IN THE MATTER OF

PACIFIC NORTHERN GAS LTD.

OCTOBER TO DECEMBER 2000 RATES
AND
2001 REVENUE REQUIREMENTS APPLICATION

DECISION

May 25, 2001

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") is a natural gas utility serving more than 26,000 residential, commercial and industrial customers in west-central British Columbia. Westcoast Energy Inc. ("WEI") owns approximately 42 percent of the common equity of PNG and all of the voting shares. PNG's system connects to WEI's transmission system near Summit Lake, B.C. and extends approximately 588 kilometres west to Prince Rupert and Kitimat.

1.2 Commission Orders Preceding the Public Hearing

Order No. G-94-00

On September 28, 2000, Pacific Northern Gas Ltd. filed an application with the British Columbia Utilities Commission (the "Commission", "BCUC") for approval to amend its rates on an interim and permanent basis, effective October 1, 2000 and January 1, 2001, pursuant to Sections 91 and 58 of the Utilities Commission Act (the "Act"). That Application proposed to increase rates to all customers, primarily as a result of liquidity issues caused by the July 1, 2000 Methanex Corporation ("Methanex") plant shutdown and higher costs of purchasing the natural gas commodity.

Subsequent to the filing of that Application on October 4, 2000, PNG advised the Commission that it had reached an Agreement In Principle ("AIP") with Methanex on a new firm gas transportation service to October 31, 2009. The AIP was subject to certain conditions and had not been signed by PNG pending Commission action on PNG's request for approval of interim rates effective October 1, 2000. In view of the AIP, PNG requested certain changes to the interim rates applied for in the Application, effective October 1, 2000. PNG also requested that the Commission hold its review of the Application in abeyance until December 1, 2000, which was the date that PNG and Methanex fixed for finalizing their agreement and removing the conditions precedent.

On October 5, 2000, the Commission approved an interim rate increase to all classes of customers, in accordance with the "Summary of Rates Effective October 1, 2000" (attached as Appendix A to Order No. G-94-00), subject to refund with interest at the average prime rate of PNG's principal bank following a public hearing.

By letter dated October 12, 2000, Skeena Cellulose Inc. ("Skeena") and Eurocan Pulp and Paper Co. Ltd. ("Eurocan") applied to the Commission pursuant to Section 91(3) of the Act to modify or set aside the Interim Order (the "Skeena/Eurocan Application"). The Skeena/Eurocan Application asserted there was insufficient evidence of any special circumstances, as required by Section 91 of the Act, before the Commission to make an interim order.

On October 19, 2000 the Commission issued Letter No. L-51-00 identifying the special circumstances as follows:

> "Those circumstances are the financial liquidity issues caused by the July 1, 2000 Methanex plant shutdown and the higher costs of purchasing the natural gas commodity, as noted in the Order, and various news releases copied to your clients by PNG."

In addition the Commission commented:

> "As it would not be productive to hold a hearing until PNG, Methanex, and the Job Protection Commissioner have been given an opportunity to finalize the agreement, the Commission will hold its review of the Application in abeyance until December 1, 2000."

On November 24, 2000 Skeena again applied to the Commission, pursuant to Section 91(3) of the Act and Commission Letter L-51-00, to modify or set aside the interim rate increase granted in the Interim Order (the "Skeena Application"). Skeena sought to have the Interim Order set aside, or modified, on the following grounds:

1. That the Commission erred in law by approving the interim rate increase in Order No. G-94-00 in circumstances where the statutory conditions for the Commission to have jurisdiction to grant such interim relief under Section 91(1) of the Act were not satisfied;

2. That the Commission erred in law by approving the interim rate increase without fixing its duration or setting a time limit for a hearing to be held and a final decision made, contrary to Section 91(2) of the Act; and

3. That, since Order No. G-94-00 was issued by the Commission, additional information had been released to the public which indicated that PNG did not make full and frank disclosure to the Commission of all facts which were relevant to its interim rate application, and this constituted a fundamental change in the circumstances or facts which were before the Commission at the time it made the Order, such that the Order should be reconsidered.

On November 29, 2000 the Commission wrote to PNG requesting a response to the Skeena Application by December 4, 2000 and asked PNG to specifically consider paragraphs 56, 60, 65 and 68 in its response. The Commission also advised that it intended to establish a regulatory agenda leading to a public hearing of the PNG Application at a Commission meeting on December 7, 2000. Further, the Commission directed PNG to provide the Commission with information on its negotiations with Methanex and the Provincial Government, and on any amendments to the PNG Application. By letter dated December 4, 2000 PNG provided its response. The letter advised that the conditions precedent in the PNG/Methanex AIP had not been fulfilled and recommended that the Commission set down a Regulatory Agenda assuming the PNG

Application as filed, subject to the understanding that amendments would be required to address certain matters set forth in the letter.

By letter dated December 6, 2000 as clarified by letter dated December 7, 2000, the Council of Forest Industries' Natural Gas Committee ("COFI NGC") also requested that the Commission set aside or modify the Interim Order to disallow the interim rate increase on the basis that the Interim Order constituted an error in law since it was contrary to:

- basic principles of fairness; and
- the rate approval scheme established under the Act.

By letter dated December 7, 2000 PNG identified the special circumstances it was relying on (which are found on page 2 of the Application) and responded to paragraphs 56, 60, 65 and 68 of the Skeena Application.

Orders No. G-113-00 and G-1-01

In Order No. G-113-00 dated December 7, 2000 the Commission established a Regulatory Agenda leading to the commencement of the oral public hearing in Terrace, B.C. on Monday, March 5, 2001.

By letter dated December 13, 2000 Eurocan filed submissions supporting the Skeena Application. Eurocan alleged that the Commission erred in law in granting the Interim Order on the grounds that the Interim Order established rates that were:

- unjust and unreasonable, contrary to the provisions of Sections 59 and 60 of the Act;
- not supported by the evidence submitted by PNG; and
- unduly prejudicial to the interests of Eurocan and PNG's other large volume industrial transportation service customers.

On January 2, 2001 the Commission issued Order No. G-1-01 with Reasons for its Decision. The Commission concluded that there was a sufficient evidentiary basis to grant the interim rate increase. The Commission further found that any failure by PNG to disclose information to the Commission at the time of the Interim Order was not of such a nature that it impacted on the special circumstances that the Commission found to be the basis for the Interim Order. The Commission noted that ratepayers were protected by the interim, refundable with interest conditions of Order No. G-94-00. The Commission had previously addressed the fact that the Interim Order did not provide for a Regulatory Timetable by issuing

Order No. G-113-00. For these reasons, the Commission dismissed the Skeena Application. The relief sought by the Eurocan Submission and the COFI NGC Submission was also denied.

Order No. G-127-00

On December 8, 2000 PNG revised its Application to flow through projected higher natural gas purchase costs for 2001 under the approved gas supply contracts for the service area, based on November 23, 2000 forward gas prices for 2001 that averaged US$5.47/MMBtu[1] at Sumas and a currency exchange rate of US$0.650/Cdn$1.00. The gas cost allocation calculation deemed that gas commodity purchase costs were 25 percent fixed charges and 75 percent variable charges.

On December 18, 2000 PNG further revised the Application, and included a request to increase the gas supply cost deferral account Rider from $0.10/GJ to $0.30/GJ, based on recovery of the estimated account balance to the end of 2000 over three years. PNG also requested an increase in the propane Gas Supply Charge in the Granisle rate. On December 19, 2000, PNG provided a gas cost allocation calculation that deemed that gas commodity purchase costs were 100 percent variable charges. This calculation yielded Gas Supply Charges that were more comparable to the market value of the natural gas commodity, especially for commercial, interruptible, small industrial, seasonal off peak and natural gas vehicle ("NGV") customers. Gas Supply Charges based on deeming gas commodity purchase costs as 100 percent variable charges, plus the proposed gas supply cost deferral account Rider, were estimated to increase typical annual bills for residential customers by 25 percent, for small commercial customers by 28 percent and for small industrial customers by 52 percent, relative to July 2000 rates.

In Order No. G-127-00 the Commission accepted PNG's December 18, 2000 projection of total natural gas purchase costs for 2001. Gas Supply Charges based on deeming gas commodity purchase costs as 100 percent variable charges were also approved as interim rates effective January 1, 2001, subject to refund with interest at the average prime rate of PNG's principal bank. Corresponding changes to fixed monthly charges that included a quantity of gas commodity were also approved as interim rates.

Gas Cost Variance Account ("GCVA") Riders of $0.300/GJ for PNG sales customers and of $0.001/GJ for PNG transportation customers were approved, effective January 1, 2001, as well as a propane Gas Supply Charge for Granisle of $13.685/GJ.

1 1 MMBtu equals 1.0551 gigajoule ("GJ"). A GJ is a unit of energy. One GJ is about the amount of energy contained in 915 cubic feet of natural gas, or 29 litres of gasoline, or 278 kilowatt hours of electricity, or 0.16 barrels of oil.

PNG was directed to file, by June 5, 2001, a report on actual gas prices and costs for the 2001 year to date compared to forecast, price expectations for the remainder of the year, the impact on the gas supply cost deferral account, and any rate changes that would then be proposed. The report is to also discuss the effect of current and proposed rates on sales.

Order No. G-14-01

On January 29, 2001 PNG filed with the Commission another application to pass through increases in its gas supply costs effective February 1, 2001. Specifically, PNG applied for a $0.475/GJ increase in the Gas Supply Charges for sales customers, based on January 29, 2001 forward gas prices for the remainder of 2001, plus a $1.068/GJ increase in the GCVA Rider for sales customers, based on recovery of the forecast account balance to the end of January 2001, over the following 12 months.

PNG requested that the gas cost rate increases take effect February 1, 2001 and that the GCVA balance be recovered over 12 months, in order to improve its financial liquidity. High gas prices in December 2000 and January 2001 had exacerbated PNG's liquidity problems.

In Order No. G-14-01 the Commission approved the requested change to the GCVA, for the primary purpose of improving PNG's financial liquidity. The Commission was not satisfied that the requested Gas Supply Charge increase was appropriate at that time, pending a review of gas commodity charges for gas utilities on a quarterly basis while gas prices remain highly volatile.

The Commission approved an interim increase of $1.068/GJ to the GCVA Riders for Rate Schedules 1, 2, 4, 5, 6, and 7 effective February 1, 2001. Corresponding increases to minimum monthly charges for Rate Schedules 4, 5, and 6 that included a quantity of gas commodity were also approved as interim rates effective February 1, 2001. The period over which the deferral account balance would be recovered was a matter to be addressed in the March 5, 2001 public hearing. The interim increases would be refunded with interest at the average prime rate of PNG's principal bank if they were reduced by this Commission Decision.

1.3 Closure of the Methanex Corporation Plant

On May 24, 2000 Methanex announced that it would close its Kitimat methanol plant for an initial period of 12 months commencing July 1, 2000. The reason for this closure was the substantial increase in natural gas prices over the previous 12 months. At the time of the Methanex announcement, natural gas prices were in the $Cdn4.00/GJ range. By March 2001 natural gas prices were in the $Cdn7.00/GJ range (T1: 15).

Methanex accounts for approximately two-thirds of the volumes transported on the PNG-West system and 45 percent of PNG-West's total operating margin when the plant is operating at normal levels. Three transportation contracts currently exist (Exhibit 1, Tab Application, p. 2). The largest contract for 44 MMcf/d, expires on October 31, 2002 and is subject to 80 percent take-or-pay. Two smaller contracts for 2 MMcf/d and 11 MMcf/d, expire on October 31, 2003 and October 31, 2009 respectively, and are both subject to the same 80 percent take-or-pay commitment.

PNG estimated that the annual loss in operating margin over the next several years would be $5.3 million in 2001, $7.5 million in 2002, $18.6 million in 2003, and $19.1 million in 2004. As a result of these anticipated losses, PNG's credit rating has been reduced and its lender of operating funds put PNG on notice that it must significantly reduce its operating line of credit debt.

To respond to these events, PNG restructured its organization and reduced its payrolls, as well as other costs.

PNG and Methanex also negotiated the AIP which was presented to the British Columbia Job Protection Commission ("Job Protection Commission"). The AIP included a $0.32/GJ "load retention rate" and was contingent on a $45 million line of credit from the Provincial Government to PNG and gas royalty concessions to Methanex. The Province, in the end, did not agree to reduce its royalties on gas purchases by Methanex or to provide assistance to PNG and the AIP expired.

1.4 The Applications

Increases in approved rates to meet revenue requirements have been requested for three distinct periods. The first period, October 1, 2000 to December 31, 2000, was characterized by PNG as a "liquidity crisis" and specific cash needs were identified by the Utility. Some $700,000 was needed to draw down deferred expenses, and this portion was to have come from a $1.00/GJ increase in residential and commercial rates and a 10 percent increase in industrial rates. Other increases sought, but not initially approved by the Commission, included approximately $500,000 from changing the rate design for commercial rates and two rate charges to Methanex for "unrecovered" depreciation and deferred income taxes.

The "second" Application was for the Test Year, January 1, 2001 to December 31, 2001. This Application was designed to generate approximately $13.2 million of additional operating margin for the following purposes:

1. $3.3 million for the 2001 Revenue Deficiency (Exhibit 1B, p. 1);
2. $3.8 million to accelerate the amortization of deferred expenses;
3. $2.9 million to increase depreciation charged to Methanex; and
4. $3.2 million to increase booked deferred income taxes charged to Methanex.

The "third" Application was the increase in the GCVA Rider effective February 1, 2001.

The PNG Applications (the "Applications") are considered in detail in Chapter 2 of this Decision. Methanex also applied to the Commission for approval of a long term load retention rate to help it reopen. The Methanex Application is reviewed in Chapter 3.

1.5 The Public Hearing Process

The oral public hearing began March 5, 2001 in Terrace, B.C. After five days of evidence the hearing adjourned to continue at the Commission offices in Vancouver and concluded on Tuesday, March 13, 2001 (day six). The Commission ordered a schedule for Written Argument.

The interests of residential and industrial customers were represented in the public hearing and presentations were made by the Mayors of Fort St. James, Houston and Telkwa, and the president of the Terrace and District Chamber of Commerce. The public hearing was well attended and covered by local media.

2.0 PACIFIC NORTHERN GAS LTD. APPLICATIONS

The PNG Applications are focused on the viability of the Utility during the 15-month period from October 1, 2000 to December 31, 2001, with the expectation that the Methanex plant remains closed. The Applications deal with utility operations, revenue requirements, gas supply costs, rate design matters, and liquidity issues to assure the short-term viability of the Utility. PNG was reluctant to address the consequences of the termination of the major contract with Methanex in October 2002 and the balloon payment on long-term debt in July 2002. This Chapter reviews the significant issues in the applications and concludes with the resultant rates that will apply if there is no agreement on longer term rates with Methanex. The Applications are unique to the extent that PNG is facing a liquidity crisis and the proposed rates threaten the competitiveness of natural gas to competing fuels.

2.1 Margin Deferral Accounts and Load Forecasts

PNG forecasts its sales by class of customer. Over the years, the Commission has periodically approved deferral accounts to record the difference between forecast industrial sales and actual sales when circumstances made it difficult to accurately forecast sales.

The Commission usually approves forecasts which are the best estimates of deliveries for the year, and then bases approved revenue requirements on these forecasts. Where a deferral account is established, it is normally based on the expected consumption levels so that the year-end balance should be close to zero.

In this case two unusual circumstances have caused the Commission to take a different approach. Firstly, as discussed elsewhere in this Decision, PNG has a liquidity problem which requires increased recovery of deferred costs which have been incurred for the benefit of all customers. Secondly, British Columbia Hydro and Power Authority's ("B.C. Hydro") deliveries are expected to reach unprecedented levels this year, generating revenue which should benefit all customers. Taken together, these two circumstances support the use of the surplus B.C. Hydro revenues for increased amortization of deferral accounts, after compensating for reduced forecast deliveries from other industrial customers.

In the forecasts of large industrial customer deliveries, there are three instances where PNG's original load forecasts differ significantly from more recent estimates made with the benefit of actual delivery information. For revenues from Eurocan, Skeena and B.C. Hydro, the Commission accepts the load forecasts in PNG's Applications for revenue requirement purposes, but uses more up-to-date projections for the purposes of estimating the Industrial Customer Deliveries Deferral Account ("ICDDA") surplus. Details of the ICDDA and the load forecasts follow.

2.1.1 <u>Margin Deferral Accounts</u>

PNG has historically used a low load forecast for B.C. Hydro sales and recorded the difference between projected and actual margin received in a deferral account. The 2000 Alternative Dispute Resolution ("ADR") settlement included an agreement for the ICDDA to record the difference between PNG's Applications projections and actual margin received from Methanex, Skeena and Eurocan. PNG's Applications (Application Tab, p. 20) requested continuation of the ICDDA for 2001, and PNG requested that B.C. Hydro be added to this account (PNG Final Argument, p. 21). In its Reply Argument PNG proposed to extend the margin deferral account to all customer classes, and proposed that any credit revenue in the 2001 margin deferral account be applied to PNG's deferred expenses.

Methanex supported the use of a deferral account to cover variations in margin from all customers due to the considerable uncertainty in forecast volumes for 2001 (Final Argument, On Other Issues, p. 13). Eurocan and the CAC (B.C.) et al. argued that PNG is already compensated for business risk related to variations in deliveries and should not be permitted to avoid business risk by continuing the ICDDA.

The Commission approves continuation of the ICDDA and extends it to include B.C. Hydro as requested by PNG. This deferral account is to record the revenue resulting from the difference between actual sales to Methanex, Skeena, Eurocan and B.C. Hydro and the forecast sales used by PNG in its revenue requirement application and interim rates. The Commission directs that any surplus in the ICDDA at year-end be used to write down other deferral accounts.

2.1.2 Load Forecasts

Residential Sector (Rate Schedule 1)

PNG projected residential gas deliveries based on the forecast average use per customer and the forecast weighted average number of customers. PNG forecast average annual use per residential customer at 108.5 GJ based on the 1999 average reduced by 0.5 percent in each of 2000 and 2001 to reflect conservation measures. The weighted average number of customers was based on the estimated number of customers in 1999 plus estimates of the number of customer additions in 2000 and 2001. Additions were forecast based largely on community-level estimates of conversions and new construction by PNG service area personnel. On this basis, PNG projected the weighted average number of customers at 20,771 for 2001. The resulting forecast of residential gas deliveries was 2,253,200 GJ.

PNG's forecasting methodology was consistent with its forecasts in prior applications. However, PNG's residential load forecast did not account for any reduction in gas sales due to the unusually large proposed rate increases. The cost of heating with natural gas versus heating with electricity or wood would be one key factor in the decision of existing customers to continue using natural gas as the primary heat source and the decision of home owners/builders in deciding what heat system to install in new homes. In Exhibit 2B, PNG provided a comparison of annual heating costs for a typical residential customer using natural gas, electricity and oil based on the interim rates approved effective February 1, 2001. Although heating with natural gas remains less expensive than heating with propane or oil, it is approximately 26 percent more expensive than heating with electricity, assuming a furnace that is 70 percent efficient. A PNG witness testified that the average efficiency of conventional furnaces installed prior to minimum efficiency standards is about 65 percent. At 65 percent efficiency, natural gas would be about 35 percent more expensive than electricity. PNG and Methanex both indicated that they expected natural gas prices to soften in the next few years, and the proposed rates include a rate rider of $1.368/GJ that is likely to be reduced in July 2001 and removed by February 1, 2002. These reductions would improve the competitiveness of natural gas relative to electricity and other fuels.

PNG suggested that there would be little permanent fuel switching unless there is a prolonged period where gas heating costs exceed electric heating costs due to the capital investment required (Final Argument, p. 12). In the short term PNG recognized that there may be a modest impact on Test Year deliveries as a result of energy conservation and fuel switching (Final Argument, p. 12). A PNG witness testified that customers would look for low cost, temporary solutions such as small unit electric heaters that could be abandoned when gas prices become competitive again (T3: 422). If the high cost of heating with natural gas persists for a number of years, however, a PNG witness agreed that the current rates were near the level that would warrant consideration of fuel switching (T3: 552).

The evidence from Mayors Togyi, Euverman and Hartwell suggested that residents are starting to reduce their consumption of natural gas by turning back thermostats and switching to wood or wood pellets. The Mayors also gave evidence that rate increases would increase the level of fuel switching significantly. PNG responded that high natural gas rates would have to be sustained over a long period of time before people would switch to wood because people prefer natural gas (T3: 421).

Eurocan argued that PNG's test year forecasts ignored recent data and do not reflect the impact of the significant gas price increases that took place late in 2000. Eurocan suggested that PNG's forecasts for average annual residential customer use were materially overstated. The Consumers' Association of Canada (B.C. Branch) et al. ["CAC (B.C.) et al."] and Methanex both argued that customers would cut back consumption in response to high rates [CAC (B.C.) et al. Final Argument, pp. 5 and 6; Methanex Final Argument, p. 2].

The Commission agrees with PNG that permanent fuel switching would likely require the current high gas rates to persist for a prolonged period. In the short term, customers may reduce their heating costs and their gas consumption by burning more firewood or using portable electric heaters. The Commission expects that most of these customers would return to historic consumption levels if natural gas rates soften in the future. The Commission accepts PNG's forecast of residential gas deliveries.

Commercial Sector (Rate Schedules 2, 3 and 4)

PNG projected total commercial gas deliveries (Rate Schedules 2, 3 and 4 combined) based on its forecasts of average use per customer and the weighted average number of customers. PNG projected average use per customer at 528.7 GJ based on a continuation of the historical decline in use per account. The weighted average number of commercial customers was estimated at 2,904 based on the expectations of PNG service area personnel concerning new construction and customer additions. On this basis, total commercial gas deliveries were projected at 1,535,242 GJ. Deliveries to interruptible commercial and large commercial customers were then forecast based on a review of historical deliveries and surveys of most of the customers. Forecast deliveries to these two rate classes were deducted from the total commercial forecast in order to determine small commercial deliveries as a residual.

PNG's load forecast did not include any allowance for price elasticity effects. PNG indicated that the typical consumption for a commercial customer is about 460 GJ (T1: 129). Based on the proposed rate of \$13.770/GJ plus monthly basic charges, the annual cost of heating would be [(460 X \$13.770) + (12 X \$10.75)] X 1.07 = \$6,916. For a customer with a 65 percent efficient furnace, the electricity equivalent would be 460 GJ X 0.65 = 299 GJ or 299 GJ X (23,827 kWh / 85.8 GJ) = 83,033 kWh. Assuming the electricity rate indicated by PNG in Exhibit 2B (\$0.0649/kWh), the annual heating cost would be about \$5,766 (including GST) using electricity. On this basis, the cost of heating with natural gas at 65 percent efficiency would be approximately 20 percent higher than the cost of heating with electricity. However, the competitive position of natural gas relative to electricity may improve over the next year if the \$1.368 rate rider is removed by February 1, 2002 and if natural gas prices soften.

PNG suggested that there would be little permanent fuel switching unless the high gas rates persist, but agreed that there may be a modest impact on Test Year deliveries as a result of energy conservation and fuel switching (Final Argument, p. 12). CAC (B.C.) et al. and Methanex both argued that customers will cut back consumption in response to high rates [CAC (B.C.) et al. Final Argument, pp. 5 and 6; Methanex Final Argument, p. 2].

The Commission agrees with PNG that commercial customers are unlikely to permanently switch fuels unless the high gas prices persist for a prolonged period. The Commission finds that while there may be some opportunity for commercial customers to reduce consumption in the short term through conservation or by using portable electric heaters, such impacts are likely to be modest. The Commission accepts PNG's forecast of commercial gas deliveries.

Seasonal Off-peak (Rate Schedule 6)

Seasonal off-peak deliveries are provided to operators of asphalt plants. PNG projected seasonal off-peak deliveries at 33,446 GJ for 2001 based on the expectations of the operators of the asphalt plants. This forecast is slightly lower than the average from 1995-1999 (34,637 GJ – information on actual 2000 deliveries was not provided), but slightly higher than actual deliveries in 1998 (33,001 GJ) and 1999 (30,537 GJ).

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

Natural Gas Vehicles (Rate Schedule 7)

PNG projected deliveries for NGV at 34,899 GJ for 2001. This forecast was considerably below historical deliveries due to a decline in conversions, retirement of previously converted vehicles and no penetration of factory equipped NGVs in the region's market.

The Commission accepts PNG's forecast of NGV sales in 2001.

Small Industrial Sector (Rate Schedule 5 and Transport)

PNG projected small industrial deliveries at 1,805,625 GJ for 2001 based on information from customer surveys and historical deliveries (Exhibit 1, Tab 1, pp. 9 and 10; Final Argument, p. 13). This is 3.8 percent less than actual deliveries in 2000 (1,877,369 GJ – PNG Final Argument, p. 13), but considerably higher than the average from 1995-2000 (1,709,508 GJ: based on Exhibit 2A, response to BCUC IR1, 13.9).

In its Final Argument Canadian Forest Products ("Canfor") anticipated that over the next few years, present levels of natural gas consumption at both the Fort St. James and Houston Sawmill Divisions would be reduced dramatically. Canfor is actively pursuing a number of options to utilize its wood residue over the next few years and the rapid escalation in the commodity costs for natural gas is a key driver in this initiative.

The Commission accepts PNG's small industrial forecast.

<u>Large Industrial Sector</u>

Methanex Corporation

PNG forecast Methanex deliveries at 4,380,000 GJ for 2001. This estimate assumed that the methanol plant would remain closed but that the ammonia plant would take an average of 12,000 GJ per day for 365 days. Since the ammonia plant was, in fact, closed from December 2000 to mid-February 2001, forecast deliveries to Methanex could be somewhat high if the methanol plant remains closed. This could be balanced against the possibility that the methanol plant could reopen for part of 2001. No parties objected to PNG's forecast for Methanex.

The Commission accepts PNG's forecast of 4,380,000 GJ delivered to Methanex.

Skeena Cellulose Inc.

PNG forecast deliveries to Skeena at 3,400,000 GJ in 2001. This forecast assumed that both the A and the B mills in Prince Rupert would run for the full year with a 10 to 14 day maintenance shutdown in September. PNG's forecast is somewhat below deliveries to Skeena in 2000 (3,699,860 GJ: Exhibit 40), but is higher than average deliveries to Skeena from 1995-2000 (3,173,475 GJ: Exhibit 40). The B mill is not operating at the present time (PNG Final Argument, p. 14). In its Reply Argument PNG suggested that the forecast of deliveries to Skeena be reduced to 2,700,000 GJ to recognize the closure of the B mill and lower pulp prices so far in 2001. Skeena did not address PNG's forecasts.

The Commission accepts PNG's original forecast of 3,400,000 GJ in 2001 for revenue requirement purposes. Given that the B mill is not operating, the Commission considers PNG's revised forecast of 2,700,000 GJ to be a reasonable projection of deliveries for the purpose of estimating the ICDDA balance.

Eurocan Pulp and Paper Co. Ltd.

PNG forecast 2001 deliveries to Eurocan at 3,175,472 GJ. This forecast was based on Eurocan's estimate from the summer of 2000 (Exhibit 6, p. 3), and is somewhat higher than both average deliveries from 1995-2000 (2,883,087 GJ: Exhibit 40) and deliveries to Eurocan in 2000 (2,679,594 GJ: Exhibit 40). Due to the significant increases in the price of gas, Eurocan revised its natural gas forecast to 2,700,000-2,900,000 GJ on page 4 of its Evidence. Eurocan further revised its forecast to 2,600,000 GJ in Schedule 1.1 of Exhibit 7A. In its Reply Argument PNG suggested that the forecast of deliveries to Eurocan be reduced to 2,600,000 GJ based on Eurocan's most recent forecast.

Eurocan also provided evidence that it is investigating plant modifications that could further reduce natural gas consumption (T4: 676-678). Eurocan's natural gas use is primarily related to the recovery boiler (10 percent), the power boiler (75 percent) and the lime kiln. The power boiler is fuelled by both natural gas and biomass/hog fuel. With recent gas prices, Eurocan has been burning 100 percent oil in the recovery boiler and is getting ready to modify the lime kiln to use oil. Eurocan indicated that the proposed rate increase will be sufficient to justify purchasing the equipment to burn oil full time in the power boiler.

The Commission accepts PNG's original forecast of 3,175,142 GJ for 2001 for revenue requirement purposes. Based on the evidence provided by Eurocan, the Commission considers PNG's revised forecast of 2,600,000 GJ to be a reasonable projection of deliveries for the purpose of estimating the ICDDA balance.

Alcan Smelters and Chemicals Inc. ("Alcan")

PNG projected deliveries to Alcan at 900,000 GJ in 2001. This projection is slightly lower than Alcan's average consumption from 1998-2000 (928,000 GJ: Exhibit 2, response to BCUC IR, p. 46), but slightly higher than the five year average from 1996-2000 (874,000 GJ: Exhibit 2, response to BCUC IR, p. 46).

The Commission accepts PNG's forecast of deliveries of 900,000 GJ for Alcan.

British Columbia Hydro and Power Authority

B.C. Hydro maintains two gas turbine generators in Prince Rupert in ready-to-operate condition. These turbines were installed to be run in emergencies, but they have been used for commercial power generation in the last three years. When operating, each turbine consumes 6,000-8,000 GJ per day (T2: 364). Actual deliveries to B.C. Hydro in 2000 were 947,946 GJ (Exhibit 2A, response to Eurocan IR1, p. 3).

PNG has historically forecast deliveries to B.C. Hydro at 10,000 GJ, for emergency standby purposes only (Exhibit 2A, response to BCUC IR1, p. 47). In its Reply Argument PNG suggested that the load forecast to B.C. Hydro be revised to 900,000 GJ, which is B.C. Hydro's approximate consumption in 2001 up to April 4, 2001.

The CAC (B.C.) et al. argued that PNG should use a realistic delivery estimate for B.C. Hydro (CAC (B.C.) et al. Final Argument, p. 13), and Methanex suggested that the Commission should use the best information available at the time of the hearing to determine anticipated revenue from all customer classes

(Methanex Final Argument, p. 13). PNG expressed concern that any forecast of significant B.C. Hydro revenue for 2001 not exacerbate PNG's cash flow problem in 2002 when it needs to refinance its $12 million debenture payment (PNG Reply Argument, p. 8).

Extrapolating the deliveries to B.C. Hydro to April 4, 2001 throughout the remainder of 2001 would yield full-year consumption of around 3,500,000 GJ.

The Commission accepts PNG's original forecast of 10,000 GJ in 2001 for revenue requirement purposes only. The circumstances facing B.C. Hydro and the market opportunities outside of British Columbia would indicate that the plant could operate profitably throughout the year. However, the Commission believes that 10 percent downtime should be allowed for maintenance, outages and market conditions, leaving 3,150,000 GJ as a reasonable projection of deliveries for the purpose of estimating the ICDDA balance.

2.2 Gas Supply Costs

Gas prices moved upward starting in April 2000, and increased sharply in November 2000. Early in 2001 prices moderated somewhat. PNG provided information about actual prices to March 2001 and forward prices as of March 6, 2001 (Exhibit 27). The following is a summary of this information, plus actual data for 1999. The forward prices are the fixed prices in as-spent dollars that could have been established with financial counterparties on March 6, 2001 for gas purchases in the future.

	1999 Actual	2000 Actual	2001 Actual/Forward	2002 Forward	2003 Forward	2004 Forward	2005 Forward
Sumas, US$/MMBtu	2.15	4.17	6.45	5.23	4.85	4.79	4.78
Sumas, $/GJ	3.03	5.87	9.38	7.61	7.03	6.93	6.90
Station No. 2, $/GJ	2.79	4.89	8.43	6.95	6.43	6.41	6.45

Methanex stated that it did not have a current forecast of gas prices. It expected prices to trend lower, toward the finding cost of the resource in the continental United States of about $US 2.75/GJ ($Cdn 4.20/GJ). Finding costs in British Columbia may be slightly lower (T6: 1019-1022).

The massive increase in gas prices in 2000 was the main reason for large increases in PNG's sales rates and the shutdown of the Methanex plant. The details of the methodology that PNG used to calculate gas commodity charges were less of a factor affecting sales rates. The Commission generally flows through gas commodity rate changes under Section 61(4) of the Utilities Commission Act without a public process. Any under or overpayments by customers relative to actual gas costs, are recorded in PNG's GCVA. The account balance is charged to, or credited to, customers in future rates. Over time, the GCVA ensures that customers pay, and PNG recovers, the Company's actual prudent cost of buying the gas commodity.

The following is a summary of PNG's approved and requested gas commodity charges:

Gas Supply Charges and Sales GCVA Rider, in $/GJ

	July 1 2000	October 1 2000	January 1 2001	February 1 2001
Gas Supply Charge				
Residential RS1	5.853	6.531	8.189	8.189
Commercial RS2	5.810	6.521	8.138	8.138
Commercial RS4	3.472	3.890	6.522	6.522
Small Industrial RS5	4.469	5.004	7.233	7.233
Seasonal RS6	4.399	4.925	6.071	6.071
NGV RS7	4.086	4.576	6.779	6.779
Sales GCVA Rider	$ 0.100	$ 0.100	$ 0.300	$ 1.368

The January 1, 2001 Gas Supply Charges are from PNG's amended Application, and are $0.012 to $0.030/GJ higher than the interim rates that were approved by Order No. G-127-00 (Exhibit 1B, p. 2). The very slight differences result from roundings and re-running the large and complex model that allocates pooled gas supply costs to PNG-West, Fort St. John and Dawson Creek. Order No. G-14-01 denied PNG's request for a Gas Supply Charge increase for February 1, 2001.

The Gas Supply Charges effective October 1, 2000 and January 1, 2001, and the February 1, 2001 GCVA Rider, were approved as interim rates in part because PNG referenced its liquidity concerns when requesting the rate increases, but mainly so that the fixed/variable cost allocation and the duration of GCVA recovery in rate riders could be discussed in the hearing.

2.2.1 Gas Cost Allocation Methodology

Commencing with the 1997/98 gas contract year, PNG has managed the gas commodity requirements for the PNG-West service area and for Pacific Northern Gas (N.E.) Ltd. ["PNG (N.E.)"] service areas in Fort St. John and Dawson Creek as one consolidated demand and supply pool. The Commission's June 18, 1998 PNG 1998 Revenue Requirements and Cost of Service Allocation Decision approved PNG's methodology to allocate pooled supply costs among rate classes in the three service areas. Although PNG now is generally buying gas at 100 percent load factor, the Application deemed that 25 percent of gas purchase costs were a demand (or fixed) charge. Demand charges are allocated based on the peak day demand of each customer class, and so a relatively large portion of such costs is assigned to customers with low load factors.

Commission Order No. G-127-00 approved Gas Supply Charges effective January 1, 2001 that were based on an assumption that gas purchase costs are 100 percent variable charges.

Deeming gas purchase costs to be 100 percent variable charges caused a reallocation of costs to higher load factor groups such as small industrial sales customers and company use gas. Gas Supply Charges for lower load factor customers were correspondingly reallocated down. The forecast unit cost of company use gas for 2001 is $7.07/GJ. The corresponding Station No. 2 gas price is $7.02/GJ, and there would also be Westcoast Energy Inc. charges to move the gas from Station No. 2 to the PNG interconnect.

PNG considered that the results of deeming 100 percent of gas purchase cost as variable charges were more reflective of market prices (PNG Argument, p. 21). The CAC (B.C.) et al. supported PNG's gas supply cost flow-through methodology and PNG's objective of a gas cost flow-through more reflective of market prices [CAC (B.C.) et al. Argument, p. 17].

The Commission considers that, at least for 2001, PNG's gas cost allocation methodology with 100 percent of gas purchase costs as variable costs results in gas commodity charges for high load factor classes that are very comparable to corresponding market prices. The methodology also reduces the premiums in the gas commodity charges for residential and other low load factor classes, relative to the corresponding market prices. The methodology is approved.

2.2.2 Forecast Gas Costs and Gas Supply Charges

PNG requested approval of January 1, 2001 Gas Supply Charges and February 1, 2001 GCVA Riders as filed March 1, 2001 (Exhibit 1B, pp. 2, 3, and 5). The proposed Gas Supply Charges were based on November 23, 2000 forward prices for 2001 (T4: 610; Exhibit 1A, p. l; Exhibit 1, Tab Rates, p. 10, revised December 8, 2000). The price forecast averages $US 5.47/MMBtu ($Cdn 7.98/GJ) at Sumas and $7.02/GJ at Station No. 2. Recognizing that PNG is using both Sumas and Station No. 2 pricing in 2001, the average is about $7.50/GJ.

Using this price forecast, PNG predicted the following gas supply costs for PNG-West for 2001 (Exhibit 1B, pp. 1 and 8; T4: 611).

2001 Gas Purchases

	TJ	Million $	$/GJ
PNG-West Sales	4409.9	35.358	8.02
Company Use Gas	475.7	3.363	7.07
	4885.6	38.721	7.93

This gas cost forecast recognized the benefits of PNG's price risk management (hedging) activities for 2001 (PNG response to Undertaking at T4: 628). The forecast hedging benefits appear to be in the $5 million range, so that the requested Gas Supply Charges are approximately $1.00/GJ lower than those that would be indicated solely by the gas price forecast. That is, the requested Gas Supply Charges correspond to a net gas price of approximately $6.50/GJ.

As of March 6, 2001 actual and forward prices for 2001 average $9.38/GJ at Sumas and $8.43/GJ at Station No. 2 (Exhibit 27). This is an increase of approximately $1.40/GJ from the November 23, 2000 forecast. The higher gas prices increased the benefits from PNG's price hedges, to approximately $10 to $12 million for PNG-West (T4: 612 and 628; Exhibit 2D, p. 2). PNG confirmed that the interim rates that have been in place since October 1, 2000 have not fully recovered the cost of gas purchases over the period. However, by hedging and electing to purchase part of the supply at Station No. 2, PNG was "able to offset quite a bit" of the higher costs (T4: 613 and 614).

Looking beyond 2001, PNG's Cash Flow projections assumed a $0.50/GJ reduction in market prices for natural gas in each of 2002 and 2003 (Exhibit D, p. 1). However, as benefits from PNG's hedging program cannot be assumed for future years, the cost of gas purchases is likely to be somewhat higher in 2002. This is confirmed by comparing the $6.50/GJ net gas price that corresponds to 2001 Gas Supply Charges, to Station No. 2 forward prices. The March 6, 2001 forecast indicates a gas price increase of about $0.50/GJ for 2002, followed by a reduction of about the same amount for 2003.

The Methanex assessment of market fundamentals indicated prices (and Gas Supply Charges) could fall by an additional $2.00/GJ over the period. Notwithstanding the recent high volatility in gas prices, the PNG and Methanex forecasts provided a reasonable range of likely Gas Supply Charges.

The Commission determines that the January 1, 2001 Gas Supply Charges are confirmed. The variance between the approved charges and the prudently incurred actual costs will flow to the Gas Cost Variance Account.

2.2.3 February 1, 2001 - Gas Cost Variance Account Rider

The Commission, by Order No. G-14-01, approved an increase in the GCVA Rider from $0.30/GJ to $1.368/GJ effective February 1, 2001. The Rider was calculated to recover the forecast balance in the GCVA to the end of January 2001 over 12 months. In its January 29, 2001 filing for a gas commodity rate increase, PNG stated that the GCVA balance to the end of 2000 was $8.5 million, and projected that the balance would increase to $11.5 million by January 31, 2001. The PNG-West portion of the balance was 52 percent, or $4.4 million and $6.0 million, respectively. The increase was made interim so that parties could discuss the period over which the GCVA balance should be recovered.

Due to a larger than expected hedging benefit in January 2001 and PNG's actual mix of Station No. 2 and Sumas pricing, the GCVA balance decreased by $2.2 million in January 2001 to give a total GCVA balance of $6.3 million as at January 31, 2001 (PNG response to Undertaking, T4: 615). This implies a PNG-West account balance of $3.3 million at January 31, 2001.

PNG requested that the interim GCVA Rider continue in effect, on the undertaking that PNG would file a report with the Commission prior to July 1, 2001 confirming the balance in the GCVA. The GCVA Rider could be adjusted at that time.

Methanex expressed concern that by amortizing GCVA and revenue deficiency account balances over one year rather than three years, PNG exacerbated the rate impacts of the recent gas price increases and fluctuations in the business cycle (Methanex Argument, p. 12).

Commission Determination

In response to the increase in gas prices in 2000, the Commission reviewed BC Gas Utility Ltd.'s, ("BC Gas") practices related to the setting of gas commodity rates and management of gas cost reconciliation account balances. Commission Letter No. L-5-01, dated February 5, 2001, established "Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance". BC Gas is to file quarterly reports on gas costs and gas commodity revenue, and to apply for a rate change if forecast costs for the next 12 months differ from forecast revenues by more than 5 percent. The Commission did not change the three year amortization of the BC Gas gas cost reconciliation account balance at the end of 2000, but found that future amounts accumulated in the account should be amortized over 12 months in normal circumstances. Letter No. L-5-01 stated that the Guidelines would also be appropriate for other gas utilities in the Province and was circulated to all gas utilities.

Several options exist with regard to PNG's February 2001 GCVA Rider. One would be to leave the January 1, 2001 Rider of $0.30/GJ in place. This would recover the January 31, 2001 account balance within three years.

Alternatively, if the account balance is to be recovered over one year, the actual January 31, 2001 account balance would permit a reduction in the Rider to about $0.75/GJ effective February 2001. However, as discussed previously, a problem with either of the foregoing options is that actual gas prices are higher than the forecast upon which the requested Gas Supply Charges are based. Hedging benefits are expect to offset most but not all of the higher gas costs, so it is likely that additional charges are being recorded in the GCVA as 2001 goes forward.

Another option is PNG's recommendation to reassess the situation in mid-2001. Order No. G-127-00 directed PNG to file a report on actual and forecast gas costs and impacts on the GCVA, by June 5, 2001. This is consistent with the Guidelines subsequently issued in Letter No. L-5-01. This report would address changes to the GCVA Rider and Gas Supply Charges that are needed, so as to eliminate the PNG-West GCVA balance over the appropriate time period.

The Commission is cognizant of the concern expressed by Methanex, that amortization of GCVA balances over one year can exacerbate the impact of gas price increases on consumers. Nevertheless, as stated in Letter No. L-5-01 to BC Gas, the Commission is of the view that recovery of gas cost deferral account balances over one year is generally appropriate.

The Commission is very concerned that the poor quality of PNG's accounting of GCVA balances as at January 31, 2001 has resulted in customers paying a higher GCVA Rider for the February to June 2001 period than would have been set if more accurate and timely information had been reported. The GCVA balance, while still positive, is being reduced by the $1.368/GJ rider faster than forecast. **The interim increases in the GCVA Rider approved by Order No. G-14-01 are confirmed for the February 1 to July 1 period, however reductions to this rider are likely to be implemented July 1, 2001, following the Commission's review of PNG's updated GCVA balance and gas supply forecast information to be filed by June 5, 2001 as directed in Order No. G-127-00.**

2.3 Modified Depreciation Rate and Unbooked Deferred Taxes

Modified Depreciation Rate

According to the Applications, the Methanex Modified Depreciation Rate is based on assuming what depreciation rates would have been applied to capital additions attributable to Methanex if the estimated capital additions attributable to Methanex service had been depreciated over the life of the Methanex contracts. As characterized by PNG, this "contract life depreciation", less the "normal" depreciation expense that is already in Methanex's rates, was to be spread over the projected 80 percent minimum volumes under the remaining terms of the Methanex contracts (assuming that the methanol plant does not reopen and none of the Methanex contracts are renewed) to determine the Modified Depreciation Rate applicable to Methanex. The revenue received from the Modified Depreciation Rate would be applied to depreciation expense after deducting income tax expense (Exhibit 1, Tab Application, p. 6).

From an accounting perspective, depreciation is a mechanism for distributing the cost of a capital asset over its useful life, and the reflection of this cost in the operating statement. It is a process of allocation, not of valuation. Section 56 of the Utilities Commission Act requires the Commission to determine and set proper and adequate rates of depreciation, and requires a public utility to adjust its depreciation rates to conform to the rates fixed by the Commission. The Commission requires gas distribution utilities such as PNG to conform to its Uniform System of Accounts, which classifies their costs under specified accounts so the Commission and others can compare like costs between utilities under the same account numbers or categories of revenues and costs. The Uniform System of Accounts also requires that depreciation be charged in amounts which will allocate the service value of the plant over its estimated service life in a systematic and rational manner. The charges must be computed in conformity with the group system under the straight line method and at rates approved by the Commission.

PNG's depreciation rates were last changed pursuant to the Commission's May 29, 1996 Decision. When PNG completed its 1995 cost of service/rate design study it considered it appropriate to conduct a Depreciation Study as well (Exhibit 5, April 9, 1996). PNG engaged the consulting firm of Stone & Webster who used a detailed review of individual asset groups and remaining life techniques to determine new rates by account. As described, the technique recognizes any over or under accruals resulting from changes in expected life, retirement patterns, and net salvage. Although at the time PNG believed that depreciation studies should be conducted approximately every five years, it did not conduct another study. Instead, in this hearing PNG characterized the Modified Depreciation Rate and the Unbooked Deferred Taxes Rate increases and the increase to the commercial customer class as rate design adjustments. The increase to the other industrial transportation customers was required to help PNG's liquidity problems. (T1: 65 and 66).

PNG did not believe that its proposal to collect additional depreciation from Methanex would be inconsistent with the Commission's Uniform System of Accounts as the depreciation charge would be allocated to the appropriate plant account based on the incremental facilities actually installed (Exhibit 2; BCUC IR1, p. 11). PNG stressed that it was not seeking a retroactive recovery of depreciation expense but was asking to increase future depreciation based on the limited project life.

<u>Unbooked Deferred Taxes Rate</u>

PNG identified that in 1986, Methanex (then Ocelot Chemicals) was in financial distress due primarily to low methanol prices. As part of an overall package to keep the methanol plant operating, PNG agreed to suspend the collection of normalized income taxes in Methanex's rate and extended this tax treatment to all of its customers. PNG has now applied for Commission approval to recover from Methanex the unbooked deferred taxes that were not collected from Methanex from 1986 to present. Revenue generated from the Unbooked Deferred Taxes Rate would be applied to increase deferred income tax expense, thereby increasing the deferred income tax credit on the balance sheet (Exhibit 1, Tab Application, p. 7).

Generally Accepted Accounting Principles require a company to record as an expense the income tax as calculated from the accounting income on the company's books, rather than on the taxable income amount determined by the taxation rules. During periods of growth accounting income will generally exceed taxable income and, while the company collects both the current and deferred tax component from its customers, it only remits the current taxes payable to the taxation authorities, leaving the remainder as a deferred credit on the balance sheet. However, a rate regulated company is not required to recognize future income taxes to the extent that future income taxes are expected to be recovered from future customers. For every dollar of deferred income taxes recorded, the utility must recover from the customer two dollars (assuming a 50 percent tax rate) so that the after tax revenue is sufficient to provide the deferred income tax. Most of the utilities under the Commission's jurisdiction (including PNG) have been allowed to record income tax expense on the taxes payable method.

The Utility's rationale for now collecting unbooked deferred income taxes from Methanex only is that PNG does not expect its current contracts with Methanex to be extended and therefore PNG would be unable to collect Methanex's share of its unbooked deferred income taxes once the existing contracts expire (Exhibit 2: BCUC IR1, p. 9).

Discussion

PNG was not aware of any regulatory precedents or examples for these proposals which charge only one customer. However, PNG also stated that it was not aware of any regulated utility in North America with a similar customer profile. Unlike PNG's other industrial customers with renewable resources, Methanex's load is used as a feedstock in the manufacture of methanol (Exhibit 2: BCUC IR1, p. 11). Forest companies may be sold or reorganized but PNG believed they would remain customers of the Utility. If Methanex closes permanently, it would not be replaced.

PNG explained its rationale for restricting the Modified Depreciation Rate and the Unbooked Deferral Taxes Rate to Methanex as reflecting only the depreciation related to assets that were allocated directly to Methanex and deferred taxes only attributable to Methanex, both of which should not be transferred to remaining customers if Methanex leaves (T1: 68-70).

The CAC (B.C.) et al. supported PNG's position on both proposals, noting:

> "If Methanex is allowed to avoid these charges, it will result in substantially increased costs to PNG's other customers of $6.2 million this year (T. v.1, p. 91) and $11.8 million in total through 2009 (Application Tab Application pp. 6-8). Methanex can avoid these charges by agreeing to keep the Kitimat plant operating. It has chosen not to do so." [CAC (B.C.) et al. Argument, p. 12]

Methanex argued that PNG was wrong in that it did not prepare a fully allocated cost of service study either before or after its rate restructuring proposals (Methanex Argument, p. 16). Mr. Donohue, during cross-examination by Mr. Wallace, noted that the last cost of service study was considered by the Commission in 1998 (T1: 78). The resulting June 18, 1998 Decision stated at page 2:

> "In addition, the Commission invites PNG to apply for further inter-class shifts in revenue for 1999 and 2000 in line with the direction indicated in the Fully Allocated Cost of Service study submitted as part of this Application. However, such changes, when combined with revenue requirement increases associated with transportation and with changes in gas supply costs, should not result in an increase in the total revenue requirement of the class, including gas costs, of more than 10 percent."

Mr. Dyce acknowledged that the liquidity issue forced the Company to ignore this requirement, although he characterized it as a guideline (T1: 80).

Commission Determination

The Commission rejects the notion that a single customer should be targeted for special depreciation and tax treatment part way through a long-term contract, and PNG was unable to provide regulatory precedents for its proposals.

The Commission accepts that depreciation over a contract life is reasonable in certain circumstances, provided it is established up front as a condition of providing service. Asphalt plants which have a short life are appropriately charged the cost of their extensions over the limited life. Had specific assets been allocated to Methanex when it joined the system, and had the 20-year life depreciation been part of the contract agreed to between the parties and approved by the Commission, the accelerated depreciation would have been appropriate. The Commission does not approve the modified depreciation proposal.

In the case of the deferred taxes, the Commission finds that it would not be fair, just or reasonable to solely target Methanex for deferred tax treatment, even if it is only on a go forward basis. The PNG argument that Methanex is different from other customers because it will not be replaced if it permanently closes is not an adequate reason to justify the selective tax treatment.

2.4 Financing and Liquidity Issues

As previously noted, PNG applied to increase rates on an interim and final basis for the period October 1, 2000 to December 31, 2000 and for the January 1, 2001 to December 31, 2001 fiscal period. PNG stated that the applications were made as a result of Methanex's announcement that it would shut down its Kitimat methanol plant on July 1, 2000. The closure meant a reduction in operating margin of $5.3 million per year. After the announcement, the Dominion and the Canadian Bond Rating Services reduced the rating of long-term debt and preferred shares and the Company's bankers reduced its line of credit.

The response of PNG to these actions was to forego a declaration of common dividends, reduce its budgeted capital expenditures by 20 percent in 2000 and 40 percent in 2001, reduce staffing by 20 percent, and file these Applications. According to PNG, approval by the Commission will address its near-term liquidity problems and help get its costs in line with the likelihood of the methanol plant not reopening.

2.4.1 Royal Bank of Canada Credit Facility

Following the Methanex shut down announcement the Royal Bank of Canada proposed a restructuring of its demand loan facility with PNG. The new credit facility, as approved by Commission Order No. G-117-00, reduced the amount available from $35 million to $30 million with further unspecified reductions, and increased the rate of interest charged. The arrangements also require PNG to provide security over accounts receivable and inventory, as well as security on other assets on a pari passu basis with PNG's Trust Indenture. PNG provided a summary of the Royal Bank of Canada arrangements in Exhibit 2, Methanex IR1, page 1. PNG's president testified that this is the number one issue that the Commission has to address in these proceedings (T1: 20).

Ms. Fletcher noted that the credit line would be reduced to the level that can be supported by accounts receivable and inventory, in the range of $5-12 million, with indications that the limit would be reached in July 2002 when the sinking fund payment will be required (T1: 94).

2.4.2 July 2002 Balloon Payment

In addition to the constraints on PNG's current cash flow, PNG is required to make a $12 million balloon payment in July 2002 to retire a portion of its secured debenture indebtedness. (Exhibit 1, Tab Application, p. 2). PNG was reluctant to discuss any fiscal periods beyond 2001, stating that the disposition of this Application by the Commission for 2000/2001 rates is a necessary first step (Exhibit 2: Methanex IR1, p. 2).

2.4.3 October 1, 2000 to December 31, 2000

The Company's revenue requirements for the January 1, 2000 to December 31, 2000 fiscal period had been set by Commission Order No. G-37-00, which approved a Settlement Agreement on the accepted components of the Utility's Rate Base, Income and Return for the period. That Order, as do all Commission revenue requirement Orders and Decisions, allowed the recovery of current expenses in current rates, but deferred certain expenditures for recovery in future periods.

In the ordinary course of events these latter expenditures, while effectively cash outlays, would be financed by the utility until such time as they were approved by the Commission for recovery in customer rates. As PNG's line of credit had been reduced, its cash flow projections now showed that it would be unable to meet its obligations.

Consequently, the October 1, 2000 interim increase, as approved by Commission Order No. G-94-00, was not designed to increase the Company's approved revenues; instead it increased the cash flow by accelerating the amortization of the deferral accounts. By the time of the hearing PNG suggested that the revenue received from the increase in residential and commercial rates [detailed at Exhibit 2: CAC (B.C.) et al. IR1, p. 2] be applied to the GCVA, and the increase in industrial customer rates ($388,504 after income tax) be applied to other deferral accounts, being Extraordinary Plant Losses from 1993, Line Breaks in 1991 and 1992, and certain engineering studies (amounting to $178,686), as shown in Exhibit 2: BCUC IR1, page 61 and described in Exhibit 24.

Methanex argued that it was unfair to apply only the industrial proceeds to deferral accounts which benefit all customers, and that the engineering study deferral accounts had not been formally approved by the Commission in advance (Methanex Argument, pp. 12 and 13). In addition, Methanex argued that acceleration exacerbates the rate impacts and, if this is unavoidable, the shareholders should bear the risk of any detrimental impacts on the level of sales and service.

PNG gave its reasons as to why the engineering study costs should be recovered in its rates, and stated that it was for the Commission to determine which customer class should pay them (PNG Reply, p. 7).

Commission Determination

The interim rate increases effective October 1, 2000 were approved to increase cash flow in order to accelerate the amortization of deferral account balances that record expenditures made by PNG on behalf of its customers. The increases were reasonable short term customer contributions. The Commission approves as final the October 1, 2000 interim rates, for the period from October 1, 2000 through December 31, 2000.

As in any other revenue requirements application, the Commission is required to make a determination on the prudence of utility expenditures. After reviewing the evidence, the Commission determines that, at this time, the evidence does not adequately support recovery of costs for the following engineering studies:

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

PNG is directed to reverse the credit of the foregoing amounts of after-tax funds to these accounts. In its next revenue requirement application, PNG is 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 expenditures.

Order No. G-94-00 approved a 10 percent interim increase in Delivery Charges for all customers, plus a $0.418 to $0.711/GJ increase in the Gas Supply Charges for sales customers. By treating all of the $1.00/GJ residential and commercial increase as a gas commodity charge, PNG increased the amount credited to the GCVA by approximately $375,267, or $208,273 after tax. While the GCVA is the responsibility of sales customers, the Commission agrees that the expenditures recorded in the other deferral accounts were made to benefit all customers. PNG is directed to reverse the allocation of revenue to the GCVA from the approved October 1, 2000 Delivery Charge increase in an amount to have sales customers (residential, commercial and small industrial) contribute their fair share of the write down of the Line Break Costs and Pipe Line Rehabilitation Costs deferral accounts.

PNG confirmed that the additional revenue could have been applied to any of the deferral accounts (T3: 481 and 482). Deferral accounts for Line Break Costs and Pipe Line Rehabilitation Costs are reported to have 2000 year end balances of $931,000 and $847,000, respectively (Exhibit 1B, p. 16). The Commission directs PNG to apply one half of the forgoing amounts of approximately $208,873 and $171,930 to each of the Line Break Costs and Pipeline Rehabilitation Costs deferral accounts.

2.4.4 January 1, 2001 to December 31, 2001

As shown on the Cost of Service Comparison table in Exhibit 1B, the Application (revised February 28, 2001) forecast a cost of service of $43.8 million in fiscal 2001 and seeks to recover a traditional revenue deficiency of $3.3 million revenue for the period. The resulting rate increase is shown in the column headed 2001 Revenue Requirement of the Summary of Rates schedule also provided in Exhibit 1B.

However, PNG has also applied for an additional $9.9 million, of which $1.6 million is to be obtained from commercial customers by increasing their average rates to the residential level, $2.0 million from industrial transportation customers by making permanent the 10 percent increase approved on an interim basis (PNG Argument, p. 20) to be applied against deferral accounts as ultimately approved by the Commission, $2.9

million from Methanex as a Modified Depreciation Rate, and $3.3 million from Methanex as an Unbooked Deferred Taxes Rate (T1: 91). These proposed rate increases are shown in the column headed Rate Restructuring of the Summary of Rates schedule in Exhibit 1B. PNG characterized these increases as “rate restructuring” partly because they are outside the “traditional” revenue requirements and partly because its current Revenue Requirement Model could not be quickly updated to accommodate the proposal. PNG argued, however, that its proposed rate restructuring increase is 100 percent cost based, and reflects the Company’s need to now recover past period expenses, incurred on behalf of its customers, which had been deferred to a future period (PNG Reply, pp. 20 and 21).

2.4.5 Cash Flow Projections

PNG provided cash flow projections to December 31, 2003 (Exhibits 2D and 2E). Scenario 1 (that is, proposed rates approved, but no dividends to shareholders) estimated a bank line peak of $17.6 million in 2002, which Ms. Fletcher said would be unacceptable to the shareholders. Scenario 2 (proposed rates, with dividends) estimated a bank line peak of $35 million, which would be unacceptable to the bank. However, these are scenarios, not forecasts, and Ms. Fletcher pointed out that it was more likely that PNG would be able to obtain external financing or a long-term debt placement (T2: 209 and 210).

In response to a request from Commission counsel, PNG provided a number of new cash flow scenarios, with the addition of a calculation of its return on actual equity. While the bank line peak changes, in all cases beyond 2001 the return on actual equity is low. Page 1 of Exhibit 2G (attached as Appendix A) shows that, with the proposed revenue requirement, but without the Modified Depreciation Rate or the Unbooked Deferred Taxes Rate, and with no dividend payout, the bank line peak in the years after 2001 would be about $24 million, and the return on equity would drop from 5.9 percent to negative amounts.

However, the Company’s model provided cash flows on a consolidated basis. Mr. Wallace noted that the capital structure for PNG-West in Exhibit 1B has only a $6.4 million cash requirement (T2: 215-217). PNG provided Exhibit 19 in response, showing the components of the $30 million demand line requirement at the beginning of 2001. In addition to the short-term debt requirements to finance the rate base, this exhibit showed the additional requirements due to the acquisition of PNG (N.E.), for the pre-tax, non-rate base GCVA, and the daily peaking requirement in excess of the normal cash working capital allowance in the Application.

In Exhibit 25, Methanex reallocated the short-term debt shown in Exhibit 19. It argued that the problem was that PNG is carrying too much short-term debt (for which it has been compensated), that most of it is associated with the PNG (N.E.) purchase, and that PNG, acting prudently, would have replaced this with long-term debt and equity before the current situation developed (Methanex Argument, pp. 5 and 6).

In past Applications, PNG has agreed that the make-up of the actual capital structure is management's responsibility. In 1997, PNG retained Kathleen McShane, Foster Associates Inc. to render an opinion on the reasonableness of PNG's common equity proposed in its 1998 to 2002 Revenue Requirements Application. As noted in the Commission's June 18, 1998 Decision at page 12:

> "In her pre-filed evidence, Ms. McShane testified that management should retain the discretion to determine the capital structure for the Utility, and that rates should reflect the actual capital structure, as long as the resulting ratios are reasonable and there is no prima facae evidence that cross-subsidization between utility and non-utility operations has occurred (Exhibit 1, Tab 5, p. 2)."

Exhibit 2 from that application, was PNG's response to Methanex Information Request question 48, as follows:

> 48. Reference: Application Tab 5, page 6, lines 24-27
>
> Request:
>
> (a) Provide references to and quotations from regulatory decisions which:
>
> > " ... have frequently recognized that the regulator cannot prescribe the capital structure that the utility must maintain ..."
>
> Response:
>
> The role of management in determining capital structure has been confirmed in numerous decisions since the 1950's. My research indicates that there have been no major deviations from this finding since that time. Please find below selected citations from decisions which affirm management's role (selected passages attached).
>
> 1. Re: Mountain States Telephone & Telegraph Co. (Idaho PUC, 1954)
> 2. Re: Mountain States Telephone & Telegraph Co. (Montana PSC, 1958)
> 3. Re: Southern Bell Telephone & Telegraph Co. (Florida PSC, 1966)
> 4. Re: Chesapeake & Potomac Telephone Co. (D. of Columbia PSC, 1964)
> 5. Re: Tampa Electric Co. (Florida PSC, 1971)
> 6. Boston Gas Co. v. Mass. Dept. of Public Utilities (1971)
> 7. Penn PUC v. Bell Telephone Co. of Penn. (1971)
> 8. Re: Hoosier Gas Corp. (Indiana PSC, 1985)
>
> (b) Reconcile the above statement with the statement at page 3, lines 26-28 that:
>
> > "In Canada, regulators have tended to gravitate toward reliance on deemed common equity ratios or have explicitly set upper limits on the common equity ratio they will allow for rate making purposes."

Response:

The regulator can only prescribe the capital structure ratios and capital cost rates which are allowable for rate making purposes; the regulator does not have the authority to prescribe the actual capital structure which the company employs. The choice of actual capital structure is the function of management.

As well, in its 1996 application to acquire the shares of Centra Gas Fort St. John, PNG stated that the purchase would not place any restriction on its ability to obtain short- or long-term financing and therefore would not jeopardize the ongoing financial integrity of PNG or Centra Gas Fort St. John [now amalgamated with PNG (N.E.)].

In the current proceeding PNG's Reply noted that for rate making purposes PNG must fairly allocate its capital structure between the two operations; however, PNG's lenders do not separately finance PNG-West and PNG (N.E.). When PNG last replaced short-term debt with long-term debt in 1997, PNG (N.E.) was required to pledge its assets in support. PNG stated that it would be impossible to determine what line of credit would be available for PNG if it did not have PNG (N.E.) as a subsidiary (PNG Reply, p. 3). As well, Mr. Dyce noted that the PNG (N.E.) operation provides diversity, and that the downgrading would have happened sooner without the PNG (N.E.) operations (T4: 598).

Commission Determination

Methanex argued that liquidity is the responsibility of management and shareholders, and the Commission should not increase PNG's rates simply to improve cash flow (Methanex Argument, p. 3). The Commission generally agrees, and will set rates to meet approved revenue requirements. However, the Commission has approved rate increases or rate riders to accelerate the amortization of deferral accounts related to gas costs, on the basis that the deferral accounts represent costs that have been incurred on behalf of customers. As a result of the unique circumstances facing PNG, the Commission will allow the Utility an opportunity to reduce certain deferred costs to the extent that customers' rates can remain competitive with other fuels.

2.4.6 Alternative Financings

Mr. Wallace asked whether, given the amount of the investment funded by debt, PNG had given any consideration to selling PNG (N.E.). Mr. Dyce responded that, as PNG (N.E.) is a restricted subsidiary, it would likely require debenture holder approval (T4: 598).

Methanex explored the possibility of more extreme actions by the Company, such as merging with another gas company. Mr. Dyce responded that management had been looking, on and off, over the last five to ten years, but could not find a buyer. Using 2000 ADR volumes, Mr. Donohue noted that the Methanex take-or-pay was worth about $15.3 million per year. When Mr. Wallace asked if there was any opportunity to use the Methanex take-or-pay creatively, Mr. Dyce stated that there were a number of discussions with Methanex, but that PNG could not accept anything less than the net present value of the Methanex obligations. With regard to writing down rate base, Mr. Dyce responded that this would be addressed closer to 2002, when the main Methanex contract expires (T1: 198-202). In any case, in his exchange with Mr. Lutes, Mr. Drazen agreed that if the equity is written down and the Commission sets rates based on the capital structure with the equity written down, that would reduce the cash flow of the company and exacerbate the cash liquidity problem. However, he also noted that, if the equity is written down and the rate base goes down, then the total cost of service goes down and the rates become more affordable (T6: 947).

The CAC (B.C.) et al. also addressed the issue of alternative financing, noting on page 8 of its Argument:

> "A further option which was suggested by Mr. Drazen, one of Methanex's witnesses, was a loan to PNG from its customers, which would have the impact of reducing income tax liability. However, aside from the Commission's lack of jurisdiction to direct customers to loan money to the utility, the only voluntary loan proposal was that of Methanex, which contains a number of conditions in which, as Mr. Guenther, another Methanex witness, has agreed was not adequate in itself to deal with PNG's liquidity problems."

The Commission recognizes that PNG may have no choice but to consider alternative financing if the current circumstances continue to deteriorate.

2.5 Operating, Maintenance and Administrative Expenses

Gross operating, maintenance, administrative and general expenses ("OMA&G") for PNG in 2001, excluding the cost of company use gas and gas lost and unaccounted for, are projected to total $11.6 million, a 17 percent decrease from the $14 million applicable in 2000. The decrease reflects the combined impact of reducing operating costs through reorganizing how PNG provides service to its customers and decreasing capital expenditures by 40 percent. Most of these changes have been motivated by the reduction in sales volumes to Methanex (Exhibit 1C, revised by Exhibit 1D).

2.5.1 Human Resources Reductions and Severance Costs

In late October 2000, in addition to earlier reductions, PNG decided to reduce the Company's staff complement further before the end of the calendar year. The primary focus of this reorganization was the termination of "over the counter service" and the creation of a "customer care centre" in Terrace. Thirty-five positions in field offices and in the Vancouver office were eliminated, although five temporary employees have been contracted (T1: 185; T3: 473 and 474). The difference between salaries and benefits in the 2001 Test Year and the 2000 Decision exceeds $2 million. This amount excludes the one-time severance settlements of approximately $1,000,000 (Exhibit 2: BCUC IR1, p. 36; Exhibit 1D). The difference in salaries and benefits, before accounting for the severance pay, represents 90 percent of the reduction in OMA&G costs.

The severance settlements of $239,000 paid out by PNG prior to November 1, 2000, were written off in that year against salaries and benefits saved. The $729,000 in severance settlements paid late in the year 2000 are proposed to be written-off through the amortization of deferred charges in 2001, as a non-recurring expense.

Eurocan criticized PNG for not reducing costs earlier since PNG testified that the resultant cost reductions have not had a material adverse effect in the quality and safety of the service it provides and PNG knew of the potential closure of the methanol plant for many years.

The CAC (B.C.) et al. was of the view that the one-time severance costs associated with the reorganization process should be limited to the estimated cost of $729,000. The CAC (B.C.) et al. felt that it would be inappropriate and inconsistent to allow the Company a deferral account on the 2000 reorganization expenses that potentially assigns ratepayers the recovery of additional costs if ratepayers were not given the opportunity to capture additional cost savings that may result from this reorganization.

The CAC (B.C.) et al. argued that the one time severance cost associated with the reorganization process should be recovered over at least two fiscal years, rather than only in the 2001 rates. As noted in the PNG Argument (page 22), the restructuring will result in significant permanent cost savings over the long term.

The Commission believes that PNG has acted responsibly to downsize its operations in anticipation of the large loss of revenue if Methanex permanently closes. Further downsizings may be necessary in future, provided safety is not jeopardized. The recovery of up to $729,000 in severance settlements from late 2000 is approved for recovery in 2001, so that PNG will be better placed to deal with the potential loss of Methanex revenue after October 2002.

2.5.2 Human Resources Reductions and Safety of Operations

As part of the Utility's recent reorganization, PNG centralized its administrative work at a new Customer Care Centre in Terrace. The reorganization resulted in the elimination of a number of positions. Although most of the cuts were in the administrative area, some service personnel were affected, including the sole service positions in Houston and Fort St. James (T2: 377). PNG explained that, in the past, service personnel in smaller communities such as Houston and Fort St. James had spent part of their time on administrative tasks which are now centralized in Terrace. The elimination of administrative duties, combined with a slowdown in customer growth, left the resident service personnel with insufficient work (T4: 665).

Mayor Togyi of Fort St. James and Mayor Euverman of Houston provided testimony concerning the impact of service cuts on their communities. Mayor Hartwell of Telkwa also gave a statement about safety and service concerns. The Mayors expressed concerns about safety and, in particular, PNG's limited ability to respond to emergencies in towns without resident service personnel (T1: 29 and 45; T2: 386). Mayor Togyi described the problems he faced when a pilot light went out, and the District of Houston provided a letter describing PNG's failure to respond to a recent gas leak at the Houston Health Centre (Exhibit 12B). The testimony of the Mayors indicated that there is at least a perception of reduced safety and that customers have had difficulty contacting PNG for assistance.

PNG stated that it does not believe that safety has been negatively affected by the reorganization (T2: 377). A key criterion in the decision to reduce service personnel was the maintenance of adequate emergency response time. The Vanderhoof office now has two qualified emergency response personnel, and provides emergency response to Fort St. James. The Smithers office with three personnel provides emergency response to Houston and Telkwa. Emergency response personnel are also located at Burns Lake (two staff), Kitimat (two staff), Prince Rupert (two staff), and Terrace (four staff). The maximum response time from an operating office to an outlying area is generally 40 minutes. The only exception is the 60 minutes response time from Burns Lake to Granisle, which was not changed by the reorganization (T4: 664-667). PNG further described its relationship with local fire departments, which have been trained to deal with emergencies until PNG personnel can arrive (T4: 709).

Regarding PNG's failure to respond to the Houston Health Centre gas leak, PNG admitted that for several days beginning January 29, 2001, PNG had phone system problems which have since been resolved (T4: 663). Customers should now be able to contact PNG in an emergency. PNG stated that its emergency number is printed on the billing statements and will also be listed in the new phone books when they are published during this year (T4: 716). As a result of the reorganization, PNG now has an emergency telephone number that is distinct from the number for customer inquires. The response to calls to the emergency number is dispatched by the Customer Care Centre in Terrace during business hours and after hours by PNG's answering service (T4: 708-718).

Eurocan expressed concern for the future safety of its employees and its customers. While PNG does not believe that safety has been adversely affected to date (T2: 377), Eurocan argued that it is unreasonable to assume that it can continuously cut costs without eventually finding itself unable to provide adequate safety.

Commission Determination

The Commission concludes that PNG's reorganization of administration and service has not had a material impact on safety. However, the Commission is concerned that customers have a perception of reduced safety and that some customers may not know PNG's emergency phone number. The Commission strongly encourages PNG to address both these problems promptly through improved customer communications and education. The Houston Health Centre incident may have been an isolated problem, but the Commission directs PNG to publicize alternate arrangements for emergency calls if similar circumstances develop in the future.

2.5.3 Westcoast Energy Inc. Services - Order No. G-92-97

PNG described its "Westcoast Administrative Services Agreement Charges" in its Application at Tab 1, page 28. The utility provided comparisons with prior years and a detailed break-down according to function and between "Administration" and "Pipeline Operations". The 2001 Test Year forecast included $337,752 for administrative services and $234,612 for pipeline services for a total of $572,364, representing an increase over the utility's 2000 forecast of approximately $6,000. In response to a BCUC staff information request about possible reductions in this expense, PNG responded with the following commentary:

> "Charges shown in 2001 for WEI services have not been changed as a result of the significant restructuring occurring at PNG. PNG believes that as a direct result of the restructuring both the Westcoast services and charges will increase. The main reason for this is the elimination of numerous PNG head office employees who, in the past, carried out functions such as information technology, human resources, payroll, health, safety, environmental, drafting, financing, investor relations, corporate governance, etc. The downsizing of PNG's head office will result in more reliance on outside support in many areas. PNG's experience has been that WEI provides administrative services at less cost than comparable services from third parties. The extent to which the WEI services will increase will be determined as we gain experience operating with a much smaller head office staff." (Exhibit 2: BCUC IR1, p. 37)

Methanex noted that the allocations from WEI were not subject to scrutiny this year but should be watched carefully in the future to ensure that savings in OM&A are not simply replaced by higher allocated costs from WEI (Methanex Argument, p. 11).

Commission Determination

The Commission accepts the forecast of Westcoast services for 2001 but the Commission does not accept PNG's assertion that "… as a direct result of the restructuring both the Westcoast services and charges will increase." PNG will be required to fully demonstrate the need for any future increases in 2002 and beyond. Any increases in excess of inflation must be justified and supported with adequate information.

2.5.4 Company Use Gas

PNG uses company use gas for the operation of its pipeline system, primarily for compressor fuel. PNG buys the gas as part of gas supply purchases and recovers the cost as part of Operating expense in its Delivery Charges. The shutdown of the methanol plant caused greater than normal uncertainty in the forecast of company use gas, and PNG requested approval of a deferral account for this expense. The shutdown also raised concerns about how PNG calculates the company use gas charge in rates; this rate design matter will be discussed in Section 2.7.5.

Although actual compressor fuel consumption for 1996-1999 averaged 3.22 percent, PNG amended the compressor fuel forecast for 2001 to 1.70 percent (Exhibit 1B, p. 1). One re-staged compressor unit at Station R1 can generally handle the system load with Methanex shut down and is expected to consume 1.1 to 1.7 percent for fuel (T4: 644-647; Exhibit 33). If both B.C. Hydro generating units in Prince Rupert or one generating unit and the ammonia plant in Kitimat are operating during the heating season, PNG expects it will also need Station R3 intermittently. This would increase the compressor fuel use to as much as 2.0 percent (Exhibit 2B, pp. 4 and 5).

PNG also requests an increase in the allowance for heating gas to 0.41 percent. Most heating gas is used for line heaters, and consumption averaged 0.23 percent over 1996-1999. With Methanex shut down the absolute volume for this use will decrease, but the reduced forecast volume is a larger percentage of actual deliveries (Exhibit 2B, p. 5; T4: 647-650).

Unaccounted for gas has been quite variable in past years. PNG requested approval to use 0.40 percent for 2001, and to continue the practice of deferring variances that fall outside of a range of 0.2 to 0.7 percent of deliveries.

The other components of company use gas are line pack changes (which PNG assumed will be zero) and blowdowns and losses. Blowdowns and losses averaged 0.15 percent over 1996-1999, and PNG proposes 0.20 percent for 2001.

The requested total usage rate is 2.71 percent of forecast sales and transportation deliveries, which corresponds to 475,674 GJ of company use gas (T4: 647). The cost of company use gas was determined as part of the allocation of forecast gas supply costs, and would be reconciled with actual gas supply costs using the Gas Cost Variance Account (T2: 246-247). Company use gas for 2001 was predicted to cost $3.363 million, or $7.07/GJ (Exhibit 1B, p. 1).

PNG felt that the lack of historical operating experience with Methanex shut down and the current high commodity cost of gas justified a deferral account to record the difference between forecast and actual compressor fuel use. This account would also record unaccounted for losses or gains that are outside the 0.2 to 0.7 percent band.

No party took issue with the usage rate that PNG proposed. The CAC (B.C.) et al. opposed a company use gas deferral account, on the basis that this is a load forecasting risk for which PNG is compensated by a higher premium on the benchmark Return on Equity [CAC (B.C.) et al. Argument, p. 16]. PNG responded that its equity risk premium does not compensate the Company for the significantly greater forecasting risk to which it is currently exposed (PNG Reply, p. 14).

Commission Determination

PNG's forecast of compressor fuel usage and the other components of company use gas appear reasonable in the present circumstances. With uncertainty whether Methanex will continue to be shut down, and the lack of historical information about this operating configuration, it is reasonable to defer variances related to both the compressor fuel rate and other company use gas costs. Similar reasons support including heating gas variances in the deferral account. The Commission agrees with the continuation of deferral account treatment of unaccounted for gas outside the 0.2 to 0.7 percent band. Consistent with the treatment of the GCVA, the Commission expects this deferral account will be an interest bearing, non-rate base account (Exhibit 1B, p. 17).

The Commission approves a deferral account for recording variances in compressor fuel usage and heating gas, and unaccounted for gas outside the 0.2 to 0.7 percent band.

2.5.5 Maintenance Costs

PNG set out the major details of its $275,000 reduction in Maintenance costs in its Application at Tab Application, page 14. The major changes from 2000 to 2001 were identified as:

> "1. Labour - $66,000 decrease
>
> This reduction is a direct result of the reduced staffing level for 2001 vs. 2000. The majority of this amount ($46,000) results from the reduction in the compressor station area as fewer compressor units are projected to be operating in 2001 than previously.
>
> 2. Other - $209,000 decrease
>
> This decrease results from non-labour compressor station maintenance cost reductions of $56,000 due to reduced utilization. The planned expenditures on materials and supplies for regulating station maintenance have also been reduced by $37,000, while contractor charges for meters has been reduced by $42,000 based on the anticipated reduction in meter recalls to historic levels. The remaining decrease results from numerous reductions in materials, supplies, equipment, contractor charges and expenses all related to the reduction in the number of field employees.
>
> 3. Major Reductions identified by BCUC Uniform Account Code:
>
> 865 - Pipelines
>
> | | |
> |---|---|
> | 2000 - $ | 112,000 |
> | 2001 - | 76,000 |
> | Decrease - $ | 36,000 |
>
> The two contributors to this reduction are pipeline valve maintenance ($19,000), and minor protection for road crossings ($13,000). The planned expenses for the minor protection for road crossings has been reduced due to the overall reduction in economic activity throughout the service area.
>
> 866 - Compressors
>
> | | |
> |---|---|
> | 2000 - $ | 183,000 |
> | 2001 - | 69,000 |
> | Decrease - $ | 114,000 |
>
> Summer student/casual labour has been eliminated creating a reduction of $20,000. Station maintenance has also been reduced by $92,000 due to the reduction of compressor station personnel, and the planned reduced utilization of the compressor units.
>
> 867 - Compressors
>
> | | |
> |---|---|
> | 2000 - $ | 112,000 |
> | 2001 - | 51,000 |
> | Decrease - $ | 61,000 |

This reduction is due to reduced time and materials spent on this activity. The level of activity planned for 2001 is based on historical experience and planned productivity improvements.

878 - Meters

2000 - $	126,000
2001 -	83,000
Decrease - $	43,000

The majority of this reduction is due to a planned reduction in the levels of meter recalls for both the commercial ($7,000) and residential ($20,000) sectors. The anticipated level of recalls has been reduced back down to historical levels after a significant rise in 1999 numbers due to sample recall failures. The 1999 volume of recalls was so great not all of them could be completed in 1999 and some were completed in early 2000, therefore this reduction returns our expenses to the historical levels. The final area of cost reduction in the account is distribution pressure turbine meter maintenance. Planned expenditures have been reduced in this area by $16,000 based on historical experience and planned productivity improvements."

The Commission approves the applied for levels of maintenance for 2001. If the Methanex plant does not reopen, the Commission will expect PNG to obtain further compressor maintenance savings in 2002.

2.6 Rate Base and Capital Additions

The Applications forecast a Net Plant in Service at the beginning of 2001 of $160.690 million, and a mid-2001 Utility Rate Base of $144.682 million (Exhibit 1B, p. 14).

Following is a comparison of forecast and actual capital additions (Exhibit 1, Tab 2, p. 1; Exhibit 42).

Millions of Dollars

	Test Year 2001	Actual 2000	Forecast 2000	ADR 2000
Additions	$ 3.525	$ 5.270	$ 6.185	$ 5.761

In response to the Methanex shutdown, PNG reduced its 2000 capital additions to 91 percent of the 2000 ADR settlement level. Actual capital additions in 2000 resulted in a Plant in Service at the beginning of 2001 of $159.776 million, or $0.914 million lower than the forecast in the Application (Exhibit 42).

Additions in 2001 were forecast to be almost 40 percent below the 2000 ADR levels. PNG felt that the remaining expenditures would be necessary to ensure that the existing system functions safely, reliably and economically. The number of new customer connections was expected to be relatively low, and the proposed Main Extension and Service Connection Policy would increase Customer Contributions and so reduce PNG's rate base.

Methanex expressed concern that Construction Overhead of $1.690 million was a high proportion of the $3.525 million total 2001 additions (Methanex Argument, p. 12). PNG attributed this to its large reduction in Capital expenditures for 2001, while OM&A costs cannot be reduced below a level that is essential for safe and adequate operation of the system (Exhibit 2, Tab 1, p. 37). PNG's construction and customer service personnel respond to emergency situations, with construction personnel typically providing the first response to transmission line incidents (T4: 662).

Under Working Capital for 2001, PNG amended the Gas Purchases expense in its Expense Lead Days schedule from $51.5 to $38.7 million (Exhibit 1B, p. 20). The expense is net of projected hedge impacts relative to the November 23, 2000 gas price forecast (PNG response to Undertaking, T4: 628).

Gas purchases are paid for by the 25th day of the month following the month of delivery, and these payments represent the actual prices paid to suppliers. Hedging transactions are separate arrangements that are settled by about the 9th day of the month of gas delivery. PNG acknowledged that a change probably should be made to the working capital model to reflect this situation (T4: 625-630). Assuming a hedging impact for 2001 of approximately $5 million, the effect of the change would appear to reduce Working Capital and Utility Rate Base by about $0.5 million.

PNG stated that its entire rate base is useful, since all of the facilities are required so that the Utility can fulfill its contractual obligations to provide transportation service to Methanex through October 31, 2002 (PNG Argument, p. 11). Eurocan requested that the Commission appraise the value of PNG assets on a basis that excludes the methanol plant-related facilities from rate base. While the methanol plant is shut down, Eurocan considered that these facilities are not used and useful, and that the potential for the plant to shut down is a business risk that PNG should have protected itself against (Eurocan Argument, p. 23 and 27). Methanex also proposed a reduction in the rate base on which PNG is allowed a return (Methanex Argument, p. 14).

Commission Determination

The Commission considers that safety is of paramount importance. Reliability of service to customers and economy of operations may need to be sacrificed to some extent in order to maintain the safety of the system. PNG appears to have made safety its priority when

determining the capital expenditures that are needed for 2001. The Commission expects PNG to be vigilant that necessary expenditures are made to ensure the safety of the system.

The Commission expects PNG to adjust its Working Capital model to reflect hedging impacts before filing its next revenue requirement application.

The Commission accepts PNG's position that its obligation to provide transportation service to Methanex precludes the removal of assets from regulated service or a reduction to Utility Rate Base for 2001.

2.7 Rate Design Issues

2.7.1 Excess Contributions from Methanex

Methanex argued that it has, historically, paid much more than PNG's allocated cost of serving Methanex. In Exhibit 4A, Methanex estimated the difference between PNG's revenue from Methanex and its cost of serving Methanex (i.e., the "excess contribution"). Methanex's estimate was derived by interpolating and extrapolating revenue-cost ratios from various cost of service studies to get estimated ratios for each year from 1984 to 2000. From these ratios, Methanex estimated the excess contribution at $70-80 million. The excess contribution was used to suggest that the current rates to Methanex are already high enough to cover PNG's cost of serving Methanex and the cost of additional depreciation and the deferred income taxes (Exhibit 4A, p. 3). The Commission was encouraged to reduce the rate to Methanex even if it does not approve the load retention rate application (Exhibit 4, p. 18).

PNG disputed Methanex's excess contribution estimate since:

(a) Cost allocation studies are judgmental and were not undertaken until the early 1990s;

(b) PNG has not recovered sufficient depreciation from Methanex based on an assessment of incremental costs and current depreciation rates;

(c) Methanex has not contributed its appropriate share of PNG's unbooked deferred income taxes; and

(d) The Methanex rate covered only the incremental cost of PNG's expansion and made no contribution to the cost of the existing plant including approximately 6 MMcf/d of available capacity it utilized as part of the 1982 expansion and 4MMcf/d it commenced to utilize in 1994 (PNG response to BCUC IR1, p. 65).

PNG noted that the rates to other customers did not decline when Methanex came on line (PNG response to Methanex IR1, p. 6), but agreed that the facilities installed for Methanex have provided benefits to the other customers in terms of security (T4: 604) and reliability (T4: 600). PNG indicated that cost of service studies may not deal with the vintage of the plant (T2: 259) and that cost of service studies do not adequately deal with interruptible deliveries (T2: 257-260). Including a value for interruptible service could significantly reduce the combined revenue to cost ratio. Methanex agreed that its excess contribution estimate only looked at firm deliveries, and that including an imputed value for valley gas would reduce the revenue to cost ratio thereby reducing excess contributions.

PNG noted that the Commission has approved all rates to Methanex and, as such, determined that the rates were not unjust or unreasonable at that time (PNG response to BCUC IR1, p. 65). PNG believed that it would not be appropriate to review 18 years of Commission decisions in the context of this hearing (PNG response to BCUC IR1, p. 65), but recognized that the Commission has previously directed PNG to increase residential and commercial rates to raise their revenue to cost ratios to the 0.9 to 1.0 range so that their rates recover an appropriate portion of their allocated costs (Exhibit 1, Application Tab, p. 21).

Commission Determination

The Commission does not find the Methanex study to be conclusive for several reasons. PNG has correctly pointed out that the study did not include the existing capacity that was accessed by Methanex in 1982 and 1994. The value of interruptible service at very low rates has not been included and the benefits to Methanex of flow-through taxes and depreciation rates are not accounted for. The Commission is only able to conclude that Methanex has had a high revenue to cost ratio based on studies of total plant and total revenues. Whether Methanex has paid rates sufficient to cover all of the assets that could be specifically devoted to Methanex service is not clear.

2.7.2 Commercial Customer Rates

PNG proposed, effective October 1, 2000, to increase residential rates by $1.00/GJ to $11.15/GJ, or approximately 10 percent, and commercial firm rates by $2.07/GJ. This would make the annual average unit rate for a commercial customer consuming 460 GJ per year the same as the average unit rate for a residential customer consuming 132 GJ/year ($11.15/GJ) (Exhibit 1, Tab Application, pp. 4-5). The average unit rate means the equivalent $/GJ cost of the total basic charge and consumption charges for the consumption of a typical customer in the class.

In Exhibit 1B PNG revised its application and proposed, effective January 1, 2001, to increase the commercial firm delivery charge by $1.18/GJ over the July 1, 2000 approved delivery charge, apart from any revenue requirement and gas supply cost adjustments. This rate restructuring adjustment would make the average unit rate for a commercial customer consuming 460 GJ/year the same as the average unit rate for a residential customer consuming 132 GJ/year ($12.98/GJ). The average annual rate increase due to rate restructuring for a commercial customer consuming 460 GJ/year would be approximately 14 percent. The impact of the commercial rate restructuring on revenues is approximately $1.7 million (T1: 91).

The commercial customer rate restructuring was not approved on an interim basis for inclusion in rates effective October 1, 2000 or January 1, 2001 because rate design changes are normally applied on a prospective basis, after a hearing.

In support of its proposal PNG stated that it considered the service provided to residential and commercial customers to be similar. The Utility also stated that both residential and commercial customer classes required the same level of physical plant and effort for billing and related services. PNG submitted that, because commercial users receive an income tax deduction for their costs, the commercial users' fuel rate would be lower than residential customers on an after-tax basis (Exhibit 2, Tab 1, p. 1). PNG stated during the hearing that the commercial customer rate restructuring was related to PNG's need for additional cash flow and that the revenue would be used to accelerate the recovery of deferred expenses that had previously been incurred (T1: 89 and 90; T3: 467).

PNG further supported the increase to commercial firm rates by updating the revenue to cost ratios from its 1998 Fully Allocated Cost of Service ("FACOS") study. In 1998, the revenue to cost ratios for residential and commercial firm customers were 0.73 and 0.65 respectively (Exhibit 2, Tab 1, p. 3). The Commission, in its June 1998 PNG Revenue Requirements and Rate Design Decision, had invited PNG to apply for further inter-class rate shifts to bring the revenue to cost ratios closer to one, as long as the total revenue due from a class, including gas costs, did not increase by more than 10 percent.

PNG stated that applying the unit residential margin to the forecast commercial firm deliveries and comparing the result to the allocated commercial cost of service yielded a revenue to cost ratio of 1.0. PNG considered this to be an acceptable result given that a range of 0.9 to 1.1 is generally considered to be reasonable (Exhibit 2, Tab 1, p. 1). PNG's updated FACOS analysis indicated that, with the proposed shift, the revenue to cost ratio for commercial firm customers would be 0.97; without it, the revenue to cost ratio would be 0.72. The residential revenue to cost ratio in 2001, irrespective of a commercial rate increase, would be 0.83.

Commission Determination

By implication, if the average per unit revenues are the same and the resulting revenue to cost ratio for commercial firm customers is 0.97 versus 0.83 for residential customers, the unit costs for residential customers must be greater than for commercial customers. This suggests that, based on the detailed 1998 FACOS study results, the costs for residential customers are higher than for commercial customers, contrary to PNG's general assertions that they are the same. Alternatively, the Commission notes that the typical commercial customer consumption level of 460 GJ/year is less than the average commercial customer consumption of 529 GJ/year which may have distorted the revenue to cost comparisons. In the absence of other overriding objectives, parity in revenue to cost ratios generally meet rate design criteria better than parity in the rates to residential and commercial customers.

The Commission is concerned that the level of analysis undertaken is too crude to have confidence that the resulting commercial revenue to cost ratio would be 0.97, 1.0 or slightly greater than 1.0. However, the previous revenue to cost ratio for this class was the lowest of any customer classes and the Commission believes that all classes must bear an appropriate proportion of the allocated costs of the utility, within the constraints of competing energy prices.

In these circumstances, the Commission approves a rate restructuring charge for commercial rates (RS2) of $0.85/GJ effective July 1, 2001. This increase will lead to an approximate revenue to cost ratio of about 0.9 and the Commission believes that this rate is appropriate compared to competing energy sources. The Commission directs that the revenue generated from the rate restructuring charge be used to write down deferral accounts. Any future rate design adjustments will require a new FACOS study before they will be considered.

2.7.3 Industrial Customer Rates

Rate increases of 10 percent were approved on an interim basis effective October 1, 2000 to enable PNG to accelerate the amortization of deferral accounts and thereby reduce its liquidity problems. In Section 2.4.3 the Commission approves these increases for the October-December 2000 period.

Effective January 1, 2001 the Applications divide the 10 percent industrial (and commercial transport RS3) rate increases into two parts: increases in margin required from all customers to meet revenue requirements and increases in margin to accelerate amortization of deferred expenses. The latter component is referred to in the Applications as rate restructuring and if approved would required a contribution of approximately $2.0 million from industrial customers.

PNG supported the restructuring of commercial rates by updating the revenue to cost ratios from its 1998 FACOS study and demonstrating that without restructuring, the ratio for commercial customers would be 0.72 (Exhibit 2, Tab 1, p. 3). In the same exhibit, PNG showed that with industrial rate restructuring, revenue to cost ratios would be 1.02 for Methanex, and 1.23 to 1.42 for Skeena, Eurocan and Alcan.

During cross-examination by Mr. Wallace, Mr. Dyce stated that the restructuring charges were arbitrary, and that PNG had tried to balance what the customers could bear with the Utility's liquidity issues (T1: 164). PNG supported the restructuring of industrial rates by arguing that the increases were small and would only cost Eurocan and Skeena about $250,000 and $275,000 respectively (PNG Final Argument, p. 20).

Several industrial customers argued against the increases. Canfor stated that it is actively pursuing alternate fuel options and that the 17.4 percent rate increases since June 2000 and the potential for further rate increases make alternatives more attractive (Final Argument, pp. 1 and 2). Eurocan submitted that it is reducing gas consumption and looking at alternative fuel options (Exhibit 6, p. 3). Eurocan argued that its rates were higher than just and reasonable rates (Final Argument, p. 20). Skeena stated that it cannot afford to further increase its costs (Final Argument, p. 2). Methanex's arguments against the current and proposed rates are dealt with in Section 2.7.1 and Chapter 3 of this Decision.

Commission Determination

The Commission is concerned that the proposed increases to industrial customer rates could contribute to an increased loss of load if implemented on a long-term basis and finds that the rate restructuring charges proposed by PNG are too high. The Commission approves 50 percent of the industrial and RS3 restructuring charges shown in the column headed 2001 Rate Restructuring of the Summary of Rates schedule in Exhibit 1B. This achieves a better balance between PNG's liquidity needs and what customers should reasonably bear.

2.7.4 Revised Main Extension Policy and Service Connection Charges

Main Extension Policy

PNG sought Commission approval of revisions to its main extension policy and economic test for customer contributions. PNG's current main extension test calculates the annual cost of delivering a unit of energy to a customer on a proposed extension, based on the utility's current cost of service. It then calculates the maximum investment in a proposed main extension project that the utility can make without causing the net present value ("NPV") of the cost of delivering energy to exceed that of existing customers in the same rate class. If the maximum allowable capital investment is greater than the estimated cost of the proposed extension, the extension will be constructed with no contribution required from the customers who will be served from it. If the estimated cost of the proposed extension will be greater than the allowable capital investment, the difference is allocated to the expected customers over a five-year period (Exhibit 1, Tab 2, p. 13).

The objective of the proposed new extension test remains the same: to determine the maximum amount that can be invested in a proposed extension without adding costs to existing customers. However, the new test is based on the current margins of the appropriate rate class instead of the difference between the actual revenues and the approved allocation of costs.

PNG offered several reasons to support the revised test. First, PNG stated that it prevents a rate class that is under-recovering its actual cost of service from transferring additional costs to other rate classes. Second, the new test can be updated easily by simply updating fixed fees and margins. Third, the proposed test can be easily applied to any rate class, whereas the old test had been difficult to use for industrial or interruptible customers. Fourth, PNG noted that the revised test enabled the utility to depreciate the rate base associated with a particular main extension over the same time period as used for the NPV calculations. The Utility considered this aspect of the new test to be useful in situations where a main extension was being requested to serve a load with an uncertain and potentially short operating life (Exhibit 1, Tab 2, pp. 14 and 15).

PNG also proposed to end any utility financing for main extension contributions because, in order to provide financing under its present circumstances, PNG would have to raise its lending rate to approximately the same level as should be commercially available to credit-worthy customers.

The impact of the proposed test, in most cases, would be to decrease the maximum company contribution (Exhibit 1, Tab 2, p. 15) and increase the required customer contribution. The proposed test also tends to decrease the required customer contribution of low volume consumers in a given customer class relative to larger volume consumers. This occurs because the proposed test recognizes that low volume customers pay a higher rate per GJ due to the monthly charge. Consequently, a base level of company investment is justified simply on the basis of the monthly charges it will receive (Exhibit 2, Tab 1, p. 9).

During the hearing PNG testified that the difference in the maximum company contribution per customer resulted from four key factors: a slightly higher marginal cost of capital; full depreciation of the main extension over the test period; no cross-subsidy between rate classes; and, a higher unit cost of fuel gas (T3: 577). PNG, in argument, claimed that both its existing and proposed extension policies were consistent with the Commission's existing System Extension Test Guidelines, and that it did not consider the higher capital cost contribution required under the modified main extension policy to be a major deterrent to new additions (PNG Final Argument, pp. 22 and 23).

Individual customer contributions under PNG's current main extension policy are allocated to all of the customers expected to connect to the extension during the first five years of a new main's operations. Under its proposed main extension policy, PNG would collect customer contributions by requiring the initial (pioneer) customers to pay the full amount of any required customer contributions. Customers connecting to the extension in the following four years would be required to pay an appropriate share of the total customer contribution, and the pioneer customers would receive a proportional share of any such subsequent contributions (Exhibit 1, Tab 2, p. 12). PNG indicated that it had not finalized a policy to handle collection of main extension shortfall amounts from non-pioneer customers and the refund of subsequent contributions to pioneer customers (Exhibit 2, Tab 1, p. 8).

Only the CAC (B.C.) et al. commented on the main extension policy and test. It supported the revised test on the basis that it would provide the correct price signal for customers deciding whether to install natural gas, and that it will tend to reduce PNG's capital requirements [CAC (B.C.) et al. Argument, pp. 13 and 14].

In the current circumstances, the Commission approves the proposed new main extension test subject to review of the actual tariff proposal when it is filed.

<u>Service Connection Charges</u>

PNG applied to increase the service connection charge in order to collect from each new customer, the full average cost of a service line, regulator and meter. For 2001, this charge is estimated to be $1000 (Exhibit 1, Tab 2, p. 11). This is somewhat less than the average cost of service connections for PNG-West in 2000 ($1,364) and slightly less than the six-year average for the years 1995 to 2000 ($1,073) (Exhibit 2, Tab 1,

p. 5). PNG submitted that the rationale for charging new customers the full average cost of the service connection, was the lack of cash flow. PNG testified that it simply did not have sufficient funds to construct new services unless the customer was prepared to pay the cost (T1: 191).

PNG agreed that charging new customers the average cost of a service connection would result in some customers paying more and others less than the actual costs incurred by the Utility in providing their connections. However, the Utility submitted that the proposal was consistent with other aspects of utility operations where "postage-stamp" rates were applied. Moreover, PNG stated that it believed that the cost of most service connections fell in a reasonably narrow band around the average cost. However, the Utility was not able to supply more disaggregated data showing the range of service connection costs or the percentage of service connections within various cost ranges (Exhibit 2, Tab 1, p. 5).

The Utility stated that it had considered, as alternatives to the postage-stamp charge, charging either the estimated or actual cost of individual service connections and had rejected those approaches. PNG concluded that charging the actual cost would be considered unacceptable by new customers when the actual cost exceeded a previous estimate, and that charging the estimated cost, while acceptable to customers, would increase administrative burden and costs for the Utility. Nevertheless, PNG stated that it would give further consideration to service connection fees based on estimated costs (Exhibit 2, Tab 1, p. 7). When asked about alternative approaches, PNG stated that it was not seeking a permanent arrangement but, at the present time, for financing reasons PNG was requesting approval of a user-pay approach (T3: 571).

The increased service connection charge was neither supported nor opposed in argument.

Commission Determination

In the present circumstances, the Commission directs PNG to charge new customers the estimated full cost of each service connection. The proposal is generally fair to new and existing customers and it minimizes the Utility's financial exposure to new customers.

As the finances of PNG improve, the Commission will request that the Utility consider an approach such as that of BC Gas (which charges a lower standard fee for most service connections and a surcharge once the estimated cost exceeds a certain limit that is higher than the standard fee) which is preferable in its trade-off between fairness and administrative ease.

2.7.5 Company Use Gas Charge in Rates

The cost of company use gas in 2001 is projected to be $3.363 million or $0.106/GJ of total forecast deliveries and minimum annual bill quantities (T4: 648; Exhibit 1B, p. 9).

The $0.106/GJ charge is included in all Delivery Charges, including those billed as Deficiency Volumes under the minimum annual bill provision of the Methanex contracts. PNG defers the after-tax value of company use gas charges received with respect to Deficiency Volumes (T2: 247-251; Exhibit 16). When the Deficiency Volumes are delivered in a future period, PNG draws down the deferral account to pay for the fuel gas that is consumed to deliver the Deficiency Volumes. In the event the Deficiency Volumes become non-deliverable, the deferred amount becomes a credit balance deferral that would go back to the credit of the remaining customers on the system (T2: 251).

Methanex proposed that the company use gas charge should be a simple flow-through to all customers that reflects the use and cost of this gas. The charge would be calculated based on actual volumes moved each month. For industrial customers, Methanex proposed the charge be limited to uses that relate to gas transmission, and exclude those on the distribution system. As it will not be able to make up all of the Deficiency Volumes that it has incurred, Methanex argued that it should be credited with the company use gas charges that relate to non-deliverable Deficiency Volumes. Methanex also requested more visible accounting of deferred company use gas charges (Methanex Argument, pp. 15-17).

Under the Methanex proposal the charge for company use gas would apply to actual deliveries, as a variable charge that is separate from the Delivery Charge. However, this approach is inconsistent with the current Methanex service contracts, as the company use gas cost has been included in Deficiency Volume payments for many years (T4: 659). Both a Delivery Charge that includes the cost of company use gas and the 80 percent factor that is used to calculate the minimum bill are longstanding features of the Methanex contracts. Adoption of Methanex's approach would cause rates in 2001 for other customers to increase (T4: 659).

Looking to the future, PNG has offered to replace the minimum annual bill provision in its industrial contracts with a demand/commodity rate structure (Exhibit 2, Tab 1, p. 26). PNG stated it is likely the commodity portion of the rate would include variable costs such as compression fuel, and therefore would meet Methanex's objective. On the other hand, with demand/commodity rates there would be no make-up of prepaid Deficiency Volumes (T4: 660-661). PNG stated that to date demand/commodity rates have not found favour with its large industrial customers (Exhibit 2, Tab 1, p. 26). PNG also stated that, as long as it is obliged to deliver Deficiency Volumes to Methanex, there is no basis to refund the corresponding deferred company use gas charges to any customer (PNG Reply, p. 10).

Methanex indicated that it was indifferent between demand/commodity rates and a minimum annual bill (take-or-pay) rate structure. The Company felt that either cost recovery mechanism could be structured in such a way as to result in the same outcome (T6: 1031).

A second concern with PNG's company use gas methodology was that, since Deficiency Volumes are predicted in 2001, customers using gas pay only part of the real cost of company use gas related to their deliveries. By including all forecast and minimum bill volumes in the calculation, PNG calculated a company use gas charge of $0.106/GJ. The full cost of delivering each GJ can be calculated using the company use gas usage rate of 2.71 percent and the unit cost of $7.07/GJ, resulting in a charge of $0.192/GJ.

The difference between $0.106 and $0.192/GJ is recovered via the minimum annual bill payments, and PNG defers this revenue. Nevertheless, PNG must pay for all of the $3.363 million of company use gas in 2001; presumably this additional cost would be carried forward in the deferral account that PNG has requested. If the Deficiency Volumes eventually become non-deliverable, the deferred revenue would revert to customers and offset the cost of PNG's extra gas purchases in 2001. If Methanex starts up for 2002, it would appear that company use gas costs for all customers would increase to cover the cost of gas to deliver the Deficiency Volumes.

One possible response to this situation would be to include the full company use gas cost of $0.192/GJ in all Delivery Charges. However, this might lead to criticism that PNG rates recover more than its projected cost of service.

Commission Determination

The Commission notes that the large increase in gas prices and the Methanex plant shutdown have focused attention on how the cost of company use gas is recovered in rates. PNG's practice of averaging the projected cost of company use gas over all the Delivery Charge quantities that are forecast for the year gives rise to certain concerns. Eventually, the solution may be a variable company use gas charge that applies to actual deliveries, more or less as Methanex proposed. However, the Commission is not prepared to make this isolated change to the transportation service contracts at this time. The interests of PNG and other customers would not be adequately protected if this one aspect of the service contracts is changed.

Similarly, the current transportation service contracts with Methanex and the other large industrials identify minimum annual bill payments that are based on the approved Delivery Charges. The contracts make no provision for refunding part of the payments if Deficiency Volumes become non-deliverable. The Commission is not prepared to change this one aspect of the service contracts without considering all relevant aspects of the contracts.

In these circumstances, the Commission accepts the continuation of PNG's current company use gas practices because the industrial contracts are the result of negotiations many years ago which may well have considered tradeoffs between various Utility and customer obligations. It would be unfair to select one issue for change without considering the fairness of all the obligations in their aggregate. It is apparent that PNG's methodology relies on a deferral account to reconcile company use gas costs and revenues. The details about how the deferral account will function are unclear. PNG should file a timely report that sets out how the proposed company use gas deferral account and the account for deferral of company use gas associated with Deficiency Volumes will function in 2001, 2002 and 2003. The Commission expects that both of these deferral accounts will be interest bearing accounts.

The Commission notes that start-up of the Methanex plant would immediately render the proposed company use gas charges out-of-date. If the methanol plant was operating at normal levels, the company use gas charge would increase (Exhibit 2B, p. 7). In the event Methanex starts up, it appears necessary for PNG to immediately request an increase in the company use gas charge.

2.8 Return on Equity and Capital Structure

2.8.1 Capital Structure

PNG has applied for a common equity component of 36.0 percent within an overall capital structure as shown in the table below. The capital structure approved by Commission Order No. G-37-00 is provided for comparison purposes (Exhibit 1B, p. 26).

	Application 2001	ADR 2000
Short-Term Debt	4.48 %	3.53 %
Long-Term Debt	56.07 %	57.05 %
Preferred Shares	3.46 %	3.41 %
Common Equity	36.00 %	36.00 %
	100.00 %	100.00 %

The arguments on capital structure were more concerned with PNG's liquidity problems, with Methanex arguing that the Company's actual capital structure is carrying too much short-term debt, especially with the need to finance the $12 million balloon payment in 2002 (Methanex Argument, p. 4). These liquidity issues were dealt with in Section 2.4.

In its 1998 Revenue Requirement/Rate Design Decision, the Commission determined that, for rate making purposes, the appropriate equity component is the actual equity component of PNG subject to a ceiling of 36.0 percent. Any equity in excess of 36.0 percent will attract the short-term debt rate. The Commission determined the dollar value by subtracting the acquisition premium related to Fort St. John, and the common equity shown for PNG (N.E.) and for Fort St. John from the consolidated equity value.

The Commission also stated:

> "After review of the evidence, the Commission is convinced that there is significant benefit to allowing management as much flexibility in determining its capital structure as is consistent with sound rate making. Indeed, the Commission agrees with the expert witnesses provided by both PNG and Methanex, that the views of management with respect to the capital structure should be reflected in rates except where the resulting ratios are clearly unreasonable or there is evidence that cross-subsidization between utility and non-utility operations has occurred." (June 18, 1998 Decision, p. 17)

The Commission agrees that the capital structure in Exhibit 1B should be used in conjunction with the automatic rate of return on equity adjustment mechanism to establish the rates for service.

2.8.2 Return on Common Equity

PNG used a 10 percent rate of return on common equity for the purpose of determining its 2001 rate of return on rate base (Exhibit 1B page 26). This rate of return on common equity is made up of the Commission's 9.25 percent authorized common equity return for a benchmark low risk utility and PNG's 75 basis point increment for its higher business risks compared to those of the benchmark utility.

Methanex argued that PNG should not get the same return that a utility able to serve its customers at competitive rates does (Methanex Argument p. 14). More specifically, the CAC (B.C.) et al. argued that continuation of the Industrial Customer Deliveries Deferral Account allows the Company to maintain its revenue requirement and avoid the risk associated with the possible load loss. It therefore removes the business risk for which the premium on the ROE is supposed to be compensation. Although the CAC (B.C.) et al. believed that the Commission should not grant PNG the Industrial Customers Deliveries

Deferral Account, it stated that, if it does, the 75 basis point premium on the ROE should be reduced to reflect the lower risk the company is assuming [CAC (B.C.) et al. Argument, p. 15].

Eurocan also argued that, by granting PNG's Applications, the Commission would be sheltering PNG from the risk for which it seeks a premium return (Eurocan Argument, p. 23).

PNG argued that it cannot gain access to long-term debt markets and that its shareholders are making a significant contribution to the liquidity problem by increasing PNG's common equity at a rate of approximately $4 million per year without obtaining a common equity return on the excess equity (PNG Reply, p. 3).

Following a generic hearing into Rates of Return on Common Equity, the Commission issued its Decision on June 10, 1994. In that Decision, the Commission determined the required rate of return on equity for a low-risk, high-grade utility based on long-term Canada bond yields. The Commission then went on to consider the capital structure and perceived business risk of the individual utilities. From the evidence on business risks facing PNG, the Commission determined that an incremental premium of 75 basis points relative to the set of low-risk, high-grade utilities should be awarded.

The Commission summarized the business risk of PNG as follows:

> "The Commission recognizes the risks imposed upon PNG by the high concentration of industrial sales; however, it believes the short-term impacts of these risks to be significantly mitigated through the government guarantees [Methanex], the use of minimum bill provisions [other industrials], and the existence of a deferral account associated with interruptible sales. ..... The Commission finds that the major risk facing the shareholders of PNG is the risk of permanent impairment through the loss of one or more of the industrial customers." (June 10, 1994 Decision, p. 34)

This Application has been made with respect to the 2001 fiscal year. PNG argued that its long term risks are, with the closure of the Kitimat plant, greater today than at any time since 1982, and its short-term risks are greater than ever (PNG Argument, p. 11).

The Commission finds that the 75 basis point premium above the low risk utility return awarded through the automatic adjustment formula remains appropriate for PNG in 2001.

2.8.3 Interest on Short-term Debt

PNG testified that the average rate of its bankers acceptances outstanding at December 31, 2000 was 7.74 percent, but its Applications used an average short-term debt rate of 7.50 percent for 2001. Its most recent forecast is an average of 7.25 percent for 2001 (T4: 582). PNG argued that substituting this rate for the 7.50 percent rate used in the Applications would have no appreciable impact on the required return on rate base and any variance arising from a difference in projected and actual short-term interest rates is carried in a deferral account for recovery in the following fiscal year (PNG Argument, p. 11).

The Commission normally prefers to use the most accurate forecast of costs to set revenue requirements but in this instance the 0.25 percent is insufficient to warrant an adjustment when any actual variance will flow to the deferral account.

2.9 Rate Impacts: October 2000 through December 2001

The effects of the Commission's determinations in this Chapter are to improve PNG revenues and to direct a substantial contribution by customers to improve the cash flow of the Utility. While PNG is responsible for funding the approved capital structure of the Utility, the Commission is committed to ameliorate the present circumstances by minimizing the cash requirements of PNG to the extent it can. All of the additional ratepayer payments directed by the Commission are appropriate for customers to contribute, since they are to write down accounts which have been determined to be the responsibility of customers to fund at some point in time.

The actions directed by the Commission to assist PNG with its liquidity problems have been specified in this Chapter and include charges to write down specific rate-based deferral accounts, gas cost riders to offset the GCVA, commercial and industrial class rate restructuring with the additional revenues directed to pay down deferral accounts, the allocation of the ICDDA surplus to write down deferral accounts and the revamping of the Utility mains extension test and service connection requirements so as to minimize Utility financing for these functions.

The Commission requested that Intervenors provide submissions on its jurisdiction to set rates, pursuant to Section 59 of the Act, in the event that the approved revenue requirement awarded PNG resulted in customer rates which were uncompetitive with other energy options. In arriving at this Decision the Commission has performed the balancing of the interests of the Utility and ratepayers as required by the Act.

As a result, the Commission confirms the interim rates previously set by the Commission except for the reductions directed for the 2001 industrial and RS3 rate restructuring charges requested by PNG. PNG is to provide a detailed report by year end of all deferral accounts which remain

outstanding. PNG is to file with the Commission appropriate tariff changes, along with the Utility financial schedules consistent with the determinations in this Decision.

3.0 METHANEX APPLICATION

3.1 Introduction

Methanex is a public company with headquarters in Vancouver. Methanex produces methanol, a product derived from natural gas that is a building block for petrochemical products including acetic acid and formaldehyde. Methanol is also the fuel of choice for new fuel cell technologies developed by Ballard and others for automotive and stationary power applications.

Methanex is the world's largest producer of methanol, manufacturing approximately 24 percent of the world's supply. Methanex operates or has an interest in methanol plants located in British Columbia, Alberta, Louisiana, Trinidad, New Zealand and Chile.

Methanex's Kitimat plant was constructed in 1982 and has a current production capacity of about 450,000 to 500,000 metric tonnes ("MT") of methanol per year. The Kitimat plant purchases approximately 22-25 PJ of natural gas annually, making it the largest single gas consumer in British Columbia. Approximately 70 percent of this gas is required to produce methanol. The remaining 30 percent is used by two ammonia plants located on-site at the Kitimat plant. Natural gas deliveries to Methanex are about two-thirds of the volumes transported on the PNG-West system and provide 45 percent of PNG-West's total operating margin when the plant is operating at normal levels.

The methanol industry has undergone substantial globalization over the past decade. While the Kitimat plant is efficient in terms of manufacturing capability, it has very high input costs, even relative to other North American plants. Methanol can be transported easily and, therefore, new methanol plants are often located near "distressed" or "stranded" natural gas production areas. Plants located in these areas often have long term, low cost, fixed gas supply contracts that are much lower in cost than plants in more developed regions. These regions generally also have competitive tax structures.

The Kitimat plant is currently Methanex's highest cost operation. It lost more than $30 million in 1999, of which $21 million were cash losses. At the end of 1999, Methanex wrote off approximately $80 million in investment in the Kitimat plant. Methanex estimated plant losses in 2000 at $23 million (Exhibit 4, p. 4).

Methanex indicated that the key competitive disadvantage of the Kitimat plant relative to other North American producers is the high cost of the PNG transportation toll (Exhibit 4, p. 5). Methanex has historically paid about $22 million per year to PNG for firm and interruptible gas transportation services. This amounts to about $37 per MT of methanol or about 30 percent of the Kitimat plant's variable costs excluding gas purchases (Exhibit 4, p. 9). Provincial government capital taxes, provincial government sales taxes, motor fuel taxes and property taxes were cited as other factors that make the Kitimat plant unprofitable (Exhibit 4, p. 5).

On May 24, 2000 Methanex announced that it would close its Kitimat methanol plant for an initial period of 12 months commencing July 1, 2000 (PNG Final Argument, p. 1). The methanol plant remains closed today.

Methanex is contractually obligated to provide hydrogen to one ammonia plant (the purge plant) until 2011 (T5: 806). As a result of its shutdown on July 1, 2000, Methanex exercised its option to suspend delivery of hydrogen for reasons of economic hardship. Consequently, the ammonia plant closed and has not reopened. Methanex is permitted to suspend delivery of hydrogen for reasons of economic hardship for a maximum of three one-year periods over the life of the contract (T6: 1036). Thereafter, Methanex would have to provide alternate feedstock or replace the output of the plant through third party purchases (T6: 1036). The other ammonia plant ("the KAM plant") continued to operate when the methanol plant closed. It shut down in December, but restarted in mid-February, 2001. The KAM plant is currently using about 12,000 GJ/day (T1: 134).

Methanex's plants have different cost structures. Plants in North America have higher costs than plants in Chile, New Zealand and Trinidad (T5: 741). Methanex does not expect to make the Kitimat plant competitive with methanol plants in other regions in the world that have access to very low cost gas (T5: 737). Methanex believes that there would be a basis for operating the Kitimat plant if it becomes the best, most competitive plant in North America (T5: 783) and its cost structure is reduced so that the Kitimat plant is at least very close to cash break even in the bottom of the business cycle (T5: 742 and 743).

Methanex has tried, prior to and following the Kitimat plant closure, to find a way to keep the plant open on a sustainable basis. Methanex tried to negotiate a cost restructuring economic plan for the Kitimat plant through the Job Protection Commission, tried to negotiate support from the Provincial Government and tried to renegotiate gas transportation costs with PNG (Exhibit 3, p. 4). The AIP between PNG and Methanex was concluded in October 2000. The AIP was subject to certain conditions including PNG receiving financial assistance of up to $45 million in loans or guarantees from the Provincial Government or other parties and Methanex reaching an agreement with the Provincial Government through the Job Protection Commission with respect to further cost restructuring. The Provincial Government was unwilling to provide the financial assistance sought by PNG, and Methanex was unable to achieve concessions from the Provincial Government with respect to its cost restructuring. Consequently, the AIP has not been implemented.

On December 21, 2000 Methanex applied to the Commission, pursuant to Sections 58, 59 and 60 of the Act, for approval of a load retention rate and asked that the Load Retention Rate Application (the "Methanex Application") be considered with PNG's rate application. The Commission agreed to add the Methanex Application to the PNG 2001 Revenue Requirements proceeding and notified Intervenors in a letter dated January 9, 2001.

3.2 Methanex's Current Contracts with PNG versus the Methanex Application

Methanex's current contracts with PNG, the proposed load retention rate and differences between the proposed load retention rate and the AIP are described below. The views of Methanex, PNG and other Intervenors with respect to the Methanex Application are also identified.

Methanex's Current Contracts with PNG

Methanex currently has three contracts for firm gas transportation from PNG. The first contract for 44 MMcfd expires on October 31, 2002, the second contract for 2 MMcfd expires on October 31, 2003 and the third contract for 11 MMcfd expires on October 31, 2009. Methanex estimated firm energy delivered under the three contracts at 64,003 GJ/day until October 31, 2002, 14,600 GJ/day from November 1, 2002 to October 31, 2003 and 12,352 GJ/day from November 1, 2003 to October 31, 2009 (Exhibit 5, Tab 1, p. 12).

The firm transportation contracts include an 80 percent take-or-pay commitment from Methanex. When Methanex pays for gas not taken because they are taking less gas than the 80 percent minimum, the transportation service that they have paid for but not yet taken is called deficiency volumes. When Methanex takes above 80 percent in a subsequent period, the deliveries above 80 percent are considered deliveries of deficiency volumes and do not attract any charges because they have already been prepaid (T2: 249 and 250). The deficiency volumes may be carried forward to the earlier of the termination of the contract or five years on a first-in, first-out basis (T2: 250).

The Commission set the 2001 firm rate for Methanex at $0.997/GJ in Chapter 2 of this Decision. Since the cost of company use gas is included in the rate, Methanex is required to pay the cost of company use gas on the 80 percent minimum even if actual deliveries are below the minimum.

Methanex also uses interruptible service on PNG when the Kitimat plant is operating. The 2001 rate for interruptible transportation service approved by the Commission in Chapter 2 of this Decision is $0.318/GJ including company use gas.

Methanex's Application

The Methanex Application proposed to combine the three firm agreements into one contract. The new contact would be effective November 1, 2000 for firm transportation of 64,000 GJ/day from November 1, 2000 to October 31, 2009. The new agreement would involve a 100 percent take-or-pay commitment, but Methanex would be able to terminate the contract upon payment of a scheduled amount that reflects the present value of remaining commitments under the new contract.

Methanex proposed a firm rate of $0.32/GJ plus the cost of company use gas for transmission service and an interruptible rate of $0.16/GJ plus the cost of company use gas for transmission service. The $0.32 rate approximates the present value of the take-or-pay requirement under the existing agreements at $0.942/GJ, the rate in effect after July 1, 2000 (Methanex Argument on behalf of its load retention proposal, pp. 8 and 14), assuming a discount rate of 10 percent per annum. The $0.16/GJ interruptible rate will cover all variable costs of operation plus make a contribution to PNG's fixed costs (Methanex Argument on behalf of its load retention proposal, p. 9).

The cost of company use gas that is additional to firm and interruptible rates would reflect the cost of company use gas for transmission service only. Methanex suggested that the cost of company use gas for transmission service would be $0.04-0.06/GJ less than the cost of company use gas currently embedded in rates (Exhibit 5, p. 18).

In return for the above rates, Methanex proposed to provide an $18 million loan to PNG and 10 percent of the Kitimat plant's positive cash flow. The terms of the loan are not described in the Methanex Application, but Methanex proposed at the hearing that the loan would be recovered over the life of the contract and that the interest rate would be around 10 percent (T5: 748). If Methanex terminates the contract, the balance outstanding on the loan would be deducted from the termination payment (T6: 965). Methanex indicates that amounts of negative cash flow would carry forward to offset positive cash flow before calculating the 10 percent profit sharing amount payable to PNG (T6: 1025).

Firm plus interruptible natural gas deliveries to Methanex when the methanol plant is operating are typically about 72,000-75,000 GJ/day (T1: 134). Of this total, the ammonia plants use about 20,000 GJ/day (T5: 790). Methanex proposed that the load retention rate would apply to the natural gas delivered to Methanex for use by the ammonia plants as well as the gas delivered for use at the methanol plant (T5: 791).

Differences between the Methanex Application and the Agreement In Principle

Methanex's Application is similar to the October AIP with certain notable exceptions. These exceptions are related to the level of financial assistance provided to PNG, the exclusion of assistance from the Provincial Government in reducing Methanex's cost structure, the profit sharing mechanism and the rights of Methanex if it is not operating.

- The AIP required that PNG obtain financing and loan guarantees of up to $45 million from the Provincial Government or other parties. Methanex proposes to loan PNG $18 million.
- The AIP required that Methanex obtain the assistance of the Provincial Government with regard to its cost restructuring. Such assistance has not been forthcoming.
- The AIP indicated that PNG would receive a share of positive margins from the operation of the Kitimat plant, but no percentage figure was specified. Methanex's load retention rate proposal specifies the amount payable to PNG at 10 percent of positive cash flow.
- The AIP indicated that Methanex's ongoing obligations or the required termination payment would be reduced if it temporarily or permanently suspended operations at the Kitimat plant prior to October 31, 2009 and PNG was able to re-contract with another party. Methanex has no right to be reimbursed under its load retention rate proposal.

Methanex's Rationale for its Proposal

Methanex suggested that the load retention rate would give the Kitimat plant an opportunity to become sustainable by reducing costs and providing certainty with respect to a portion of Methanex's cost structure for a period of eight to nine years. With respect to its costs, Methanex noted that its annual costs with the Kitimat plant shut down are in excess of $20 million (U.S.). Operating today with $5.00 U.S. gas would cut those losses in half, and approval of the load retention rate would cut those losses in half again (T5: 753). Methanex believed that $5.00 U.S. for gas is unsustainable (T5: 753), and indicated that a combination of methanol prices above historical averages, some reduction in gas costs and some adjustments to transportation rates could lead to a scenario in which the plant would be cash positive (T5: 753 and 754). With respect to certainty, Methanex argued that the rate increases proposed by PNG have shattered any semblance of rate stability, and that the possibility that this could happen in the future is not acceptable to Methanex (Methanex's Argument on behalf of its Load Retention Proposal, pp. 12 and 13). Methanex further submitted that reduced rates and increased certainty clearly lead to an enhanced probability of reopening the Kitimat plant on a long-term sustainable basis (Methanex's Argument on behalf of its Load Retention Proposal, p. 14).

Methanex also submitted that PNG and its customers would get at least the same revenue from Methanex that they would have if Methanex paid the take-or-pay amount based on rates in effect on July 1, 2000 (Methanex's Argument on behalf of its Load Retention Proposal, p. 7). Methanex argued that there would, in addition, be an upside for PNG and its ratepayers in terms of interruptible revenue and profit sharing (page 8). While the $18 million loan to PNG does not meet PNG's original desires ($45 million in credit from the Provincial Government or other parties), Methanex submitted that the $18 million should, when coupled with available borrowings from the Royal Bank, provide PNG with sufficient liquidity to deal with cash flow issues arising out of PNG-West's regulated activities (Methanex Argument on behalf of its Load Retention Proposal, p. 10).

Methanex further argued that its load retention rate proposal would help to retain the employment, household income and taxes related to the Kitimat plant (Methanex's Argument on behalf of its Load Retention Proposal, p. 15).

PNG's View of Methanex's Proposal

PNG opposed Methanex's Application. PNG argued that approval of the load retention rate would not assure a long term sustainable future for the plant (PNG Reply to Methanex, p. 3). In fact, PNG believed that it could move gas for nothing and the plant would still not open (T1:137). PNG noted that the stated reason for the shutdown of the Kitimat plant was the substantial increase in the price of natural gas. In this regard, PNG indicated that natural gas prices were Cdn$4.00/GJ at the time the methanol plant closed, but are now approximately Cdn$7.00/GJ (T1: 15).

PNG submitted that the Methanex Application was materially different from the AIP in three ways. First, the AIP required that Methanex receive Provincial Government support for the Kitimat plant. This support was not forthcoming. PNG's view, based on the history of the Kitimat plant, was that the plant will not operate in the long term in the absence of Provincial Government support (PNG Reply to Methanex, p. 5).

Second, the $18 million loan from Methanex would be much lower than the $45 million line of credit required under the AIP. PNG argued that the higher amount would be necessary to provide PNG with sufficient credit to meet its obligations. PNG also argued that a creditor relationship with Methanex is unworkable, that the terms of the loan have not been settled and that the bank would be unwilling to maintain its relationship with PNG if the Methanex Application was approved (PNG Reply to Methanex, p. 6).

Third, PNG submitted that the 10 percent profit sharing figure proposed by Methanex would be too low and is unacceptable to PNG.

PNG submitted that approval of the Methanex Application would significantly reduce PNG's near term cash flow when it must repay an outstanding $12 million debenture due in July 2002. In PNG's view, the Methanex Application would also deprive PNG, its lenders and its customers of the potential benefits of re-marketing the available capacity to Methanex or a third party upon termination of the existing PNG/Methanex contracts (PNG Reply to Methanex, p. 4).

During the hearing, PNG indicated that it was prepared to remove some of the conditions precedent if the rate were higher than $0.32/GJ. PNG also indicated that it had offered a $0.50/GJ rate to Methanex, and that PNG believed it could handle its own financing if it had a $0.50/GJ toll (T3: 425).

Intervenor Submissions

Canfor supported a Methanex load retention scheme provided the remaining PNG customers do not subsidize the scheme in any way.

Eurocan had no objection to a load retention rate for Methanex provided it did not adversely affect other customers, it generated revenue that would not otherwise be available to PNG, it compensated PNG for all variable costs of providing the service, and it made a contribution to fixed costs.

The CAC (B.C.) et al. opposed the Methanex Application. The CAC (B.C.) et al. noted the evidence of Methanex that:

> "To be reasonable the Load Retention Rate must increase the probability of the Kitimat Plant becoming sustainable and provide PNG and its customers with revenues that over time will exceed the Methanex Take-or-Pay and the variable costs of serving the Kitimat Plant." (Exhibit 4A, p. 11)

The CAC (B.C.) et al. submitted that Methanex had not established that its load retention rate proposal would meet either of these conditions.

Skeena argued that although there is significant uncertainty over the future operation of the methanol facility, there is enough information to suggest that PNG's assumption may not be correct and, with a suitable agreement, Methanex would be able to operate continuously. Skeena submitted that PNG should not ignore this possibility, and that the Commission should encourage PNG and Methanex to resume negotiations with the assistance of Commission staff.

3.3 Commission Findings

A load retention rate is a reduced rate designed to retain a customer who would otherwise leave the system. In order to maximize the contribution to other customers the load retention rate should be set at the highest rate that the customer is willing to pay. At a minimum the load retention rate must be high enough to leave other ratepayers no worse off than if the customer ceased taking service from the utility as well as cover the variable costs of the utility in providing the service. In the longer term, a load retention rate must at least compensate other ratepayers for the value of any rate base reductions that would occur in the absence of the load retention rate or for the potential revenue from alternative use of the pipeline capacity, whichever is greater.

The Impact of a Load Retention Rate on the Sustainability of the Kitimat Plant

Methanex recognized that a load retention rate must increase the probability of the Kitimat plant becoming sustainable (Exhibit 4A, p. 11). No parties argued that the Kitimat plant would likely be sustainable without a load retention rate. The question therefore becomes whether the load retention rate would provide any realistic possibility of the plant reopening on a sustainable basis. Methanex indicated that the reduction in variable costs and the certainty with respect to a portion of its cost structure would provide a better basis for restarting the plant (T5: 774). PNG suggested that Methanex would not operate on a sustainable basis even if the Methanex Application were approved. The CAC (B.C.) et al. also submitted that Methanex had not established that approval of its application would increase the probability of the Kitimat plant becoming sustainable (Final Argument to Methanex, pp. 6-8).

While the Commission agrees that a load retention rate would not in itself be sufficient to cause Methanex to operate the Kitimat plant on a sustainable basis, the Commission finds that the plant could become sustainable if gas prices moderate or Methanex obtains concessions from the Provincial Government. The Commission agrees with Methanex that a load retention rate would reduce its variable costs and provide certainty with respect to a portion of its cost structure and is satisfied that a load retention rate would increase the probability that Methanex will operate the Kitimat plant on a sustainable basis. Once agreed to, the PNG transportation cost would be committed so that the choice to operate the plant would not include the committed transportation cost or the fixed cost of the methanol plant which has already been written off.

<u>Rate Required to Match Take-or-Pay Requirements Before Adjustments</u>

Methanex recognized that a load retention rate must provide PNG and its customers with revenues that over time would exceed the Methanex Take-or-Pay and the variable costs of serving the Kitimat plant (Exhibit 4A, p. 11). PNG and Methanex provided estimates of the present value of revenues to PNG under six scenarios in Exhibit 2B (PNG), Exhibit 2F (PNG), Exhibit 5 (Methanex) and Exhibit 5A (Methanex). PNG's estimates assumed a valuation date of January 1, 2001 and a discount rate of 12.34 percent per annum based on PNG's pre-tax weighted average cost of capital. Methanex's estimates assumed a valuation date of November 1, 2000 and were discounted at either 10 percent per annum or 12.34 percent per annum. A 10 percent discount rate had been assumed in negotiations leading up to the AIP (Methanex Argument on behalf of its Load Retention Proposal, p. 14).

The Commission finds that any load retention rate should be implemented on a prospective basis. The Commission also finds that a discount rate of 12.34 percent is appropriate when considering impacts of the alternative load retention proposal from the ratepayers' perspective.

Under the current contracts, Methanex is obligated to pay PNG for 80 percent of its contract demand at the approved rate even if it does not take deliveries. For the purposes of comparing revenues to PNG with and without a load retention rate, the Commission finds it appropriate to assume that revenues will be in line with Methanex's 80 percent Take-or-Pay commitment and that Methanex will not operate if there is no load retention rate.

Based on the 2001 firm rate of $0.997/GJ established for Methanex in Chapter 2, future nominal firm rate increases of 2 percent per annum, an implementation date of July 1, 2001 and a discount rate of 12.34 percent per annum, the present value of revenue to PNG under the current contracts is estimated at $39.6 million in Table 3.3.1. **The calculations in the Technical Appendix show that a firm load retention rate of about $0.30/GJ would be required to generate the same revenue as the current contracts before consideration of variable costs, rate base reductions and the value of additional available capacity provided to Methanex.**

Increased Variable Costs

To hold other ratepayers harmless, revenues under the load retention rate should be adjusted by the variable costs of serving Methanex. These variable costs include the additional cost of company use gas over and above the amounts contributed by Methanex and additional compressor costs.

Revenue estimates based on the firm and interruptible load retention rates do not adequately reflect the higher company use gas costs imposed on other customers. PNG estimated company use gas costs at $0.281/GJ if Methanex operates (Exhibit 2B, p. 7). If Methanex does not operate, the cost of company use gas could be about $0.192/GJ *(2.71% company use gas factor X $7.07/GJ unit cost – see Section 2.7.5)*. The difference of $0.089/GJ represents the extra cost faced by other customers. Assuming deliveries to other customers of about 17,504,106 GJ (Exhibit 2B, p. 7) per annum, the annual additional company use gas cost paid by other customers could be about $1.6 million. This annual cost could be expected to vary over time with changes in the price of gas.

PNG indicated that it would need to hire one to two more compressor station operators if Methanex were taking normal volumes (Exhibit 2B, p. 8) and estimated the cost of the compressor station operators at about $250,000 per annum (T2: 253). The compressors also require periodic maintenance. With Methanex operating, PNG "turns around" one compressor per year at a cost of about $350,000. Without Methanex, PNG will only have to turn around a compressor about once every five or six years (T2: 254). The annual cost savings could be around $280,000.

The Commission finds that the increment to the firm load retention rate required to compensate ratepayers for variable costs related to Methanex, assuming variable costs of $2 million per annum, is about $0.09/GJ. See Technical Appendix.

Rate Base Reductions Post-2002

PNG estimated the initial cost of facilities installed for Methanex at $61.2 million and the net book value of these facilities in 2000 at $37.3 million (Exhibit 2, Tab 1, p. 13). Under the current contacts, all of these facilities are needed by PNG until at least October 31, 2002 since PNG must be prepared to deliver gas to Methanex if called upon. After expiry of the first contract on October 31, 2002, some of the facilities installed for Methanex (or, perhaps, other facilities) could be deemed to be no longer used or useful and removed from the rate base. This would reduce the rates to PNG's remaining customers.

Methanex's load retention rate proposal extends the contract to October 31, 2009. In this case, the facilities would be required throughout the life of the contract, and any rate base adjustments and the corresponding rate reductions would be postponed until at least October 31, 2009. A load retention rate would have to compensate other ratepayers for the postponement of rate base reductions if ratepayers are to be held harmless.

It is uncertain what components of PNG's rate base could be removed and sold after October 31, 2002 if there are no new contracts for the excess capacity. PNG's position was that an underutilized asset could not be removed from rate base if the asset is still necessary to serve existing customers and if the asset could not be replaced with correctly sized facilities for less than the depreciated value of the asset (T3: 501). PNG indicated that the replacement cost of any new pipeline to accommodate the loads on the PNG system without Methanex would far exceed the total rate base that is in place today (T3: 500 and 501). PNG gave evidence that two of the five compressors would see limited, if any, use beyond October 31, 2003 if the methanol plant does not operate (T3: 485 and 486). PNG indicated that it is difficult to imagine the system with loops taken out of service (T3: 490), and that studies would be required to determine which loops could be removed and still deliver design peak day volumes (T3: 491).

Calculations related to the value of rate base reductions to ratepayers are provided in the Technical Appendix. **Assuming that 25 percent of the net book value of assets installed to serve Methanex could be removed from the rate base at the end of 2002, the increment to the firm load retention rate required to compensate customers for rate base reductions is estimated at about $0.07/GJ.**

<u>Opportunity Cost of Pipeline Capacity</u>

An alternative to removing rate base would be to find new users for the capacity given up by Methanex. Methanex's load retention proposal would provide Methanex with additional firm transportation service of 17,823 TJ per year from November 1, 2002 to October 31, 2003 and 18,634 TJ per year from November 1, 2003 to October 31, 2009. Since PNG could attempt to market this capacity if Methanex permanently closed, the load retention rate must compensate PNG and ratepayers for the potential value of this capacity.

PNG is searching for opportunities to utilize the excess capacity (T1: 173). PNG suggested that a new modern mill in PNG's service area is a possibility (T1: 105), but that it is unlikely that the mill would be built in the next five years (T1: 106). The possibility that PNG will be unable to market the excess capacity must also be taken into consideration. The value of the additional capacity would be zero in this case.

Calculations related to the value of the excess pipeline capacity are provided in the Technical Appendix based on two scenarios. In the first case, Methanex is assumed to contract for the capacity upon the expiry of the first contract on October 31, 2002. Even assuming a firm rate as low as $0.15/GJ above incremental costs, the addition to the load retention rate required to compensate customers for the capacity is estimated at $0.09/GJ. In the second scenario, if another customer is assumed to contract for 5 million GJ per annum starting January 1, 2005, an additional $0.05/GJ would be required to compensate customers for the capacity.

The Commission finds that approximately $0.07/GJ would be required to compensate other ratepayers for the alternative value of the capacity or for future rate base reductions.

Value of Financial Assistance and Profit Sharing

Methanex’s Application included a loan to PNG of $18 million and a 10 percent share of the Kitimat plant’s positive cash flow. It did not provide sufficient detail to rigorously examine the benefits to PNG of these components. The loan would provide value to PNG and ratepayers if PNG were unable to obtain financing from an alternate source at a similar interest rate. The profit sharing component would provide additional revenue to PNG if Methanex were profitable, but the benefits to PNG cannot be quantified (Methanex Policy Evidence, p. 16).

A long term load retention rate must leave other ratepayers at least as well off as they would be under the current contracts. As such, the load retention option must generate revenues to PNG at least as high as revenues under the current contracts after adjusting for increased variable costs and the greater of either the potential savings to ratepayers post-2002 due to rate base reductions or the potential value of the additional pipeline capacity given up by PNG. In addition, the Commission finds that fairness to other customers demands that a multi-year load retention rate should be the maximum rate that Methanex is willing to pay. Determining an appropriate rate involves considerable judgment on the part of the Commission due to uncertainty around the potential savings to customers through rate base reductions, the potential value of the pipeline capacity post 2002 and the maximum rate that Methanex would be willing to pay. **Taking into account all of the evidence, the Commission finds that an appropriate long term load retention rate for Methanex would be no less than $0.46/GJ, based on a contract commencement date of July 1, 2001.**

The Commission, therefore, finds that the $0.32/GJ load retention rate proposed by Methanex does not adequately compensate other ratepayers and denies Methanex's Application. The Commission is hopeful that PNG and Methanex will resume negotiations and quickly agree upon a new rate for Methanex that is beneficial to PNG, Methanex and other customers. The rate approved for Methanex in Chapter 2 will remain in effect unless PNG and Methanex successfully negotiate an agreement for an extended term load retention rate that is acceptable to the Commission.

If PNG and Methanex agree on a long term load retention rate, PNG will receive less revenue during the last six months of 2001 than it would under the current contract arrangements. For example, the difference in revenue to PNG during the last six months of 2001 would be the existing take or pay revenue of $9.3 million (9.3 million GJ x $0.997/GJ) less the load retention revenue of $5.6 million (11.6 million GJ firm x $0.46/GJ + 1.4 million GJ interruptible x $0.16/GJ) plus fuel gas. The Commission considers that the rates determined for other customers in Chapter 2 are close to their maximum ability to pay. Therefore, to continue with this example, the revenue reduction to PNG of $3.7 million (which will affect the ICDDA) might require the diversion of some Commercial and Industrial restructuring revenue from the paydown of the deferral accounts to allow PNG to meet its approved revenue requirement.

The Commission anticipates that a load retention rate agreement would provide stability and certainty to PNG through 2009. This should allow the Utility to obtain debt financing. Other customers would benefit in future years as Methanex continues to contribute to PNG's revenues.

Dated at the City of Vancouver, in the Province of British Columbia, this 25th day of May 2001.

Original signed by:
Peter Ostergaard
Chair

Original signed by:
Paul G. Bradley
Commissioner

Original signed by:
Nadine F. Nicholls
Commissioner

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-51-01

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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 October to December 2000 Rates and 2001 Revenue Requirements
and
An Application by Methanex Corporation

BEFORE: P. Ostergaard, Chair)
P.G. Bradley, Commissioner) May 25, 2001
N.F. Nicholls, Commissioner)

O R D E R

WHEREAS:

A. On September 28, 2000, Pacific Northern Gas Ltd. ("PNG") filed an application to increase its rates on an interim and final basis, effective October 1, 2000 and January 1, 2001 ("the Application"), pursuant to Sections 91 and 58 of the Utilities Commission Act; and

B. The Application proposed to increase rates to all customers as a result of liquidity issues caused by the July 1, 2000 Methanex plant shutdown, higher costs of purchasing the natural gas commodity, and increased revenue requirements for the year ending December 31, 2001; and

C. Commission Order No. G-94-00 approved an interim increase, effective October 1, 2000; and

D. Commission Order No. G-113-00 established a Regulatory Agenda for an oral public hearing into the Application in Terrace, B.C. beginning on Monday, March 5, 2001; and

E. On December 8, 2000, PNG revised the Application to flow-through projected higher natural gas purchase costs for 2001 under the approved gas supply contracts for the service area, based on November 23, 2000 forward gas prices. On December 18, 2000, PNG further revised the Application, and included a request to increase the gas supply cost deferral account Rider from $0.10/GJ to $0.30/GJ, based on recovery of the account balance to the end of 2000 over three years; and

1. Commission Order No. G-127-00 accepted PNG's December 18, 2000 projection of total natural gas purchase costs for 2001 and approved gas supply charges based on deeming gas commodity purchase costs as 100 percent variable charges, as interim rates, effective January 1, 2001. Corresponding changes to fixed monthly charges that include a quantity of gas commodity were also approved as interim rates; and

G. On December 21, 2000, Methanex Corporation ("Methanex") applied to the Commission for a Load Retention Rate, which was added to the Application proceedings as Intervenor Evidence in accordance with the Regulatory Timetable in Commission Order No. G-113-00; and

H. Pursuant to a January 29, 2001 application by PNG, Commission Order No. G-14-01 approved an interim increase of $1.068/GJ to the gas supply cost deferral account Riders for Rate Schedules 1, 2, 4, 5, 6, and 7, effective February 1, 2001. Corresponding increases to minimum monthly charges for Rate Schedules 4, 5, and 6 that include a quantity of gas commodity were also approved as interim rates effective February 1, 2001; and

. . ./2

I. The Commission has 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 interim rates approved by Order No. G-94-00 are confirmed as final for the period October 1, 2000 to December 31, 2000.

2. The rates as applied for on the "Summary of Rates Schedule Effective January 1, 2001" on pages 2 and 3 of Exhibit 1B are confirmed as final effective January 1, 2001, except that the Industrial and RS-3 restructuring charges are reduced by 50 percent retroactive to January 1, 2001, and the restructuring charge for Commercial RS-2 rates is set at zero for the period January 1, 2001 to June 30, 2001 and set at $0.85/GJ effective July 1, 2001.

3. The Gas Supply Charges as applied for on the "Summary of Rates Schedule Effective February 1, 2001" on page 5 of Exhibit 1B are confirmed as final effective February 1, 2001.

4. PNG is to file, on a timely basis, amended Summary of Rates and Bill Comparison schedules as found in Exhibit 1B, conforming to the terms of the Commission's Decision.

5. PNG is to file permanent Gas Tariff Rate Schedules that are in accordance with the terms of the Commission's Decision.

6. PNG is to comply with all directions contained in the Commission's Decision.

7. The Methanex Application is denied and PNG is directed to advise the Commission by June 15, 2001 on the status of negotiations with Methanex towards establishing a long-term load retention rate based on the findings in the Commission's Decision.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of May 2001.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

TECHNICAL APPENDIX

Methanex recognized that a load retention rate must provide PNG and its customers with revenues that over time will at least cover the Methanex Take-or-Pay arrangements and the variable costs of serving the Kitimat plant. At the hearing no parties suggested that Methanex would be likely to operate on a sustainable basis without a load retention rate. The Commission must, therefore, consider two base-case scenarios: the current contracts remain in force until their expiration dates with Methanex shut down or a load retention rate is agreed upon and Methanex operates.

Under the current contracts Methanex is obligated to pay PNG for 80 percent of its contract demand at the approved rate even if it does not take deliveries. PNG retains the right to the excess pipeline capacity that will become available as the Methanex contracts expire. In the event that this capacity is not used and useful after October 31, 2002, the Commission may be able to remove assets from rate base, thereby reducing rates to customers.

Net benefits under the current contracts may then be expressed as:

Current Contract Revenue (“CCR”) + Max. of [Capacity Value, Value of Rate Base Reductions (“RBR”)]

The load retention rate provides revenue to PNG from 2001 to 2009. If the methanol plant is assumed to operate in this period, then PNG and ratepayers will incur variable costs that should be deducted from this revenue in determining net benefits to ratepayers. In this case, net benefits to ratepayers could be expressed as:

Firm Load Retention Revenue (“FLRR”) + Interruptible Load Retention Revenue (“ILRR”) – Increased Variable Costs (“VC”)

The Commission’s objective is to find a firm load retention rate, R, such that the benefits to ratepayers will be at least as high under the load retention rate as they are under the current contracts. That is, find R such that:

FLRR + ILRR – VC >= CCR + Max of (Capacity Value, Value of RBR)

which implies:

FLRR >= CCR – ILRR + VC + Max of (Capacity Value, Value of RBR)

The minimum long term retention rate level R is equal to the FLRR divided by the present value of firm capacity under the LR rate (“PVFC”). Consequently, dividing each component by the PVFC yields the minimum discounted rate level R:

R >= (CCR/PVFC) – (ILRR/PVFC) + (VC/PVFC) + [Max of (Capacity Value, Value of RBR)/PVFC]

Table 3.3.1 provides estimates of the present value of revenue to PNG under the current contracts, the present value of interruptible revenue under a load retention rate and present value of firm deliveries (in GJ) for both scenarios. The estimates in Table 3.3.1 and the rates discussed below assume that the load retention rate would commence July 1, 2001 and a discount rate of 12.34 percent per annum.

Rate Required Before Consideration of Variable Costs, Capacity Value and Rate Base Reductions

In Table 3.3.1, CCR is estimated at $39.6 million based on a firm rate of $0.997/GJ in 2001 with nominal future increases of 2 percent per annum. ILRR is estimated at $2.4 million based on an interruptible load retention rate of $0.160/GJ and the PVFC is estimated at 123.8 million GJ in Table 3.3.1. Based on these figures, (CCR/PVFC) = $0.320/GJ and (ILRR/PVFC) = $0.019/GJ. The firm load retention rate required before consideration of variable costs, the value of the capacity and rate base reductions is estimated at $0.320/GJ - $0.019/GJ = $0.301/GJ.

Variable Costs

Since VC and PVFC are both present values at the same discount rate over the same period, VC/PVFC is the same as annual variable costs divided by the annual firm capacity under the load retention rate. Annual firm capacity under the load retention rate is about 23.2 million GJ. If the additional cost of compressor station operators, the additional cost of turning around compressors and extra company use gas cost incurred by other customers amount to $2 million per year, then the addition to the load retention rate required to compensate PNG's other customers would be about $0.09/GJ.

Rate Base Reductions Post 2002

PNG provided a summary of depreciation on assets installed for Methanex based on current depreciation rates in Exhibit 2, Tab 1, p. 13. The net book value of assets installed for Methanex at the end of 2002 is about $33.8 million. Extending the depreciation through to 2009 suggests a net book value of about $21.6 million by the end of 2009 (see Table 3.3.2).

At any given time the present value of depreciation and the return on capital paid by shareholders to PNG is approximately the same as the current book value of the assets if the discount rate equals the weighted average cost of capital. As such, the difference between payments from ratepayers if the assets installed to serve Methanex were removed from rate base at the end of 2002 and the payments from ratepayers if the assets were removed from rate base at the end of 2009 may be approximated as the difference between the present value of the net book value in 2002 and the present value of the net book value in 2009. At a discount rate of 12.34 percent, the present value of the net book value of assets in 2002 is about $28.4 million and the present value of the net book value of assets in 2009 is about $8.0 million. The potential savings to ratepayers before adjusting for the additional impact of taxes is, therefore, about $20.4 million.

Assuming there is little or no capital cost allowance remaining on the assets installed to serve Methanex, the difference in potential rate base reductions would have to be corrected for tax effects, since 43.5 cents of every dollar collected towards depreciation goes to taxes (T1: 97). After adjusting for taxes, the potential savings to ratepayers could be about $20.4 million / (1-0.435) = $36.1 million.

It is uncertain what components of rate base could be removed and sold after October 31, 2002 if there are no new contracts for the excess capacity. Assuming that 25 percent of book value of assets installed for Methanex could be removed from rate base after the end of 2002, the present value of savings to ratepayers could be about $9.0 million. The required increment to the load retention rate would, in this case, be about $9.0 million / 123.8 million GJ = $0.07/GJ.

Capacity Value

The present value of firm capacity under the current contracts is estimated at 38.0 million GJ in Table 3.3.1, based on 80 percent of contract demand. The present value of firm capacity at 100 percent of contract demand is about 47.6 million GJ. The present value of firm capacity under the load retention rate (PVFC) is estimated at 123.8 million GJ in Table 3.3.1. The pipeline capacity given up by PNG by signing the load retention rate is therefore 123.8 million GJ – 47.6 million GJ = 76.2 million GJ.

The value of this capacity is obviously uncertain. There may be some possibility that Methanex would recontract for the capacity upon expiry of its first contract. Alternately, another existing or new customer could pick up some fraction of the capacity. The following examples illustrate how the value of the capacity could be calculated based on two specific sets of assumptions.

For the first example, assume that Methanex would recontract for the capacity at $0.15/GJ above variable costs after the first contract expires in the absence of a load retention rate agreement. In this case, the present value of revenue would be about 76.2 million GJ X $0.15/GJ = $11,430,000. Dividing this revenue by the PVFC (123.8 million GJ) indicates that an additional $0.09/GJ would be required to compensate PNG and customers for the capacity.

Alternately, assume that, in the absence of a load retention rate agreement, new or existing customers come forward to take an additional 5,000,000 GJ per year from January 1, 2005 to October 31, 2009. Discounting this capacity at 12.34 percent per annum yields a present value of about 12.3 million GJ. If the rate were, for example, $0.50/GJ above incremental cost, then the present value of the additional revenue would be about $6.2 million. Dividing this revenue by the PVFC (123.8 million GJ) indicates that an additional $0.05/GJ would be required to compensate PNG and customers for the capacity in this case.

The firm load retention rate required before consideration of variable costs, the value of capacity and rate base reductions is estimated at about $0.30/GJ. Assuming an adjustment of $0.09/GJ for variable costs and an adjustment of $0.07/GJ for the value of the capacity or rate base reductions, the firm load retention rate required after consideration of these factors could be about $0.46/GJ.

Table 3.3.1
Present Value of Revenues to PNG
Based on a Firm Rate of $0.9973/GJ in 2001 with Future Increases of 2% Per Annum Under the Existing Contracts

	2001	2002	2003	2004	2005	2006	2007	2008	2009	Present Value	
Present Value of Revenues at 80% Take-or-Pay Level Based on Rate Approved in Chapter 2											
Contract 1 (GJ)	7,171,019	11,951,698	0	0	0	0	0	0	0	17,604,282	
Contract 2 (GJ)	1,792,896	3,585,792	3,585,792	3,585,792	3,585,792	3,585,792	3,585,792	3,585,792	2,988,160	19,109,197	
Contract 3 (GJ)	326,304	652,608	543,840	0	0	0	0	0	0	1,328,796	
Total Deliveries (GJ)	9,290,219	16,190,098	4,129,632	3,585,792	3,585,792	3,585,792	3,585,792	3,585,792	2,988,160	38,042,275	
Firm Rate	$0.9973	$1.0172	$1.0376	$1.0583	$1.0795	$1.1011	$1.1231	$1.1456	$1.1685		
Total Revenue	$9,265,135	$16,469,313	$4,284,869	$3,794,997	$3,870,897	$3,948,315	$4,027,281	$4,107,827	$3,491,653	$39,567,943	(CCR)
Present Value of Revenues Under Methanex's Proposed Load Retention Rate											
Contract 1 (GJ)	8,963,774	17,927,548	17,927,548	17,927,548	17,927,548	17,927,548	17,927,548	17,927,548	14,939,623	95,538,456	
Contract 2 (GJ)	2,241,120	4,482,240	4,482,240	4,482,240	4,482,240	4,482,240	4,482,240	4,482,240	3,735,200	23,886,496	
Contract 3 (GJ)	407,880	815,760	815,760	815,760	815,760	815,760	815,760	815,760	679,800	4,347,301	
Total Firm (GJ)	11,612,774	23,225,548	23,225,548	23,225,548	23,225,548	23,225,548	23,225,548	23,225,548	19,354,623	123,772,254	(PVFC)
Interruptible (GJ)	1,382,500	2,765,000	2,765,000	2,765,000	2,765,000	2,765,000	2,765,000	2,765,000	2,304,167	14,735,079	
Total Deliveries (GJ)	12,995,274	25,990,548	25,990,548	25,990,548	25,990,548	25,990,548	25,990,548	25,990,548	21,658,790	138,507,333	
Interruptible Rate	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16		
Interruptible Revenue	$221,200	$442,400	$442,400	$442,400	$442,400	$442,400	$442,400	$442,400	$368,667	$2,357,613	(ILRR)
Discount Factors (12.34%)	0.9713	0.8902	0.7924	0.7053	0.6279	0.5589	0.4975	0.4429	0.3942		

Table 3.3.2
Current Book Value of Assets Installed for Methanex
Based on PNG's response to BCUC IR No. 1, Question 4.1

		Amount	1999	2000	2001	2002	2003	2004	2005	2006
462	Compr Str	2,631,176	85,250	85,250	85,250	85,250	85,250	85,250	85,250	85,250
462	Compr Str	44,600	1,445	1,445	1,445	1,445	1,445	1,445	1,445	1,445
463	Reg. Struct	289,158	13,012	13,012	13,012	13,012	13,012	13,012	13,012	13,012
465	Mains	19,013,537	475,338	475,338	475,338	475,338	475,338	475,338	475,338	475,338
465	Mains	6,633,624	165,841	165,841	165,841	165,841	165,841	165,841	165,841	165,841
465	Mains	1,678	42	42	42	42	42	42	42	42
465	Mains	4,771,786	119,295	119,295	119,295	119,295	119,295	119,295	119,295	119,295
465	Mains	3,958,601	98,965	98,965	98,965	98,965	98,965	98,965	98,965	98,965
465	Mains	7,588,112	189,703	189,703	189,703	189,703	189,703	189,703	189,703	189,703
466	Compressor	9,948,079	359,126	359,126	359,126	359,126	359,126	359,126	359,126	359,126
466	Equipment	2,000,000	72,200	72,200	72,200	72,200	72,200	72,200	72,200	72,200
466		2,674,262	96,541	96,541	96,541	96,541	96,541	96,541	96,541	96,541
466		285,952	10,323	10,323	10,323	10,323	10,323	10,323	10,323	10,323
467	Reg.	1,152,790	53,144	53,144	53,144	53,144	53,144	53,144	53,144	53,144
467	Equipment	151,454	6,982	6,982	6,982	6,982	6,982	6,982	6,982	6,982
468	Commun.	3,250	219	219	69					
468	Commun.	19780	1,335	1,335	1,335	74				
TOTAL	Total	61,167,839	1,748,761	1,748,761	1,748,611	1,747,281	1,747,207	1,747,207	1,747,207	1,747,207
	Cumulative Depreciation		22,084,199	23,832,960	25,581,571	27,328,852	29,076,059	30,823,266	32,570,473	34,317,680
	Net Book Value		39,083,640	37,334,879	35,586,268	33,838,987	32,091,780	30,344,573	28,597,366	26,850,159

Net Book Value in 2002	$33,838,987
Discount Period	1.5 years
Discount Rate	12.34%
Present Value at July 1, 2001	$28,419,454
Net Book Value in 2009	$21,643,692
Discount Period	8.5 years
Discount Rate	12.34%
Present Value at July 1, 2001	$8,049,868
Difference in Present Values	$20,369,585

PACIFIC NORTHERN GAS LTD.
Years Ended December 31
($ 000's)

EXTRAPOLATED CASH FLOWS - Proposed Rates No UDITR or MDR, No Dividends

	2001	2002	2003	2004	2005
Cash from operations	21,545	8,052	5,226	10,643	8,110
Cash used in investing activities					
- Gas Variance Account	2,701	(0)	0	0	-
-other	(6,186)	(6,222)	(6,012)	(6,264)	(6,354)
Repayment of long term debt	(3,300)	(13,300)	(1,300)	(1,800)	(1,800)
Redemption of preferred shares	-	-	-	-	-
Other financing activities	52	-	-	-	-
Common dividends	-	-	-	-	-
Preferred dividends	(338)	(338)	(338)	(338)	(338)
Increase (decrease) in cash	14,474	(11,809)	(2,424)	2,241	(382)

EXTRAPOLATED RECEIPTS AND DISBURSEMENTS - Proposed Rates No UDITR or MDR, No Dividends

	2001	2002	2003	2004	2005
RECEIPTS					
Sales Receipts - Current Rates	95,205	98,040	95,904	95,390	95,894
- Proposed Rates	1,878	1,633	1,632	1,641	1,641
Transportation Receipts Ex Methanex	10,447	9,022	9,022	9,031	9,031
Methanex	18,808	17,599	4,235	3,630	3,630
Hedge Receipts	19,996	-	-	-	-
Off-system Sales Receipts	31,987	31,686	30,810	30,132	30,105
Other Receipts	2,661	2,761	561	561	561
SUBTOTAL	180,983	160,740	142,164	140,385	140,862
DISBURSEMENTS					
O&M & G&A	16,188	13,730	13,934	14,233	14,360
Interest Expense (long term)	7,607	6,720	5,941	5,790	5,616
Principal (long term debt)	3,300	13,300	1,300	1,800	1,800
Interest Expense (Short Term)	1,499	1,209	1,604	1,668	1,585
Gas Purchases	123,553	110,708	105,828	105,996	107,107
Capital Expenditures	5,694	5,779	5,866	5,954	6,043
Deferred Charges Expenditures	870	757	240	496	496
Common Dividends	-	-	-	-	-
Preferred Dividends	338	338	338	338	338
Taxes	7,458	20,006	9,535	1,868	3,897
SUBTOTAL	166,508	172,548	144,586	138,144	141,244
TOTAL	14,475	(11,808)	(2,422)	2,241	(382)
Memo:					
Bank Indebtedness (cash) EOY	$8,948	$20,756	$23,180	$20,939	$21,321
Est. Bank Line Peak In Year	$29,237	$23,925	$23,177	$23,939	$24,321
Return on Actual Equity	9.1%	5.9%	-2.1%	-1.9%	-2.4%

Except as noted below, the extrapolations reflect PNG's February 28, 2001 revisions to its rate applications for 2001, including the change in the income tax rate. In addition, the period through January 2002 includes the February 1 Gas Cost Recovery Rate Rider increase of $1.068/GJ for PNG-West core market customers.

The other key assumptions implicit in the extrapolated cash flows are:

a) Rates for PNG West's industrial and core market remain at 2001 levels throughout the period;

b) Rates for the PNG (N.E.) core market change inaccordance with PNG's gas purchase costs;

c) The methanol plant does not operate during the five year period;

d) Other large industrial transportation volumes are lower by 386 TJ than PNG's application (reflecting the revised volume estimate provided by Eurocan in its evidence) with additional losses of 1,035 TJ forecast for 2002 which continue into 2003;

e) Any operating margin available to PNG in excess of its estimated cost of service in 2002 is used to amortize deferral account balances.

APPEARANCES

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R.B. WALLACE M. COLLETTE	Methanex Corporation
K. GUSTAFSON	Eurocan Pulp and Paper Co. Ltd.
J. POWELL	Skeena Cellulose Inc.
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]
MAYOR JIM TOGYI	District of Fort St. James
J. RIGSBY	Terrace and District Chamber of Commerce
MAYOR TOM EUVERMAN	District of Houston

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ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

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District of Houston – Panel	MAYOR TOM EUVERMAN
Terrace and District Chamber of Commerce – Panel	JUSTIN RIGSBY
Eurocan Pulp and Paper Co. Ltd. – Panel	WILLIAM LEGROW LON SCHROEDER
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Herself	MAYOR SHARON HARTWELL The Village of Telkwa
Herself	MARIE STEVENS
Himself	FRED GLOVER

LIST OF EXHIBITS

	Exhibit No.
Pacific Northern Gas Ltd. Application for October to December 2000 Rates and 2001 Revenue Requirements, dated September 28, 2000 with December 18, 2000 revised pages	1
Pacific Northern Gas Ltd. cover letter	1A
Pacific Northern Gas Ltd. letter, dated March 1, 2001 and revised Schedules, dated February 28, 2001	1B
Pacific Northern Gas Ltd. October to December 2000 Rates and 2001 Revenue Requirements Application Executive Summary, dated September 28, 2000	1C
Pacific Northern Gas Ltd. three page document to B.C. Utilities Commission, dated March 6, 2001	1D
Pacific Northern Gas Ltd. responses, dated January 22, 2001, to: B.C. Utilities Commission Information Request No. 1; Methanex Corporation Information Request No. 1; Methanex Corporation Information Request No. 2; Eurocan Pulp and Paper Co. Ltd., Information Request No. 1; and British Columbia Public Interest Advocacy Centre Information Request No. 1	2
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Pacific Northern Gas Ltd. responses to Eurocan Pulp and Paper Co. Ltd. Information Request No. 2, dated March 2, 2001	2C
Pacific Northern Gas Ltd. revised response to B.C. Utilities Commission Information Request No. 1, question 5.0 regarding Cash Flows, dated March 5, 2001	2D
Exhibit No. 2D corrected page 6 of 7 and page 7 of 7	2E
Pacific Northern Gas Ltd. Scenarios A and B in response to B.C. Utilities Commission Information Request No. 2, question 22.2, dated March 7, 2001	2F
Pacific Northern Gas Ltd. response to Undertaking to Mr. Fulton at transcript pages 475-477, Additional Cash Flow Extrapolation Scenarios, dated March 8, 2001	2G
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