BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-92-11

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Applications by Pacific Northern Gas Ltd.
for Approval of its 2011 Revenue Requirements and Consolidated Gas Sales Tariff
for the Pacific Northern Gas Ltd.-West Service Area

BEFORE: D.A. Cote, Panel Chair/Commissioner
N.E. MacMurchy, Commissioner
D. Morton, Commissioner

May 20, 2011

O R D E R

WHEREAS:

A. Pacific Northern Gas Ltd. (PNG) filed on November 30, 2010 with the British Columbia Utilities Commission (Commission), pursuant to sections 58 to 61, 89 and 90 of the *Utilities Commission Act* (the Act), its 2011 Revenue Requirements Application (Application) to increase, among other things, delivery rates. The Application forecast a 2011 revenue deficiency of approximately $4.5 million comprised of a net increase in cost of service of $0.5 million and a decrease in margin of $4.0 million;

B. The Application also sought refundable interim rate relief, pursuant to sections 58 to 61, 89 and 90 of the Act, to allow PNG to amend its rates on an interim basis, effective January 1, 2011, pending the hearing of the Application and orders subsequent to that hearing, on the basis that on January 1, 2011 PNG's rates would otherwise no longer be fair, just and not unduly discriminatory;

C. Under Order G-182-10 dated December 7, 2010, the Commission approved for PNG the delivery rates and Rate Stabilization Account Mechanism rider set forth in the Application on an interim basis, effective January 1, 2011 and set out a Preliminary Regulatory Timetable;

D. At the request of PNG the Commission, by Letter L-102-10, suspended the Preliminary Regulatory Timetable pending PNG filing amendments to the Application. On January 17, 2011, PNG filed these amendments to the Application (Amended Application). The Amended Application forecasts a 2011 revenue deficiency of approximately $2.7 million comprised of a net decrease in cost of service of $1.3 million and a decrease in margin of $4.0 million;

E. By Order G-8-11, the Commission set the regulatory timetable for the Amended Application;

F. On March 14, 2011, by Letter L-17-11, the Commission confirmed the use of a Negotiated Settlement Process (NSP) with negotiations to commence on April 26, 2011;

G. On April 15, 2011, PNG filed an update to the Amended Application to reflect a number of adjustments for year end 2010 figures and other corrections that came to light during the information request/response process (Updated Application). The Updated Application forecast a 2011 revenue deficiency of approximately $2.1 million comprised of a net decrease in cost of service of $2.4 million and a decrease in margin of $4.5 million;

H. The NSP discussions were held in Vancouver on April 26 and 27, 2011. A Negotiated Settlement Agreement was reached among the participants and circulated on May 3, 2011 to Registered Interveners for comment;

I. Letters of support of the Negotiated Settlement Agreement have been received from PNG and the Registered Interveners, all of whom participated in the NSP;

J. The Commission has reviewed the Negotiated Settlement Agreement for PNG's 2011 Revenue Requirements, which will result in a revenue deficiency of approximately $.5 million, and considers that approval is warranted.

NOW THEREFORE pursuant to sections 89 and 58 of the Act, the Commission orders as follows:

1. The Negotiated Settlement Agreement for PNG's 2011 Revenue Requirements Application, as issued on May 10, 2011 is approved and attached as Appendix A to this Order.

2. PNG is to file an amended Summary of Rates and Bill Comparison schedules based on the Negotiated Settlement Agreement.

3. PNG is to refund to customers the difference between permanent 2011 rates and the interim rates with interest in accordance with Order G-182-10.

4. The Commission will accept, subject to timely filing by PNG, Gas Tariff Rate Schedules to reflect the permanent rates approved in accordance with the terms of this Order. PNG is to provide notice of the permanent rates to customers via a bill message, to be reviewed in advance by Commission Staff to confirm compliance with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 20th day of May 2011.

BY ORDER

Original signed by:

D.A. Cote
Panel Chair/Commissioner

Attachment

BRITISH COLUMBIA UTILITIES COMMISSION

WILLIAM J. GRANT
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Log No. 35193

VIA EMAIL

May 10, 2011

TO: Registered Interveners
(PNG-West 2011 RRA)

Re: Pacific Northern Gas Ltd. (PNG-West)
Negotiated Settlement Agreement
2011 Revenue Requirements Application

Enclosed with this letter is the proposed settlement package for PNG-West's 2011 Revenue Requirements Application.

This settlement package is now public and is being submitted to the Commission. Also enclosed are Letters of Support and Comment received to date from the participants in the negotiated settlement process.

The Commission will consider the settlement package to set final rates.

Yours truly,

on behalf of:
William J. Grant

CM/cms

cc: Mr. Craig Donohue
Director, Regulatory Affairs and Gas Supply
Pacific Northern Gas Ltd.
cdonohue@png.ca

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Pacific Northern Gas Ltd.
(PNG-West Division)

2011 Revenue Requirements Application

NEGOTIATED SETTLEMENT AGREEMENT

Introduction

B.C. Utilities Commission staff (Commission staff), representatives of Pacific Northern Gas Ltd. (PNG), the B.C. Old Age Pensioners Organization (BCOAPO) and the Peace River Regional District (PRRD) met on April 26 and 27, 2011 for the purpose of negotiating a settlement of the PNG-West Division 2011 revenue requirements application (Application). The settlement discussions were facilitated by a third party. Agreement was reached on April 27, 2011 among the parties that participated in the negotiated settlement process (NSP 2011). The result of NSP 2011 is to reduce the applied for Test Year 2011 revenue deficiency by $1.6 million, from approximately $2.1 million to $0.5 million. The following table summarizes the adjustments to the Application to achieve this reduction.

	(000's)	
Items	**PNG-West NSP 2011 Adjustments to the Application**	
1.0	Reductions to 2011 O,M,A&G Budget	$ (273)
2.0	LNGP Option Fees June 30 '11 Payment	$ (46)
3.0	Shared Service Charge to PNG(N.E.)	$ 71
4.0	PTP Settlement Allowance	$ (500)
5.0	NSP Settlement Allowance	$ (200)
6.0	Pension Asset Removal from Rate Base	$ (145)
7.0	Deferred Income Tax Drawdown Increase	$ (130)
8.0	Forecast Margin Recovery Increase	$ (377)
	Total	**$ (1,600)**

Under NSP 2011 the gas delivery rate increase for residential customers effective January 1, 2011 compared to the corresponding delivery rate as of October 1, 2010, is $0.17/GJ. This represents an annual bill increase of $11.04 or 0.9 percent for the average residential customer consuming 66.7 GJ/year. With the approved gas commodity rate decrease as of April 1, 2011 and the NSP 2011 delivery rate, the annual gas bill for a typical residential customer is now 2.9 percent lower compared to the annual bill using October 1, 2010 rates. The details underpinning the above noted figures and a number of other matters agreed to by the parties that did not directly result in adjustments to the Test Year 2011 cost of service set forth in the Application are provided in the following pages.

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1.0 West Fraser Kitimat Paper Mill Contract Termination Payment

References:

Exhibit B-1, p. 61
Exhibit B-8, IR 1.49

Issue:

Should PNG amortize the West Fraser Mills contract termination payment over the December 2010 to December 2013 period as a credit to the cost of service?

Discussion:

West Fraser gave six months' notice of termination of its contract with PNG at the end of May 2010 and paid PNG a contract termination payment of $5.152 million on December 1, 2010. PNG sought Commission approval under the Application to record the contract termination payment in an interest bearing deferral account and to amortize the termination payment as a credit to the cost of service over the 37 month period from December 1, 2010 to December 31, 2013, the original expiration date under the terminated contract.

Settlement:

PNG's proposal to record the contract termination payment in an interest bearing deferral account and to amortize the payment in equal monthly amounts as a credit to the cost of service over the 37 month period from December 1, 2010 to December 31, 2013 is accepted.

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2.0 Margin Adjustment

References:

Exhibit B-1-3
Exhibit B-13
Exhibit B-14

Issue:

Should forecast 2011 gas deliveries to the residential, small commercial sales and large commercial sales customers be increased compared to the forecasts contained in Exhibit B-13?

Discussion:

The parties reviewed and discussed the 2011 gas deliveries forecasts to the residential, small commercial sales and large commercial sales customer classes that had been filed by PNG culminating with the forecasts contained in Exhibit B-13. PNG provided the parties with a detailed explanation of how 2011 forecast sales to the six large commercial sales customers was determined having regard to their historical gas use.

Settlement:

The normalized 2010 uses per account for the residential and small commercial sales customers of 66.7 GJ/year and 308.9 GJ/year, respectively, will be used to forecast 2011 deliveries to these customers. This increases the 2011 margin forecast by approximately $377,000. PNG's forecast of 2011 deliveries to the large commercial sales customers is accepted.

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3.0 Shared Service Cost Recovery from PNG (N.E.)

References:

Exhibit B-1, p. 30
Exhibit B-8, IR 1.51
Exhibit B-10, 2.13.0
Exhibit B-13, p. 7

Issue:

Should the parties accept the cost allocators and level of shared service cost recovery by PNG-West from PNG (N.E.) during Test Year 2011 as set forth in the Application?

Discussion:

It was noted that the basis of the calculation of the shared service costs had not been reviewed by a third party for many years. In particular, the time study allocator had not been reviewed in detail since completion by PNG of an internal study in 2003 to document and record time spent by PNG-West employees on PNG(N.E.) matters. The major reasons for the significant cost increases in 2011 were discussed.

Settlement:

The cost allocators and level of shared service cost recovery by PNG from PNG (N.E.) during Test Year 2011 as set forth in the Application, in the updates in Exhibit B-13 and any adjustments flowing from NSP 2011, are accepted.

PNG will file with the Commission a Cost Allocators and Level of Shared Service Cost Recovery Application as a standalone application in the Fall of 2012. The application will be based on a shared services cost study prepared by a third party consultant (Shared Services Study). The Shared Services Study will incorporate a time study commencing in July 2011 that will run for one year to collect data on time spent by PNG-West personnel on PNG(N.E.) matters. Given the increasing number of customers in the PNG(N.E.) service area and the reduction of customers in the PNG-West service area, the Shared Services Study will specifically evaluate if the customer count allocator remains the best allocator for Customer Care Center Costs. In addition, the Shared Services Study will include an analysis of whether Customer Care Center services provided to PNG(N.E.) from the PNG-West Terrace office could be provided more economically on a standalone basis from a dedicated Customer Care Centre in the PNG(N.E.) service area. PNG will issue requests for proposals for the Shared Services Study and will review the bids with Commission staff, BCOAPO and the PRRD prior to awarding the contract for the Shared Services Study.

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4.0 Overhead Capitalization Rates

References:

Exhibit B-1, p. 16
Exhibit B-1, p. 55
Exhibit B-1, Tab 6
Exhibit B-8, IR 1.21.1

Issue:

Should the Commission give approval for PNG to commence in the Test Year 2011 to calculate overhead capitalization in accordance with the methodology set forth in the 2010 Overhead Capitalization Study (OHC Study) provided under Tab 6 of the Application?

Discussion:

The OHC Study was prepared internally by PNG. Consequently, PNG engaged KPMG to conduct an independent evaluation of the OHC Study for validation purposes. KPMG found the PNG overhead capitalization methodology to be a reasonable basis for the allocation of costs and its methodology is within the range of practice established by the external guidance and observable capitalization allocation practices applied by Canadian utilities and utilities subject to the jurisdiction of the Commission.

The main reason PNG decided to carry out the OHC Study was the pending transition by PNG from Canadian GAAP (CGAPP) to International Financial Reporting Standards (IFRS). When the OHC Study was initiated it was anticipated PNG would transition to IFRS effective January 1, 2011. However, in the intervening period the Canadian Accounting Standards Board announced an optional one-year deferral for regulated entities, postponing the transition to IFRS to January 1, 2012. PNG made the decision to take the one-year deferral on this transition. However, PNG will still need to prepare 2011 comparative figures in accordance with IFRS. The findings in the OHC Study are in accordance with CGAPP and in compliance with IFRS. As noted earlier, KPMG has concluded that the rates are in line with what other Canadian utilities and utilities regulated by the Commission are applying.

Settlement:

The overhead capitalization rates recommended in the OHC Study are accepted for use in Test Year 2011 and PNG will apply the same capitalization overhead rates for rate setting purposes as it does for external financial reporting purposes once IFRS is adopted. The proposed changes outlined in Exhibit B-1, at page 55 regarding the capitalization of components of cost are accepted.

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5.0 Depreciation Rates

References:

Exhibit B-1, p. 18
Exhibit B-8, IR 1.26
Exhibit B-10, IR 2.9

Issue:

Should the Commission give approval for PNG to commence in the Test Year 2011 to apply a straight-line depreciation methodology where depreciation will be calculated to reflect the use of an asset over its estimated economic useful life and to commence depreciation when the asset is available for use?

Discussion:

In 2010, Gannett Fleming prepared a deprecation study for PNG primarily to determine what depreciation rates should be applied by PNG having regard to IFRS requirements (Depreciation Study). The last depreciation study was done in 1995 for the PNG-West system. The new Depreciation Study is set forth under Tab 7 of the Application. A major finding of the Depreciation Study was the extension of the useful life of significant pipeline assets, resulting in reduced depreciation expense.

Gannett Fleming advised that the Equal Life Group (ELG) procedure is superior to the Average Service Life (ASL) procedure in matching depreciation expense and consumption of service value but also confirmed that the ASL procedure is appropriate and is used by the majority of utilities in North America and conforms to past practice. PNG used ASL to determine depreciation expense in Test Year 2011. The assumptions in the underlying recommended depreciation rates in the Depreciation Study were reviewed and confirmed by management.

PNG determined the Test Year 2011 depreciation rates per the Depreciation Study using the remaining useful lives and average service lives provided in the Depreciation Study. No third party review was completed in respect of management decision not to use some of the recommendations in the Depreciation Study. For Test Year 2011 applying all of the Gannett Fleming recommendations would result in projected depreciation expense approximately 1.7 percent less than depreciation expense determined by PNG applying most of the recommendations in the Depreciation Study.

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Settlement:

Depreciation expense will be determined on the basis proposed in the Application for Test Year 2011 only. PNG will obtain an independent review of the reasonableness of the areas where PNG management decided to vary from the Depreciation Study recommendations including the depreciation expense calculation, the decision to use the specifically identified assets methodology rather than the recommended group methodology for asset classes 484, 485, and 479 and the decision to adopt the ASL procedure rather than ELG. Gannett Fleming is an acceptable third party to carry out this review. The results of the review will be included with PNG's 2012 revenue requirements application. PNG's next revenue requirements application will use the same depreciation rates for rate setting purposes as it does for financial reporting.

6.0 IFRS – Property, Plant and Equipment

References:

Exhibit B-1, p. 19
Exhibit B-1, p. 51-59
Exhibit B-8, 1.27
Exhibit B-10, IR 2.10

Issue:

Should PNG be permitted to adopt certain accounting changes for regulatory purposes for Test Year 2011 to enable it to align with its financial reporting requirements under IFRS even though PNG will not be using IFRS for external financial reporting purposes until 2012?

Discussion:

The parties discussed the pros and cons of the accounting changes proposed by PNG in the Application. The changes are very technical in nature and customer rates in Test Year 2011 will not be negatively impacted by the proposed changes. PNG noted that applying the requested accounting changes in Test Year 2011 will not require the Commission to make any IFRS policy determinations given the accounting changes are consistent with CGAAP.

Settlement:

The accounting changes requested by PNG in the Application with regard to plant, property and equipment and which are in accordance with CGAAP, are accepted.

PNG's plant, property and equipment regulatory schedules will be presented on a gross basis for Test Year 2011 and not on a net book value basis as applied for by PNG.

PNG requested at Tab Application, Page 23 of Exhibit B-1 to record an addition of $927,585, based on December 31, 2009 balances, to its Plant Gains and Losses rate base deferral account to reflect the undepreciated value of assets that were retired but not fully depreciated. However, the request was withdrawn in the amendments to the Application filed as Exhibit B-1-3 and during negotiations the request was restored. The parties agreed to PNG's restored request provided that no amortization could be taken in Test Year 2011 on these assets. Furthermore, the parties did not consider PNG's ability to recover the balance in a future period nor did they discuss whether the sum of the net book values (NBV) of the individual assets as compared against the NBV of the entire asset class amounted to $927,585 as PNG stated in the Application. The parties agreed that the recoverability, amortization period and dollar value of the deferral account will be addressed as part of PNG's next revenue requirements application.

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7.0 Operating Expenses – Pipeline #665

References:

Exhibit B-1, p. 6
Exhibit B-1, Tab 1, p. 3
Exhibit B-1-2, Tab 1, p. 3
Exhibit B-13, Tab 1, p. 3
Exhibit B-10 IR 2.1

Issue:

What is the appropriate 2011 budget for Account 665 pipeline operating expenses excluding Company use gas and Spectra gas control expenses?

Discussion:

The actual expenses in this Account over the past several years were reviewed. The factors contributing to the higher than average increase in 2011 were discussed.

Settlement:

The 2011 budget for Account 665 of $870,000 at Tab 1, Page 3, Line 3, will be reduced by $52,000 to $818,000.

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8.0 Operating Expenses – Customer Care #711/713/714

References:

Exhibit B-10, IR 3.1-3

Issue:

What is the appropriate 2011 budget for Accounts 711/713/714 Customer Care costs?

Discussion:

The actual expenses in these Accounts over the past several years were reviewed. It was noted that actual expenses were less than budgeted expenses over the last three years.

Settlement:

The 2011 budget for Accounts 711/713/714 of $1,490,000 at Tab 1, Page 3, Lines 28/30/31, will be reduced by $78,000 to $1,412,000.

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9.0 <u>Administrative & General - Account 721 - Bonuses</u>

<u>References:</u>

Exhibit B-1, p. 9,
Exhibit B-13, Tab Rates, p. 8
Exhibit B-8, IR 1.10.1

<u>Issue:</u>

Should employee bonuses in Account 721 be budgeted at $443,765 for 2011 or be kept at the actual 2010 level of $405,198?

<u>Discussion:</u>

It was noted that the 2011 budgeted bonuses figure was 9.6 percent higher than the actual corresponding bonuses figure for 2010 which was higher than inflation and higher than the budgeted salary increase of 3.25 percent.

<u>Settlement:</u>

The 2011 budget under Account 721 for bonuses will be reduced to $405,000, the actual expense applicable in 2010 and $39,000 less than the Test Year 2011 applied for figure.

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10.0 Administrative & General - Account 721 – Travel Expenses

References:

Exhibit B-8, IR 1.10.1
Exhibit B-10, IR 2.7.1

Issue:

What is the appropriate 2011 budget for travel expenses under Account 721?

Discussion:

The actual expenses in this Account over the past several years were reviewed. The factors contributing to the higher than average increase in 2011 were discussed.

Settlement:

The 2011 budget under Account 721 for travel expenses will be reduced by $14,000 to $73,000.

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11.0 Administrative & General - Account 721 –Employee Expenses

References:

Exhibit B-8, IR 1.10.1
Exhibit B-10, IR 2.7.2

Issue:

What is the appropriate 2011 budget for employee expenses under Account 721?

Discussion:

The actual expenses in this Account over the past several years were reviewed. The factors contributing to the higher than average increase in 2011 were discussed.

Settlement:

The 2011 budget under Account 721 for employee expenses will be reduced by $21,000 to $69,000.

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12.0 Administrative & General - Account 725 – Executives Pension Expense

References:

Exhibit B-1, p. 10
Order G-55-07 (2007 RRA)
Order G-39-09

Issue:

Have 2/3 of the pension cost of including executive bonus' in pensionable earnings been deducted from the applied for Test Year 2011 cost of service?

Discussion:

It was noted that at Tab Application, Page 12 of Exhibit B-1 that PNG stated it considered it is appropriate to recover all of the cost of including bonuses for the purpose of determining pensionable earnings. Specifically, the pension cost in 2011 of including bonuses for salaried employees in pensionable earnings is $71,000. Of this amount, $50,000 pertains to PNG's executives and $21,000 pertains to non-executives. It was also confirmed that a 2/3's reduction in the PNG executives share of this cost was $33,333 (i.e. $50,000 x 2/3) and that a reduction of that amount from the 2011 budgeted cost of service has been applied by PNG to reduce Administrative and General Expenses in Test Year 2011 (Exhibit B-1, Tab 1, Page 5, Line 30). This is consistent with the Commission's directive under the 2007 Revenue Requirements Decision and with the NSP 2010 settlement agreement (Exhibit B-1, p. 12).

Settlement:

The parties acknowledged PNG's decision to reduce its Test Year 2011 Administrative and General expenses budget by 2/3 of the pension cost of including bonuses in the pensionable earnings of PNG's executives.

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13.0 Administrative & General - Account 725 – Employee Benefits - Pension

References:

Exhibit B-1, p. 11, 39, 40 & 58
Exhibit B-1, p. 3
Exhibit B-8, IR 1.31, 1.32
Exhibit B-10, IR 2.11, 2.12
Exhibit B-14, IR 3.4
Exhibit B-13, Tab 2, p. 10 & 11

Issue:

Should PNG's requested accounting change in 2011 with regard to its non-pension post retirement benefit (NPPRB) plan be accepted? Should PNG be allowed to include any funding differences in pension and NPPRB plans in rate base?

Discussion:

The parties discussed PNG's request in the Application for approval to adopt the full accrual method of accounting for its NPPRB plan. It was noted this would be consistent with the treatment accorded to other utilities. It was also noted that two new regulatory schedules were included in Exhibit B-1 at Tab 2, Pages 10 and 11 to show the impact on rate base of accounting for the funding differences for PNG's NPPRB and pension plans.

Settlement:

The parties agreed to the full accrual method for accounting for PNG's NPPRB plan. The inclusion in rate base of the funding differences for PNG's NPPRB and pension plans was not accepted and therefore the applied for adjustment to the calculation of PNG's rate base was also not accepted.

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14.0 Maintenance Expense – All Other

References:

Exhibit B-1, p. 7
Exhibit B-8, IR 1.7.3, IR 1.11.2

Issue:

What is the appropriate 2011 budget for the maintenance expenses other than the expenses budgeted under Accounts 866, 867 and 875?

Discussion:

It was observed that the 2011 budget for other maintenance expenses of $137,000 was higher than the 2006 to 2010 average of actual expenditures.

Settlement:

The 2011 budgeted other maintenance expenses will be reduced by $40,000 to $97,000.

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15.0 Maintenance Expense – Meters Account 878

References:

Exhibit B-1, p. 7
Exhibit B-8, IR 1.7.2

Issue:

What is the appropriate 2011 budget for Account 878 meters?

Discussion:

The historical costs under Account 878 meters were reviewed by the parties noting that the budget for 2011 was $29,000 higher than actual expenditures in 2010. The meter testing and re-verification process was discussed noting some new governmental requirements are being phased in over the next few years that will impact costs.

Settlement:

The 2011 budget for Account 878 meters will be reduced by $29,000 to $157,000.

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16.0 Capital Additions – Account 478 Meters

References:

Exhibit B-1, p. 37
Exhibit B-6, IR 1.13.2
Exhibit B-8: IR 1.22 and 1.57

Issue:

What is the appropriate budget for new meters to be purchased in 2011?

Discussion:

It was noted that the budgeted number of required new meters had been lower than actual installed meters over a number of years but that the number of new meters per year will likely increase over time with the phasing in of the new governmental requirements.

Settlement:

The 2011 budget for new meters under Account 478 at Tab 2, Page 3, Line 25 will be reduced to $100,000 from the applied for figure of $183,000.

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17.0 Deferred Income Tax on Regulatory Accounts

References:

Exhibit B-1, p. 21
Exhibit B-8, p. 77-79

Issue:

Is it appropriate to change the presentation of deferral accounts from a net of tax to a gross tax basis with future income tax amortization as an offset to reflect net of tax amortization for rate making purposes?

Discussion:

There is no change in either the net balance of a rate base deferral account included in the rate base calculation nor the cost of service with this presentation change. The impact on the cost of service also remains the same as the amortization of the deferred charge is shown on a gross basis with a related future income tax expense when previously the amortization was shown on a net-of-tax basis (Exhibit B-8, BCUC IR 1.33.1).

Settlement:

The change from a net-of-tax basis presentation to a gross tax basis, with a related future income tax expense, is accepted.

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18.0 Deferral Accounts

References:

Exhibit B-10, IR 2.15
Exhibit B-8, IR 1.48
Exhibit B-1, p. 29
Exhibit B-1-3, p. 7

Issue:

Should the changes to the deferral accounts requested by PNG in the Application be accepted?

Discussion:

The various changes to the deferral accounts requested by PNG in the Application were reviewed.

In particular, the parties discussed whether the LNGP option fee payment deferral account should reflect an assumption that the next $1 million option fee payment will be made on June 30, 2011 and whether the interest should be calculated on the before tax balance as PNG has yet to pay income tax on the option fees.

Settlement:

The terms agreed to by the parties in respect of the deferral accounts are set forth in the table below. Further details on the deactivated facilities deferral account are set forth in section 23 of this NSP 2011 settlement agreement.

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	Deferral Account Type			Amortization Expense
Deferral Accounts	**Rate Base**	**Interest Bearing**	**Amortization Period**	**Test Year 2011 ($000's)**
Line Break Costs	X		120 months straight line per individual line break	174
Plant Gains and Losses[1]	X		120 months straight line per individual plant gain/loss	27
Investigative Digs	X		10 percent per year on the declining balance	61
Industrial Customer Deliveries		X	calendar year 2011	(29)
Property Tax Variance		X	calendar year 2011	(50)
BCUC Proceedings[2]		X	calendar year 2011	4
CAP/ROE Hearing		X	calendar year 2011	91
IFRS	X		amortization to be set in 2012	0
Old Revolving Debt Issue Costs		X	calendar year 2011	88
Pipeline Inspections		X	calendar year 2011	193
Deactivated Facilities[3]	NA	NA		0
BCUC Fees		X	calendar year 2011	2
Short Term Interest		X	calendar year 2011	14
Long Term Interest		X	calendar year 2011	(87)
Propane Air Plant		X	10 year mortgage style at short term debt rate (4 yrs remaining)	73
LNGP Option Fee Payment[4]		X	balance, excluding Dec'10 option fee payment, over 2011	(1,578)
			Gross Amortization	**($1,016)**
			Less Future Income Taxes	291
			Net Amortization	**($725)**
West Fraser Termination Payment			37 months mortgage style from Dec'10 to Dec'13	($1,687)

Notes:

1. The BCUC Accounts described at Tab Application, Page 23 to be recorded in this deferral account. See also section 6 of this NSP 2011.
2. BCUC Proceedings deferral account to record difference between budgeted and actual expenses.
3. Deactivaed facilities to be returned to rate base effective January 2011.
4. Credit interest reflects assumption that $1 million option fee payment is made on June 30, 2011 and agreement to calculate interest on the before tax balance with customers assuming the risk of a CRA reassessement for the interest that would have been calculated on an after tax basis.

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19.0 Level of Deferred Income Taxes Draw Down

References:

Order G-55-07 (2007 RRA)
B-13, Tab 2, p. 1, line 16
Exhibit B-1, p. 32
Exhibit B-8, IR 52.1
Exhibit B-10, IR 2.14

Issue:

Should PNG increase the deferred income taxes draw down of $900,000 set forth in the Application to further reduce the Test Year 2011 cost of service, and if so by how much?

Discussion:

The parties decided to discuss the level of deferred income taxes draw down after agreement had been reached on all other matters. The agreed to reduction in the applied for revenue deficiency was almost $1.5 million when the parties turned their minds to the appropriate level of deferred income taxes draw down. The discussion focused on the overall level of bundled rates that PNG's customers would be facing without any further decrease in the applied for Test Year 2011 cost of service. The impact on PNG's cash flows and financial metrics were also addressed. It was also noted that bundled rates for residential and commercial sales customers effective April 1, 2011 would be less than the corresponding rates effective October 1, 2010, as a result of the gas commodity reductions offsetting the gas delivery rate increase that would be effective January 1, 2011 under NSP 2011.

Settlement:

The level of deferred income taxes draw down will be increased by $100,000 to $1 million.

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20.0 Unaccounted for Gas (UAF) Volume Deferral Account

References:

Order G-33-10 (NSP 2010)
Exhibit B-1, p. 45

Issue:

Should PNG continue the UAF volume deferral account on the basis that the UAF volume forecast for Test Year 2011 is set at zero with PNG recording the variance between zero percent and a loss of up to 1.0 percent without having to seek further Commission approval?

Discussion:

UAF volumes have fluctuated from year to year. More recently losses and gains have resulted in an average of close to zero percent, which is superior to the other three comparable utilities. Under the Application, PNG is applying to maintain the same treatment regarding the UAF volume deferral account that was agreed to under NSP 2009 and NSP 2010.

Settlement:

PNG can continue the UAF volume deferral account on the basis that the unaccounted for gas volume forecast for Test Year 2011 is set at zero with PNG recording the variance between zero percent and a loss of up to 1.0 percent in the UAF volume deferral account, without having to seek further Commission approval of the deferral.

~~CONFIDENTIAL~~

21.0 PNG Sale of Pacific Trail Pipelines (PTP)

References:

Exhibit B-8 IR 1.18 & 1.19
Exhibit B-10 IR 2.8

Issue:

Can the Commission require a public utility to reimburse its rate payers for the indirect costs of employee time and overhead allocation from the sale proceeds of a non utility asset for which those indirect costs were incurred by the public utility and recovered from its rate payers in rates?

Discussion:

The parties' discussed each other's positions on the issue. No resolution was reached and all parties indicated they were prepared to have this issue addressed through litigation.

Settlement:

The parties agreed not to litigate this matter in consideration of PNG agreeing to reduce the Test Year 2011 cost of service by $500,000 with the adjustment being referred to as the "PTP Settlement Allowance". The parties acknowledged this was a reasonable resolution to avoid incurring the significant costs that would ensue from protracted litigation over the issue.

~~CONFIDENTIAL~~

22.0 Non-Regulated Business (NRB)

References:

Exhibit B-1: p. 13-15; Tab 1, p. 5
Exhibit B-8, p. 21-38
Exhibit B-8, IR 1.11

Issue:

Should the reduction for NRB costs as set forth at Tab 2, Page 5, Line 31 of the Application be increased?

Discussion:

The parties' discussed each other's positions on the issue and were unable to reach agreement on whether the reduction to the Test Year 2011 cost of service for NRB activities should be increased.

Settlement:

The NSP 2011 Settlement Allowance of $200,000 reflects in part the resolution of this matter without having to identify how much if any of the settlement allowance represents any party's position in respect of this matter. PNG will prepare a Code of Conduct and Transfer Pricing Study in 2011 to address NRB matters. PNG will file the Study with the Commission for approval no later than September 1, 2011 with the intention of applying the policy and code of conduct commencing in 2012.

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23.0 Deactivated Facilities

References:

Exhibit B-1, p. 28 & 56
Exhibit B-1-3, p. 6
Exhibit B-8, IR 1.35
Order G-99-06

Issue:

Should the deactivated facilities that resulted after the closure of the Methanex plant be reclassified from an interest bearing deferral account into Plant in Service earning a full rate base return?

Discussion:

The rationale for initially creating the interest bearing deactivated facilities deferral account was reviewed in light of recent events that have increased the probability of these facilities being reactivated. Discussion also focused on what level of return on these facilities results from being in a deferral account that bears interest at the short term debt rate compared to the higher return when these facilities are in rate base.

Settlement:

The deactivated facilities are to be put back into rate base. The parties acknowledged that depending on future circumstances, the deactivated facilities deferral account may need to be restored. The NSP 2011 Settlement Allowance of $200,000 reflects in part consideration for the fact the deactivated facilities earn a higher return in rate base compared to the short term interest rate that applied to the deferral account.

~~**CONFIDENTIAL**~~

24.0 Other Matters

References:

Exhibit B-1, p. 33

Issue:

Should there be a review of PNG's capital structure and ROE in 2012?
What should the process be for review of PNG's 2012 revenue requirements application?
What additional regulatory schedules should PNG file as part of its 2012 revenue requirements application?

Discussion:

A negotiated settlement of PNG's Capital Structure and Equity Risk Premium application was reached in May 2010. The issue of when to have another review of capital structure and ROE issues was addressed in the settlement agreement attached to Order G-84-10. Item 1.0 of the settlement agreement stated in part that "The above parameters are intended to reflect current business, financial and regulatory risks in each service area and should circumstances change, any party may request the Commission to make adjustments accordingly. In this regard, PNG agreed to review the reasonableness of the deemed common equity thicknesses and equity risk premiums no later than 2013." It was noted that current business circumstances are expected to be relatively unchanged in 2012 and that by 2013 there will be more certainty around whether any of the proposed LNG export projects will be built.

The parties noted that PNG's revenue requirements applications had been settled for the last three years and settlement of the 2011 revenue requirements application would add another year. The merits of having a public hearing process from time to time were discussed.

Some of the schedules prepared for information responses were reviewed to determine if similar schedules should be incorporated into the 2012 revenue requirements application for the purpose of providing more fulsome information.

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Settlement:

PNG will file capital structure and ROE evidence as part of its 2013 revenue requirements application.

PNG will prepare its 2012 revenue requirements application assuming the Commission will be reviewing the application through a public hearing process. The parties acknowledged that the Commission will decide on whether a written or oral hearing will be appropriate and any other details concerning the process.

PNG will present its full IFRS conversion plan as part of its 2012 revenue requirements application including a proposal to address each retained earnings adjustment and a list of each IFRS election it plans to take.

PNG's 2012 revenue requirements application regulatory schedules will include the Test Year 2012 forecast, the NSP 2011 figures and the 2008 to 2010 three year period actual figures. The parties acknowledge that it may not be practical to produce this level of detail for all regulatory schedules such as those under Tab 2, p. 2-7 & 12-20 and Tab 3, p. 1.

The following schedules will also be incorporated into PNG's 2012 revenue requirements application to facilitate the understanding of capital additions:

- A plant continuity schedule in the format of the table produced in Exhibit B-8, IR 24.1. The schedule will separate plant accounts by pre 2011 and post 2011 additions and the depreciation expense calculation will be shown separately for pre and post additions.
- A schedule showing PNG's forecast plant additions in the prior year compared to actual additions including information on all material differences. The information will be in the same format as the table provided in Exhibit B-8, IR 1.22.1.
- A schedule showing the Test Year 2012 plant additions, by project, including overhead and excluding overhead allocation and the relevant plant in service account in the same format as the table provided in Exhibit B-8, IR 1.22.3.

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Craig P. Donohue
Director, Regulatory Affairs & Gas Supply

Via E-Mail and Mail

May 9, 2011

B.C. Utilities Commission
6th Floor - 900 Howe Street
Vancouver, B.C.
V6Z 2N3

File No.: 4.2.7(2011)

Attention: William J Grant
Consultant to BCUC

Dear Sir:

Re: Negotiated Settlement Agreement for the PNG-West Division 2011 Revenue Requirements Application Project No. 3698611

Pacific Northern Gas Ltd. hereby confirms its acceptance of the terms set forth in the Negotiated Settlement Agreement for the PNG-West Division 2011 revenue requirements application enclosed with your letter to the parties to the NSP dated May 6, 2011.

Please direct any questions regarding this letter to my attention.

Yours truly,

C.P. Donohue

cc. Jim Quail – BCOAPO
Carolyn MacEachern – Young, Anderson
Philip Nakoneshny - Commission Staff

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Jodie Gauthier
Articled Student

May 9, 2011 Our File:7472

Erica M. Hamilton
Commission Secretary
BC Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Re: Pacific Northern Gas Ltd. (PNG-West) Negotiated Settlement Agreement 2011 Revenue Requirements Application

This is to confirm that our clients agree that the Negotiated Settlement Agreement finalized by the Commission's staff in this proceeding accurately captures the consensus outcome of the negotiation process, and that our clients consent to the Commission making an Order incorporating its terms as the resolution of this Application.

We wish to thank Mr. Grant and the Commission's staff for their excellent work in assisting the parties to resolve all of the issues in this proceeding in a fair, effective and efficient manner.

Yours truly,
BC PUBLIC INTEREST ADVOCACY CENTRE

Original in file signed by

Jim Quail
Executive Director

cc: parties of record

YOUNG ANDERSON
BARRISTERS & SOLICITORS

REPLY TO: VANCOUVER OFFICE

VIA EMAIL: bill.grant@bcuc.com

May 9, 2011

William J. Grant
Consultant to BCUC
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Mr Grant:

Re: Pacific Northern Gas Ltd. (PNG-West)
Negotiated Settlement Agreement – 2011 Revenue Requirements Application
Our File No. 00033-0408

Thank you for your letter of May 6, 2011, enclosing the final Negotiated Settlement Agreement in respect of the above Application We are confirming that the Peace River Regional District accepts the Negotiated Settlement Agreement as attached to the above correspondence.

We wish to thank you and the Commission staff for all of your work and assistance in this matter If you have any questions, please contact the writer at your earliest convenience.

Yours sincerely,

YOUNG ANDERSON

C. MacEachern

Carolyn MacEachern
maceachern@younganderson ca

CM/ss

copy to: Craig Donohue, Director, Regulatory Affairs and Gas Supply, Pacific Northern Gas Ltd
Fred Banham, Chief Administrative Officer, Peace River Regional District
Wayne Hiebert, Director – EA, Peace River Regional District