consultant was engaged to provide advice on design improvements to a heat exchanger at the Methanex regulating/meter station (Exhibit 1, p. 28). This item was not expensed because it was anticipated that it would be a much larger project.

The recommendation of the consultant was to install an entirely new system with the ultimate cost expected to be about $200,000. However, PNG decided not to proceed and the existing system was retained (T1: 115). The boiler was replaced but further modifications were not made. There was uncertainty over whether Methanex would remain on the system and whether this station would be required.

The engineering report was delivered to PNG in September 1999 and the consultant was likely hired much earlier. At that time, the shutdown of the methanol plant could not have been anticipated. It is the Commission's view that PNG should recover this expenditure and amortize it into 2002 rates.

6.6.6 Municipal Franchise Project

This project involved the investigation for the possible acquisition of distribution facilities outside the existing PNG service area (T1: 116). PNG suggests that this is similar to the investigation of gas distribution facilities in the northeast of the province (Exhibit 1, p. 28). PNG considered that the acquisition of these assets would allow the Company to more widely allocate overhead costs (T3: 465). PNG further testified that all of the legal and similar outside costs related to PNG's acquisition of PNG (N.E.) were capitalized and became part of the capital costs of PNG (N.E.) (T2: 222-223).

The Forest Companies believe that the Municipal Franchise project should have had its costs attributed to new customers in the same fashion that occurred in the PNG (N.E.) situation (Argument, p. 38).

In the Commission's view this project should be a risk for the shareholders of the Utility, and therefore, the expense is not approved for deferral account treatment.

6.6.7 Wood Residue Generation Study

The study reviewed the wood waste potential from Smithers west in the PNG service area to determine the feasibility of wood residue based electrical generation or cogeneration. In addition, municipal residues were considered to determine if they could improve the economics of a wood residue plant. The objective was to use the information to protect its natural gas markets by burning the wood residue in a small power generation unit (T1: 117). The conclusion was that wood residue supply in the area from Smithers to Kitimat and Prince Rupert would be inadequate to permit the operation of an economically viable power generation facility (Exhibit 1, Tab 2, p. 28). PNG was not aware that Eurocan had expended similar funds on a similar study (Exhibit 2, Tab 3, p. 10; Exhibit 3, p. 13). PNG was also unclear about whether it would own and operate such a generation facility or sell it to another party (T1: 117).

The Forest Companies argued that when Eurocan funded a similar study and did not proceed, its shareholders bore the cost. They argued that, similarly, PNG shareholders should bear the cost of the project (Argument, p. 38).

The Commission finds that PNG might not have undertaken such a study if it had explored the issue with its major customers first. If the project had turned out to be feasible, PNG might have structured the project as a non-regulated business or sold the operation to another party. The Commission, therefore, denies PNG's application to recover the costs of this study in rates.

6.7 Other Deferral Accounts

The 2001 Decision approved an increase in some customer rates from October 1, 2000 to December 31, 2001 through a rate rider. The additional revenue was used to draw down balances in the unamortized deferred charges and PNG reported that from October 1 to December 31, 2000 it collected rider revenue totaling $1.076 million ($597,000 after-tax) and from January to December 2001 the rider revenue was $1.562 million ($883,000 after-tax) (Exhibit 2, BCUC IR 1, Q. 11.2, pp. 186-188). PNG records its unamortized deferral accounts on an after-tax basis and recorded the rider revenue collected as a reduction to the unamortized balances in line break costs and pipeline rehabilitation costs in 2000 and 2001 (Tab 2, p. 15 and Exhibit 2, BCUC IR 1, Q. 8.9, p. 139).

None of the intervenors commented on the treatment of the rider revenue collected by PNG.

The Commission accepts that the rider revenue collected from October 1, 2000 to December 31, 2001 has been properly reflected in the unamortized deferral accounts.

7.0 INCOME AND CAPITAL TAXES

7.1 Income Taxes

PNG revised its income tax rates from 40.5 percent to 38.5 percent to reflect approved income tax rate decreases (Exhibit 1, Tab 3, p. 1; Exhibit 1A, p. 47).

The Commission accepts the revised income tax rates for 2002.

7.2 Provincial Capital Tax

The Provincial Capital Tax rate was reduced from 0.3 percent to 0.15 percent effective September 1, 2001 and will be eliminated effective September 1, 2002. PNG does not expect to benefit from this reduction in the Provincial Capital Tax payable due to an assessment of past year Provincial Capital Tax returns. PNG reported that it has received a capital tax audit assessment of $18,000 from a 1999 audit (Exhibit 1, Tab Application, p. 9).

PNG stated that it has received a draft capital tax reassessment for the years 1997 to 2000 where the contributions in aid of construction have been included in the category of taxable capital. The total reassessment would increase capital taxes by $88,000 (Exhibit 2, BCUC IR 1, Q. 9.2, p. 143). When interest is included, the total tax assessed is $108,000. PNG has not included this tax assessment in the Application and is planning to appeal the ruling. If PNG is unsuccessful in its appeal then it intends to seek cost recovery in the next revenue requirements application (T3: 469).

The Commission considers that where customers have made non-refundable contributions to the cost of utility plant additions, those contributions in aid of construction should be excluded in the determination of taxable capital. The Commission supports PNG in its appeal.

8.0 CAPITAL STRUCTURE AND COST OF CAPITAL

8.1 Short-Term Debt

PNG originally forecast a cost of short-term debt at 6 percent for 2002 (Exhibit 1, Tab 5, p. 1) and revised the debt cost to 2 percent in Exhibit 1A, pages 3 and 49, to reflect an interest cost equivalent to the expected bank interest rate on cash deposits. For 2002 PNG set its total capital structure to be equal to the total rate base with the short-term debt component as a balancing item. The 2002 mid-year average forecast for short-term debt has ranged from negative balances of $2 million to $2.6 million (Exhibit 1, Tab 5, p. 1 and Exhibit 1C, p. 13). PNG acknowledged that if an adjustment is made to the requested common equity component, an offsetting adjustment is traditionally recorded to the mid-year balance of short term debt (T5: 700). The actual 2002 short-term debt balance may be higher due to non-rate base deferral accounts representing GCVA variances, property tax variances and other deferred costs.

The Commission accepts the 2002 forecast cost of short-term debt and that short-term debt will be the balancing item in the 2002 capital structure.

8.2 Long-Term Debt

PNG stated that the redemption of the $12 million Series 2002 Debentures and the replacement with a lower cost long-term debenture has resulted in interest savings compared to 2001 (Exhibit 1, Tab Application, p. 11). The interest rate under the Series 2002 Debenture was 10.85 percent and PNG is forecasting the replacement floating rate debenture will have an interest cost for 2002 that is less than 10.85 percent (Exhibit 1, Tab Application, p. 19). This refinancing is shown in rates where the average cost of long-term debt for 2002 is forecast as 8.51 percent compared to an average 2001 long-term interest cost of 9.24 percent (Exhibit 1C, p. 13). The difference between the forecast average floating interest rates and the actual interest rates on this replacement Series 2010 debenture is recorded in a deferral account approved by Commission Order No. G-122-01.

On December 12, 2001 PNG (N.E.) applied to the Commission for approval of a $4.5 million long-term loan from PNG. The terms of the long-term loan from PNG to PNG (N.E.) are the same as the $12 million Series 2010 debenture. PNG reflected this long-term loan in its capital structure as a reduction to its $12 million debenture for a net debenture balance of $7.5 million at the beginning of 2002 (Exhibit 1, Tab 5, p. 2). The $4.5 million loan to PNG (N.E.) was included as an issue in the 2002 PNG (N.E.) Revenue Requirements Application which was approved by the Commission in Order No. G-57-02 and Reasons for Decision.

In its 2002 Revenue Requirements Application, PNG (N.E.) also applied for Commission approval to revise an existing $8 million long-term loan from PNG to PNG (N.E.). The request to revise the existing loan was denied by Commission Order No. G-57-02 and Reasons for Decision. The Commission has determined that the owners of PNG(N.E.) have an obligation to honour the loan which had been made by the previous owner. The incremental cost is not to be borne by PNG ratepayers.

The Commission accepts the long-term debt as forecast for 2002.

8.3 Common Equity Component and Return on Common Equity

The thickness of the common equity component and the required return on common equity are interrelated issues, and are considered together in this section. PNG applied to increase the deemed common equity component from 36 to 45 percent and to increase the risk premium over the return on common equity ("ROE") of a low risk benchmark utility from 75 to 150 basis points (0.75 to 1.5 percent) based on the recommendation of its consultant, K. McShane of Foster Associates (Exhibit 1). Based on the low risk benchmark utility ROE for 2002 of 9.13 percent, the risk premium applied for by PNG would generate a ROE of 10.63 percent. In the Revised Application, the request for an increase to the risk premium was reduced to 100 basis points as a result of the new agreement with Methanex (Exhibit 2B, p. 74; Exhibit 1C), which would reduce the ROE to 10.13 percent.

The circumstances underpinning PNG's request for a changed equity structure or ROE are uncertainty around the continuing viability of PNG's two largest customers: Methanex's Kitimat plant and Skeena Cellulose. During her testimony, Ms. McShane stated that the primary issue cited by Canadian Bond Rating Service ("CBRS") in downgrading PNG's ratings from triple B to double B was the uncertainty surrounding PNG's industrial customers (T4: 503). After filing the MOA, PNG stated that the future risk of insufficient competitive room to recover all of its costs is the primary reason underlying PNG's application to increase its common equity component to 45 percent. (Exhibit 2B, BCUC IR 3, p. 67). PNG's current actual equity component is over 45 percent and will be 50 percent by the end of the test year (T4: 518).

Ms. McShane's analysis indicates a differential in the required equity return between PNG and the benchmark utility, assuming the same capital structure, of 250-300 basis points (Exhibit 1, Tab 5, p. 16). She stated that this differential could be recognized through (1) similar capital structures for PNG and the benchmark utility and a ROE 250-300 basis points above that of the benchmark utility; (2) a capital structure for PNG that effectively offsets its higher risk relative to the benchmark; or (3) a combination of a stronger capital structure and a higher risk premium. She recommends the third option (Exhibit 1, Tab 5, pp. 16-17).

In support of her conclusions, Ms. McShane pointed to PNG's market/book ratio of 50 percent, based on a share price of $10.00, and a price/earnings ratio of 5.7. Both the market/book and price/earnings ratios, in her view, supported a much higher risk premium than 75 basis points. Ms. McShane also supports her conclusion by reference to PNG's double B debt rating and comparing yields on double B rated corporate bonds and A-rated utility bonds. She estimates that the difference is in the range of 150-300 basis points "…with a focus on 200-250 basis points." (Exhibit 1, Tab 5, p. 13).

Ms. McShane also estimates that PNG's business risk beta would be in the approximate range of 0.50 to 0.55 leading to a levered beta estimate of 1.1-1.2 and a market risk premium of 250-300 basis points (Exhibit 1, Tab 5, p. 16). Based on all of the above, Ms. McShane recommended an equity risk premium relative to the benchmark utility of 1.5 percent to compensate for PNG's higher risk, based on a capital structure containing 45 percent common equity.

During her testimony, Ms. McShane acknowledged that, based on revised data, including a more recent share price of $14.10, the market/book ratio would be 0.67 rather than 0.5, and the cost of capital calculated in her evidence (at pp. 9 -10) would be 12.5 percent (T4: 565) rather than 15.3 percent (Exhibit 1, Tab 5, p. 10). Ms. McShane further acknowledged that the range of .50 to .55 for PNG's business risk beta was based on her judgement considering several factors including the Methanex volume reductions and Skeena uncertainty as well as the general economic and physical risks that PNG faces. She also stated that the estimate of business risk is imprecise (T4: 572-3). Ms. McShane agrees that the risks facing PNG are not systematic risks but are company specific risks and the pure Capital Asset Pricing Model suggests investors should not be compensated for those risks "…although the market reality says otherwise" (T4: 579).

Subsequent to Ms. McShane's testimony, PNG filed the Revised Application to take into account its MOA with Methanex, and reduced its equity risk premium request to 1 percent (100 basis points) (Exhibit 1C). PNG states that Ms. McShane had concluded that the impact of the new agreement with Methanex was to reduce the required risk premium by 50 basis points to 100 basis points (Exhibit 2B, BCUC IR 3, Q. 26.1.2, pp. 74-75; T5: 720-21).

PNG concedes that the MOA reduces the risk that the Methanex load will be lost, but states that there is also an increase in risk due to the transfer of some margin from Methanex to the core market leaving much less room to shift further margin to the core market. Further, PNG argues that the level of business risk it faces is higher than the last time its capital structure and return were reviewed because the agreement is for only seven years and has no provincial backstop, the future of Skeena remains in doubt, and the agreement does not guarantee that Methanex will remain in the longer term. PNG also states that, if the Commission decided at some time that PNG's rates needed to be lower just for competitive reasons creating a forecast unrecoverable revenue deficiency, PNG would probably seek approval to have that deficiency recorded in a deferral account for recovery in the future when rates became competitive again (T5: 707).

Intervenors generally opposed the requested increase. Alcan and the Forest Companies submitted that any increases to the risk premium or the capital structure should be denied. CAC (BC) *et al.* argues that if the Commission approved that higher return and thicker equity requested by PNG, this would result in a direct transfer from ratepayers to shareholders. Methanex also opposed the proposed additional equity and increased ROE and argues that rate increases arising from a higher return on equity will only lead to greater uncertainty regarding PNG's long-term economic viability (Reply Argument, p. 9).

Commission Findings

PNG and its witness, Ms. McShane, have gone to significant effort to attempt to demonstrate that the currently allowed equity component and return on equity are insufficient to provide fair and reasonable compensation for its service. The paradox facing the Commission is that some of the additional risk that PNG cites to justify an increased risk premium or equity thickness is its potential inability to recover its return on investment due to the competitive prices of alternative fuels. As Methanex points out, rate increases from a higher return on equity would only lead to greater uncertainty regarding PNG's long-term viability. PNG notes that, irrespective of the factors leading to a cost increase, customers tend to focus on the total gas bill (T5: 704-05). A July 6, 2001 report on PNG by Dominion Bond Rating Service ("DBRS") states that "…current rates are already high, and further upward adjustments could have a significant negative impact on demand, and thus, on the Company's financial profile and ability to meet its debt obligations." The DBRS report goes on to state that if the Commission "…does not approve rate adjustments to cover cost of service and earn the approved ROE on deemed equity, or if the rate adjustments are so high (given the already high rates in existence) that demand is significantly negatively affected, the company's EBIT and net income beyond 2002 will be very weak." (Exhibit 2, Q. 10.1.1, pp. 1 and 4). The Commission accepts the argument of Methanex and others that any increase in the delivered cost of gas to customers leads to greater uncertainty for PNG.

PNG has stated that there is sufficient room, although not much room, for it to raise its rates sufficiently to recover all of its costs, including a higher ROE and thicker equity structure (Exhibit 2B, Q. 22.1, p. 66). PNG however agreed that there is little, if any, room for PNG to extract further rate increases from its residential customers (T5: 596-97). Under at least one scenario discussed during the hearing, the efficiency-adjusted cost of residential gas heat could exceed the cost of heating with electricity by 18 percent (Exhibit 37; T5: 588-91). PNG suggested that the loss of that competitive room as a result of the new agreement with Methanex was one of the reasons for PNG's higher risk (Exhibit 2B, BCUC IR 3, Q. 26.1.1, p. 74). Had the Methanex plant closed the loss of competitive room would have been much greater.

PNG states that the rates agreed to in the MOA provide it with the opportunity to become more financially stable over the long-term (Exhibit 1B, p. 5). The MOA between Methanex and PNG has reduced or eliminated a substantial risk that Methanex would close its Kitimat plant following the expiry of its largest contract in November 2002 and leave the system with little or no compensation to PNG.

Based on the available evidence, the Commission concludes that there is insufficient evidence to support the case that, with the MOA between PNG and Methanex in place, the risk to PNG has increased since the last review of its capital structure and return on equity. The MOA, the ICDDA and recovery of Skeena bad debt all limit risks to PNG. Therefore, the Commission denies PNG's Application for an equity component of 45 percent and a ROE risk premium of 100 basis points.

9.0 2002 REVENUE REQUIREMENTS

9.1 Allocation of the Overall Revenue Deficiency Among Customer Classes

For several years prior to the current application, PNG has allocated the revenue deficiency on the basis of the gross margin for each customer class (PNG Argument, p. 16). The gross margin is based on 2002 test year sales that include some deficiency volumes that do not attract the full margin. Therefore, PNG proposed in its November 30, 2001 application to allocate the revenue deficiency to customers based on the full normalized gross margin attributable to each customer class (Exhibit 1, Tab Application, p. 15). The share of the revenue deficiency to each customer class would be based on the proportion of the normalized gross margin for the customer class to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by the forecast deliveries equals the proposed rate change (Exhibit 1, Tab Rates, p. 4).

In its February 25, 2001 amendment (Exhibit 1A), PNG revised its proposal with respect to Methanex. PNG stated that the original proposal failed to recognize that all deliveries during the January to October period above the 80 percent minimum take-or-pay obligation would be the make-up of deficiency volumes incurred during the methanol plant shutdown from July 2000 to June 2001 (Exhibit 1A, p. 5). Consequently PNG proposed that for Methanex the allocated deficiencies would be spread over firm and interruptible deliveries attracting full margin (i.e. excluding deliveries of make-up deficiency volumes)

(Exhibit 1A, p. 12). In summary, PNG used the full Methanex interruptible volumes (i.e. both deficiency volumes and those attracting full margin) to calculate the share of the revenue deficiency to be borne by Methanex. However, in calculating the November to December interruptible rate, PNG divided Methanex's interruptible revenue deficiency share by only those volumes attracting full margin (T1: 100).

Allocation of the revenue deficiency on the basis of the normalized gross margin rather than the gross margin has the effect of increasing the Methanex January to October 2002 firm rate by 1.06 cents/GJ and decreasing the residential rate by about 8.8 cents/GJ (T3: 409). Although the greatest impact of PNG's proposed method is on Methanex, it also has some impact on small industrial customers, which are also projected to have some deficiency volumes (T1: 97).

PNG argued that basing the allocation method on the normalized gross margin eliminates understating the gross margin from customers that have prepaid deficiency volumes (PNG Argument, p. 16). PNG testified that in some cases it has used the net gross margin as the allocator, but that in most cases it has used the normalized gross margin (T1: 97). PNG also noted that the magnitude of deficiency volumes in 2002 was extraordinary (T1: 98) and that it had allocated on the basis of normalized gross margin previously, following its 1996 Revenue Requirements hearing (T3: 409-10).

After the MOA was filed, PNG again revised the allocation method with respect to Methanex (Exhibit 1B). In Exhibit 1B none of the revenue deficiency is allocated to Methanex based on normal gross margin in November and December 2002 since the MOA contemplates fixed rates. PNG's revised proposal for Methanex spreads the allocated revenue deficiencies (both firm and interruptible) over the minimum 80 percent firm deliveries attracting full margin over the January to October period. The interruptible revenue deficiency allocation is included in the firm rate. Make-up deficiency volumes would remain excluded. The impact of this change is to increase the rates to Methanex by approximately 29 percent. Other customer rates also increase as a result of the MOA, and PNG considers its proposal for 2002 Methanex rates to be reasonable given the reduced firm and interruptible rates under the MOA (Exhibit 1B, pp. 5 and 12).

Methanex argues that the proposal seeks to recover the interruptible revenue deficiency allocation attributable to Methanex in the firm rate. Methanex further submits that only it has been normalized as 2002 gross margin and 2002 normalized gross margin for all other customer classes are identical. In its view, fairness requires that if one customer is normalized all should be normalized, or alternatively, none should be normalized, and that the proposed normalization is unfair, discriminatory and contrary to the provisions of the Act (Methanex Argument, p. 13).

PNG in reply argument states that the normal gross margin figure represents the assignment of costs on the PNG pipeline system and that excluding the prepaid deficiency volume margin would under-allocate the revenue deficiency to Methanex. PNG further notes that the cost allocation to the small industrial customer transport class also incorporates projected deficiency volume deliveries in the normalized gross margin (Reply Argument, p. 12).

Aside from basing the allocation of the revenue deficiency on the normalized gross margin, PNG recommends no further rate rebalancing and suggests that such rebalancing should be deferred until it can complete a Fully Allocated Cost of Service ("FACOS") study. It suggests that this should be done in the context of the 2003 rate application (Exhibit 1, Tab Application, p. 14).

Commission Findings

The Commission accepts PNG's arguments that basing the allocation of costs on the normalized gross margin is appropriate in this instance where there are significant deficiency volumes. Allocating revenue deficiency on the basis of the simple gross margin would under-allocate the costs to those with significant deficiency volumes.

The Commission approves the cost allocation methodology as applied for by PNG. The Commission accepts the suggestion by PNG that it defer further rate rebalancing until it can review the allocation of costs among its rate classes. The Commission directs PNG to include a FACOS study with its 2003 Revenue Requirements Application.

9.2 Rate Changes

<u>Rate Changes from the 2001 Decision</u>

Commission Order No. G-94-00 approved interim rate increases effective October 1, 2000 that were not designed to increase the Utility's approved revenue but to increase cash flow by accelerating the amortization of deferral accounts. The 2001 Decision approved as final the October 1, 2000 interim rates for the period from October 1, 2000 to December 31, 2000 (2001 Decision, p. 26).

The 2001 Decision approved a \$0.85/GJ rate restructuring charge for commercial rates (RS2) effective July 1, 2001. The 2001 Decision stated that this increase would lead to an approximate revenue to cost ratio of 0.9 and the Commission believed this rate was appropriate compared to competing energy sources. The revenue generated from the RS2 rate restructuring charge was to be used to write down deferral accounts (2001 Decision, p. 43). PNG considered the RS2 rate restructuring to be a permanent rate design increase and confirmed that the Utility was applying to include this rate change as a part of normal margin starting in 2002 (Exhibit 1, Tab Application, pp. 12-14; T3: 478-479). **The Commission confirms that the RS2 rate restructuring is a permanent change and will form part of Utility margin effective January 1, 2002.**

The 2001 Decision approved rate restructuring increases effective January 1, 2001 equal to 50 percent of the increases applied for by PNG for industrial and commercial (RS3) customers (2001 Decision, pp. 43-44). PNG recorded the rate restructuring revenue collected from RS2, RS3 and industrial customers as non-GCVA rate rider revenue. PNG confirmed that the rate restructuring increases for industrial and RS3 customers were removed effective January 1, 2002 (T5: 691). Further discussion on the rate rider revenue from October 1, 2000 to December 31, 2001 occurs in Section 6.7 of this Decision.

Order No. G-127-01 made the PNG rates to Methanex interim effective October 1, 2001. PNG considered that in the event the MOA was approved then the interim rates to Methanex should be made permanent effective from October 1, 2001 to December 31, 2001 (T5: 716-717). Methanex did not take issue with PNG's proposed treatment of Methanex's interim rates from October 1, 2001 to December 31, 2001. **The Commission confirms the Methanex interim rates as permanent from October 1, 2001 to December 31, 2001.**

Rate Changes from the 2002 Decision

The PNG Application requested recovery of a revenue deficiency of $6.8 million (Exhibit 1) which was amended to $6.6 million on February 25, 2002 (Exhibit 1A). The PNG Application assumed that when the Methanex 44 MMcf/d contract ended on October 31, 2002, Methanex would continue to take volumes at a normal level and pay an interruptible rate for volumes taken above the remaining firm contracts. The 2002 gross margin from Methanex was shown as $20.02 million (Exhibit 1A, p. 12)

On December 19, 2001 Commission Order No. G-149-01 approved PNG's requested 2002 interim rate increases in delivery charges, except for the revenue requirement resulting from increases in the common equity component and increases in the risk premium effective January 1, 2002. On January 3, 2002 PNG filed interim rate schedules in accordance with Order No. G-149-01 that were based on a 2002 revenue deficiency of approximately $4.66 million. The interim rates were approved as filed by Order No. G-149-01, effective January 1, 2002.

In the Revised Application the rates that would be charged to Methanex from the New Contract starting on November 1, 2002 reduced the 2002 gross margin from Methanex to $18.6 million. The decrease in the

2002 gross margin that would be received from Methanex ($1.42 million) was offset by unused deficiency volumes valued at about $753,000 that Methanex would forego under the New Contract. The result was a 2002 revenue deficiency of $7.28 million (Exhibit 1B, p. 8). By Exhibit 1C, PNG reduced the requested risk premium from 150 to 100 basis points, which decreased the 2002 revenue deficiency to $6.77 million.

This Decision on the PNG Revised Application has adjusted for 2002 the load forecast, operating, maintenance and general and administrative expenses, rate base deferral accounts and requested increases in the common equity component and risk premium. **The Commission directs PNG to file 2002 regulatory schedules and an amended Summary of Rates and Bill Comparison schedule based on PNG's Revised Application and the adjustments contained in the Decision.**

The Commission anticipates that the adjustments contained in the Decision will result in a 2002 revenue deficiency that is lower than the revenue deficiency used as a basis for setting the 2002 interim rate increases. As directed by Order No. G-149-01, the interim rate increases are subject to refund with interest at the average prime rate of PNG's principal bank. PNG proposed that if the permanent rates approved differed from the interim rates, PNG would rebill its customers at the permanent rates from January 1, 2002 (Exhibit 1, Tab Application, p. 20). **The Commission directs PNG to report the average refund by customer class that will result from the 2002 permanent rates and to advise the Commission on whether the refund should occur as a credit on customers' bills or a refund payment.**

Dated at the City of Vancouver, in the Province of British Columbia, this *31st* day of July 2002.

Original signed by:
Peter Ostergaard
Chair

Original signed by:
Nadine F. Nicholls
Commissioner

Original signed by:
Paul G. Bradley
Commissioner

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-56-02

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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 Ltd.
for Approval of 2002 Rate Increases

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

O R D E R

WHEREAS:

A. By Order No. G-127-01 dated November 22, 2001, the Commission directed that Methanex Corporation's ("Methanex") September 28, 2001 application for a load retention rate ("Methanex Application") would be reviewed coincident with the anticipated Pacific Northern Gas Ltd. ("PNG") 2002 Revenue Requirements Application. That Order made PNG's rates to Methanex interim effective October 1, 2001; and

B. On November 30, 2001, PNG filed for approval its 2002 Revenue Requirements Application (the "Application") to increase its 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

C. On December 13, 2001 the Commission, by Order No. G-132-01, established a Pre-hearing Conference on the Application and the Methanex Application for January 8, 2002, and scheduled the commencement date for an oral public hearing into these Applications for March 6, 2002 in Terrace, B.C.; and

D. The Pre-hearing Conference took place in Vancouver on January 8, 2002, and an oral public hearing on the Applications was held in Terrace, B.C. on March 6, 7, and 8, 2002, and completed in Vancouver on March 11, 2002; and

E. At the conclusion of the oral public hearing, the Commission set a timetable for final argument commencing with the filing of final argument by PNG and Methanex on March 28, 2002; and

F. PNG and Methanex entered into a Memorandum of Agreement as of March 20, 2002, to terminate their existing agreements for firm transportation and interruptible gas sales service and to replace those agreements with a new agreement effective November 1, 2002 (the "MOA"). The new agreement, if approved, would result in the withdrawal of the Methanex Application; and

G. Having regard to the impact of the terms of the MOA upon the Application presently before the Commission, PNG applied to the Commission on March 27, 2002 to postpone the filing of final argument to a date to be set by the Commission, and to fix a date for an oral hearing of the revised application, and to approve a revised hearing and argument schedule; and

H. PNG's March 27, 2002 application also explained the revisions to the Application that are required to reflect the terms of the implementation of the new agreement contemplated under the MOA effective November 1, 2002 (the "Revised Application"); and

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I. By Order No. G-20-02 dated March 28, 2002, the Commission approved postponement of the filing of final argument to a date to be fixed by the Commission. That Order also requested that intervenors advise the Commission in writing, by April 2, 2002, whether they consented to PNG filing the Revised Application and for their position on PNG's proposed timetable; and

J. On April 2, 2002, intervenor comment letters were received from the British Columbia Public Interest Advocacy Centre ("BCPIAC"); West Fraser Timber Co. Ltd., Canadian Forest Products Co. Ltd. and Eurocan Pulp and Paper Co. Ltd. (the "Forest Companies"); and Alcan Primary Metal Group ("Alcan"); and

K. On April 3, 2002, PNG provided written comments on the issues raised by the Forest Companies; and

L. By Order No. G-23-02 dated April 3, 2002, the Commission requested that intervenors and PNG provide comments by April 12, 2002 on the issues raised by the Forest Companies with a reply by the Forest Companies by April 19, 2002; and

M. The Commission reviewed the submissions from the intervenors and PNG and by Order No. G-31-02 reconvened the oral public hearing on May 27, 2002 in Vancouver to review PNG's Revised Application and the MOA, and by Reasons for Decision addressed the issues raised by the intervenors and PNG; and

N. The oral public hearing concluded on May 27, 2002. A new schedule for written final argument was established, concluding with PNG and Methanex filing replies on July 5, 2002; and

O. Methanex in argument dated July 5, 2002 stated that if the Commission approves the MOA, then it will be unnecessary to rule on the merits of the Methanex Application; and

P. The Commission considered the Applications and the evidence adduced thereon, all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves the MOA, subject to the conditions contained in the Decision issued concurrently with this Order. By providing conditional approval of the MOA, the Commission considers that a ruling on the merits of the Methanex Application is unnecessary.

2. The Commission confirms the Methanex interim rates as permanent from October 1, 2001 to December 31, 2001.

3. PNG is to file regulatory schedules and an amended Summary of Rates and Bill Comparison schedule based on PNG's Revised Application and the adjustments contained in the Decision issued concurrently with this Order.

4. The Commission anticipates that the adjustments contained in the Decision will result in a 2002 revenue deficiency that is lower than the revenue deficiency used as a basis for setting the 2002 interim rate increases. As directed by Order No. G-149-01, the interim rate increases are subject to refund with interest at the average prime rate of PNG's principal bank. PNG is to report the average refund by

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customer class that will result from the 2002 permanent rates and advise the Commission on whether the refund should occur as a credit on customers' bills or a refund payment.

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

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

APPEARANCES

G.A. FULTON	British Columbia Utilities Commission, Counsel
J. LUTES	Pacific Northern Gas Ltd.
R.B. WALLACE	Methanex Corporation
K. GUSTAFSON	Canadian Forest Products Co. Ltd. Eurocan Pulp and Paper Co. Ltd. West Fraser Timber Co. Ltd.
R.J. GATHERCOLE	Consumers' Association of Canada (B.C. Branch) et al. [British Columbia Old Age Pensioners' Organization, Council of Senior Citizens' Organizations of B.C., federated anti-poverty groups of B.C., Senior Citizens' Association of B.C., End Legislated Poverty]
K. DUKE	Alcan Primary Metal Group
R. VANDERKOOI	Hudson Bay Hot House

B. MCKINLAY P.W. NAKONESHNY R.N. BROWNELL E. CHENG J.W. FRASER	Commission Staff
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Canadian Forest Products Co. Ltd.	KIRKE MACMILLAN
City of Terrace	MAYOR JACK TALSTRA

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