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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-55-07

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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.
(PNG-West Division)
for Approval of 2007 Revenue Requirements and Rates

BEFORE: L.A. Zaozirny, Panel Chair and Commissioner
L.A. O'Hara, Commissioner

May 29, 2007

O R D E R

WHEREAS:

A. On October 26, 2006, Pacific Northern Gas Ltd. ("PNG", "PNG-West" and "Granisle") filed for approval of its 2007 Revenue Requirements Application ("the Application") to amend its rates for the Delivery Charge, Company Use Gas Cost ("CUGC") (not applicable to Granisle) and Revenue Stabilization Adjustment Mechanism ("RSAM") Rider (not applicable to Granisle) on an interim and permanent basis, effective January 1, 2007, pursuant to Sections 89 and 58 of the Utilities Commission Act ("the Act"); and

B. Methanex Corporation ("Methanex") closed its methanol/ammonia complex in Kitimat in November 2005 and the Methanex contract was terminated effective March 1, 2006. As a result, PNG's 2007 margin revenue forecast does not include any fixed demand charges from Methanex; and

C. In its Application, PNG forecasts a 2007 revenue deficiency of approximately $1.415 million before a proposed deferred tax drawdown. This revenue deficiency is primarily due to a reduction in forecast margin revenue recovery from customers. This margin revenue reduction is offset by PNG crediting to its cost of service $6.752 million from the contract termination payment of $23.3 million that Methanex paid to PNG on February 28, 2006; and

D. PNG proposes to draw down the deferred income tax balance of $14.462 million by $600,000 in the 2007 test year to further mitigate the impact of the forecast 2007 margin revenue reduction. This drawdown would reduce the 2007 revenue deficiency from $1.415 million to $527,000; and

E. As a consequence of the aforementioned, PNG proposes to increase the rate for the Delivery Charge for all natural gas and Granisle propane service customers, except West Fraser Mills-Kitimat ("West Fraser") who has a contract in place that provides for fixed demand charges over the term of the contract and, therefore, any rate change would not apply to this customer; and

G. PNG also proposes to decrease, for all natural gas customers except West Fraser, the CUGC, and increase the propane Delivery Charge rate for Granisle residential customers, effective January 1, 2007.

H. On November 23, 2006, by Order No. G-146-06, the Commission, pursuant to Section 89 of the Act, approved for PNG an interim refundable rate increase in the Delivery Charge rates for all classes of customers, except West Fraser, and an interim rate increase in the RSAM rider for Residential (not applicable to Granisle) and Small Commercial Sales customers, all as filed in the Application, effective January 1, 2007. In the same order, the Commission, pursuant to Sections 61(4) and 89 of the Act, also approved the interim decrease in the CUGC rate, as filed in the Application, effective January 1, 2007; and

I. On December 5, 2006, PNG filed its Fourth Quarter 2006 Report (the "Report") on gas supply costs and the commodity Gas Cost Variance Account ("GCVA") balances for PNG-West and Granisle based on November 21, 2006 natural gas and propane forward prices. For PNG-West, PNG requests no changes to Gas Supply Cost Recovery Charges and the GCVA credit rate rider of $0.642/GJ, and proposes to retain in place the Company use gas price and Unaccounted for Gas ("UAF") volume deferral account GCVA credit rider of $0.254/GJ. PNG also requests to maintain the CUGC rate approved on an interim basis by the Commission under Order No. G-146-06 as interim pending the review of this Application; and

J. By Order No. G-166-06 dated December 15, 2006, the Commission approved the permanent commodity rates for PNG-West and Granisle, as filed in the Report, effective January 1, 2007, except for the CUGC rates that remain interim rates pending review of this Application; and

K. By Commission Order No. G-2-07, the Commission determined that a written public hearing process should be established to review this Application and set a regulatory timetable; and

L. On February 23, 2007, PNG filed an update to its 2007 Revenue Requirements Application ("the Revised Application"), which forecasts a revenue deficiency of $570,000, up from $527,000 in the Application filed on October 26, 2006. The Revised Application proposes to draw down a total of $900,000, up from $600,000 in the original Application, from the deferred income tax balance in the 2007 test year; and

M. In accordance with the regulatory timetable, PNG filed a Final Argument on March 15, 2007. Intervenors, specifically the Ministry of Energy, Mines and Petroleum Resources, BC Old Age Pensions' Organization et al., and Mr. R.W. Childs, filed Final Arguments on March 22, 2007 and PNG filed a Reply Argument on March 29, 2007 to address the issues raised by Intervenors; and

N. The Commission has considered the Application, the Revised Application, the evidence adduced in relation thereto, and written Arguments, all as set forth and discussed in the Reasons attached as Appendix A to this Order.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves a 2007 revenue deficiency adjusted from $570,000 to approximately $362,279, as filed in the schedules accompanying PNG's Revised Application and adjusted in the Reasons attached as Appendix A to this Order.

2. The Commission approves PNG's request to draw down a total of $900,000 from the deferred income tax balance for 2007.

3. The approved 2007 revenue deficiency and the resulting rates for the Gas Delivery Charge are less than the revenue deficiency used to derive the interim rates which have been in effect since January 1, 2007. PNG is to file an amended Summary of Rates and Bill Comparison schedule conforming to the terms of the Reasons attached as Appendix A to this Order, along with a method for refunding excess payments to customers.

4. PNG is to file, on a timely basis, amended Gas Tariff Rate Schedules in accordance with this Order.

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

DATED at the City of Vancouver, in the Province of British Columbia, this 29th day of May 2007.

BY ORDER

Original signed by:

L.A. Zaozirny
Panel Chair and Commissioner

Attachment

An Application by Pacific Northern Gas Ltd.
(PNG-West Division)
for Approval of 2007 Revenue Requirements and Rates

REASONS FOR DECISION

1.0 INTRODUCTION

1.1 Background

Pacific Northern Gas Ltd. (“PNG”, the “Utility”, the “Company”) delivers natural gas to about 23,000 customers, including large industrial operations, in a region extending west of Prince George to tidewater at Kitimat and Prince Rupert. PNG’s transmission pipeline connects with the Spectra Energy (formerly Duke Energy) system near Summit Lake north of Prince George and extends 587 kilometers to the west coast. In addition, propane vapour distribution is provided in the community of Granisle. A wholly-owned subsidiary, Pacific Northern Gas (N.E.) Ltd. [“PNG(N.E.)”], serves some 16,000 customers in the Fort St. John, Dawson Creek, and Tumbler Ridge areas of northeastern British Columbia.

PNG’s head office is in Vancouver. Customer care and administrative functions of both PNG and PNG(N.E.) are supported from a regional office in Terrace. On August 30, 2005, one of PNG’s largest industrial customers, Methanex Corporation (“Methanex”), gave notice of termination of its transportation agreement with the Company. Under the terms of the agreement, Methanex made a termination payment to the Company of approximately $23.3 million on February 28, 2006, the effective date of the termination. On August 16, 2006, by Order No. G-99-06, the Commission approved that PNG record the termination payment in an interest-bearing credit deferral account, to be amortized into income over the 44-month period from March 1, 2006 to October 31, 2009, to coincide with the original date of expiry of the transportation agreement. In the same Order, the Commission approved PNG's application to recover in customer rates the reduction in revenue from the Methanex contract termination.

1.2 The Application

On October 26, 2006, PNG filed for approval of its 2007 Revenue Requirements Application (“the Application”) to amend its rates for the Delivery Charge, Company Use Gas Cost (“CUGC”) (not applicable to Granisle) and Revenue Stabilization Adjustment Mechanism (“RSAM”) Rider (not applicable to Granisle) on an interim and permanent basis, effective January 1, 2007, pursuant to Sections 89 and 58 of the Utilities Commission Act (“the Act”).

In its Application, PNG forecasts a 2007 revenue deficiency of approximately $1.415 million which is mainly due to a reduction in forecast margin revenue recovery from customers. This margin revenue reduction is substantially offset by PNG crediting to its cost of service $6.752 million from the contract termination payment of $23.3 million that Methanex paid to PNG on February 28, 2006. Without this credit, the revenue deficiency would have been significantly higher. To further mitigate the impact of the forecast 2007 margin revenue reduction, PNG proposes to draw down the deferred income tax ("DIT") balance of $14.462 million by $600,000 in the 2007 test year. This proposed drawdown and credit to the 2007 income tax expense would reduce the 2007 revenue deficiency from $1.415 million to $527,000.

PNG proposes to increase the Delivery Charge rate for all natural gas customers, effective January 1, 2007, except West Fraser Mills-Kitimat ("West Fraser") who has a contract in place that provides for fixed demand charges over the term of the contract. PNG also proposes to amortize the projected September 30, 2006 RSAM balance over a three year period and recover the annual amortization by way of a rate rider. The rider is only applicable to the Residential and Small Commercial Sales rate classes for natural gas customers, and amounts to $0.458/GJ effective January 1, 2007. The overall net increase in rates will increase the annual natural gas bills for the Residential and Small Commercial Sales classes by approximately 3.1 and 3.3 percent, respectively.

PNG also proposes to decrease, for all natural gas customers except West Fraser, the CUGC from $0.185/GJ in 2006 to an interim rate of $0.128/GJ, effective January 1, 2007.

PNG proposes to increase the propane Delivery Charge rate for Granisle residential customers, effective January 1, 2007. The increase in rates will increase annual propane bills for these customers by approximately 2 percent.

By Order No. G-146-06 dated November 23, 2006, the Commission, pursuant to Section 89 of the Act, approved for PNG an interim refundable rate increase in Delivery Charge rates for all classes of customers, except West Fraser, and an interim rate increase in the RSAM rider for Residential (not applicable to Granisle propane service customers) and Small Commercial Sales customers, all as filed in the Application, effective January 1, 2007. In the same order, the Commission, pursuant to Sections 61(4) and 89 of the Act, also approved the interim CUGC rate of $0.128/GJ, as filed in the Application, effective January 1, 2007.

On December 5, 2006 PNG filed its Fourth Quarter 2006 Report (the "Report") on gas supply costs and the commodity Gas Cost Variance Account ("GCVA") balances for PNG-West and Granisle based on November 21, 2006 natural gas and propane forward prices. For PNG-West, PNG requests no changes to Gas Supply Cost Recovery Charges and the GCVA credit rate rider of $0.642/GJ, and proposes to retain in place the Company use gas price and Unaccounted for Gas ("UAF") volume deferral account GCVA credit rider of $0.254/GJ. PNG also requests that there be no change to the Company use gas cost rate approved on an interim basis by the Commission under Order No. G-146-06 and to maintain this rate as interim pending the review of this Application.

Commission Order No. G-166-06 dated December 15, 2006 approved the permanent commodity rates for PNG-West and Granisle, as filed in the Report, effective January 1, 2007, except for the CUGC rates that remain interim pending review of PNG's Application.

On February 23, 2007, PNG West filed an update to its 2007 Revenue Requirements Application ("Revised Application") having regard to actual results for 2006, the low-risk benchmark return for 2007 and other pertinent information that was not available prior to the original Application in October 2006. The Revised Application forecasts a revenue deficiency of $570,000, up from $527,000 in the original Application. The Applicant further proposes to draw down a total of $900,000, up from $600,000 in the original Application, from the deferred income tax balance in the 2007 test year to offset lower forecast use per account for residential and small commercial customers in the revised Application in relation to the original Application in October 2006. PNG proposes a slight increase in delivery charges and the RSAM rider from the interim rates approved per Commission Order No. G-146-06 for residential and small commercial customers. The proposed permanent RSAM rider for 2007 is $0.46/GJ, up from the interim RSAM rider of $0.458/GJ, effective January 1, 2007. PNG also proposes a small increase in the unit CUGC rate from the interim rate of $0.128/GJ to $0.136/GJ, effective January 1, 2007.

1.3 The Written Hearing Regulatory Process

Interventions were received from the British Columbia Public Interest Advocacy Centre on behalf of the BC Old Age Pensioners' Organization, Council of Senior Citizens' Organizations of B.C., Federated Anti-Poverty Groups of B.C., Senior Citizen's Association of B.C., End Legislated Poverty, and the Tenants Rights Action Coalition (collectively known as "BCOAPO"). The B.C. Ministry of Energy, Mines and Petroleum Resources ("MEMPR"), David Humber (Westpine MDF/West Fraser Mills Ltd), R.W. Childs (BC Government Services Employee's Union) and Gunter Oldendorf (representing himself) also intervened.

BCOAPO submitted that an oral public hearing would be appropriate for this Application, while both PNG and Mr. Childs considered that a written hearing would be more appropriate. The Ministry indicated no preference. The Commission considered the submissions received, and by Commission Order No. G-2-07, determined that a written public hearing process should be established to review the 2007 Application.

By Order No. G-2-07, the Commission established a regulatory timetable which provided three rounds of Commission and two rounds of Intervenor information requests, followed by PNG Final Argument on March 15, 2007, Intervenor Arguments on March 22, 2007 and PNG Reply Argument on March 29, 2007.

2.0 DRAWDOWN OF DEFERRED INCOME TAXES

PNG used the "flow-through" or taxes payable method of accounting for income taxes from inception to July 1, 1978 and resumed this method from 1987 to the present for rate-making purposes. The flow-through method recognizes income taxes currently payable and makes no provision for future income taxes or deferred income taxes ("DIT").

From July 1, 1978 until its suspension on November 6, 1986, PNG used the normalized method of accounting for income taxes, which gave rise to timing differences between the taxes payable and taxes for accounting purposes. During that time period, deferred taxes were recorded for accounting purposes primarily due to depreciation expense being significantly lower than the capital cost allowance deducted for tax purposes, with the expectation that in future periods, the deferred taxes would be drawn down to mitigate rate increases once the depreciation expense exceeds the Capital Cost Allowance ("CCA"); i.e. "cross-over" is reached. The main reason for PNG to suspend the collection of DIT in late 1986 was to lower rates for all customers (Exhibit B-3, BCUC 1.1.1, p. 2).

PNG noted that over the last decade, it has reached "cross-over", where DIT could have been drawn down to mitigate increases in current tax expense, due to depreciation expenses being more than the CCA if PNG had followed normalized tax accounting throughout the period (Exhibit B-3, BCUC 1.1.1, p. 2). In the original Application, PNG requested to draw down $600,000 of its DIT 2006 year-end balance of $14.462 million in 2007 and credit this amount to income tax expense in 2007 to ameliorate the impact of projected lower margin recovery in 2007 on customers' rates (Exhibit B-1, Tab Application, PNG-West, p. 5). The requested drawdown amount has increased in the Revised Application to $900,000 in view of declining forecast use per account for residential and small commercial customers compared to figures used in the original Application (Exhibit B-8, PNG West Update, p. 2) to offset the projected further margin reduction in 2007.

The drawdown of DIT has a multiplier effect on the reduction of revenue requirements in that such a drawdown results in a lower DIT balance and a consequent higher rate base, which leads to an increase in return on common equity and short-term debt expenses. Furthermore, the DIT drawdown has to be grossed up to a before-tax amount and, as a result, taxable income is reduced and overall income tax expenses for rate-making purposes decrease more than the DIT drawdown amount. As PNG illustrated, assuming a corporate tax rate of 34.12 percent, a DIT drawdown of $600,000 would cause a reduction of $910,747 in revenue requirements (Exhibit B-3, BCUC 1.1.8, p. 6).

PNG admits that the risk associated with drawing down DIT in 2007 is a lower cash flow available to the Company, which reduces PNG's financial flexibility having regard to the Company's cash requirement and financial covenants under its bank operating line of credit. PNG determines that a drawdown of $900,000 of DIT is "manageable under most foreseeable circumstances" and will not imperil PNG's ability to maintain its financial health or to comply with its financial covenants. Nevertheless, PNG submits that the $900,000 DIT drawdown should be viewed as a cap because increasing this amount would put pressure on PNG's cash flows and would negatively affect PNG's ability to comply with its financial covenants (PNG's Final Argument, p. 4).

BCOAPO supports the DIT drawdown in principle and notes that "ratepayers have paid in the past for these deferred income taxes and deserve to have the advantage of a drawdown to limit rate increases that are clearly, given BC Hydro rate comparisons, unacceptable and which will lead to increasing problems for the utility. This is particularly the case when the ongoing viability of this utility continues to be in question and the economic situation in the service area continues to be bleak" (BCOAPO Final Argument, pp. 6-7).

Commission Determination

The Commission Panel notes that PNG's DIT balance of $14.462 million at the end of 2006 was accumulated during the period 1978 to 1986 when PNG used the normalized method of accounting for income tax purposes and when, as a result, deferred taxes were recorded due to the CCA for income tax purposes being significantly higher than the depreciation expense for accounting purposes. During that time period PNG was allowed to include the deferred income tax expense in the cost of service to be collected in current rates from all customer classes with the expectation that in future periods the DIT would be drawn down to mitigate rate increases once the depreciation expense recorded exceeded CCA deducted for tax purposes or the cross-over point was reached. The Commission Panel also observes that for the entire last decade the depreciation expense already has exceeded the CCA claimed. In other words, the cross-over has occurred in respect of those assets which gave rise to the DIT balance. Consequently, in those circumstances the DIT balance would have been drawn down to mitigate increases in current income tax expense had PNG still followed the normalized tax accounting method. Finally, the Commission Panel acknowledges that PNG proposes the drawdown primarily to ameliorate the impact of projected lower margin recovery in 2007 on customers' rates in addition to mitigating the scenario described above, which could have justified an application some years earlier.

The Commission Panel has reviewed the National Energy Board's August 1992 Decision, which allowed Westcoast Energy Inc. to draw down its DIT balance. The Commission Panel recognizes that the accumulation of deferred income taxes is intended to protect a future generation of customers from rate increases caused by attainment of the cross-over point. PNG has chosen to preserve the DIT balance for a "rainy day" or for use only when it lacks other means to mitigate rate increases and, as stated by the Applicant, it is facing that circumstance in 2007. Accordingly, the Commission Panel is persuaded that the intergenerational equity principle would be served by allowing a drawdown at this time to moderate the rate increase pressure caused by the projected lower margin recovery in 2007.

The Commission Panel approves PNG's request to draw down a total of $900,000 from its DIT balance in 2007 to mitigate the impact of projected lower margin recovery on customers' rates. Furthermore, the Commission Panel continues to urge PNG to explore other opportunities to reduce costs and improve its competitiveness in rates and services.

3.0 PNG'S ONGOING CHALLENGES

BCOAPO expresses continued concerns with PNG's ongoing problems and the Utility's failure to fully address them. BCOAPO submits that PNG's "… history of significant rate increases, coupled with the economic situation in PNG West's service area, continues to lead to decreases in natural gas deliveries and increases in revenue deficiency … This is exacerbated, particularly for residential customers, when PNG's rates are compared with BC Hydro's electricity rates in the service area … continuing the decline in the utility's customer base and customer use rates" (BCOAPO Final Argument, paras. 2-3). Citing Order No. G-99-06 and the Commission's expectation that PNG "make best efforts to control and where possible, reduce costs", BCOAPO disagrees that PNG has done everything it can to control its costs … at a time "when the ongoing viability of this utility continues to be in question and the economic situation in the service area continues to be bleak" (BCOAPO Final Argument, paras. 4-5, 17, pp. 2, 7).

In his submission, R.W. Childs also comments on the difficult economic conditions in the northwest area "with the closing and dismantling of the Terrace Lumber Co. Mill … the highest unemployment rate in BC and three of the five largest population decreases in Canada according to the 2006 Canada Census … (permanent closure of the area's) second largest retailer Zellers ...". Mr. Childs does not "believe PNG will be able to maintain affordable, reliable, secure and safe gas service until PNG addresses the eroding customer base and usage and introduces specific methods to stop that erosion" (R.W. Childs Final Argument, pp. 1-2).

In response, PNG maintains that it is constantly looking for opportunities to reduce its rates. The most significant current action is the investing of substantial funds, solely at shareholders risk, to obtain the environmental permits required to authorize the construction of the KSL Project pipeline (PNG Reply Argument, para. 4, p. 1). PNG believes that economies of scale and improved utilization of the expanded transmission system will lead to materially lower rates for its existing customers (BCUC 1.1.9). PNG has also been making representations to the Province regarding the level of property taxes paid in respect of PNG's pipeline facilities (PNG Reply Argument, para.4, p. 1).

Commission Determination

In Order No. G-99-06, the Commission stated that it was concerned that "PNG's rates are becoming less competitive" and was "mindful of the concerns expressed by a considerable number of interested parties … including comments concerning the precarious state of the economy of the northwest and the difficulties faced by industrial and commercial and residential customers alike ...". The Commission remains concerned about the current state of the Utility, given the fact that gas deliveries to residential and small commercial customers continue to decline, despite PNG's active participation in a series of rebate programs with marketing and incentives to reach out to existing and new customers.

The Commission Panel agrees with BCOAPO that PNG's Application fails to address sufficiently its current and ongoing challenges, particularly in the light of the looming cessation in October 2009 of the amortization of Methanex termination payment into the cost of service. Accordingly, **PNG is required, in the next revenue requirements application, to file a 5-year projection of revenue requirements and concomitant rate schedules for delivery charges to residential and small commercial customers assuming a scenario without the KSL Project**. The Commission Panel also urges PNG to continue to seek opportunities to reduce its property tax burden; for instance, by continuing discussions with the provincial government and by way of retaining a property tax specialist to review the assessments in relation to the nature of existing assets to ensure PNG is not overpaying at current rates.

4.0 LOAD FORECAST

PNG submitted updated load forecasts as part of its Revised Application (Exhibit B-8, Tab Rates, PNG-West, p. 8). The methodology for the updated load forecast values appears to have remained the same as that used in the original application and further explained in information request ("IR") responses. The Revised Application incorporated 2006 year end actual deliveries rather than projected deliveries.

Residential

PNG forecasts deliveries of 1,447,905 GJ to its residential customers. This value is the product of the test year weighted average customer count and the test year average use per account (Exhibit B-8, Tab Rates, PNG-West, p. 8).

The weighted average customer count for the 2007 test year is 19,178. This equals the residential customer count at December 31, 2006 plus the forecast test year net customer additions multiplied by a 35 percent new customer full-year equivalence factor (Exhibit B-6, BCUC 2.17.1, p. 2). The 35 percent figure was determined having regard to historical information on the timing of customer additions during each year. This information in conjunction with assumed monthly use per account figures resulted in the 35 percent equivalence factor. In general, more customers are attached during the fall than earlier in the year. The test year average use per residential account is 75.5 GJ and is calculated as the mid-point between the normalized 2006 actual use per account and the linear trend 2007 normalized use per account figures (Exhibit B-9, BCUC 3.29.1, p. 1).

The approach used to establish both the weighted average customer count and the average use per account is the same as that approved by the Commission for the 2006 test year.

The Commission Panel accepts PNG's 2007 deliveries forecast of 1,447,905 GJ for PNG's residential customers.

Small Commercial

PNG forecasts deliveries of 872,602 GJ to its small commercial customers. This value is the product of the test year weighted average customer count and the test year average use per account (Exhibit B-8, Tab Rates, PNG-West, p. 8).

The weighted average customer count for the 2007 test year is 2,717. This equals the small commercial customer count at December 31, 2006 minus the forecast test year net customer loss multiplied by a 70 percent lost customer full-year equivalence factor (Exhibit B-6, BCUC 2.17.1, p. 2). The 70 percent figure is an estimate of the reduction in gas use during the year resulting from customers leaving the system. PNG noted that several small commercial customers converted to commercial transportation service in late 2006 and others have converted in 2007 (Exhibit B-8, Revised Application, p. 8).

The test year average use per account is 321.2 GJ and is lower than the mid-point between the normalized 2006 actual use per account and the linear trend 2007 figure. PNG has reduced the forecast of the small commercial customer use per account figure in 2007 in its Revised Application from the mid-point to reflect the impact of small commercial customers converting to commercial transportation service. PNG explained that the downward adjustment is necessary as the small commercial customers converting to commercial transportation service have been customers with above average gas consumption levels in the small commercial customer class (Exhibit B-9, BCUC 3.29.1, p. 1).

The approach used to establish both the weighted average customer count and the average use per account is consistent with that used for the 2006 residential forecast deliveries accepted by the Commission as described above, and is based on the same methodology approved for the small commercial forecast deliveries by the Commission for the 2006 test year.

The Commission Panel accepts PNG's 2007 deliveries forecast of 872,602 GJ for PNG's small commercial customers.

<u>Granisle</u>

PNG forecasts propane deliveries of 13,213 GJ to Granisle customers. This forecast is the product of the test year weighted average customer count and the test year average use per account (Exhibit B-9, BCUC 3.30.0, p. 5).

The Commission Panel accepts the 2007 forecast of 13,213 GJ propane deliveries to Granisle customers.

Other Commercial Classes

PNG forecasts deliveries of 101,100 GJ to large commercial firm customers, 262,370 GJ to commercial transportation customers, 28,000 GJ to large commercial interruptible customers, 21,100 GJ to seasonal off-peak customers and 18,700 GJ to NGV customers for test year 2007 (Exhibit B-9, BCUC 3.29.1, p. 2). Given the relatively few customers in these customer classes, PNG forecasts 2007 deliveries based on a review of historical deliveries and expected use in 2007 based on discussions with the customers (Exhibit B-1, Tab Application, PNG-West, p. 33).

While the number of customers in the large commercial, seasonal off-peak and NGV classes is forecast to remain the same as in 2006, the commercial interruptible class is forecast to decline from four customers to two, and deliveries are forecast to fall from 32,890 GJ to 28,000 GJ. The commercial transportation class is forecast to increase from 19 customers in 2006 to 86 customers in 2007, and the deliveries are forecast to increase to 262,370 GJ in 2007 over actual deliveries of 149,030 GJ in 2006. (Exhibit B-9, BCUC 3.29.1, pp. 2-3). This is consistent with PNG's evidence that several small commercial customers converted to commercial transportation service in 2006 and 2007, and that most of these converting customers consumed in the range of 2,000 GJ per year (Exhibit B-8, p. 8).

The Commission Panel approves the 2007 deliveries forecasts to the above customer classes.

Small Industrial

PNG's small industrial customers are comprised of firm sales and firm/interruptible transportation service customers. PNG forecasts 2007 deliveries of 368,800 GJ to firm sales customers and 842,000 GJ to transportation service customers. The projected small industrial 2007 deliveries are based on the forecasts received from PNG's small industrial customers in response to the small industrial customer surveys sent out by the Utility's field staff and a review of historical deliveries. The firm sales reduction from Decision 2006 to test year 2007 is attributable to the closure of the Terrace Lumber Company, which was forecast to consume 130,000 GJ in 2006. Interruptible transportation service is also forecast to decline by an estimated 95,000 GJ relative to budgeted 2006 deliveries due to installation of a wood waste burning system by Canfor's Houston sawmill in early 2007 (Exhibit B-1, Tab Application, PNG-West, p. 35).

The Commission Panel accepts the 2007 deliveries forecast of 1,210,800 GJ for PNG's small industrial customers.

Large Industrial

PNG is forecasting total industrial deliveries in 2007 of 2,864,000 GJ, which is a decrease from the approved forecast for 2006 of 3,220,500 GJ. PNG attributes the reduction entirely to an expected decrease in deliveries to West Fraser Mills – Kitimat, which expects to consume less gas in 2007 to minimize their commodity costs. The other two large industrial customers, Alcan and BC Hydro are forecast to consume 1,000,000 GJ and 24,000 GJ respectively, which are the same as the approved forecasts for 2006 (Exhibit B-1, Tab Application, p. 35). PNG's table of large industrial deliveries relative to the actual 2006 deliveries is reproduced below (Exhibit B-9, BCUC 3.29.1, p. 3).

Large Industrial Customer Gas Deliveries (GJ)			
Customer	**Test Year 2007**	**Decision 2006**	**Actual 2006**
West Fraser Mills- Kitimat	1,840,000	2,196,500	1,976,378
Alcan	1,000,000	1,000,000	975,225
BC Hydro	24,000	24,000	28,312
Total	**2,864,000**	**3,220,500**	**2,979,215**

The Commission Panel accepts the large industrial customers forecast for 2007. Variations in the revenue margins from large industrial customers should continue to be recorded in the Industrial Customers Delivery Deferral Account on a basis consistent with past Commission Orders.

5.0 COMPANY USE GAS COST

Company Use Gas Requirement

PNG forecasts Company Use Gas requirement to decrease to 77,303 GJ for test year 2007 from 116,561 GJ under Decision 2006 (Exhibit B-8, Tab Rates, PNG West, p. 12). PNG uses gas for a number of different purposes to operate its pipeline system. Approximately 60 percent of Company use gas is used as fuel in PNG's compressors located along the transmission system. Compressor fuel gas consumption on PNG's pipeline system is forecast to be one percent of gas throughput in 2007. This is a reduction from the historical figures to reflect the impact of the Methanex closure on compressor fuel gas consumption (Exhibit B-3, BCUC 1.25.1, p. 43).

PNG noted in the Application, that its forecast of 2007 compressor fuel requirements was made using actual fuel use over the January to September 2006 period as the primary basis for the 2007 forecast. Forecast compressor fuel use for the January to September 2007 period is set at 51,086 GJ. Total projected 2007 compressor fuel use is 69,276 GJ. This compares to estimated actual requirements in 2006 of approximately 75,000 GJ based on actuals to the end of November 2006 plus a forecast for December based on actual fuel use in October and November (Exhibit B-3, BCUC 1.24.1, p. 42).

Other sectors of Company use gas, such as station heating and office and shop heating are expected to maintain levels comparable to recent years. Due to the variability in unaccounted for gas volumes and the difficulty in accurately estimating unaccounted for gas volumes, PNG proposes that the forecast 2007 Unaccounted for Gas volume be set at zero percent, the same figure used under Decision 2006, with the unaccounted for gas volume deferral account remaining in place (Exhibit B-1, Tab Application, PNG West, p. 36; Exhibit B-3, BCUC 1.25.2, p. 43).

Determination of 2007 Unit Company Use Gas Cost (CUGC) Rate

The 2007 projected cost of Company use gas is based on forecast gas prices and the quantity of gas PNG expects to purchase for Company use net of the gas to be supplied in kind by West Fraser. The forecast unit CUGC rate is $0.136/GJ (based on the February 16, 2007 forward gas strip) for test year 2007 and is calculated by dividing the forecast cost of Company use gas by total deliveries to all customers except West Fraser (Exhibit B-1, Tab Application, PNG West, p. 38; Exhibit B-8, Tab Rates, PNG West, p. 12).

The Commission Panel approves the Company Use Gas requirement and unit CUGC rate, and accepts the Unaccounted for Gas factor of zero percent for 2007.

6.0 OPERATING, MAINTENANCE, ADMINISTRATIVE AND GENERAL EXPENSES

6.1 Operating Expenses

PNG forecasts a total operating expense of $7.235 million (excluding CUGC, before transfers to capital and shared service cost recovery from PNG(N.E.)) in 2007, an increase of $253,000, or 3.6 percent over the $6.982 million approved in Decision 2006 (Exhibit B-1, Tab Application, PNG West, p. 8; Exhibit B-8, Tab 1, PNG West, p. 3). PNG noted that one of the largest cost drivers between Decision 2006 and test year 2007 is a wage increase of 2.25 percent for all unionized positions effective November 1, 2006, in accordance with the negotiated agreement between the Company and the union in March 2005. In addition, PNG advises of an accounting policy change for 2007 and onward regarding charging hand tools costing under $1,000 to operating expense account 670, rather than a capital account as in the past. The overall impact of this policy change is a shift of $13,000 from capital accounts to expense account 670.

PNG presents a 5-year historical comparison of operating expenses in the Application. Excluding the in-line inspection expenses of $255,000, which are not included in the actual 2002 base year expenses but are included for test year 2007, the adjusted operating expenses for 2007 are $6.98 million. This is $866,000 more than the $6.114 million incurred in 2002, or a 14 percent increase (2.68 percent compounded annually) over the five-year period.

Shared service cost recovery and transfers to capital will be addressed later in Sections 6.5 and 9.2, respectively.

The Commission Panel finds the historical trend to be reasonable and accepts the proposed operating expenses (before transfers to capital and shared service cost recovery) for test year 2007.

6.2 Maintenance Expenses

PNG forecasts a total maintenance expense of $403,000 in 2007, $79,000 lower compared to the provision contained under Decision 2006 and $50,000 higher than the actual maintenance expenses in 2006 (Exhibit B-1, Tab Application, PNG West, p. 12; Exhibit B-8, Tab 1, PNG West, p. 4). Lower required compressor maintenance work as a result of the Methanex closure and a forecast reduction in the number of meter recalls in 2007 account for the majority of the cost reduction.

The Commission Panel accepts the proposed maintenance expenses for test year 2007.

6.3 Administrative and General Expenses

PNG forecasts a total administrative and general expense of $6.627 million (before transfers to capital and shared service cost recovery from PNG(N.E.)) in 2007 test year, an increase of $94,000 or 1.4 percent over Decision 2006 and an increase of $36,000, or 0.5 percent over actual expenses in 2006 (Exhibit B-1, Tab Application, PNG West, p. 13; Exhibit B-8, Tab 1, PNG West, p. 5). Increases in labour and employee benefits costs and an addition of a part-time Human Resources manager account for most of the increases budgeted for 2007 over Decision 2006. The increases are offset by lower insurance premium cost forecast for 2007 (Exhibit B-8, Revised Application, p. 3).

PNG presents a 5-year historical comparison of administrative and general costs in the Application. Total administrative and general expenses (before transfers to capital and shared service cost recovery from PNG(N.E.)) for 2007 are $1.124 million more than the $5.503 million incurred in 2002, or a 20.4 percent increase (3.79 percent compounded annually) over the five-year period. It is noteworthy that insurance premium costs have actually declined from $1.443 million in 2002 to $859,000 forecast in 2007, or over 40 percent over the 5-year period.

Shared service cost recovery and transfers to capital will be addressed later in Sections 6.5 and 9.2, respectively.

The Commission Panel finds the historical trend to be reasonable and accepts the proposed administrative and general expenses (before transfers to capital and shared service cost recovery) for test year 2007, subject to concerns expressed and comments made in Section 3.0.

6.4 Bonuses Included in Pensionable Earnings

In the Application, PNG explains that its agreement in 2006 under a negotiated settlement process ("NSP") to exclude bonuses in pensionable earnings, was a "one-off initiative" to lower the 2006 cost of service having regard to the substantial revenue deficiency in 2006. PNG, therefore, asserts that it is appropriate to include bonuses in pensionable earnings suggesting that they are a key and normal component of the compensation payable to executives and non-union salaried employees. The total pension expense associated with bonuses currently included in the 2007 Application is $64,000, comprised of $61,000 for executives and $3,000 for non-executives (Exhibit B-3, BCUC 1.4.2, p. 11). Removal of such bonuses from pensionable earnings would result in a reduction of $40,006 in revenue deficiency and an effective reduction of 8 basis points in the allowed return on equity as PNG shareholders would then bear the extra costs of pension expenses associated with including a bonus in pensionable earnings (Exhibit B-3, BCUC 1.4.3, p. 12).

BCOAPO submits, at paragraphs 11 and 12 of its Final Argument, "that the Commission having taken the position with other utilities that including executive bonuses in pensionable earnings should be for the account of shareholders, it should apply the same standard to PNG…any bonuses given to executives, including the retention bonuses referred to in response to BCUC IR 1 4.6 (Exhibit B-3) should only be included in pensionable earnings for the account of shareholders". PNG responds, in its Reply Argument, that "the Commission cannot disallow the recovery of the cost of a portion of PNG's executive compensation just because it may have disallowed this cost in respect of another utility regulated by the Commission. A unilateral denial of PNG's pension costs for the bonus component of the compensation for PNG's executive team would effectively be a reduction in PNG's allowed return on equity" (PNG Reply Argument, para. 9, p. 4).

The Commission, in its Decision related to the 1992 BC Gas Inc. (now Terasen Gas Inc.) revenue requirements application, set out key criteria for including bonuses in the pension costs for rate making purposes. The Commission disallowed BC Gas's executive bonuses as a portion of pension expenses recovered in rates stating that "the current bonus is not responsive to executive performance in providing specific future benefits to customers". The Commission added that it was prepared to consider inclusion of the bonus for recovery from the ratepayers at a future date when (BC Gas) executive compensation is structured so that it responds to customer-driven performance criteria.

Furthermore, in separate proceedings, the Commission determined that retention bonuses and stock option expenses should be excluded from revenue requirements. In the Decision accompanying Order No. G-56-02 related to PNG 2002 revenue requirements application, the Commission found that a retention bonus is not a normal expense that should be recovered in customer rates on a recurring basis and the retention bonus for 2002 represents an unusual expense primarily for the benefit of shareholders. In the Decision related to Order No. G-69-04 and PNG's 2004 revenue requirements application, the Commission decided that "non-cash, non-tax deductible charge against earnings for stock options" should not form a reasonable part of a Utility's revenue requirements.

PNG's response to BCUC IR 1.4.4 and PNG's Management Information Circular, filed in response to BCUC IR 2.24.1, explain the incentive program in more detail. Under the Annual Incentive Plan (AIP, or short-term bonus plan), fifty percent of the target award is attributable to corporate performance goals which reflect earnings, safety and cost control measures and the other 50 percent of the award is for individual performance objectives. The target awards range from 7.5 percent to 25 percent for managers and executives, and 35 percent for the Chief Executive Officer (Exhibit B-6, BCUC 2.24.1, PNG Management Information Circular dated March 17, 2006, p. 7). The only available evidence pertaining to individual executive performance objectives are the CEO 2005 performance goals which include a number of income trust, stakeholder relations and workforce retention related activities.

Commission Determination

The Commission Panel continues to believe that a fundamental condition for inclusion of executive bonuses in pensionable earnings is that those current bonuses reward the executives for activities providing specific future benefits to customers.

The Commission Panel has reviewed a sample of corporate performance goals and personal performance objectives for the Chief Executive Officer, which has been disclosed in the PNG 2006 Management Information Circular at page 7. Even though the weights of performance targets contained in the AIP that are linked to providing future benefits to customers are less than clear-cut, and despite the absence of personal objectives for other executives, the Commission Panel is persuaded that an inclusion of one-third of the executive short-term bonuses under the AIP in pensionable earnings or $ 20,333 is appropriate for recovery from customers. The Commission Panel will also allow the recovery of the $3,000 of non-executive pension expense associated with bonuses.

6.5 Shared Service Cost Pool and Its Allocation to PNG(N.E.)

PNG allocates seven categories of shared services costs such as customer care, engineering, administration and corporate services to its subsidiary PNG(N.E.). The allocation is based on time spent, customer count, employee count or rate base. In 2007, a 36.6 percent fringe benefit surcharge is attached to all labour included in the cost pool (Exhibit B-3, BCUC 1.6.4, p. 16).

Excluding benefits, the labour component of the total cost pool has risen from $2.875 million in 2004 to $4.089 million in 2007, an increase of 42 percent over the last three years. Non-benefit costs allocated to PNG(N.E.) have grown from $1.08 million in 2004 to $1.432 million in 2007, an increase of 32.6 percent over the same three-year period, significantly outstripping the customer growth in the PNG(N.E.) service areas and general inflation rates over the same period.

PNG indicates that the fixed 20.8 percent used to allocate Account 721 administrative costs, which accounts for 42 percent of the total shared services costs available for allocation (Exhibit B-3, BCUC 1.6.4, p. 16) in test year 2007, is based on an internal record kept several years ago of time spent by head office employees on work related to PNG West and PNG(N.E.) (Exhibit B-3, BCUC 1.6.2, p. 14). When asked if PNG considered a re-examination of allocation bases for shared service recovery in 2007, PNG responds that the allocation details set forth in the Application narrative provides sufficient evidence to support the reasonableness of the allocation bases. The Utility considers therefore, that it is not necessary to re-examine the allocation bases in 2007 (Exhibit B-3, BCUC 1.6.3, p. 14).

BCOAPO is concerned that PNG West does not appear to have properly allocated cost recoveries to PNG(N.E.). In particular, BCOAPO questions the new expenses related to services that PNG West claims it had been provided to PNG(N.E.) for the past several years, but no cost recovery was reflected in the shared services charges. BCOAPO argues that "these shared services charges, what should properly be included and how they should be determined have been the subject of variations over the years" and suggests that an independent audit of the shared service recovery mechanism may be appropriate (BCOAPO Final Argument, para. 15, p. 6).

Commission Determination

The Commission Panel is concerned about the rapid increase in the pooled costs for PNG's shared services. The total pooled costs available for allocation have grown from $4,872,000 in 2004 to $6,256,000 in 2007 forecast, an increase of $1,384,000 over the past three years, or 8.69 percent compounded annually. The labour component of pooled costs has risen at an annual rate of 12.5 percent, much faster than the non-labour costs, which grow at a moderate pace of 2.76 percent annually.

The Commission Panel shares BCOAPO's concerns that new additions of pooled shared service costs appear to be subject to much discretion and variation over the years. In Appendix A – Reasons for Decision related to PNG(N.E.) 2007 Revenue Requirements Application ("PNG(N.E.) 2007 RRA Decision"), issued concurrently with this Decision, the Commission Panel examined the $203,951 new expenses in respect of the addition of two management labour in the Terrace management cost pool that BCOAPO referred to in its Final Argument and concluded that these new expenses should be excluded from the shared service cost pool. In the PNG(N.E.) 2007 RRA Decision (Section 4.4), shared services cost allocation methodology was raised as an issue and the Commission Panel has expressed concerns about a rapid increase in shared services cost allocation from PNG to PNG(N.E.).

The Commission Panel has compared the shared services cost consumed by PNG West and PNG(N.E.). It appears that shared service costs (excluding benefit surcharges) retained by PNG West have also increased dramatically at an annualized rate of 8.35 percent, compared to 9.86 percent allocated to PNG(N.E.) over the past three years (2004-2007) (Exhibit B-3, BCUC 1.6.4, p. 16). PNG attributed a steeper percentage of increase for PNG(N.E.) to relatively higher customer growth in the PNG(N.E.) service areas. In the Commission Panel's view, a review is required of the components of the overall shared service cost pool, including what should be included and how the costs are determined.

The Commission Panel agrees that an independent audit of the shared service cost pool, as suggested by BCOAPO, could provide useful insights, however, determines that an audit might not be cost effective at the present time due to the ongoing challenges faced by PNG and the precarious economic conditions in the northwest region. For the same reason, a new time study to justify the percentage cost allocation for account 721, albeit useful to update the 2003 time study, might not be warranted for the time being.

However, the Commission Panel does recognize the urgent need for a review of the surging shared services costs over the years. While the description of all shared services recoverable through the cost pool is helpful (Exhibit B-3, BCUC 1.6.4, pp. 17-19), the Commission Panel is more interested in the year-over-year changes in the underlying cost drivers and elements (for example, labour uses) for all the shared services.

Consequently, the Commission Panel directs PNG, in the next revenue requirements application, to provide a detailed justification for corporate expense items recorded in account 728 and administrative cost items recorded in account 721 and explain why they should be included in the cost pool. In addition, PNG is required to submit a detailed analysis of the Terrace management cost pool by position, indicating the list of services and associated benefits these positions provide to PNG(N.E.) to be qualified as a shared services cost item and how much these services would cost if they were outsourced.

7.0 BANK FEES AND EXPENSES

PNG proposes a change to the methodology for accounting for bank fees and expenses that are comprised of service/transaction fees, stand-by fees, and renewal fees & expenses (Exhibit B-1, Tab Application, PNG West, p. 23). In prior years, PNG's forecast short-term interest rate included a premium to account for non-interest banking fees and expenses associated with its bank operating line. Actual fees and expenses, along with interest expense variances between actual and forecast interest rates, were recorded in the short-term interest deferral account. PNG noted that the current methodology did not allow for a very accurate allocation of fees and expenses to its operating divisions (Exhibit B-1, Tab Application, PNG West 2007 Rate Application, p. 23).

The proposed methodology for test year 2007 separates bank fees and non-interest expenses from interest expenses or income, so that stand-by fees, service and transaction fees and renewal fees & expenses can be budgeted based on their cost drivers and allocated to responsible operating divisions accordingly. The short-term interest deferral account is thus used to track explicitly the following two categories of differences:

(1) the difference between actual and forecast bank fees and expenses; and

(2) the difference between the actual prime rate and forecast prime rate applied to the Utility's actual short-term debt balance.

The Commission Panel accepts the proposed separation of bank fees and expenses from interest expenses and incomes for the purposes of forecasting and tracking, and approves the proposed methodology for deferral of the difference between actual and forecast bank fees and expenses in the short-term interest deferral account.

8.0 RECAPITALIZATION APPLICATION HEARING COSTS

In its Decision dated July 29, 2004 related to PNG's 2004 Revenue Requirements Application ("RRA"), the Commission determined that the costs associated with the regulatory review of the January 30, 2004 Recapitalization Application, which was denied by the Commission, should be shared between the ratepayers and the shareholders and that PNG would be allowed to recover Commission and Intervenor Recapitalization Application costs billed to PNG by the Commission.

On December 17, 2004 PNG filed a second application for approval to recapitalize under an income trust ownership structure ("2nd IT Application" or "2nd Recapitalization Application"). Following a public proceeding, this 2nd IT Application was approved by Commission Order No. G-84-05 and Decision dated September 9, 2005 ("IT Decision"), as amended by Order No. G-112-05 following the review of PNG's application for reconsideration of the IT Decision ("Reconsideration Application").

In Order No. G-84-05, and the accompanying IT Decision, the Commission approved the conditions identified by PNG in its 2nd Recapitalization Application, including a condition that "no costs associated with this Application and no transaction costs, including amalgamation and securities issuance and redemption costs, related to the foregoing transactions, shall be recovered through customer rates" (Decision, p. 48). The Commission also identified five additional conditions to be included as part of the Commission's approval. Furthermore, the Commission noted that:

> PNG has accepted that the owners of PNG will take on the risk with respect to costs resulting from tax changes as they may impact income trusts and the tax deductibility by PNG of the subordinate notes in the future. This additional condition is required by the Commission Panel to ensure that ratepayers will continue to be held harmless from the proposed conversion to an income trust structure (Decision, pp. 50-51).

Following a November 7, 2005 request by PNG, the Commission, by letter dated November 18, 2005, submitted its IT Decision and Reconsideration Decision as its report and findings to the Lieutenant Governor in Council ("LGIC") pursuant to Section 53(5) of the Act. The Commission's letter also requested that the LGIC issue an Order pursuant to Section 53(1) of the Act.

There is no evidence of actions taken by PNG subsequent to the Commission approval and, when PNG was asked during the 2006 RRA proceeding about the status of the income trust conversion, PNG indicated that it was evaluating the efficiency of raising capital under an income trust structure for a proposed "KSL Project" and PNG stated that it could give no assurances that the recapitalization under an income trust ownership structure would occur (PNG West 2006 Revenue Requirements Application, Exhibit B-4, BCUC 1.24.1, p. 50). PNG also expressed its preference to resolve regulatory uncertainties arising from the termination by Methanex of its transportation contract, prior to commencing the income trust conversion process. PNG reiterated that the timing and outcome of the conversion process was unclear.

In its Decision and Order No. G-99-06 related to PNG's 2006 RRA, the Commission stated:

> The Commission Panel does not consider that it is bound, beyond the July 29, 2004 Decision related to PNG's 2004 RRA, to allow PNG to recover or share these costs between the ratepayers and shareholders as set out in that Decision. Rather, based on PNG's subsequent proposed condition as noted and as approved in the September 9, 2005 Decision and, given the status of the approved recapitalization under an income trust structure and the circumstances related thereto, the Commission Panel considers that the costs associated with the subsequent Recapitalization Application should perhaps more properly be to the sole account of the shareholders as reflected in PNG's proposed condition.
>
> The Commission Panel denies PNG's request to amortize the customers' $169,855 after tax share of the second Recapitalization Application hearing costs at 20 percent per year commencing in 2006. For greater certainty, this amount may remain in the deferral account, subject to review of the appropriate recovery of these costs in the next RRA (p. 32).

During this 2007 RRA proceeding, PNG, on December 21, 2006 in response to a Commission Information Request, advised that "[i]n light of the Federal Government's decision to begin taxing income trusts, PNG expects it will not be converting to an income trust". PNG further indicated that in its update to the 2007 RRA, to be filed in February, 2007, it would reflect the proposal to amortize the Commission's and BCOAPO's share of the 2005 Recapitalization Application costs at 20 percent per year, commencing in 2007 (Exhibit B-4, BCUC 1.10.2, p. 26).

PNG subsequently confirmed that in the wake of the Federal Government's decision in the fall of 2006 to begin taxing income trusts, PNG will not convert to an income trust. PNG, therefore, proposes to amortize the Commission's and BCOAPO's share of the 2005 Recapitalization Application costs at 20 percent $34,000 commencing in 2007 (Exhibit B-9, BCUC 3.32.0, p. 9).

PNG considers that it is appropriate to allocate the income trust application costs between PNG's shareholders and customers consistent with the Commission's decision related to the 2004 Recapitalization Application (Exhibit B-6, BCUC 2.23.1, p. 10). PNG's proposal would result in a near 50/50 sharing of the 2005 recapitalization application costs.

PNG explains that if it had converted to an income trust structure, it was expected that its shareholder and customers would have benefited. The perceived benefit to the shareholders was considered to be sufficient to justify the shareholders absorbing all of the conversion costs, including the cost of obtaining Commission approval through the recapitalization hearing process. PNG states that its decision not to convert is primarily due to the Federal Government's decision on October 31, 2006 to tax income trusts, a decision that was beyond PNG's control (Exhibit B-11, R.W. Childs 1.2.2, p. 2). PNG suggests that, under these circumstances, it is therefore reasonable to share the recapitalization hearing costs between customers and shareholders.

In this 2007 RRA proceeding, PNG has confirmed that the $342,000 balance in the BCUC proceedings deferral account at the end of 2006 is comprised of the 2005 Recapitalization Application hearing costs of $517,314. The BCUC and BCOAPO portion of the costs is $256,385 and PNG's share of the costs is $260,929 before tax (Exhibit B-3, BCUC 1.10.2, p. 26).

The following is a summary of the 2nd Recapitalization Application costs before and after tax.

2005 Income Trust (IT) App. Hearing Cost Items		PNG's share of IT App. Costs	Customer's share of IT App. Costs	Total IT App. Costs
BCUC			81,800	
BCOAPO Costs			174,585	
PNG Legal and Consultants' Fees and Misc Expenses		260,929		
	Before Tax	260,929	256,385	517,314
	Tax	-87,929	-87,385	-175,314
	After Tax	**173,000**	**169,000**	**342,000**
	PNG/Customer Split	50.6%	49.4%	

BCOAPO suggests that since PNG does not intend to proceed with the recapitalization, there is no longer any perceived benefits to ratepayers and no basis whatsoever for allocating these costs to ratepayers and that they should be for the sole account of the shareholder (BCOAPO Final Argument, paras. 7-9, pp. 3-4). In reply, PNG maintains that “given that neither PNG nor its customer will now benefit from the income trust conversion, it is fair and reasonable for PNG’s shareholders and customers to each bear an appropriate portion of the 2005 recapitalization hearing costs” (PNG Reply Argument, para. 8, p. 3).

Commission Determination

As noted above, the Commission, on September 9, 2005, by Order No. G-84-05, approved PNG’s 2nd Recapitalization Application dated December 17, 2004. Order No. G-84-05 was ultimately amended by Order No. G-112-05 subsequent to the review of PNG’s IT Reconsideration Application.

In approving PNG’s December 17, 2004 2nd Recapitalization Application, the Commission determined that the income trust structure is preferable to a conventional structure because it will provide a fair opportunity to earn a reasonable return and minimize rates to customers (Decision, p. 26). The Commission also accepted PNG’s assurance, offered as a condition to any approval, that the Company was prepared to absorb all the application costs if it was ultimately successful in recapitalizing under an income trust structure.

In considering PNG’s proposal, therefore, this Commission Panel will consider whether there is a sufficient basis or change of circumstance to deviate from the conditions and the basis of approval set forth in the Commission’s Decision and Order No. G-84-05 where it was noted that PNG has explicitly “accepted that the owners of PNG will take on the risk with respect to costs resulting from tax changes as they may impact income trusts and the tax deductibility by PNG of the subordinate notes in the future”.

The Commission Panel observes that PNG had not undertaken or proceeded with the conversion to an income trust subsequent to the Commission's approval in September, 2005, nor prior to the Federal Government's announcement on October 31, 2006. The Commission Panel acknowledges that PNG had no control over the timing or nature of the Federal Government's decision, though the Commission Panel notes that potential changes to federal tax laws were a risk that was raised and discussed during both proceedings to consider PNG's IT Applications.

Given that PNG no longer intends to proceed with the IT conversion, "primarily because of the Federal Government decision", the Commission Panel agrees with BCOAPO that there are no longer any perceived benefits to ratepayers and no basis for allocating these costs to customers. Furthermore, the Commission Panel notes the considerable delay post-Commission approval of the 2nd IT Application and PNG's rationale for not proceeding with the conversion which, in the Commission Panel's view, largely concerned PNG's strategic business reasons related to the potential KSL project. The Commission Panel does not consider that such circumstances now justify a sharing of the application costs between PNG shareholders and ratepayers.

The Commission Panel does not consider that the circumstances of and surrounding the Federal Government announcement are sufficient to warrant a change to the cost allocation initially proposed and accepted by PNG, nor a departure from the Commission's expressed desire to "ensure that ratepayers continue to be held harmless from the proposed conversion to an income trust structure".

Neither does the Commission Panel find persuasive PNG's position that PNG should not be responsible for these costs because BCOAPO "aggressively opposed the conversion" (PNG Reply Argument, para. 7, p. 2) and in light of the "significant costs of [BCOPAO] vehemently opposing the application" (PNG Reply Argument, para. 8, p. 3). The Commission Panel recognizes that these were costs over which PNG understandably had no control. However, when PNG filed its 2nd Recapitalization Application and when PNG had initially agreed to absorb the regulatory costs associated therewith, PNG was aware, or should have been aware, that the Commission and other stakeholders would wish to carefully and thoroughly examine the merits and risks of PNG's proposal, particularly given the challenges faced by this Utility. In the Commission Panel's view, the use of an expert witness was justified to perform such an examination and, as well, BCOAPO was essentially the only party in a position to perform this role.

The Commission Panel, however, does note PNG's argument to support its position provided in PNG's response to BCUC IR 2.23.1, where PNG remarked that "PNG's second recapitalization application was filed to respond to concerns raised by the Commission in its decision on PNG's first recapitalization application" and that "the 2005 recapitalization application was a valid response by PNG and a sincere effort to improve the financial health of PNG for the benefit of customers and shareholders alike".

Nonetheless, PNG had agreed post-filing of the 2nd Recapitalization Application to absorb the disputed costs and the Commission does not find compelling PNG's arguments to depart from that position.

Having carefully considered the submissions and the circumstances, the Commission Panel finds that the Commission and BCOAPO portion of the 2005 IT Application costs should not be to the account of PNG's ratepayers and is to be a shareholder cost for 2007.

9.0 RATE BASE AND CAPITAL EXPENDITURES

The mid-year rate base is forecast to increase slightly in 2007 to $131.8 million from $131.2 million in the 2006 Decision. This is mainly due to a $900,000 (mid-year amount of $450,000) drawdown of deferred income taxes and an increase in cash working capital attributable to the removal of customer deposit as a credit, offset partially by a decrease in Plant in Service, due to a lower level of capital additions and a larger amount of accumulated depreciation budgeted for 2007, as compared to Decision 2006 (Exhibit B-8, Tab 2, PNG West, p. 1).

9.1 Capital Expenditures

For 2007, PNG is forecasting capital additions of $5.878 million, including capitalized overhead of $1.494 million. As shown in the following table, significant specific capital expenditures forecast for 2007, excluding capitalized overhead, amount to $3,114,000 (Exhibit B-1, Tab Application, PNG West, p. 27).

Summary of Major 2007 Capital Projects

Capital Expenditure	Amount
Upper Arden Valley rehabilitation	$1,538,000
Unspecified mainline repairs	$159,000
Mobile/work equipment	$948,000
Measurement upgrades	$172,000
Distribution system improvement	$67,000
Distribution services rehabilitation	$114,000
Install inspection barrels	$116,000
Total	$3,114,000

The Commission Panel has reviewed the justification for these capital projects as contained in the Application. The Commission Panel has also reviewed the Utility's response to BCUC IR 1.15.1 for actual capital additions compared to approved from 2002 to 2006 and finds the variances to be acceptable. Accordingly, the Commission Panel approves the capital additions forecast for 2007 as filed.

9.2 Transfers to Capital

PNG proposes that 17.7 percent of overhead should be allocated to capital projects (Exhibit B-1, Tab Application, PNG West, p. 16). The percentage of overheads allocated to capital projects is based on the budgeted component of direct labour in capital projects expected to be completed during the test year divided by total labour. PNG requests Commission approval to fix the transfer rates as a percentage of actual overhead expenses, regardless of the actual component of direct labour in capital projects completed in 2007.

The Commission Panel accepts the overhead capitalization rate of 17.7 percent for PNG West. However, the Commission Panel is of the view that, using a pre-determined fixed overhead capitalization rate to compute actual transfers to capital could be subject to large variances, compared to actual direct labour spent on capital projects. This is more evident in the light of large historical differences between the actual and approved capital expenditures over the last several years (Exhibit B-3, BCUC 1.15.1, p. 35). Consequently, while accepting the current methodology for the purpose of setting current rates, the Commission Panel requires PNG, in its next revenue requirements application to:

- **explain the pros and cons of using a fixed overhead capitalization rate, rather than recording overhead to capital based on the actual component of direct labour;**

- **provide the actual direct labour spent on capital projects and a summary of supporting timesheets by project for 2007, discuss and calculate the variance between the actual direct labour for capital projects supported by timesheets and the forecast direct labour for capital projects based on the fixed overhead capitalization rate; and**

- **comment on the merits of using a three-year actual moving average of actual direct labour transfers to capital as a proxy to set the current year's transfer to capital rate for rate making purposes.**

9.3 Cash Working Capital

PNG proposes to remove customer deposits as a credit to cash working capital as it pays interest on the customer deposits. PNG noted this was an "oversight for many years" (Exhibit B-1, Tab Application, PNG West, p. 23). This error has resulted in PNG providing a credit to all customers for a full rate of return on rate base on the deposits in addition to PNG providing an interest credit directly to the customer that makes the deposit in accordance with tariff requirement (Exhibit B-3, BCUC 1.7.1, p. 19).

The proposed change to cash working capital would result in an increase to the rate base. To mitigate the incremental impact on the rate base, PNG further proposes to adopt a methodology utilized by Terasen Gas Inc. to use the customer deposit funds as a source of short-term debt with a borrowing rate equal to the rate paid on the customer deposits. Assuming the forecast average deposit of $670,000, customer deposit rate of 2.6 percent and the assumed short term debt rate of 5.52 percent, PNG estimates that the proposed change would reduce 2007 revenue requirements by $20,000 (Exhibit B-3, BCUC 1.7.4, p. 21).

The Commission Panel accepts the removal of customer security deposits as a credit to cash working capital. Further, the Commission Panel agrees with the proposal to use customer security deposits as a source of short-term debt with the financing rate equal to the rate of interest that PNG pays on the customer deposits.

10.0 DEFERRAL ACCOUNTS

10.1 Long-Term Debt Interest Expense Deferral Account

PNG plans to raise $12.5 million new long-term debt, of which $7.5 million will be loaned to PNG(N.E.), by the end of the first quarter in 2007 (Exhibit B-1, Tab Application, PNG West, p. 25). The new debt facility will have a term to maturity of 20 years and its credit spread is comparable to existing long-term debt series. PNG is agreeable to capturing the difference of actual interest rate and the forecast interest rate on this anticipated long-term debt issue in a new long-term interest deferral account (Exhibit B-6, BCUC 2.28.1, p. 15).

The Commission Panel approves a new long-term interest deferral account to capture the interest rate differentials between the actual and forecast interest rates on the planned new long-term debt issue in 2007.

10.2 Depreciation Adjustment Credit Deferral Account

The Commission approved the applied-for interest-bearing depreciation adjustment credit deferral account in the Order No. G-99-06, related to PNG's 2006 RRA, in the wake of the Company's discovery in 2005 of over-depreciation of various assets that should have been retired between 1988 and 2001 (Exhibit B-6, BCUC 2.22.2, p. 7). In this proceeding, PNG notes that new depreciation adjustment credit deferrals totaling $434,000 were added in 2006 (Exhibit B-8, 2007 RRA Update, Tab 2, PNG West, p. 11; Exhibit B-9, BCUC 3.33.0, p. 10). PNG requests the Commission's approval of amortization of the new 2006 credit deferral addition and the credit interest thereof ($13,000) in test year 2007, in accordance with the original approval of this deferral account.

The Commission Panel accepts the new 2006 depreciation adjustment credit deferrals and the associated credit interest to be amortized in 2007, in accordance with Commission Order No. G-99-06.

10.3 Methanex Contract Termination Payment Amortization

On August 16, 2006, by Order No. G-99-06, the Commission authorized PNG to record the Methanex contract termination payment in an interest bearing credit deferral account, to be amortized into income over the 44-month period from March 1, 2006 to October 31, 2009. The credit to the cost of service in 2007 is $6,752,000, reflecting a 12-month amortization of the Methanex termination payment as compared to a 10-month amortization in 2006. As a result, the credit in 2007 is $1,199,000 more than in 2006. PNG seeks Commission confirmation of the amortization of the Methanex contract termination payment in 2007 on the same basis as approved by the Commission under Decision 2006 (PNG West Final Argument, para. 25, p. 6).

The Commission Panel accepts the amortization of the Methanex contract termination payment for 2007, as filed in the Application.

10.4 ICDDA and RSAM Deferral Account

The Industrial Customer Deliveries Deferral Account ("ICDDA") is a deferral account for variances in large industrial customer delivery margins (i.e. the difference between the forecast and actual large industrial customer deliveries); and RSAM implemented in 2003, is a deferral account for variances from forecast in deliveries for residential and small commercial customers. Continuity of deferred charges for test year 2007 (Exhibit B-8, Revised Application, Tab 2, PNG West, p. 11) details the budgeted amortization of ICDDA-05, ICDDA-06 and RSAM balances in 2007.

The Commission Panel approves the amortization of ICDDA and RSAM balances for 2007, as filed in the Revised Application.

11.0 CAPITAL STRUCTURE AND COST OF CAPITAL

PNG West's rate of return on equity is based on a Commission approved rate of return for a low-risk benchmark utility plus an approved risk premium of 65 basis points. As the allowed return on equity for a low-risk benchmark utility in 2007 is 8.37 percent, the allowed return on equity is 9.02 percent for PNG West. The Utility sets forth a deemed common equity component of 40 percent in the Application, the same figure approved by the Commission under Decision 2006 (Exhibit B-1, Tab Application, PNG West, p. 23).

With the planned issuance of a long-term debt facility of $5 million by the first quarter of 2007, lower than $17 million budgeted under Decision 2006, PNG West's long-term debt is forecast to drop from 52.72 percent under Decision 2006 to 46.56 percent of the total capitalization in 2007 (Exhibit B-8, Revised Application, Tab 5, PNG West, p. 1). PNG's short-term debt as a percentage of the total capitalization is forecast to rise to 9.64 percent in 2007 compared to 3.47 percent under Decision 2006.

The Commission Panel accepts the common equity component of 40 percent and the proposed capital structure, including the percentage mix of the short-term borrowings and long-term debt.

12.0 DEMAND SIDE MANAGEMENT

In its response to the MEMPR IR No. 1.3.1 (Exhibit B-4, p. 2), PNG discusses its actions and plans to address the need for new customers. In that response PNG identified that it is currently working in conjunction with the B.C. Ministry of Energy, Mines and Petroleum Resources and BC Hydro to assist customers to reduce their energy consumption through a series of rebate programs. Programs aimed at modifying consumer demand are commonly called Demand-Side Management ("DSM") programs.

In its Final Submission dated March 22, 2007, MEMPR identifies that the Province's February 2007 Energy Plan encourages utilities to develop cost-effective DSM programs and rate designs that encourage efficiency and conservation. MEMPR suggests that PNG should submit a DSM program for review and approval by the Commission, and should address DSM in conjunction with other utilities to identify barriers to the implementation of reasonable and cost effective programs and to identify potential solutions. MEMPR also notes that the 2007 Energy Plan states that it [Ministry] will "…monitor and assess progress on the development and implementation of price structures and advanced metering to encourage energy efficiency and conservation, and may propose additional regulatory measures (e.g. Special Directions) if required".

PNG in its Reply Argument dated March 29, 2007 states that "…the idea of PNG, particularly with respect to the PNG-West system, incurring additional overhead costs associated with creating and administering DSM programs and thereby increasing its rates is counterproductive and would exacerbate customer concerns regarding PNG's gas rate levels." PNG submits that appropriate price signals are the single most important factor in correctly shaping the demand curve and that the marginal retail price of gas faced by its customers is well in excess of its marginal cost of gas. PNG further submits that BC Hydro's electricity rates are priced "…well below it's marginal cost for most customers, leading to electricity use in applications that could more efficiently be served by natural gas". PNG states that appropriate price signals for other fuels should be in place, particularly for electricity, prior to PNG being directed to develop DSM programs "…and thereby increase the disparity between gas and electricity rates". The evidence provided by PNG with respect to use per account trends shows that the actual normalized use per account for residential customers has declined from 113.2 GJ in 1997 to 71.8 GJ in 2006, a decrease of 37 percent (Exhibit B-9, BCUC 3.30.0, p. 4).

BCOAPO submits that PNG's "… history of significant rate increases, coupled with the economic situation in PNG West's service area, continues to lead to decreases in natural gas deliveries and increases in revenue deficiency … This is exacerbated, particularly for residential customers, when PNG's rates are compared with BC Hydro's electricity rates in the service area …" (BCOAPO Argument, paras. 2-3, p. 1).

Commission Determination

The Commission Panel notes that high natural gas rates, reflected in the declines in the average use per account in the PNG service area appears to be acting as an effective incentive in encouraging customers to conserve, to be more energy efficient, and to switch to alternative fuel sources, such as electricity. However, it is unclear to what extent the reduction in use per account for several customer classes may be a result of DSM programs or of the relative price of gas to alternative fuel, which may cause fuel switching or conservation by customers.

The Commission Panel further notes that the Energy Plan encourages the identification of barriers to DSM. In PNG West's case the high cost of gas appears to act both as a surrogate for DSM programs, in that it causes a similar result as DSM, and a barrier to formal DSM programs due to their expense and the impact of lost revenues on PNG's rates. Such lost revenues whether resulting from formal DSM or high natural gas prices tend to increase the rates and potentially drive more customers off the system.

In view of the focus on DSM in the 2007 Energy Plan, PNG is directed to address DSM and the barriers to DSM in its next revenue requirements application. PNG should discuss the extent to which additional DSM activity is appropriate in the context of the relative level of consumer energy rates in the PNG service area.