

PACIFIC NORTHERN GAS (N.E.) LTD.

(Fort St. John/Dawson Creek Division)

2012 Revenue Requirements Application

to the

B.C. Utilities Commission

November 30, 2011



Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

2012 REVENUE REQUIREMENTS APPLICATION

November 30, 2011

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**IN THE MATTER OF the Utilities
Commission Act, R.S.B.C. 1996,
c. 473, as amended**

- and -

In The Matter Of

**PACIFIC NORTHERN GAS (N.E.) LTD.
(Fort St. John/Dawson Creek Division)**

2012 REVENUE REQUIREMENTS APPLICATION

November 30, 2011

**TO: British Columbia Utilities Commission
Sixth Floor
900 Howe Street, P.O. Box 250
Vancouver, B.C.
V6Z 2N3**

PACIFIC NORTHERN GAS (N.E.) LTD. ("PNG(N.E.)") hereby applies to the British Columbia Utilities Commission (the "Commission") for approval to amend the rate schedules of PNG(N.E.)'s Fort St. John/Dawson Creek ("FSJ/DC") division in accordance with this Application, effective January 1, 2012. PNG(N.E.) seeks such approval on an interim basis pursuant to sections 58 to 61, 89 and 90 of the Utilities Commission Act (the "Act"). The following narrative provides the submissions by PNG(N.E.) in support of the rates applied for in this Application.

INTRODUCTION

PNG(N.E.)'s 2012 revenue requirements Application sets out PNG(N.E.)'s budgeted 2012 costs and forecast revenues using currently approved rates and forecast 2012 gas deliveries. The extent to which forecast revenues vary from forecast costs determines whether PNG(N.E.) is seeking Commission approval of rate increases or decreases for the Fort St. John/Dawson Creek Division. PNG(N.E.) compares its forecast 2012 costs to the Commission approved negotiated settlement of PNG(N.E.)'s 2011 revenue requirements application ("NSP 2011") to put the 2012 figures in context. The forecast 2012 calendar year figures are identified in this Application under the heading "Test Year 2012".

This Application has been prepared using U.S. Generally Accepted Accounting Principles ("US GAAP"). On October 6, 2011, PNG(N.E.) received Commission approval to use US GAAP for regulatory accounting and reporting purposes for the period January 1, 2012 to December 31, 2014. Please refer to the PNG-West 2012 revenue requirements application which includes a section entitled "Overview of Conversion to US GAAP".

The following regulatory financial schedules are included under Tabs 1 to 5 of this Application:

- Tab 1 - Utility Income & Return
- Tab 2 - Utility Rate Base
- Tab 3 - Income Taxes
- Tab 4 - Common Equity
- Tab 5 - Return on Capital

The regulatory schedules compare the Test Year 2012 figures to the NSP 2011 figures. In addition the actual historical cost of service figures are provided for the years 2008 to 2010 as agreed to under section 14.0 of the NSP 2011 settlement agreement. A Table is provided on the next page comparing the Test Year 2012 cost of service described in this Application to the NSP 2011 cost of service approved by the Commission.

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)

TEST YEAR 2012 vs. NSP 2011
 COST OF SERVICE COMPARISON
 (\$000)

EXPENSES	Test Year	NSP	Difference	
	2012	2011	Total	Subtotal
Operating				
Labour	1,757	1,671	86	
Other	2,937	2,751	186	
Sub-total	<u>4,694</u>	<u>4,422</u>	<u>271</u>	
Maintenance				
Labour	115	96	19	
Other	323	237	86	
Sub-total	<u>438</u>	<u>333</u>	<u>105</u>	
Administrative and General				
Labour	0	0	0	
Total Company Benefits	725	599	126	
Other	1,213	1,200	13	
Sub-total	<u>1,938</u>	<u>1,799</u>	<u>139</u>	
Total (O, M, A & G) Excluding Co. Use	7,069	6,554	516	516
Transfers to Capital Operating	(55)	(176)	120	
Transfers to Capital Admin. & Gen.	(250)	0	(250)	
Property Taxes	1,109	1,125	(16)	
Depreciation	1,334	1,393	(59)	
Amortization	(126)	314	(440)	
Other Income	(260)	(149)	(111)	
Adj. for 2011 Tomslake Rate Base Disallowance	(6)	0	(6)	
Settlement Allowance	0	(138)	138	(623)
Total Expenses Excluding Co. Use	8,815	8,923	(107)	(107)
Income Taxes	330 ⁽¹⁾	259 ⁽²⁾	71	
Return on Common Equity	1,704	1,626	78	
Short Term Debt	109	90	19	
Long Term Debt	1,236	1,176	61	228
Total Cost of Service Excluding Co. Use	12,194	12,073	121	121
Company Use Gas	303	326		
Total Cost of Service Including Co. Use	12,497	12,399		
			2011 to 2012 Cost of Service Increase / (Decrease)	121
			2011 to 2012 Margin Decrease (Increase) / Decrease	210
			2012 Revenue Deficiency / (Sufficiency)	331

1. Deferred income tax drawdown of \$ 9

2. Deferred income tax drawdown of \$ 100

The major components of the Test Year 2012 cost of service are summarized below in comparison to the corresponding figures under NSP 2011. The Table shows the main drivers of the projected revenue deficiency in 2012.

Cost of Service Items	(\$000's)		
	Test Year 2012	NSP 2011	2012/2011 Difference
Operating, maintenance, administrative and general expenses	\$7,069	\$6,554	\$516
Transfers to capital operating, administrative and general	(305)	(176)	(130)
Other cost of service Items including property taxes, depreciation and amortization	2,051	2,545	(494)
Return components including return on equity, income taxes and debt costs.	3,379	3,150	228
Total Cost of Service Ex. Co. Use Gas	\$12,194	\$12,073	\$121
Margin Using 2011 Rates	\$11,863	\$12,073	\$210
Test Year 2012 Revenue Deficiency			\$331
Total Cost of Service Ex. Co. Use Gas	\$12,194	\$12,073	
Company use gas cost pass through	303	326	
Total Cost of Service including Company Use Gas Cost	\$12,497	\$12,399	

The following provides the main reasons for the Test Year 2012 cost of service being higher than the NSP 2011 cost of service.

OPERATING EXPENSES

The Table below sets forth historical operating expenses and the Test Year 2012 applied for amounts.

BCUC Account	\$000's					
	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2010	Actual 2009	Actual 2008
670 – Supervision	\$474	\$470	\$4	\$336	\$334	\$410
675 – Mains and Services	430	388	42	364	392	356
685 – General Operations	203	196	7	220	239	227
688 – Other General Operations	619	597	22	560	503	481
711/713/714 Customer Care	487	490	(2)	419	417	336
712 Meter Reading	234	228	6	233	236	223
Add Shared Service Costs	1,354	1,205	149	1,036	1,000	927
718 Uncollectible Accounts	47	0	47	119	159	156
Other Inc. 665 and 673 Expenses	844	848	(4)	624	541	497
Subtotal	\$4,694	\$4,422	\$271	\$3,909	\$3,821	\$3,613
Transfers to Capital	(55)	(176)	120	(255)	(212)	(200)
Operating Expenses Excluding Co. use gas cost	\$4,638	\$4,247	\$392	\$3,654	\$3,609	\$3,413

The figures in the above Table exclude the Company use gas operating cost as that is treated as a pass through cost since it is dependant on prevailing gas supply market prices.

The following provides more detailed information on NSP 2011 to Test Year 2012 changes in operating costs as summarized by Commission Account number in the above Table.

Account 673 – Removing and Resetting Meters

Included in the Other category above is a forecast increased expenditure of \$25,000 in Test Year 2012 for the above account. This is due to an increase in the amount of labour allotted to this account, due to an increased number of meter recalls (1,566 in 2012 vs. 329 in 2011).

Account 675 – Mains and Services

The main cause of increased expenditures in the mains and services account is labour (\$28,000) primarily to respond to line locate requests in a timely manner. Material costs are also being shifted into this account (\$10,000) to more accurately reflect their use.

Account 688 – Other General Operations

The forecast expenditures in the other general operations Account 688 are increasing in 2012 compared to 2011 due to an increase in labour rates (\$16,000) and labour allotted to this account.

Account 718 – Uncollectible Accounts

In the April 15, 2011 update to the 2011 revenue requirements application, PNG(N.E.) proposed recording no bad debt expense for 2011 as there was an adequate allowance for doubtful accounts for its core market accounts receivable at that time. The April 15, 2011 letter to the Commission stated the following in this regard:

Uncollectible Accounts

For rate setting and for accounting purposes, PNG has been including an estimate of its annual bad debt expense based on the average bad debt expense in the previous 3 years adjusted for inflation. This amount historically constitutes approximately 0.65% of total revenues (excluding large industrials and off-system sales) for PNG West, 0.5% for PNG(N.E.)'s FSJ/DC division, and has varied from 0.05% to 0.25% for the PNG(N.E.) Tumbler Ridge division.

During the past three years, PNG commenced a new bad debt process using its Banner CIS system to better keep track of its aged receivables and has spent a substantial amount of time to clean up its "old" accounts receivables. PNG has also seen a decrease in uncollectible accounts.

As at December 31, 2010, on a consolidated company wide basis, PNG had an allowance for doubtful accounts of \$850,000 while accounts receivables greater than 90 days amounted to \$455,000 on a consolidated basis. Given this difference, PNG is proposing in the Updated Apr. 15'11 application not to record any bad debt expense for 2011 for the PNG(N.E.) FSJ/DC division as there is an existing adequate allowance for doubtful accounts for the current year. This will be reviewed annually to ensure the Company continues to record an appropriate bad debt expense in 2012 and onwards.

PNG(N.E.) has reviewed what the appropriate bad debt expense should be for the FSJ/DC division for Test Year 2012. PNG(N.E.) has estimated the provision for bad debt expense to be approximately 0.17% of projected core market revenues. This amounts to the \$47,000 figure set forth under Tab 1, Page 3, Line 29 for 2012.

Shared Service Costs – Operations and Customer Care

The increase in shared service costs mainly reflect the increased labour rates of 3% and benefits loading due mainly to the higher pension expense. See also the PNG-West 2012 revenue requirements application for further explanations.

MAINTENANCE COSTS

BCUC Account	\$000's					
	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2010	Actual 2009	Actual 2008
867 Regulating Stations	48	47	1	50	72	38
875 Mains and Services	174	170	4	135	177	98
878 Meters	59	58	1	40	42	45
All Other	157	57	99	13	24	35
Total	\$438	\$333	\$105	\$239	\$315	\$216

PNG(N.E.)'s overall 2012 planned maintenance activities at a budgeted cost of \$438,000 are responsive to system needs and are at a level PNG(N.E.) considers will ensure PNG(N.E.)'s facilities are kept in good working order and ensure continued safe, reliable and secure gas delivery service to its customers. See Tab 1, Page 4 for the detailed budget figures. The forecast expenditures for Mains and Services under Account 865 (included in All Other in the above Table) are increasing by \$72,000 due to contractor charges for right-of-way clearing and investigative dig activity related to close interval survey results, with labour (\$14,000) and material costs (\$10,000) related to these activities making up the remainder of the increase in this Account.

ADMINISTRATIVE AND GENERAL COSTS

\$000's						
Cost Element	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2010	Actual 2009	Actual 2008
721 Administration	\$17	\$14	\$3	\$2	(\$4)	\$2
Add 721 Shared Service Costs	816	849	(34)	749	\$726	664
722 Audit/Legal Fees	123	57	65	71	\$85	54
723 Insurance	96	95	1	124	\$117	129
725 Employee Ben.	725	599	126	456	\$447	460
728 General	43	50	(7)	64	\$42	41
Add 728 Shared Service Costs	119	134	(16)	122	\$105	93
Sub-total	1,938	1,799	139	1,587	\$1,518	1,442
Less: Transfers to Capital	(250)	0	(250)	(247)	(\$208)	(203)
Total	\$1,688	\$1,799	(\$111)	\$1,340	\$1,310	\$1,240

Administrative and general costs, net of transfers to capital, have decreased from \$1,799,000 under NSP 2011 to \$1,688,000 in Test Year 2012, a decrease of \$110,000. Explanations are provided below by BCUC Account.

Accounts 721 and 728 – Shared Service Costs

Lower administrative shared services charged by PNG (i.e. the parent company of PNG(N.E.)) under Accounts 721 and 728 reflect mainly the impact of the implementation of a Transfer Pricing Policy (“TPP”) by PNG in 2012. Through the TPP, PNG will now recover charges from Non-Regulated Business (NRB) activities on a fully loaded basis, which includes a recovery of facilities charges and general overheads. This results in a lower shared services pool of costs to be recovered by PNG from PNG(N.E.). Offsetting this decrease to some extent is the general labour increase of 3% and an increase in benefits loading due to the higher pension expense in 2012. See the PNG-West 2012 revenue requirements application for further explanations.

Account 722 – Audit/Legal Fees

The fees expected to be paid to in 2012 to outside consultants and lawyers in relation to the 2012 and 2013 revenue requirements applications account for \$29,000 of the increase in Account 722. These applications require more outside assistance due to the 2012 application being subject to a public hearing process and the 2013 application requiring expert testimony on ROE and capital structure matters. Audit fees were incorrectly budgeted in 2011. The budget for audit fees in 2011 was in the range of \$54,000. This compares to the budget of \$78,000 in 2010 and the budget in 2012 of \$90,000. Hence the relative increase is in the range of \$12,000 and not \$36,000 compared to the incorrect 2011 budget figure of \$54,000.

Account 725 – Employee Benefits

Employee benefits costs in 2012 are budgeted to increase by \$126,000. Approximately \$101,000 of this increase is due to higher Company pension plans costs. PNG's actuaries have provided a preliminary 2012 pension expense estimate which is higher than 2011 mainly due to a decrease in the discount rate (4.6% in 2012 versus 5.3% in 2011). The discount rate is lower primarily due to current financial market conditions and was determined following the new guidelines issued on September 21, 2011 by the Canadian Institute of Actuaries' Educational Note on the discount rate to be used for accounting purposes.

The Non-Pension Post-Retirement Benefits (NPPRB) are approximately the same as NSP 2011 mainly due to the reset of its unamortized net actuarial gains and losses to zero (see "Overview of Conversion to US GAAP" section in PNG-West 2012 revenue requirements application) offsetting the impact of the lower discount rate used to calculate the NPPRB expense.

PNG(N.E.) has included additional expected increases in employer contributions for CPP, EI, and group benefit premiums in the 2012 budget.

SHARED SERVICE CHARGES BY PNG TO PNG(N.E.)

The following Table summarizes the shared service charges allocated by PNG to PNG(N.E.)’s Fort St. John/Dawson Creek division over the 2008 to 2012 period. The allocation methodology used in 2012 by PNG to calculate the charges to its wholly owned subsidiary is the same as applied under NSP 2011.

	(\$ 000's)						
Allocated Costs	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2011	Actual 2010	Actual 2009	Actual 2008
721 - Administration	\$647	\$664	(\$17)	\$664	\$622	\$604	\$543
725 - Benefits	169	186	(17)	186	127	123	121
685 - General Operations	473	415	58	415	384	362	324
725 - Benefits	132	116	16	116	80	83	82
711/713/714 - Cust. Care	526	496	31	496	479	466	432
725 - Benefits	223	178	45	178	93	89	90
728 - Corporate	119	134	(15)	134	122	105	93
Subtotal Costs	1,765	1,709	56	1,709	1,607	1,537	1,392
Subtotal Benefits	524	480	44	480	300	295	293
Total	\$2,289	\$2,189	\$100	\$2,189	\$1,907	\$1,831	\$1,685

Shared service charges by PNG to PNG(N.E.)’s FSJ/DC division are projected to increase in 2012 from 2011 levels due to the combined effect of cost increases and decreases in the PNG-West cost pools that are allocated from PNG to PNG(N.E.). The level of those cost increases and decreases will be considered by the Commission in the context of its review of the PNG-West 2012 revenue requirements application.

TRANSFERS TO CAPITAL

PNG(N.E.) has used the capital overhead allocation methodology approved under NSP 2011 to calculate the transfers of budgeted 2012 operating, administrative and general expenses to capital. PNG(N.E.) is using the same capitalization overhead rates for both rate setting purposes and for external reporting purposes.

PNG(N.E.) has made one reclassification in the presentation of Transfers to Capital as the benefits loading associated with field personnel was included under “Transfers to Capital – Operating Expenses” in NSP 2011 instead of under “Transfers to Capital – Administrative and General Expenses” as all employee benefits are included under BCUC Account 725 Employee Benefits.

Overall, there has been an increase in Transfers to Capital of approximately \$132,000 mainly due to the allocation of the Vice-President of Operations time spent in PNG(N.E.) capital projects, an increase in salaries, increase in benefits loading due to the higher pension expense and higher direct charges to capital projects and their associated benefits loading amounts.

PROPERTY TAXES

Cost Element	\$000's					
	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2010	Actual 2009	Actual 2008
Property Taxes	\$936	\$893	\$43	\$809	\$755	\$698
1% in Lieu	173	232	(59)	243	223	260
Total	\$1,109	\$1,125	(\$16)	\$1,052	\$978	\$958

Actual 2011 property taxes on assessed property were 1 percent higher than forecast under NSP 2011 due to higher assessment values than originally anticipated, offset by a decline in mill rates. The Test Year 2012 provision for taxes on assessed property is also higher than actual taxes of \$902,000 in 2011 to reflect the impact of anticipated increases in assessed values in the range of 4 percent resulting from additional distribution mains and service installations. The 1 percent in lieu tax is based on revenues received in 2010.

DEPRECIATION

The forecast Test Year 2012 depreciation expense has been calculated using depreciation rates determined on the basis set forth in PNG(N.E.)'s 2011 revenue requirements application. Section 3.0 of the NSP 2011 settlement agreement provided the following with respect to depreciation:

“Depreciation expense will be determined on the basis proposed in the Application for Test Year 2011 only. PNG(N.E.) will obtain an independent review of the reasonableness of the areas where PNG(N.E.) 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(N.E.)'s 2012 revenue requirements application.”

A copy of a letter from Gannett Fleming is reproduced on the following pages in response to PNG(N.E.)'s agreement to “obtain an independent review of the reasonableness of the areas where PNG(N.E.) 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.” The letter supports management's decisions regarding the determination of depreciation rates as set forth in its 2011 revenue requirements application.



Gannett Fleming

*Excellence Delivered **As Promised***

November 25, 2011

Pacific Northern Gas
Suite 950 – 1185 West Georgia Street
Vancouver, British Columbia
V6E 4E6

Attention: Ms. Janet Kennedy

Gannett Fleming, Inc. Review of the Calculation of Depreciation Expense

Gannett Fleming, Inc. (“Gannett Fleming”) has reviewed the discussion related to depreciation rates in Section 5.0 of Appendix A to BCUC Order G-92-141. As per your request Gannett Fleming has provided the Attached “Gannett Fleming Review of Depreciation Expense”.

The attached document specifically replies to the order for PNG to “obtain an independent review of the reasonableness of 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.”

If you have any questions on the comments in the attached review, please feel free to call me at (403) 257-5946.

Sincerely,

GANNETT FLEMING, INC.
Valuation and Rates Division

Larry E. Kennedy
Director, Canadian Services

LEK/hac

PACIFIC NORTHERN GAS
GANNETT FLEMING, INC. REVIEW
OF THE CALCULATION OF DEPRECIATION EXPENSE

PROVIDED IN RESPONSE TO BCUC ORDER G-92-11

Composite Rate vs. Remaining Useful Lives

The Gannett Fleming depreciation study developed depreciation rates based on the plant in service as at December 31, 2009. The depreciation rates calculated within the depreciation were calculated using the Average Service Life (ASL) Procedure applied on a remaining life basis. The depreciation study, in Section V-Detailed Calculations, determined the appropriate level of annual depreciation accrual for each vintage of installed plant by dividing the net book value of the plant within the vintage by the remaining life of each vintage. The annual accrual for each vintage was then summed and divided by the net book value to determine a composite remaining life. The sum of the accruals for each vintage was also divided by the original cost of installed plant to determine a composite remaining life depreciation accrual rate.

For the determination of its depreciation expense as per its 2011 rate filing, PNG used the remaining useful lives for each vintage as provided in the depreciation study rather than the group composite rate and calculated the expense by dividing the net book value of each vintage by the remaining life applicable for each vintage as at the calculation date. This estimation is consistent with the implementation of the Gannett Fleming depreciation study results into the PNG accounting systems. In order to implement the results of the Gannett Fleming depreciation study, PNG entered into its plant accounting ledgers, the remaining life applicable for each vintage of each asset account. The remaining life used was based on the applicable vintage remaining life from the Gannett Fleming study. As such the PNG annual calculations are based on the results of the remaining life calculations from the Gannett Fleming study. In developing the depreciation expense, the PNG system divides the net book value of each vintage within each account by the remaining life as at the date of the calculation. Gannett Fleming notes that this is a mirrored version of the same calculation as made in the Gannett Fleming study in order to develop a composite depreciation rate.

The vintage distribution of the plant in service as used in the Gannett Fleming depreciation study was developed using an extract of the PNG plant accounting ledgers which provided an in service date. As such, the depreciation study data is consistent with the plant accounting ledgers of PNG. The composite depreciation rates as developed in the depreciation study, if applied to the plant accounting balances would result in a level of depreciation expense consistent with the depreciation expense resulting from the procedures currently used by PNG. As such, the PNG procedures are following the recommendations within the Gannett Fleming study, and Gannett Fleming finds that the current PNG procedures for the calculation of depreciation expense are appropriate and reasonable. Gannett Fleming further finds that the manner in which the forecast 2011 depreciation expense was determined is consistent with the results of the Gannett Fleming depreciation study.

Use of the ASL Procedure vs the Equal Life Group (ELG) Procedure

As indicated above, PNG has implemented the Gannett Fleming depreciation study by applying the same composite remaining life to all investment for each vintage installation within a group. This implementation procedure is more conducive to the calculation of depreciation rates developed using the ASL procedure rather than the ELG procedure. Depreciation rates calculated using the ELG procedure have a number of individual remaining life calculations applied to each of the installed plant vintages. As such, the remaining life calculation applied to each vintage is already a composite remaining applicable to the vintage. While in the view of Gannett Fleming, this separation of the installed costs by vintage into a number of individual remaining life groups provides increased accuracy, it would be virtually impossible to implement within the PNG accounting system. In contrast with the ASL procedure, the same remaining life calculation is applied to

all costs within a vintage. This allows for the easier conversion from the summed depreciation accruals inherent in the composite remaining life and depreciation rate from the depreciation study to the implementation requirements within the PNG accounting systems.

As indicated previously, the PNG system calculates depreciation expense by dividing the net book value of each vintage of the asset by the remaining life of the asset class vintage. The current net book value of each vintage of the asset class has not recognized that each vintage of installed plant can have a number of individual remaining life estimates, and at least conceptually, a number of individual and differing net book values. As such it would be virtually impossible to assign a correct ELG determined remaining life to each vintage as is required within the PNG systems. Given the wide spread use of the ASL procedure throughout North America, and further given that the ELG procedure had not been previously approved for use by the BCUC, Gannett Fleming views that the merits associated with the conversion to the ELG procedure would not be justified given the costs and administrative burden associated to implement the ELG procedure. As such, Gannett Fleming views that the use of the ASL procedure is reasonable in the current circumstances of the current PNG system.

Unit Depreciation Method – Asset Classes 484, 485 & 479

The assets that comprise asset classes 484 – Transportation Equipment; 485 – Heavy Work Equipment and Account 479 – Other Distribution Equipment are large, identifiable and easily tracked by unit. In fact these assets largely need to be tracked by individual unit for other business requirements. The company has developed policies with regard to the replacement of the assets in these accounts, and can easily determine the remaining life of each unit. As such, the depreciation on the assets within these accounts can easily be tracked on a unit depreciation basis. In the circumstances of these accounts with highly identifiable and individually tracked assets the use of unit depreciation provides a reasonable and appropriate level of depreciation expense.

The Depreciation Study completed in 2011 had regard to PNG(N.E.)’s expectation that it would be transitioning to International Financial Reporting Standards (“IFRS”). PNG(N.E.) obtained Commission approval under Order G-168-11 dated October 6, 2011 to adopt U.S. Generally Accepted Accounting Principles (“US GAAP”) for regulatory accounting and financial reporting purposes commencing January 1, 2012 and ending on December 31, 2014. PNG(N.E.) confirms that the adoption of US GAAP has not required a change to how depreciation will be determined by PNG(N.E.) for regulatory accounting and financial reporting purposes going forward compared to what was done in 2011. However, as is noted under the Overview of Conversion to US GAAP in the PNG-West 2012 revenue requirements application, PNG(N.E.) will return to its practice of commencing depreciation on new additions effective January 1 of the year following the year in which the addition was completed. This is easier to administer and accurately forecasts total depreciation expense.

Total depreciation expense forecast for Test Year 2012 is lower than under NSP 2011. This is mainly because as noted above, PNG(N.E.) will return to the practice of commencing depreciation on new additions effective January 1 of the year following when the addition was completed. Hence, no depreciation on forecast 2012 capital additions is included in Test Year 2012 depreciation expense.

AMORTIZATION

	(\$000’s)		
	Test Year 2012	NSP 2011	2012/2011 Difference
Gross Amortization	(\$126)	\$314	\$322
Future Income Taxes	\$19	(\$102)	(\$124)
Net of FIT	(\$107)	\$212	\$198

The Table above provides gross amortization and then a deduction of the future income taxes at the bottom of the Table to result in the after tax amortization expense. Schedule 1 Utility Income and Return shows the gross amortization figures with an offsetting deduction to income tax expense equal to the associated future income tax. A table is provided below to show the specific deferral accounts.

	Account Type				
	Rate Base - RB Interest Bearing - IntB		Amortization Expenses (\$000's)		
Deferral Accounts	Test Year 2012	NSP 2011	Test Year 2012	NSP 2011	2012/2011 Difference
Plant Gains and Losses	RB	RB	(24)	0	(24)
IFRS / US GAAP	RB	RB	55	0	55
BCUC Fees	IntB	IntB	(8)	4	(12)
Short Term Interest	IntB	IntB	(5)	3	(8)
Long Term Interest	IntB	IntB	(70)	(131)	61
Consolidated Gas Tariff Transition	IntB	N/A	(60)	0	(60)
2011 Depreciation Adjustment	IntB	N/A	(49)	0	(49)
Property Tax Variance	IntB	IntB	10	24	(14)
BCUC Hearing & CAP/ROE App.	IntB	IntB	1	44	(43)
DC Industrial Deliveries	IntB	IntB	12	15	(4)
Common Equity	IntB	IntB	11	385	(374)
Old Revolving Debt Issue Costs	IntB	IntB	0	30	(30)
Reserve for Damages	IntB	IntB	0	(71)	71
		Subtotal	(\$126)	\$303	(\$429)
		Future Income Taxes	19	(91)	111
		Net Total	(\$107)	\$212	(\$319)

More detailed commentary is provided below in the context of each deferral account.

Plant Gains and Losses

This deferral account is used to record extraordinary plant losses and the undepreciated value of assets that were retired but not fully depreciated (i.e. recoverable from customers) or over depreciated (i.e. to be credited to customers). It will also be used to record gains and losses from the disposal of assets as per the NSP 2011 settlement. The last paragraph of section 4.0 of the NSP 2011 settlement agreement stated:

“PNG(N.E.) requested Commission approval to establish a new Plant Gains and Losses rate base deferral account set forth in Exhibit B-1 at Tab Application, at Page 17 of the FSJ/DC section and at Page 16 of the TR section of the Application. The December 31, 2009 credit balances (i.e. \$264,000 in FSJ/DC and \$30,000 in TR) were recorded to this rate base deferral account to reflect the over depreciation of assets that had been retired and remained in plant, property and equipment. However, the request was withdrawn in the amendments to the Application filed as Exhibits B-1-2 and B-1-3 and during negotiations the request was restored. The parties agreed to PNG(N.E.)’s restored request provided that no amortization could be taken in Test Year 2011. Furthermore, the parties did not consider PNG(N.E.)’s ability to refund the balance in a future period nor did they discuss whether the dollar values were properly determined. The parties agreed that the recoverability, amortization period and dollar value of the deferral account balances would be addressed as part of PNG(N.E.)’s next revenue requirements application.”

The makeup of the \$264,000 figure set forth at Tab 2, Page 9 of PNG's original 2011 revenue requirements application was based on information available in November 2010. When the final NSP 2011 regulatory schedules were filed with the Commission in May 2011 the year end 2010 figures were available and this figure was revised to \$238,000 and reflected in the final NSP 2011 regulatory schedules accordingly.

As noted in the NSP 2011 settlement agreement, none of the \$238,000 figure was amortized in 2011. The forecast year end 2011 balance in this deferral account is a credit of \$242,000. The 2012 addition of \$62,000 represents the removal costs to be incurred in Dawson Creek to remove some above ground piping that will be retired in 2012.

PNG(N.E.) is seeking Commission approval to amortize the balance in the Plant Gains and Losses deferral account over 10 years. PNG(N.E.) considers the 10 year period to be appropriate for this type of rate base deferral account.

IFRS / US GAAP

The IFRS deferral account commenced in 2009 to record third party costs incurred to facilitate the conversion to IFRS. In 2011 PNG(N.E.) decided to adopt US GAAP for regulatory accounting and financial reporting purposes. PNG(N.E.) obtained Commission approval under Order G-168-11 dated October 6, 2011 to adopt US GAAP. Section 3 of this Order approved PNG(N.E.)'s "request to record one-time conversion costs associated with the adoption of US GAAP in a US GAAP rate base deferral account". For ease of reference, PNG(N.E.) has recorded the US GAAP adoption costs incurred to date in 2011 as part of the pre-existing IFRS deferral account given the fact both matters relate to accounting changes.

Section 4 of Order G-168-11 directed PNG(N.E.) "to seek approval for the amortization period and recoverability of the US GAAP deferral account and to address the disposition of the previously incurred IFRS conversion costs as part of the 2012 RRA." PNG(N.E.) is seeking Commission approval to amortize the joint IFRS/US GAAP projected year end 2011 balance over the 2012 to 2014 three year amortization period. PNG(N.E.) considers three years to be appropriate given this is the initial period of time over which PNG(N.E.) will initially apply US GAAP pending further review in 2015. As noted in the US GAAP application, total conversion costs [i.e. for both PNG and PNG(N.E.)] expected to be incurred in 2011 (\$250,000) and 2012 (\$150,000) have been allocated to each division based on rate base and included as additions to their respective deferral account in their respective years.

BCUC Fees

There will be no changes to how this deferral account will be administered in 2012 compared to what has applied over the last several years. It is still an interest bearing deferral account with a one year amortization period.

Short Term Interest

The short term interest deferral account records the difference between the underlying customer security deposit and short term operating line interest rates. There will be no changes to how this deferral account will be administered in 2012 compared to what has applied over the last several years. It is still an interest bearing deferral account with a one year amortization period.

Long Term Interest

The long term interest deferral account records the difference between the underlying long term forecast interest rates and actual interest rates. There will be no changes to how this deferral account will be administered in 2012 compared to what has applied over the last several years. It is still an interest bearing deferral account with a one year amortization period.

Consolidated Gas Tariff Transition

The Commission approved the Consolidated Gas Sales Tariff filed by PNG in 2011 to harmonize a number of items between the PNG-West and PNG(N.E.) service areas. There was no application fee in the PNG(N.E.) service area until August 1, 2011 when the fee of \$30 per application was implemented. Similarly, higher reconnection fees of \$60 were made effective August 1, 2011. PNG(N.E.) agreed to record the incremental fees collected from August 1 to December 31, 2011. The forecast credit balance has been included in this Application in an interest bearing deferral account and is being amortized in 2012.

2011 Depreciation Adjustment

This is a new deferral account that PNG(N.E.) is requesting the Commission to approve. In the 2011 revenue requirements application, PNG(N.E.) had applied and obtained Commission approval to commence recording depreciation as soon as a capital addition was put into service in order to be compliant with IFRS and had included \$47,730 of anticipated depreciation on 2011 additions in the 2011 cost of service. PNG(N.E.) is now requesting to return to the historical methodology of commencing to record depreciation on additions in the year following the year when the addition was completed which is allowed under US GAAP. The credit of \$47,730 recorded in this deferral account adjusts for the fact PNG(N.E.) is returning to this historical methodology. No changes have been made to the depreciation rates determined in accordance with the Depreciation Study filed with the 2011 revenue requirements application and accepted under NSP 2011. This deferral account will be fully amortized in 2012 and will not exist post 2012.

Property Tax Variance

The Property Tax Variance deferral account records the difference between budgeted costs used for rate making purposes and actual costs. There is a debit addition in 2011 which is being amortized in 2012.

BCUC Hearing & CAP/ROE App

A minor addition in 2011 to this deferral account in respect of BCUC hearing costs will be amortized in 2012.

DC Industrial Deliveries

This deferral account is used to record the difference between the forecast margin used to set rates and actual margin recovery from one industrial customer located in the Dawson Creek service area. The forecast year end 2011 balance is being amortized over one year in 2012. The update to this Application to be filed in February/March 2012 will reflect the actual year end 2011 figure.

Common Equity

The remaining balance in this deferral account at year end 2011 will be fully amortized in 2012.

Old Revolving Debt Issue Costs

This deferral account was fully amortized in 2011 and hence the reason for no amortization expense in Test Year 2012.

Reserve for Damages

This deferral account was fully amortized in 2011 and hence the reason for no amortization expense in Test Year 2012.

OTHER INCOME

Test Year 2012	NSP 2011	2012/2011 Difference
\$260,000	\$149,000	\$111,000

The other income forecast is significantly higher in Test Year 2012 compared to the NSP 2011 forecast due to the implementation of the new connection and reconnection fees under the Consolidated Gas Sales Tariff that was approved by the Commission effective August 1, 2011. The forecast of the connection/reconnection fees is \$152,000 based on an analysis of revenue since August 1, 2011 and historical reconnection numbers.

INCOME TAXES

	(\$000's)		
	Test Year 2012	NSP 2011	2012/2011 Difference
Tax before FIT	\$311	\$361	(\$38)
FIT on Deferrals	19	(102)	121
Total	\$330	\$259	\$84

The Test Year 2012 income taxes are higher compared to NSP 2011 primarily due to higher return on equity from higher rate base.

CAPITAL STRUCTURE AND RETURN ON COMMON EQUITY

	Test Year 2012	NSP 2011	2012/2011 Difference
Rate of Return on Equity	9.90%	9.90%	0
Common Equity Thickness	40.0%	40.0%	0
Common Equity (000's)	\$17,207	\$16,424	\$783
Return on Equity (000's)	\$1,704	\$1,626	\$78

PNG(N.E.) is recommending that the rate of return on equity and the deemed common equity thickness for Test Year 2012 be maintained at the same levels as agreed to under NSP 2011. A higher rate base level is the major reason for higher common equity and return on equity in Test Year 2012 compared to NSP 2011.

INTEREST EXPENSE

	Test Year 2012	NSP 2011	2012/2011 Difference
Short-term debt	\$109,000	\$90,000	\$19,000
Long-term debt	\$1,236,000	\$1,176,000	\$60,000

The short term debt component of PNG(N.E.)'s capital structure for rate making purposes balances the capital structure to the rate base. The increase in short term debt interest expense for 2012 reflects a general increase in interest rates forecast for 2012 compared to 2011. Specifically, the short term interest rate is projected to increase from 4.65 percent under NSP 2011 to 4.78 percent in Test Year 2012. The forecast interest rate on operating line borrowings is a consensus forecast of the average prime rate for 2012 taken from the October 2011 Econolink Report, plus PNG(N.E.)'s credit spread of 100 basis points. The forecast customer deposit interest rate for 2012 has been increased from 2011 by the increase in the forecast average prime rate from the Econolink.

The 2012 long term debt interest expense reflects higher debt levels due to PNG(N.E.)'s higher rate base relative to NSP 2011 and slightly higher projected interest rates on PNG(N.E.)'s floating rate debt compared to the projection used in NSP 2011. The projected interest rate on long term debt is forecast to increase from 5.18 percent under NSP 2011 to 5.25 percent for Test Year 2012.

COMPANY USE GAS COST

Test Year 2012	NSP 2011	2012/2011 Difference
62,989 GJ	65,040 GJ	(2,051 GJ)
\$303,183	\$325,512	(\$22,329)

The volume of Company use gas forecast for Test Year 2012 is lower than the forecast under NSP 2011 due primarily to lower forecast deliveries. Slightly lower gas commodity costs in conjunction with the decline in requirements results in a relatively minor reduction in overall Company use gas costs in Test Year 2012 compared to the NSP 2011 projection.

CAPITAL ADDITIONS

	Test Year 2012	NSP 2011	2012/2011 Difference
Additions including overhead	\$3,468,000	\$2,942,000	\$526,000
Less overhead	(275,000)	(253,000)	(\$22,000)
Net	\$3,193,000	\$2,689,000	\$504,000

The major capital additions planned for 2012 are summarized in the Table below.

Description	Budgeted Cost
New Additions	\$688,000
Customer Growth	339,000
Distribution System	858,000
Mobile/Heavy Equipment	235,000
Structures and Grounds Upkeep	512,000
Facility Modifications	326,000
Total	\$2,958,000

The expenditures shown above are considered necessary to ensure PNG(N.E.) continues to provide its customers with safe, reliable and secure gas delivery service in 2012. These projects account for approximately 93 percent of the total capital expenditures forecast for 2012, excluding overhead. Information about each of the projects identified above is provided below.

New Additions - \$688,000

The cost of new service additions (\$378,000), new mains (\$143,000) and new and replacement meters and meter sets (\$167,000) make up the expenditures for 2012.

Customer Growth - \$339,000

Several smaller projects to ensure the operational reliability and adequacy of the system to meet the load demands placed on it are forecast for 2012. The single largest project is the addition of an indirect fired lineheater at an existing pressure reducing facility at a total cost of \$110,000. Rebuilding two separate smaller pressure control stations and replacing two smaller lineheaters for a combined cost of \$207,000 is required due to increased customer load creating potential pressure regulation issues if left unaddressed. The remainder of the forecast expenditures relate to smaller projects involving minor looping of distribution main to maintain adequate system pressures.

Distribution System - \$858,000

The largest project is the continued removal of mechanical couplings on the distribution system. This activity will occur in both Dawson Creek and Fort St. John at a forecast cost of \$320,000. The other main activity in this area is the continued replacement of PE 2306 pipe at an estimated cost of \$225,000. The installation of 6,500 meters of distribution main to eliminate the need for a regulator station and improve system security and reliability is also forecast at \$230,000. A number of smaller projects account for the remainder of the distribution system capital projects.

Mobile/Heavy Equipment - \$235,000

The mobile/heavy equipment budget in 2012 includes the replacement of a flat deck trailer (\$46,000), and five replacement vehicles. One of the vehicles is a three quarter ton truck and the remainder are half ton pick-ups (\$169,000). All replacement vehicles meet or exceed PNG(N.E.)'s replacement criteria of 7 years or 160,000 kilometres.

Structure and Grounds Upkeep - \$512,000

The single largest item in this category of expenditure is the repair/replacement of a wall for the 40 year old Dawson Creek operations centre. PNG(N.E.) has had an independent engineering assessment performed which has determined there are structural deficiencies that must be rectified to ensure the long term safety and functioning of the building. The estimated cost of correcting the structural deficiencies is \$421,000. The remainder of the forecast expenditures are for a number of smaller projects in 2012 focused on ensuring continued access and safe operation of pressure reducing facilities and general office buildings.

Facility Modifications - \$326,000

These are modifications to existing facilities to improve their operational safety and reliability. The major activities planned for 2012 include: continuing to add station alarms to certain facilities, the lowering of a section of high pressure line due to safety and operational concerns, and replacement of a number of obsolete regulators, valves and associated equipment.

PNG(N.E.) agreed under NSP 2011 to include a Table in its 2012 revenue requirements application in the format set out below.

Plant in Service Additions Account Details 2012

Major 2012 Capital Projects (larger than \$50,000)	Budgeted Cost Excluding Overhead	Budgeted Cost Including Overhead	Plant in Service Account #
Lineheater Replacement	\$110,000	\$121,000	467
Lineheater Replacement	59,000	65,000	467
Repair Ops. Centre wall	421,000	487,000	472
Lowering HP line	75,000	82,000	465
Mechanical coupling removal	320,000	347,000	475
Meters New/replacements	167,000	167,000	478
PE 2306 replacement	225,000	244,000	475
Lineheater Replacement	59,000	65,000	467
Upgrade Pressure Reducing Stn.	64,000	71,000	467
Install station alarms	68,000	75,000	467
Services	378,000	415,000	473
Mains	143,000	155,000	475
Distribution syst. Improvement	230,000	249,000	475
Mobile Equipment	169,000	169,000	484
Work Equipment	66,000	66,000	485
Other	639,000	690,000	
Total	3,193,000	3,468,000	

PNG(N.E.) also agreed under NSP 2011 to include in its 2012 revenue requirements application a Table showing budgeted 2011 capital additions compared to actual 2011 capital additions. This Table will be filed when PNG(N.E.) files its year end 2011 update to this Application. The update is expected to be filed in late February 2012 or early March 2012.

NON-PENSION POST RETIREMENT BENEFITS AND PENSION PLANS

The following discusses the rate base treatment proposed by PNG(N.E.) in respect of non-pension post retirement benefits (“NPPRB”) and Company pension plans. This is the same narrative as presented in the PNG-West 2012 revenue requirements application. It is reproduced here for ease of reference rather than simply cross-referencing to the PNG-West application.

Non-Pension Post Retirement Benefits Plan Expenses and Funding

Prior to 2004, the Company recovered in its rates actual NPPRB paid. By year end 2003, the consolidated unfunded liability of the Company’s NPPRB plan was \$4.7 million. In response to the growing accrued obligation, PNG requested and the Commission approved, recovery of the current service cost portion of its NPPRB plan expense in addition to its actual payments of NPPRB commencing in 2004. The Commission’s approval was conditioned on PNG creating a trust structure into which the current service cost portion of the NPPRB plan expenses recovered in rates had to be deposited. PNG requested Commission relief from this condition since the only structure available was a Canada Revenue Agency (“CRA”) approved retirement compensation arrangement (“RCA”) trust where each contribution to the RCA trust had to be matched with an equal remittance to a refundable tax account with CRA. Since no interest or other return was paid on the refundable tax account, the return on the NPPRB funds collected in rates was significantly less than the effective return which would have been earned by PNG’s customers had the Commission approved its request to credit the cumulative after-tax funds collected against the Company’s rate base. The Commission denied PNG’s request and the NPPRB RCA trust was created.

Effective January 1, 2009, the AcSB removed the temporary exemption providing relief to entities subject to rate regulation from the general requirements regarding recognition and measurement of assets and liabilities arising from rate regulation. To comply with this change in accounting standard, in 2009 PNG recognized the full liability related to its NPPRB plan expenses, with the offsetting entry made to establish a regulatory asset. At the end of 2010, PNG’s consolidated unfunded liability for NPPRB was \$5.4 million.

As a result of these factors, PNG applied to commence recovering the full NPPRB expense in rates to customers in its 2011 revenue requirement application. PNG also proposed that the current service portion of the NPPRB expense continue to be contributed to the RCA but that the remainder of after-tax amount of the non-cash expense (i.e. the NPPRB expense recovered in excess of the 2011 cash cost of retiree non-pension benefits) be recognized as a credit to rate base. Through the NSP settlement process, PNG was approved to commence recovering the full NPPRB expense in rates, however, the settlement also provided that PNG would contribute the full amount of the non-cash expense to the RCA. The RCA trust account has a forecast balance of \$681,000 at December 31, 2011 with a similar amount being credited in the CRA refundable tax account.

With the conversion to US GAAP reporting commencing January 1, 2012, the estimated unamortized transitional obligation of \$861,000 under its NPPRB plan at December 31, 2011 will be debited to the Company's retained earnings, all else remaining the same. This is a result of the full accrual accounting methodology for NPPRB's being adopted earlier under US GAAP than Canadian GAAP such that transitional obligations had to be fully amortized by the end of 2011 under US GAAP while under Canadian GAAP they were being amortized through the end of 2018. PNG requests that the Commission explicitly approve recognition of a regulatory asset equal to the unamortized transitional obligation at the end of 2011 in order to offset the retained earnings impact of the conversion to US GAAP. PNG also proposes to fully amortize this regulatory asset January 1, 2012, with a concurrent equal and offsetting amortization of its regulatory deferred income tax liability. Further, PNG also proposes to fully amortize the net unfunded liability associated with its NPPRB plans in the same manner. By doing so, PNG's rate base will be unaffected and the complications of developing an appropriate amortization methodology for each of these independent items will be avoided which in turn will reduce the ongoing administration required for a growing number of regulatory accounts. Below are the details of the proposed amortization of these accounts and the impacts on the Company's consolidated balance sheet as well as the divisional rate base impacts.

January 1, 2012 Amortization Proposal – NPPRB
 Consolidated Financial Statements

	Debit	Credit
Amortization of NPPRB regulatory asset		\$2,496
Amortization of FIT on NPPRB regulatory asset	\$624	
Amortization of NPPRB transitional obligation regulatory asset		861
Amortization of FIT on NPPRB transitional obligation regulatory asset	215	
Amortization of deferred income tax regulatory liability – PNG-West	2,017	
Amortization of deferred income tax regulatory liability – PNG(N.E.)	501	

Example

PNG Consolidated Balance Sheet at January 1, 2012
 (\$000s)

	Prior to Proposed Amortization	Following the Proposed Amortization
<u>Assets</u>		
NPPRB regulatory asset	\$ 2,496	\$ -
Unamortized NPPRB transitional obligation regulatory asset	861	-
All other assets	<u>234,343</u>	<u>234,343</u>
	\$237,700	\$234,343
<u>Liabilities</u>		
NPPRB funded status	\$ 5,744	\$ 5,744
Deferred income tax regulatory liability – PNG-West	9,862	7,845
Deferred income tax regulatory liability – PNG(N.E.)	826	326
FIT on NPPRB funded status	(1,436)	(1,436)
FIT on NPPRB regulatory asset	624	-
FIT on NPPRB transitional obligation regulatory asset	216	-
Retained earnings	76,300	76,300
Accumulated OCI	(1,790)	(1,790)
All other liabilities and shareholder equity	<u>147,354</u>	<u>147,354</u>
	\$237,700	\$234,343

PNG-West 2012 Rate Base
 (\$000s)

	Prior to Proposed Amortization	Following the Proposed Amortization
Deferred income taxes	(\$9,362)	(\$7,345)
Historical unrecovered NPPRB expense requiring amortization (net-of-tax)	1,506	-
NPPRB transitional obligation adjustment requiring amortization (net-of-tax)	511	-
After-tax balance net NPPRB liabilities	(2,017)	(2,017)
All other rate base items	142,567	142,567
	<u>\$133,205</u>	<u>\$133,205</u>

FSJ/DC 2012 Rate Base
 (\$000s)

	Prior to Proposed Amortization	Following the Proposed Amortization
Deferred income taxes	(\$449)	(\$5)
Historical unrecovered NPPRB expense requiring amortization (net-of-tax)	325	-
NPPRB transitional obligation adjustment requiring amortization (net-of-tax)	119	-
After-tax balance NPPRB liabilities	(444)	(444)
All other rate base items	43,467	43,467
	<u>\$43,018</u>	<u>43,018</u>

Tumbler Ridge 2012 Rate Base
 (\$000s)

	Prior to Proposed Amortization	Following the Proposed Amortization
Deferred income taxes	(\$353)	(\$297)
Historical unrecovered NPPRB expense requiring amortization (net-of-tax)	41	-
NPPRB transitional obligation adjustment requiring amortization (net-of-tax)	15	-
After-tax balance NPPRB liabilities	(56)	(56)
All other rate base items	2,839	2,839
	<u>2,486</u>	<u>2,486</u>

PNG also proposes to commence winding up the RCA for its NPPRB plan. As noted above each contribution to the RCA trust has to be matched with an equal remittance to a refundable tax account with CRA and no interest or other return is paid on the refundable tax account. As a result, the return on NPPRB funds under the RCA trust structure is significantly less than the effective return which can be earned by PNG's customers when cumulative after-tax funds collected provide a credit to the Company's rate base.

Given that the beneficiaries of the RCA trust are PNG retirees, funds withdrawn from the trust can only be used to purchase benefits for retirees under the NPPRB plan and no immediate wind-up of the RCA trust is possible. In order to effect the proposed wind-up, PNG proposes that it does not contribute any NPPRB expense to the RCA trust in 2012 and commencing in 2013 that it use the RCA trust funds (with matching withdrawals from the refundable tax account) to pay the cash costs of retiree non-pension post-retirement benefits. Given that the regulatory approvals for the requested wind-up of the RCA trust structure are not likely to be obtained until sometime in 2012, PNG believes that deferring withdrawals from the RCA trust fund until 2013 will significantly simplify administration and accounting for this proposed change.

As noted earlier, PNG also proposes that the after-tax amount of the non-cash expense (i.e. the NPPRB expense recovered in excess of the 2012 cash cost of retiree non-pension benefits) be recognized as a credit to rate base.

Pension Plan Expenses and Funding

PNG is of the view that NPPRB and pension plans funding differences should be accorded equal rate base treatment.

At December 31, 2010 the Company recognized a pension asset, gross of related future income taxes, on its balance sheet of \$2.5 million on a consolidated basis with this asset expected to be \$3.4 million at the end of 2011. This amount represents the funding contributed to its pension plan, as required by legislation, in excess of the actuarially determined expense of its pension plan. As is considered appropriate by the Company, the actuarially determined expense has been recovered in rates. However, the plan contributions in excess of the expense have been funded by the Company with no compensation. PNG proposes in this Application to have the Company's after-tax pension asset recognized in rate base. The after-tax average pension asset proposed for inclusion in PNG-West rate base in 2012 equals \$2.0 million (see Tab 2, Page 1, Line 15 and the supporting new schedule at Tab 2, Page 10, Line 19).

IDENTIFIED SERVICE QUALITY METRICS

The Commission directed PNG(N.E.) under Order G-192-11 to report on five key service quality metrics commencing with the 2012 revenue requirements application. The requested data is provided in the following Table for all of the PNG(N.E.) divisions.

<u>Description</u>	<u>2011 YTD*</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>
Number of emergency calls	386	462	532	461
Average response time per call	19.5 minutes	18.5 minutes	17.5 minutes	18 minutes
Number of calls with response time over 40 mins.	25	20	21	19
No. of Underground leaks	26	9	8	13
No. of Reportable Environmental Incidents	0	1	0	0
Lost Time Injury Frequency Rate	0	0	0	4.02
Customer Complaints to BCUC**	N/A	0	0	0

*January to October 31, 2011.

**Information reflects Commission's March 31 fiscal year end (i.e. data for 2010 is from April 1, 2010 to March 31, 2011)

2012 FORECAST GAS DELIVERIES

The Test Year 2012 forecast of gas deliveries determines the projected margin PNG(N.E.) will receive from its customers during 2012 to pay the cost of serving those customers. The NSP 2011 gas deliveries forecast is compared to the Test Year 2012 forecast in the table below. The numbers have been rounded for ease of reference. Decreases from NSP 2011 to Test Year 2012 are indicated by bracketing the figures.

<u>Customer Groups</u>	NSP 2011 compared to Test Year 2012	
	Changes in Forecast Deliveries (GJ)	Changes in Forecast Margin (\$)
Residential	(11,000)	(26,000)
Small Commercial Sales	(34,600)	(87,000)
Large Commercial Sales	1,500	1,000
Commercial T-Service	6,300	15,000
Industrial Sales	114,600	143,500
Industrial T-Service (RS6)	(155,900)	(197,200)
Industrial T-Service (RS9/10/11)	(46,100)	(59,500)
Total	(125,200)	(\$210,200)

Residential Firm Sales Customers

Forecast deliveries to the residential customer class are determined based on the forecast use per account in each of the Fort St. John and Dawson Creek service areas times the number of customers in each area. The Test Year 2012 uses per account are lower than used under NSP 2011. PNG(N.E.) has trended historical normalized uses per account. The 2012 figures are the average of the linear trend figures for 2012 and the forecast normalized 2011 uses per account in each area. The Fort St. John forecast Test Year 2012 use per account is 107.1 GJ/year compared to the NSP 2011 figure of 109.5 GJ/year. For Dawson Creek the Test Year 2012 forecast use per account is 106.0 GJ/year a slight reduction from the NSP 2011 figure of 106.4 GJ/year. PNG(N.E.) considers that customers are continuing to conserve energy and are installing more efficient appliances resulting in the trend to lower use per account.

Small Commercial Firm Sales Customers

Similar to the residential customer use per account forecasts for 2012, PNG(N.E.) has trended historical normalized uses per account and taken the average of the projected 2011 normalized use per account and the linear trend figures calculated for 2012 to calculate forecast 2012 uses per account for the small commercial firms sales customers. The Fort St. John Test Year 2012 use per account forecast is 452.8 GJ/year compared to the NSP 2011 figure of 472.0 GJ/year. The corresponding Dawson Creek figures are 493.0 GJ/year for Test Year 2012 compared to 510.0 GJ/year for NSP 2011.

Other Core Market Customers

The following summarizes the projected 2012 deliveries to the large commercial firm, small industrial sales and transportation service customers for both Fort St. John and Dawson Creek in comparison to forecast deliveries under NSP 2011.

Customer Class	(GJ's)		
	Test Year 2012	NSP 2011	Difference
Large Commercial Sales	309,950	308,450	1,500
Commercial T-Service	79,100	72,800	6,300
Industrial Sales	287,606	173,000	114,606
Industrial T-Service (RS6)	449,100	605,000	(155,900)
Industrial T-Service (RS9/10/11)	421,700	467,800	(46,100)

The large commercial sales forecast in 2012 is slightly higher than in 2011 based on the forecasts of deliveries to these customers. There is no specific reason for the increase. There is no obvious reason for the higher forecast 2012 deliveries to the commercial transportation service customer class as well. The 2012 forecast to the small industrial sales customer class is much higher due to the addition of two new customers which account for 108,306 GJ of the increase. One of the RS6 transportation service customers is taking much less gas in 2011 and this is expected to prevail in 2012. A number of other RS6 customers are expected to consume less gas in 2012 compared to their budgeted 2011 volumes. Similarly, many of the customers in the RS9/10/11 group are expected to reduce gas consumption in 2012. The forecasts for 2012 are more in line with projected deliveries in 2011.

RATE MATTERS

Allocation of Revenue Deficiency

PNG(N.E.) has allocated the 2012 revenue deficiency to its customers using the projected 2012 gross margin by customer class as the allocator. This is consistent with the methodology approved by the Commission over the past several years.

Derivation of Forecast Test Year Gas Deliveries and Gross Margin

PNG(N.E.) has included under Tab Rates detailed schedules showing the derivation of the forecast Test Year gas deliveries by applying the forecast use per account to the forecast average number of customers in the case of the residential and small commercial customers. The annual forecast of deliveries to other customer classes is provided for each of the Fort St. John and Dawson Creek service areas. This enables one to balance the figures shown on Schedule 1, Tab 1 for sales and transportation service with the corresponding figures shown under Tab Rates. Similarly, the derivation of projected margin recovery in the Test Year using current rates is shown on schedules included under Tab Rates to verify the figures provided in the summary sheets. There may be some small differences between the detailed schedules and the summary schedules due to rounding that occurs when utilizing large spreadsheets to calculate gross revenue, delivery margin and gas supply costs.

RSAM Rate Rider

A Table is provided under Tab Rates to show the projected year-end 2011 RSAM balance and the derivation of the RSAM rider assuming three year amortization of the projected balance. This RSAM rider calculation will be updated to reflect the most recent information available when the final 2012 regulatory schedules are filed with the Commission to set rates effective January 1, 2012. Consequently, the calculated RSAM rider at year end 2011 is indicative only. However, PNG(N.E.) is requesting that the interim rates effective January 1, 2012 reflect the forecast RSAM rate rider as PNG(N.E.) does not expect the forecast balance will change to any significant degree by year end 2011 compared to the current forecast balance.

2011/2012 Gas Supply Cost Charge Changes/GCVA Riders

The gas supply cost recovery rates shown in the “Summary of Proposed Rates Effective January 1, 2012” are based on the cost of gas shown at Tab 1, Page 1, Line 16. The forecast cost of gas in 2012 was calculated using PNG(N.E.)’s gas cost flow through model updated to reflect the 2011/2012 gas supply and price arrangements entered into by PNG with its gas suppliers and to reflect the impact of the forecast gas prices contained in a recent forward gas price strip.

The revenue requirement model is designed to show the recovery of forecast gas supply costs on a flow through basis. In other words, the net margin (i.e. gross revenue less forecast cost of sales) will be the same regardless of what projected gas supply prices are used to calculate gas supply costs. PNG(N.E.)’s fourth quarter 2011 gas supply cost report to the Commission, to be filed in early December 2011, will contain proposed gas supply cost recovery rates and GCVA rate riders that will differ from the indicative January 1, 2012 rates shown in this Application.

A Table under Tab Rates entitled “Derivation of Test Year Forecast Gas Supply Cost” shows the derivation of the cost of sales figure shown at Tab 1, Page 1, Line 16. The forecast deliveries by customer class times the indicative gas supply prices by customer class generates the cost of sales figure for each customer class.

Determination of 2012 Unit Company Use Gas Cost Rate

The 2012 projected cost of Company use gas is based on the forecast gas prices and the quantity of gas PNG(N.E.) expects to purchase for Company use. The calculation of the indicative unit Company use gas cost recovery rate is shown on a schedule under Tab Rates. PNG(N.E.) divides the forecast cost of Company use gas by total deliveries to all customers to determine the recovery rate to be embedded in rates. The figure provided in this Application is indicative only as the current Company use gas delivery rate will be reviewed in the context of PNG(N.E.)’s fourth quarter 2011 gas cost report to the Commission.

Bill Comparison of Current Rates and January 2012 Rates

PNG(N.E.) includes under Tab Rates a comparison of the projected annual gas bills for residential and small commercial customers using current rates effective October 1, 2011 and proposed January 1, 2012. The bill comparison focuses on the delivery rate increase that is required to recover the forecast 2012 revenue deficiency by keeping the gas supply cost related rates unchanged pending the Commission's review of PNG(N.E.)'s fourth quarter 2011 gas cost report. The bill comparisons for each of the Fort St. John and Dawson Creek service areas are separately discussed below since the delivery rates are different in each service area.

Fort St. John

The average rate increase for residential customers is estimated to be 2.6 percent on the delivery charge component of rates or \$12 per year for an average customer. The projected average bundled average rate of \$9.607/GJ is \$15.046/GJ lower than the electricity equivalent rate of \$24.653/GJ assuming a 90 percent gas to electricity efficiency factor and using the trailing block electricity rate applicable under the residential inclining block rate structure.

The small commercial customer average rate increase is estimated to be 2.4 percent on the delivery charge component of rates or \$33 per year for an average customer. The projected average bundled average rate of \$8.395/GJ is \$14.182/GJ lower than the electricity equivalent rate of \$22.577/GJ assuming a 90 percent gas to electricity efficiency factor.

Dawson Creek

The average rate increase for residential customers is estimated to be 2.7 percent on the delivery charge component of rates or \$11 per year for an average customer. The projected average bundled average rate of \$9.418/GJ is \$15.236/GJ lower than the electricity equivalent rate of \$24.653/GJ assuming a 90 percent gas to electricity efficiency factor and using the trailing block electricity rate applicable under the residential inclining block rate structure.

The small commercial customer average rate increase is estimated to be 3.0 percent on the delivery charge component of rates or \$35 per year for an average customer. The projected average bundled average rate of \$7.843/GJ is \$14.736/GJ lower than the electricity equivalent rate of \$22.577/GJ assuming a 90 percent gas to electricity efficiency factor.

Demand Side Management

Section 6 of the NSP 2009 settlement agreement stated the following with respect to Demand Side Management:

“Resolution:

It was acknowledged by the parties that PNG(N.E.)’s relatively small customer base made it difficult to be at the forefront of implementing DSM programs in its service area. However, PNG(N.E.) will continue to actively participate in provincial government and industry working groups that are focusing on what DSM programs to implement throughout the province. PNG(N.E.) has been attending a number of workshops and other forums to ensure PNG(N.E.) is well aware of the ambit of DSM programs potentially usable by PNG(N.E.). In this way, PNG(N.E.) is hopeful it will identify DSM programs that can be successfully implemented by a relatively small utility at reasonable cost.”

PNG(N.E.) will focus its efforts on targeting DSM programs that can help its lower income customers to reduce their energy use and costs. This is in recognition of the unique circumstances faced by customers that may not be able to afford to purchase higher efficiency natural gas appliances but at the same time may have the greatest need to reduce their energy use to achieve corresponding cost savings.”

PNG(N.E.) will continue in 2012 to address DSM in accordance with the undertaking set out under the NSP 2009 settlement agreement.

COMMISSION ORDERS SOUGHT BY PNG(N.E.)

PNG(N.E.) is seeking the following Commission approvals under this Application:

1. Approval, effective January 1, 2012, on an interim basis pursuant to sections 58 to 61, 89 and 90 of the B.C. Utilities Commission Act (the “Act”), of the delivery charges set forth under the heading “Proposed Rates January 1, 2012” as set forth in the table under Tab Rates entitled “Summary of Proposed Rates Effective January 1, 2012”.
2. Approval of the deferral accounts and amortization expenses for 2012 as set forth under Tab 2 of this Application. In particular, PNG(N.E.) is seeking Commission approval of a new deferral account for 2011, to be amortized in 2012, called the 2011 depreciation adjustment deferral account.
3. Approve recognition of a regulatory asset equal to the unamortized NPPRB transitional obligation at the end of 2011 and a regulatory asset equal to the historical unrecovered NPPRB expense and to approve of PNG(N.E.) fully amortizing both these regulatory assets January 1, 2012, with a concurrent equal and offsetting amortization of its regulatory deferred income tax liability.
4. Approve the wind-up of the Retirement Compensation Arrangement (RCA) trust with Canada Revenue Agency (CRA), waive the requirement to contribute additional funds to the RCA commencing in 2012, and commence the use of the RCA trust fund to pay the cash costs of retiree Non-Pension Post-Retirement Benefits in 2013.
5. Approve the recognition of PNG(N.E.)’s after-tax pension asset in rate base and after-tax credit to rate base equal to the average amount of after-tax funds recovered in rates for NPPRB expense in excess of the amounts contributed to the RCA trust, refundable tax account or paid for retirees’ benefits.
6. Approval to continue the unaccounted for gas volume deferral account to record the difference between forecast and actual unaccounted for gas (“UAF”) volumes in Test Year 2012 based on using a 1 percent of deliveries UAF loss factor for 2012 and requiring PNG(N.E.) to apply for Commission approval to record actual 2012 UAF losses above 1.5 percent in the deferral account.

Draft Commission Order

A draft Commission order is set out under Tab 6. The Order addresses PNG(N.E.)'s request for approval of interim rates effective January 1, 2012 and sets out a proposed preliminary regulatory timetable with the dates to be determined by the Commission. The NSP 2011 settlement agreement provides for this application to be subject to a public hearing process. The applied for rates would apply on an interim basis. Permanent rates effective January 1, 2012 would then be set and billing adjustments would be made in the ordinary course based on the final rates approved by the Commission following the conclusion of the public hearing process.

All of which is respectfully submitted

DATED at Vancouver, British Columbia this 30th day of November 2011.

PACIFIC NORTHERN GAS (N.E.) LTD.



R.G. Dyce
President

All notices and other communications in connection with this Application should be directed to:

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Pacific Northern Gas (N.E.) Ltd.
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**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2012
(\$/GJ unless otherwise specified)**

Customer Class	Rates Effective October 1, 2011	Proposed 2012 Revenue Requirement	Indicative 2011/ 12 Gas Supply Cost Change	Proposed Rates January 1, 2012	Rate Changes
Residential (RS1)					
Monthly Fixed Charge	\$7.00			\$7.00	\$0.00
Delivery Charge	3.287	0.111		3.398	0.111
Company Use	0.073		(0.003)	0.070	(0.003)
GCVA Co. Use Rider	-		-	-	-
RSAM	0.050		(0.035)	0.015	(0.035)
Subtotal Delivery	3.410	0.111	(0.038)	3.483	0.073
Gas Supply Demand	0.049		0.002	0.051	0.002
Gas Supply Commodity	4.235		0.273	4.508	0.273
GCVA Commodity Rider	(0.185)		-	(0.185)	-
Subtotal Commodity	4.099	-	0.275	4.374	0.275
Total	7.509	0.111	0.237	7.857	0.348
Small Commercial (RS2)					
Monthly Fixed Charge	\$7.00			\$7.00	\$0.00
Delivery Charge	2.704	0.075		2.779	0.075
Company Use	0.073		(0.003)	0.070	(0.003)
GCVA Co. Use Rider	-		-	-	-
RSAM	0.050		(0.035)	0.015	(0.035)
Subtotal Delivery	2.827	0.075	(0.038)	2.864	0.037
Gas Supply Demand	0.046		0.003	0.049	0.003
Gas Supply Commodity	4.243		0.272	4.515	0.272
GCVA Commodity Rider	(0.185)		-	(0.185)	-
Subtotal Commodity	4.104	-	0.275	4.379	0.275
Total	6.931	0.075	0.237	7.243	0.312
Large Commercial (RS3)					
Monthly Fixed Charge	\$150.00			\$150.00	\$0.00
Delivery Charge	2.045	0.055		2.100	0.055
Company Use	0.073		(0.003)	0.070	(0.003)
GCVA Co. Use Rider	-		-	-	-
Subtotal Delivery	2.118	0.055	(0.003)	2.170	0.052
Gas Supply Demand	0.047		0.002	0.049	0.002
Gas Supply Commodity	4.248		0.269	4.517	0.269
GCVA Commodity Rider	(0.185)		-	(0.185)	-
Subtotal Commodity	4.110	-	0.271	4.381	0.271
Total	6.228	0.055	0.268	6.551	0.323

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2012
(\$/GJ unless otherwise specified)**

Customer Class	Rates Effective October 1, 2011	Proposed 2012 Revenue Requirement	Indicative 2011/ 12 Gas Supply Cost Change	Proposed Rates January 1, 2012	Rate Changes
<u>Commercial Transportation (RS2)</u>					
Monthly Fixed Charge	\$125.00			\$125.00	\$0.00
Delivery Charge	2.111	0.064		2.175	0.064
Company Use	0.073		(0.003)	0.070	(0.003)
GCVA Co. Use Rider	-		-	-	-
Subtotal Delivery	2.184	0.064	(0.003)	2.245	0.061
<u>Small Industrial (RS4)</u>					
Monthly Fixed Charge	\$410.00			\$410.00	\$0.00
Delivery Charge	1.098	0.039		1.137	0.039
Company Use	0.073		(0.003)	0.070	(0.003)
GCVA Co. Use Rider	-		-	-	-
Subtotal Delivery	1.171	0.039	(0.003)	1.207	0.036
Gas Supply Demand	0.021		0.001	0.022	0.001
Gas Supply Commodity	4.235		0.204	4.439	0.204
GCVA Commodity Rider	(0.185)		-	(0.185)	-
Subtotal Commodity	4.071	-	0.205	4.276	0.205
Total	5.242	0.039	0.202	5.483	0.241
<u>Small Industrial Service (RS6)</u>					
Monthly Fixed Charge	\$410.00			\$410.00	\$0.00
Delivery Charge	1.2662	0.0396		1.3058	0.0396
Company Use	0.0730		(0.0030)	0.0700	(0.0030)
GCVA Co. Use Rider	-		-	-	-
Subtotal Delivery	1.3392	0.0396	(0.003)	1.3758	0.0366

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2012
(\$/GJ unless otherwise specified)**

Customer Class	Rates Effective October 1, 2011	Proposed 2012 Revenue Requirement	Indicative 2011 / 12 Gas Supply Cost Change	Proposed Rates January 1, 2012	Rate Changes
<u>Small Industrial Service (RS9)</u>					
Monthly Fixed Charge	\$8,547.04			\$8,547.04	\$0.00
Delivery Charge	1.0766	0.0818		1.1584	0.0818
Company Use	0.0730		(0.0030)	0.0700	(0.0030)
GCVA Co. Use Rider	-		-	-	-
Subtotal Delivery	1.1496	0.0818	(0.003)	1.2284	0.0788
<u>Small Industrial Service (RS10)</u>					
Monthly Fixed Charge	\$3,095.00			\$3,095.00	\$0.00
Delivery Charge	0.4194	0.0279		0.4473	0.0279
Company Use	0.0730		(0.0030)	0.0700	(0.0030)
GCVA Co. Use Rider	-		-	-	-
Subtotal Delivery	0.4924	0.0279	(0.003)	0.5173	0.0249
<u>Small Industrial Service (RS11)</u>					
Monthly Fixed Charge	\$3,095.00			\$3,095.00	\$0.00
Delivery Charge	0.3836	0.0235		0.4071	0.0235
Company Use	0.0730		(0.0030)	0.0700	(0.0030)
GCVA Co. Use Rider	-		-	-	-
Subtotal Delivery	0.4566	0.0235	(0.003)	0.4771	0.0205

**Pacific Northern Gas (N.E.) Ltd.
(Dawson Creek Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2012
(\$/GJ unless otherwise specified)**

Customer Class	Rates Effective October 1, 2011	Proposed 2012 Revenue Requirement	Indicative 2011 / 12 Gas Supply Cost Change	Proposed Rates January 1, 2012	Rate Changes
Residential (RS1)					
Monthly Fixed Charge	\$7.00			\$7.00	\$0.00
Delivery Charge	3.089	0.111		3.200	0.111
Company Use	0.073		(0.003)	0.070	(0.003)
GCV A Co. Use Rider	0.000		-	0.000	0.000
RSAM	0.050		(0.035)	0.015	(0.035)
Subtotal Delivery	3.212	0.111	(0.038)	3.285	0.073
Gas Supply Demand	0.049		0.002	0.051	0.002
Gas Supply Commodity	4.235		0.273	4.508	0.273
GCV A Commodity Rider	(0.185)		-	(0.185)	0.000
Subtotal Commodity	4.099	-	0.275	4.374	0.275
Total	7.311	0.111	0.237	7.659	0.348
Small Commercial (RS2)					
Monthly Fixed Charge	\$7.00			\$7.00	\$0.00
Delivery Charge	2.167	0.075		2.242	0.075
Company Use	0.073		(0.003)	0.070	(0.003)
GCV A Co. Use Rider	0.000		-	0.000	0.000
RSAM	0.050		(0.035)	0.015	(0.035)
Subtotal Delivery	2.290	0.075	(0.038)	2.327	0.037
Gas Supply Demand	0.046		0.003	0.049	0.003
Gas Supply Commodity	4.243		0.272	4.515	0.272
GCV A Commodity Rider	(0.185)		-	(0.185)	-
Subtotal Commodity	4.104	-	0.275	4.379	0.275
Total	6.394	0.075	0.237	6.706	0.312
Large Commercial (RS3)					
Monthly Fixed Charge	\$150.00			\$150.00	\$0.00
Delivery Charge	1.497	0.055		1.552	0.055
Company Use	0.073		(0.003)	0.070	(0.003)
GCV A Co. Use Rider	0.000		-	0.000	0.000
Subtotal Delivery	1.570	0.055	(0.003)	1.622	0.052
Gas Supply Demand	0.047		0.002	0.049	0.002
Gas Supply Commodity	4.248		0.269	4.517	0.269
GCV A Commodity Rider	(0.185)		-	(0.185)	0.000
Subtotal Commodity	4.110	-	0.271	4.381	0.271
Total	5.680	0.055	0.268	6.003	0.323

**Pacific Northern Gas (N.E.) Ltd.
(Dawson Creek Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2012
(\$/GJ unless otherwise specified)**

Customer Class	Rates Effective October 1, 2011	Proposed 2012 Revenue Requirement	Indicative 2011 / 12 Gas Supply Cost Change	Proposed Rates January 1, 2012	Rate Changes
<u>Commercial Transportation (RS2)</u>					
Monthly Fixed Charge	\$125.00			\$125.00	\$0.00
Delivery Charge	1.563	0.064		1.627	0.064
Company Use	0.073		(0.003)	0.070	(0.003)
GCVA Co. Use Rider	-		-	0.000	0.000
<u>Subtotal Delivery</u>	<u>1.636</u>	<u>0.064</u>	<u>(0.003)</u>	<u>1.697</u>	<u>0.061</u>
<u>Small Industrial (RS4)</u>					
Monthly Fixed Charge	\$410.00			\$410.00	\$0.00
Delivery Charge	1.366	0.039		1.405	0.039
Company Use	0.073		(0.003)	0.070	(0.003)
GCVA Co. Use Rider	0.000		-	0.000	0.000
<u>Subtotal Delivery</u>	<u>1.439</u>	<u>0.039</u>	<u>(0.003)</u>	<u>1.475</u>	<u>0.036</u>
Gas Supply Demand	0.021		0.001	0.022	0.001
Gas Supply Commodity	4.235		0.204	4.439	0.204
GCVA Commodity Rider	(0.185)		-	(0.185)	-
<u>Subtotal Commodity</u>	<u>4.071</u>	<u>-</u>	<u>0.205</u>	<u>4.276</u>	<u>0.205</u>
<u>Total</u>	<u>5.510</u>	<u>0.039</u>	<u>0.202</u>	<u>5.751</u>	<u>0.241</u>

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

Bill Comparison
 October 2011 to January 2012

FORT ST. JOHN AREA

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2011 \$/ GJ	Annual Bill Estimate \$	Proposed Rates Jan. 1, 2012 \$/ GJ	Annual Bill Estimate \$	Annual Bill Difference	
						\$	%
Residential:	107.1 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.784	84.00	0.784	84.00	0.00	
Delivery Charge		3.360	359.86	3.468	371.38	11.53	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.050	5.36	0.015	1.61	(3.75)	
			449.21		456.99	7.78	1.7%
Gas Supply Charge		4.284	458.82	4.284	458.82	0.00	
GCVA Rider		(0.185)	(19.81)	(0.185)	(19.81)	0.00	
			439.00		439.01	0.01	0.0%
Carbon Tax		1.2415	132.96	1.2415	132.96	0.00	
		\$9.535 /GJ	\$1,021.18	\$9.607 /GJ	\$1,028.96	\$7.79	0.8%
Small Commercial:	452.8 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.186	84.00	0.186	84.00	0.00	
Delivery Charge		2.777	1,257.43	2.849	1,289.99	32.56	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.050	22.64	0.015	6.79	(15.85)	
			1,364.07		1,380.78	16.71	1.2%
Gas Supply Charge		4.289	1,942.06	4.289	1,942.06	0.00	
GCVA Rider		(0.185)	(83.77)	(0.185)	(83.77)	(0.00)	
			1,858.29		1,858.29	(0.00)	0.0%
Carbon Tax		1.2415	562.15	1.2415	562.15	0.00	
		\$8.358 /GJ	\$3,784.51	\$8.395 /GJ	\$3,801.22	\$16.71	0.4%

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

Bill Comparison
 October 2011 to January 2012

DAWSON CREEK AREA

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2011 \$/ GJ	Annual Bill Estimate \$	Proposed Rates Jan. 1, 2012 \$/ GJ	Annual Bill Estimate \$	Annual Bill Difference	
						\$	%
Residential:	106.0 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.792	84.00	0.792	84.00	0.00	
Delivery Charge		3.162	335.17	3.270	346.58	11.41	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.050	5.30	0.015	1.59	(3.71)	
			424.47		432.17	7.70	1.8%
Gas Supply Charge		4.284	454.10	4.284	454.10	(0.00)	
GCVA Rider		(0.185)	(19.61)	(0.185)	(19.61)	0.00	
			434.49		434.49	(0.00)	0.0%
Carbon Tax		1.2415	131.60	1.2415	131.60	0.00	
		\$9.345 /GJ	\$990.57	\$9.418 /GJ	\$998.26	\$7.69	0.8%
Small Commercial:	493.0 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.170	84.00	0.170	84.00	0.00	
Delivery Charge		2.240	1,104.32	2.312	1,139.78	35.46	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.050	24.65	0.015	7.40	(17.26)	
			1,212.97		1,231.17	18.20	1.5%
Gas Supply Charge		4.289	2,114.48	4.289	2,114.48	0.00	
GCVA Rider		(0.185)	(91.21)	(0.185)	(91.21)	0.00	
			2,023.27		2,023.27	0.00	0.0%
Carbon Tax		1.2415	612.06	1.2415	612.06	0.00	
		\$7.806 /GJ	\$3,236.24	\$7.843 /GJ	\$3,254.45	\$18.20	0.6%

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)**

**Bill Comparison
October 2011 to January 2012
Average of Fort St. John and Dawson Creek**

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2011 \$/ GJ	Annual Bill Estimate \$	Proposed Rates Jan. 1, 2012 \$/ GJ	Annual Bill Estimate \$	Annual Bill Difference	
						\$	%
Residential:	106.6 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.788	84.00	0.788	84.00	0.00	
Delivery Charge		3.261	347.46	3.369	358.93	11.47	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.050	5.33	0.015	1.60	(3.73)	
			436.79		444.53	7.74	1.8%
Gas Supply Charge		4.284	456.46	4.284	456.46	(0.00)	
GCVA Rider		(0.185)	(19.71)	(0.185)	(19.71)	0.00	
			436.75		436.75	0.00	0.0%
Carbon Tax		1.2415	132.28	1.2415	132.28	(0.00)	
		\$9.440 /GJ	\$1,005.82	\$9.512 /GJ	\$1,013.56	7.74	0.8%
Small Commercial:	472.9 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.178	84.00	0.178	84.00	0.00	
Delivery Charge		2.509	1,186.27	2.580	1,220.28	34.01	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.050	23.65	0.015	7.09	(16.56)	
			1,293.91		1,311.37	17.46	1.3%
Gas Supply Charge		4.289	2,028.27	4.289	2,028.27	0.00	
GCVA Rider		(0.185)	(87.49)	(0.185)	(87.49)	(0.00)	
			1,940.78		1,940.78	(0.00)	0.0%
Carbon Tax		1.2415	587.11	1.2415	587.11	0.00	
		\$8.082 /GJ	\$3,821.80	\$8.119 /GJ	\$3,839.26	17.46	0.5%

Note: This bill comparison is the average of the uses per account and rates that apply to each of the Fort St. John and Dawson Creek delivery areas.

**Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)**

**SUMMARY OF PROPOSED GAS DELIVERY CHARGE RATE CHANGES
 EFFECTIVE JANUARY 1, 2012**

Customer Classification	2012 Test Year Gas Deliveries (GJ)	2012 Gross Margin (\$)	Allocation of Revenue Deficiency (\$)	Rate Changes for Revenue Deficiency (\$/GJ)
Residential (RS1)	1 636 820	6,662,710	181,070	0.111
Commercial				
Small Commercial (RS2)	1 123 525	3,097,521	84,180	0.075
Large Commercial Firm (RS3)	309 950	623,894	16,955	0.055
Commercial Transportation (RS23)	79 100	186,285	5,063	0.064
Small Industrial Sales (RS4)	287 606	414,043	11,252	0.039
Industrial Transport				
RS6	449 100	654,207	17,779	0.0396
RS9	55 000	165,627	4,501	0.0818
RS10	276 700	283,977	7,718	0.0279
RS11	90 000	77,964	2,119	0.0235
TOTAL	4 307 801	12 166 230	330 638	

**Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)**

SUMMARY OF REVENUE, COST OF GAS, GROSS MARGIN

Customer Classification	2012 Test Year Gas Deliveries (GJ)	Revenue (\$)	Cost of Gas (\$)	Gross Margin (\$)
Residential (RS1)	1 636 820	14 124 969	7 462 260	6,662,710
Commercial				
Small Commercial (RS2)	1 123 525	8 225 289	5 127 768	3,097,521
Large Commercial Firm (RS3)	309 950	2 039 130	1 415 236	623,894
Commercial Transportation (RS23)	79 100	186 285	0	186,285
Small Industrial Sales (RS4)	287 606	1 697 055	1 283 011	414,043
Industrial Transport				
RS6	449 100	654 207	0	654,207
RS9	55 000	165 627	0	165,627
RS10	276 700	283 977	0	283,977
RS11	90 000	77 964	0	77,964
TOTAL	4 307 801	27 454 504	15 288 275	12 166 230

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gas Deliveries
 FORT ST. JOHN

Customer Classification	Estimated Customer Count At Dec. 31st, 2011	Test Year Effective Customer Additions	Test Year Weighted Average Customer Count	Test Year Average Use Per Account (GJ)	2012 Test Year Deliveries (GJ)
Residential (Rate 1)	9,521	73	9,594	107.1	1,027,761
Commercial					
Small Commercial Sales (Rate 2)	1,557	14	1,571	452.8	711,383
Large Commercial Firm Sales (Rate 3)					156,950
Commercial Transportation (RS23)					44,000
Small Industrial Sales (RS4)					253,106
Industrial Transportation					
RS6					449,100
RS9					55,000
RS10					276,700
RS11					90,000
Subtotal Sales					2,149,200
Subtotal Transportation Service					914,800
Total					3,064,000

DAWSON CREEK

Customer Classification	Customer Count At Dec. 31st, 2011	Test Year Effective Customer Additions	Test Year Weighted Average Customer Count	Test Year Average Use Per Account (GJ)	2012 Test Year Deliveries (GJ)
Residential (Rate 1)	5,687	58	5,745	106.0	609,059
Commercial					
Small Commercial Sales (Rate 2)	816	20	836	493.0	412,142
Large Commercial Firm Sales (Rate 3)					153,000
Commercial Transportation (RS23)					35,100
Small Industrial Sales (RS4)					34,500
Subtotal Sales					1,208,701
Subtotal Transportation Service					35,100
Total					1,243,801

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)
 Summary of Test Year Gas Sales Supporting Schedule

Customer Classification	Customer Count At Dec. 31st, 2011	+ Test Year Effective Customer Additions	= Test Year Weighted Average Customer Count	x Test Year Average Use Per Account (GJ)	= 2012 Test Year Deliveries (GJ)
Residential (Rate 1)	15,208	131	15,339	106.7	1,636,820
Commercial					
Small Commercial Sales (Rate 2)	2,373	34	2,407	466.8	1,123,525
Large Commercial Firm Sales (Rate 3)					309,950
Commercial Transportation (RS23)					79,100
Small Industrial Sales (RS4)					287,606
Industrial Transportation					
RS6					449,100
RS9					55,000
RS10					276,700
RS11					90,000
Subtotal Sales					3,357,901
Subtotal Transportation Service					949,900
Total					4,307,801

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gross Margin

Fort St. John	2012 Test Year Deliveries (GJ)	Current Delivery Charge \$ / GJ	Delivery Margin	Weighted Avg. Customer Count	Current Fixed Charge	Fixed Charge Margin	Total Delivery & Fixed Charge Margin	Test Year Gross Margin
Residential (Rate 1)	1,027,761	3.357	3,450,194	9,594	7.00	805,903	4,256,096	4,256,096
Commercial								
Small Commercial Sales (Rate 2)	711,383	2.774	1,973,376	1,571	7.00	131,950	2,105,326	2,105,326
Large Commercial Sales (Rate 3)	156,950	2.115	331,949	17	150.00	30,600	362,549	362,549
Commercial Transport (Rate 23)	44,000	2.181	95,964	14	125.00	21,000	116,964	116,964
Small Industrial Sales (Rate 4)	253,106	1.168	295,628	9	410.00	44,280	339,908	339,908
Industrial Transportation								
Rate 6	449,100	1.3362	600,087	11	410.00	54,120	654,207	654,207
Rate 7			0	0		0	0	0
Rate 9	55,000	1.1466	63,063	1	8,547.04	102,564	165,627	165,627
Rate 10	276,700	0.4894	135,417	4	3,095.00	148,560	283,977	283,977
Rate 11	90,000	0.4536	40,824	1	3,095.00	37,140	77,964	77,964
Total Fort St. John	3,064,000		6,986,503			1,376,117	8,362,619	8,362,619

Dawson Creek	2012 Test Year Deliveries (GJ)	Current Delivery Charge \$ / GJ	Delivery Margin	Weighted Avg. Customer Count	Current Fixed Charge	Fixed Charge Margin	Total Delivery & Fixed Charge Margin	Test Year Gross Margin
Residential (Rate 1)	609,059	3.159	1,924,017	5,745	7.00	482,552	2,406,570	2,406,570
Commercial								
Small Commercial Sales (Rate 2)	412,142	2.237	921,962	836	7.00	70,189	992,150	992,150
Large Commercial Sales (Rate 3)	153,000	1.567	239,751	12	150.00	21,600	261,351	261,351
Commercial Transport (Rate 23)	35,100	1.633	57,318	8	125.00	12,000	69,318	69,318
Small Industrial Sales (Rate 4)	34,500	1.436	49,542	5	410.00	24,600	74,142	74,142
Total Dawson Creek	1,243,801		3,192,590			610,941	3,803,531	3,803,531

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gross Margin

FSJ/DC Combined	2012	Current		Weighted			Total	
Customer Classification	Test Year	Delivery	Delivery	Avg.	Current	Fixed Charge	Delivery	Test Year
	Gas Sales	Charge	Margin	Customer	Fixed Charge	Margin	& Fixed Charge	Gross
	(GJ)	\$ / GJ		Count			Margin	Margin
Residential (Rate 1)	1,636,820		5,374,211	15,339	7.00	1,288,455	6,662,666	6,662,666
Commercial								
Small Commercial Sales (Rate 2)	1,123,525		2,895,338	2,406	7.00	202,138	3,097,477	3,097,477
Large Commercial Sales (Rate 3)	309,950		571,700	29	150.00	52,200	623,900	623,900
Commercial Transport (Rate 23)	79,100		153,282	22	125.00	33,000	186,282	186,282
Small Industrial Sales (Rate 4)	287,606		345,170	14	410.00	68,880	414,050	414,050
Industrial Transportation								
Rate 6	449,100	1.2632	600,087	11	410.00	54,120	654,207	654,207
Rate 9	55,000	1.0766	63,063	1	8,547.04	102,564	165,627	165,627
Rate 10	276,700	0.4194	135,417	4	3,095.00	148,560	283,977	283,977
Rate 11	90,000	0.3836	40,824	1	3,095.00	37,140	77,964	77,964
Total Fort St. John / Dawson Creek	4,307,801		10,179,093			1,987,058	12,166,151	12,166,151

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Indicative Test Year Forecast Gas Supply Cost

<u>Fort St. John</u>	2012 Test Year Deliveries (GJ)	Indicative Gas Cost Charge (\$ / GJ)	Indicative Gas Cost (\$)
Customer Classification			
Residential (Rate 1)	1,027,761	4.559	4,685,562
Commercial			
Small Commercial Sales (Rate 2)	711,383	4.564	3,246,752
Large Commercial Sales (Rate 3)	156,950	4.566	716,634
Small Industrial Sales (Rate 4)	253,106	4.461	1,129,106
Total Fort St. John	2,149,200		9,778,054

<u>Dawson Creek</u>	2012 Test Year Deliveries (GJ)	Gas Cost Charge (\$ / GJ)	Total Gas Cost (\$)
Customer Classification			
Residential (Rate 1)	609,059	4.559	2,776,700
Commercial			
Small Commercial Sales (Rate 2)	412,142	4.564	1,881,016
Large Commercial Sales (Rate 3)	153,000	4.566	698,598
Small Industrial Sales (Rate 4)	34,500	4.461	153,905
Total Dawson Creek	1,208,701		5,510,219

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Indicative Test Year Forecast Gas Supply Cost

<u>FSJ / DC Combined</u>	2012	Gas Cost	Total
Customer Classification	Test Year Deliveries (GJ)	Charge (\$ / GJ)	Gas Cost (\$)
Residential (Rate 1)	1,636,820	4.559	7,462,262
Commercial			
Small Commercial Sales (Rate 2)	1,123,525	4.564	5,127,768
Large Commercial Sales (Rate 3)	309,950	4.566	1,415,232
Small Industrial Sales (Rate 4)	287,606	4.461	1,283,010
Total Fort St. John / Dawson Creek	3,357,901		15,288,273

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)**

Determination of Indicative Gas Supply Cost Rate Changes Effective January 1, 2012

Using 5 Day Average Ending November 25, 2011 Forward Gas Strip

Customer Classification	Gas Supply Costs Rates Effective October 1, 2011				Gas Supply Costs Indicative Rates Effective January 1, 2012				Indicative Gas Supply Cost Rate Changes Effective January 1, 2012			
	Demand (\$/GJ)	Commodity (\$/GJ)	Total D&C	Company Use Gas (\$/GJ)	Demand (\$/GJ)	Commodity (\$/GJ)	Total D&C	Company Use Gas (\$/GJ)	Demand (\$/GJ)	Commodity (\$/GJ)	Total D&C	Company Use Gas (\$/GJ)
Residential (RS1)	0.049	4.235	4.284	0.073	0.051	4.508	4.559	0.070	0.002	0.273	0.275	(0.003)
Small Commercial (RS2)	0.046	4.243	4.289	0.073	0.049	4.515	4.564	0.070	0.003	0.272	0.275	(0.003)
Large Commercial (RS3)	0.047	4.248	4.295	0.073	0.049	4.517	4.566	0.070	0.002	0.269	0.271	(0.003)
Small Industrial (RS4)	0.021	4.235	4.256	0.073	0.022	4.439	4.461	0.070	0.001	0.204	0.205	(0.003)
Company Use				0.073				0.070				(0.003)
Transportation Service				0.073				0.070				(0.003)

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)**

ALLOCATION OF DEMAND CHARGES EFFECTIVE JANUARY 1, 2012

Customer Classification	Peak Day Requirement		Allocation of Demand Charges (\$)	2012 Annual Requirements (GJ)	Unit Demand Charge (\$/GJ)
	(GJ)	(%)			
Residential (RS1)	17 146	51.68	83,602	1 636 820	0.051
Small Commercial (RS2)	11 263	33.95	54,915	1 123 525	0.049
Large Commercial (RS3)	3 143	9.47	15,324	309 950	0.049
Industrial Sales (RS4)	1 313	3.96	6,403	287 606	0.022
Company Use Gas	313	0.94	1,525	62 989	0
Total	33 178	100.0	161,770	3 420 890	

- Notes: 1. PNG allocates its demand charges to each customer classification based on the proportion their projected peak day gas requirement
2. The unit demand charge is the allocated demand charge divided by the projected annual gas requirements for each customer classification. There is no unit demand charge for Company use gas as the demand charges and the commodity charges for company use gas are totalled and then spread over total sales (i.e. the sum of sales and transportation service.)

**Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)**

Determination of Indicative 2012 Unit Company Use Gas Cost Rate

Using 5 Day Average Ending November 25, 2011 Forward Gas Strip	
Demand Cost	\$1,525
Commodity Cost	\$281,143
Carbon Tax	\$20,514
	<u>\$303,183</u>
Total Company use gas requirement	62 989 GJ
Deliveries	4 307 801 GJ
2012 Unit Company Use Gas Cost Rate	
\$0.070 /GJ	<u>\$303,183</u>
	4 307 801
Commodity Cost of Company Use Gas per GJ Purchased	
\$4.463 /GJ	<u>\$281,143</u>
	62 989

**Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)**

Determination of Indicative 2012 Revenue Stabilization Adjustment Mechanism (RSAM) Rider

	Residential	Small Commercial	Total
RSAM balance at year-end 2010 after-tax	\$121,276	\$190,416	\$311,693
RSAM recovery/deferral in 2011 after-tax	(\$174,671)	(\$46,573)	(\$221,243)
RSAM balance at year-end 2011 after-tax	(\$53,394)	\$143,844	\$90,450
Years of amortization			3
RSAM balance divided by 3 equals 2012 after-tax amortization			\$30,150
2012 pre-tax amortization at 2012 tax rate			\$40,200
Forecast 2012 deliveries	1,636,820	1,123,525	2,760,345
One year of pre-tax amortization divided by 2012 deliveries equals RSAM rate rider (\$/GJ)			0.015

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Forward Gas Price Strip
5 Day Average Ending November 25, 2011

	STATION #2 CDN\$/GJ	AECO CDN\$/GJ
Jan-12	3.0152	3.2332
Feb-12	2.9822	3.2402
Mar-12	2.9436	3.2376
Apr-12	2.9381	3.1971
May-12	2.9587	3.2177
Jun-12	2.9662	3.2252
Jul-12	2.9927	3.2517
Aug-12	3.0128	3.2738
Sep-12	3.0347	3.2957
Oct-12	3.0895	3.3485
Nov-12	3.3265	3.5705
Dec-12	3.6218	3.8058
Average	3.0735	3.3248

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)**

UTILITY INCOME & RETURN

**SCHEDULE 1
(000's)**

Line No.	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source	
1	Energy sales (TJ)	3 358	3 287	3 205	3 593	3 440	Tab Rates, page 12
2	Average rate per GJ	\$7.86	\$8.07	\$7.85	\$8.50	\$10.58	
3							
4	Transportation service (TJ)	950	1 146	1 140	1 323	1 363	Tab Rates, page 12
5	Average rate per GJ	\$1.48	\$1.42	\$1.17	\$1.05	\$1.06	
6							
7	Total deliveries (TJ)	4 308	4 433	4 345	4 916	4,803	Tab Rates, page 12
8							
9	Utility revenue						
10	Energy sales	\$26,086	\$24,643	\$25,147	\$30,540	\$36,399	Tab Rates, page 10
11	Interim rates - sales	293	1,894		-	0	Tab Rates, page 9
12	Transportation service	1,368	1,341	1,337	1,386	1,447	Tab Rates, page 10
13	Interim rates - transportation	37	286		-	0	Tab Rates, page 9
14							
15		27,785	28,164	26,484	31,926	37,846	
16	Cost of sales	15,288	15,765	15,814	21,778	27,456	Tab Rates, page 10 & 16
17							
18	Gross margin	12,497	12,399	10,670	10,148	10,389	
19							
20	Operating expenses	4,941	4,572	4,037	4,067	4,002	Tab 1, page 2, line 6
21	Maintenance expenses	438	333	239	315	243	Tab 1, page 2, line 10
22	Admin. & general expenses	1,688	1,799	1,340	1,310	1,230	Tab 1, page 2, line 16
23	Property taxes	1,109	1,125	1,052	977	958	Tab 1, page 6, line 4
24	Depreciation	1,334	1,393	1,517	1,440	1,363	Tab 2, page 6, line 49
25	Amortization on gross deferrals	(126)	314	43	(44)	(216)	Tab 2, page 9, line 29
26	Investment income, other revenue	(260)	(149)	(108)	(248)	(178)	Tab 1, page 7, line 7
27	Adj. for 2011 Tomslake rate base disallowance	(6)					Tab App., page 3
28	CAP/ROE deferred revenue	-	-	(294)			
29	NSP Settlement Allowance	-	(138)	-	-		
30							
31		9,118	9,248	7,825	7,818	7,401	
32							
33	Earned return before income taxes	3,379	3,151	2,845	2,330	2,988	
34	Future Income taxes on deferrals	19	(102)				Tab 2, page 9, line 30
35	Income taxes	311	361	353	289	276	Tab 3, page 1, line 14
36							
37	Earned return	\$3,048	\$2,892	\$2,492	\$2,041	\$2,712	
38							
39	Utility rate base	\$43,018	\$41,059	\$38,147	\$36,360	\$32,886	Tab 2, page 1, line 23
40							
41	Return on rate base	7.09%	7.04%	6.53%	5.61%	8.25%	Tab 5, page 1, line 18

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)**

**SUMMARY OF OPERATING, MAINTENANCE
& ADMINISTRATIVE & GENERAL EXPENSES**

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	OPERATING EXPENSES					
2	- wages	\$1,757	\$1,671	\$1,493	\$1,430	\$1,439
3	- gas	303	326	383	458	494
4	- transferred to capital	(55)	(176)	(255)	(212)	(200)
5	- other	2,937	2,751	2,416	2,391	2,175
6	Total Operating	4,941	4,572	4,037	4,067	3,908
7	MAINTENANCE EXPENSES					
8	- wages	115	96	74	91	58
9	- other	323	237	165	224	158
10	Total Maintenance	438	333	239	315	216
11	ADMINISTRATIVE AND GENERAL EXPENSES					
12	- wages	-	-	-	-	-
13	- benefits	725	599	456	446	463
14	- transferred to capital	(250)	-	(247)	(208)	(203)
15	- other	1,213	1,200	1,132	1,072	969
16	Total Admin & General	1,688	1,799	1,340	1,310	1,230
17	TOTAL EXPENSES	\$7,067	\$6,704	\$5,616	\$5,692	\$5,354

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)**

OPERATING EXPENSES

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	664 Communications	\$13	\$13	\$9	\$9	\$8
2	665 Pipelines	296	328	183	80	58
3	Pipelines - Gas	303	326	383	458	495
4	667 Regulating stations	130	131	82	87	120
5	Regulating stations - Gas	-	-	-	-	-
6	Total transmission	743	797	656	634	681
7	670 Supervision	474	470	336	334	410
10	673 Removing & resetting meters	303	278	282	293	242
11	674 Service on customer premises	50	49	36	37	39
12	675 Mains and services	430	388	364	392	356
13	677 Regulating stations	30	30	14	16	15
14	679 Other	-	-	-	-	-
15	Total distribution	1,288	1,214	1,031	1,072	1,062
16	684 Communications	1	1	1	1	2
17	685 General systems operations	203	196	220	239	227
	Shared Services from Parent	605	531	465	446	405
18	688 Other general operations	619	597	560	503	481
18	689 Transferred to capital	(55)	(176)	(255)	(212)	(200)
19	Total general	1,372	1,150	990	977	915
20	700 Sales supervision	15	15	16	15	11
21	701 Advertising	-	-	2	3	2
22	702 Demonstration and selling	2	2	-	-	-
23	709 Other	3	3	-	-	-
24	Total sales	20	20	18	18	13
25	711 Customer contracts	1	1	-	4	2
	Shared Services from Parent	257	218	189	151	141
26	712 Meter reading	234	228	233	236	223
27	713 Customer billing	464	466	401	395	316
	Shared Services from Parent	438	397	308	327	299
28	714 Credit and collections	23	23	17	18	18
	Shared Services from Parent	54	59	74	76	82
29	718 Uncollectible accounts	47	-	119	159	156
30	Total customer accounting	1,518	1,391	1,342	1,366	1,237
31	Total operating	\$4,941	\$4,572	\$4,037	\$4,067	\$3,908

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

MAINTENANCE EXPENSES

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	864 Communications	\$0	\$0	\$0	\$0	\$0
2	865 Pipe lines	132	33	12	14	22
3	866 Compressors	-	-	-	-	-
4	867 Regulating stations	48	47	50	72	38
5	Total transmission	180	80	62	86	60
6	872 Structures	13	13	0	9	6
7	875 Mains and services	174	170	135	177	98
8	877 Regulating stations	11	11	1	1	5
9	878 Meters	59	58	40	42	45
10	879 Other	-	-	-	-	-
11	Total distribution	258	252	176	229	154
12	884 Communications	-	-	-	-	1
13	885 General	-	-	-	-	1
14	Total general	-	-	-	-	2
15	Total maintenance	\$438	\$333	\$239	\$315	\$216

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

ADMINISTRATIVE AND GENERAL EXPENSES

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	721 Administration	\$17	\$14	2	(\$4)	\$2
2	Shared Services from Parent	816	849	749	726	\$664
3	722 Audit, legal & consulting fees	123	57	71	85	\$42
4	723 Insurance	96	95	124	117	\$127
5	724 Reserve for damages	-	-	0	-	\$0
6	725 Employee benefits	725	599	456	448	\$463
7	728 Shared Services from Parent	119	134	122	105	\$93
8	Regulation	37	44	38	36	\$36
9	Donations	6	6	2	3	\$1
10	Other	-	-	24	3	\$3
11	729 Transferred to capital	(250)	-	(247)	(208)	(\$203)
12	Total general and administrative	\$1,688	\$1,799	\$1,340	\$1,310	\$1,230

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

TAXES OTHER THAN INCOME TAXES

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	PROPERTY TAXES					
2	Regular	\$936	\$893	\$809	\$755	\$698
3	1% in lieu	173	232	243	223	260
4	TOTAL	<u>\$1,109</u>	<u>\$1,125</u>	<u>\$1,052</u>	<u>\$977</u>	<u>\$958</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

MISCELLANEOUS OPERATING REVENUE

(000's)

Line No.	Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	Penalty charges	\$84	\$93	\$75	\$108	\$105
2	Connection Fees	152	20	16	24	19
3	Rents	-	-	-	-	-
4	Overheads recovered	15	25	14	21	48
5	Automotive surcharges	(0)	(0)	-	-	(0)
6	Other	10	11	3	95	6
7		<u>\$260</u>	<u>\$149</u>	<u>\$108</u>	<u>\$248</u>	<u>\$178</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

UTILITY RATE BASE

SCHEDULE 2
(000's)

Line No.	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source
1	\$77,876	\$75,071	\$70,696	\$65,701	\$61,261	Tab 2, page 3, line 46
2	3,468	2,942	4,634	5,378	\$4,606	Tab 2, page 3, line 46
3	(84)	(137)	(322)	(382)	(\$167)	Tab 2, page 3, line 46
4						
5	81,259	77,876	75,008	70,696	65,701	
6	30,344	28,825	27,382	25,817	24,381	Tab 2, page 6, line 43
7						
8	50,916	49,050	47,626	44,880	41,319	
9						
10	49,100	47,864	44,880	41,319	38,420	Tab 2, pages 4 & 7, lines 1 & 1
11						
12	50,008	48,457	46,253	43,099	39,870	
13	(8,322)	(8,690)	(8,351)	(7,642)	(7,156)	Tab 2, page 16, line 13
14	(55)					Tab 2, page 17, line 7
15	(15)	81	464	346	572	Tab 2, page 9, line 10
16	(5)	(503)	(553)	(553)	(553)	Tab 2, page 20, line 8
17	-	-	(69)	(69)	(69)	
18	553	-	-			Tab 2, page 18, line 32
19	(485)	-	-			Tab 2, page 19, line 38
20	1,116	1,489	180	78		Tab 2, page 10, line 8
21	224	225	223	224	223	Tab 2, page 15, line 15
22						
23	\$43,018	\$41,059	\$38,147	\$36,360	\$32,886	

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)

GAS PLANT IN SERVICE - 2011

(\$ 000's)

Line	Description	Actual Jan/11 Beginning Balance	Forecast			Forecast '11 Ending Balance
			Additions	Allocations	Transfers	
1	Transmission plant					
2	460 Land	11				11
3	461 Land rights	81				81
4	462 Compressor structures	465				465
5	463 Regulating structures	146				146
6	465 Mains	6,464	111		8	6,583
7	466 Compressor equipment					
8	467 Regulating equipment	4,517	364		37	4,918
9	468 Communications	130				130
10	469 Other	18				18
11		11,833	475		44	12,353
12	Distribution plant					
13	470 Land	37				37
14	471 Land rights	222				222
15	472 Structures	1,558	184		34	1,776
16	473 Services	17,922	278		37	18,237
17	474 House installations	4,885	64		16	4,965
18	475 Mains	28,804	843		121	29,769
19	476 Compressor equipment					
20	477 Regulating equipment	1,456	94			1,550
21	478 Meters	1,980	129			2,109
22	479 Other	20				20
23		56,883	1,592		208	58,683
24	General plant					
25	480 Land	77				77
26	481 Land rights	1				1
27	482 Structures	1,294	153			1,447
28	483 Office equipment	295	5			300
29	484 Transportation equipment	1,131	274			1,268
30	485 Heavy work equipment	1,105	110			1,216
31	486 Tools	1,236	79			1,315
32	487 Computer equipment	898				898
33	488 Communications	319				319
38	489 Other					
39		6,355	622			6,840
40	Construction overheads					
41	Unallocated construction costs					
42	System operations transfers					
43	Administrative transfers					
44	Depreciation					
45						
46		75,071	2,689		253	77,876

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

GAS PLANT IN SERVICE - TEST YEAR 2012

(\$ 000's)

Line	Description	Forecast Beginning Balance	Forecast			Forecast '12 Ending Balance
			Additions	Allocations	Retirements	
1	Transmission plant					
2	460 Land	11				11
3	461 Land rights	81	15			97
4	462 Compressor structures	465				465
5	463 Regulating structures	146				146
6	465 Mains	6,583	179	17		6,779
7	466 Compressor equipment	-				-
8	467 Regulating equipment	4,918	492	50		5,460
9	468 Communications	130				130
10	469 Other	18				18
11		12,353	686	67		13,106
12	Distribution plant					
13	470 Land	37				37
14	471 Land rights	222				222
15	472 Structures	1,776	485	75		2,336
16	473 Services	18,237	385	38		18,660
17	474 House installations	4,965	76	8		5,049
18	475 Mains	29,769	1,021	86		30,875
19	476 Compressor equipment	-				-
20	477 Regulating equipment	1,550	53	-		1,603
21	478 Meters	2,109	154			2,263
22	479 Other	20				20
23		58,683	2,174	207		61,065
24	General plant					
25	480 Land	77				77
26	481 Land rights	1				1
27	482 Structures	1,447	26			1,473
28	483 Office equipment	300	3			303
29	484 Transportation equipment	1,268	169		(84)	1,352
30	485 Heavy work equipment	1,216	66			1,282
31	486 Tools	1,315	69			1,384
32	487 Computer equipment	898				898
33	488 Communications	319				319
38	489 Other	-				-
39		6,840	332		(84)	7,088
40	Construction overheads					
41	Unallocated construction costs		-	-		
42	System operations transfers		55	(55)		
43	Administrative transfers		154	(154)		
44	Depreciation		65	(65)		
45			275	(275)		
46		77,876	3,468		(84)	81,259

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)

GAS PLANT IN SERVICE - CONTINUITY OF PLANT COST

		(000's)	
		Test Year	Forecast
<u>Line</u>	<u>Description</u>	<u>2012</u>	<u>2011</u>
1	Balance, Beginning of Year	77,876	75,071
2	CIAC Balance, Beginning of Year	(13,651)	(13,525)
3	Plant Cost, net of CIAC, Beginning of Year	<u>64,224</u>	<u>61,546</u>
4	Additions during year:		
5	Plant Cost	3,193	2,689
6	Allocation of overheads	275	253
7	Total Plant Additions	<u>3,468</u>	<u>2,942</u>
8	Contributions in Aid of Construction	(145)	(126)
9	Total Additions	<u>3,322</u>	<u>2,815</u>
10	Plant Retirements:		
11	Normal Course	(84)	(137)
12	Deactivated Assets	-	-
13	CIAC Retirements	-	-
14	Total Retirements	<u>(84)</u>	<u>(137)</u>
15	Balance, End of Year	<u>67,463</u>	<u>64,224</u>
16	Closing balance consists of:		
17	Plant Cost	81,259	77,876
18	CIAC	<u>(13,797)</u>	<u>(13,651)</u>
19	Balance, End of Year	<u>67,463</u>	<u>64,224</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

CONTINUITY OF
ACCUMULATED DEPRECIATION

FOR THE YEAR 2011

(\$ 000's)

Line	Description	Rate	Forecast					Forecast '11 Ending Balance	
			Actual 2011 Beginning Balance	Provision	Transfers	Retirements	Recoveries		Depreciation Adjustment
1	Gathering Plant								
2	Franchises & Consents	1.00%							
3	Gas Holders - Manufacturing	1.00%							
4	Gas Holders - Storage								
5									
6									
7	Transmission plant								
8	461 Land rights	0.00%	(59)					(59)	
9	462 Compressor structures	3.37%	(171)	(16)				(187)	
10	463 Regulating structures	3.35%	(48)	(5)				(53)	
11	465 Mains	0.90%	(3,784)	(58)				(3,842)	
12	466 Compressor equipment	N/A							
13	467 Regulating equipment	3.38%	(1,655)	(153)				(1,808)	
14	468 Communications	8.06%	(105)	(10)				(115)	
15	469 Other	2.34%	(4)	(1)				(5)	
16									
17			(5,826)	(242,652)				(6,068)	
18	Distribution plant								
19	471 Land Rights	0.00%	(22)					(22)	
20	472 Structures	3.34%	(348)	(52)				(400)	
21	473 Services	1.90%	(4,087)	(340)				(4,427)	
22	474 House installations	2.85%	(2,014)	(139)				(2,153)	
23	475 Mains	1.27%	(9,942)	(366)				(10,308)	
24	476 Compressor equipment	0.00%							
25	477 Regulating equipment	7.64%	(927)	(111)				(1,038)	
26	478 Meters	5.00%	(442)	(99)				(541)	
27	479 Other	2.72%	(7)	(1)				(8)	
28									
29			(17,788)	(1,108,005)				(18,896)	
30									
31	General plant								
32	481 Land Rights		(0)	.0000				(0)	
33	482 Structures	3.35%	(705)	(43,3545)				(749)	
34	483 Office equipment	3.80%	(246)	(11,2064)				(257)	
35	484 Transportation equipment	3.72%	(833)	(42,0210)		137	(27)	(766)	
36	485 Heavy work equipment	7.66%	(237)	(84,7299)				(321)	
37	486 Tools	3.54%	(649)	(43,7496)				(693)	
38	487 Computer equipment	5.68%	(698)	(50,9674)				(749)	
39	488 Communications	16.22%	(225)	(51,7067)				(277)	
40	489 Other	#DIV/0!	(0)					(0)	
41			(3,593)	(327,736)		137	(27)	(3,811)	
42									
43			(27,207,000)	(1,678,392)	.000	136,959	(27,392)	.000	(28,775)
44									
45	Amortization of CIAC			258					
46									
47	Depreciation capitalized			72					
48									
49	Net Depreciation Expense			(1,348)					

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

CONTINUITY OF
 ACCUMULATED DEPRECIATION

Test Year 2012

(\$ 000's)

Line	Description	Forecast				Forecast '12 Ending Balance
		Jan/12 Forecast Beginning Balance	Provision	Retirements	Recoveries	
1	Gathering Plant					
2	Franchises & Consents					
3	Gas Holders - Manufacturing					
4	Gas Holders - Storage					
5						
6						
7	Transmission plant					
8	461 Land rights	(59)				(59)
9	462 Compressor structures	(187)	(16)			(202)
10	463 Regulating structures	(53)	(5)			(58)
11	465 Mains	(3,842)	(61)			(3,903)
12	466 Compressor equipment					
13	467 Regulating equipment	(1,808)	(169)			(1,977)
14	468 Communications	(115)	(10)			(126)
15	469 Other	(5)	(0)			(5)
16						
17		(6,068)	(261)			(6,330)
18	Distribution plant					
19	471 Land Rights	(22)				(22)
20	472 Structures	(400)	(59)			(459)
21	473 Services	(4,427)	(347)			(4,774)
22	474 House installations	(2,153)	(142)			(2,296)
23	475 Mains	(10,308)	(383)			(10,691)
24	476 Compressor equipment					
25	477 Regulating equipment	(1,038)	(50)			(1,088)
26	478 Meters	(541)	(104)			(645)
27	479 Other	(8)	(1)			(8)
28						
29		(18,896)	(1,087)			(19,983)
30						
31	General plant					
32	481 Land Rights	(0)				(0)
33	482 Structures	(749)	(50)			(798)
34	483 Office equipment	(257)	(6)			(263)
35	484 Transportation equipment	(766)	(58)	84	(17)	(756)
36	485 Heavy work equipment	(321)	(80)			(401)
37	486 Tools	(693)	(48)			(741)
38	487 Computer equipment	(749)	(40)			(788)
39	488 Communications	(277)	(7)			(283)
40	489 Other	(0)				(0)
41		(3,811)	(287)	84	(17)	(4,031)
42						
43		(28,775)	(1,635)	84	(17)	(30,344)
44						
45	Amortization of CIAC	28,747	236			
46						
47	Depreciation capitalized		65			
48						
49	Net Depreciation Expense		(1,334)			

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)

GAS PLANT IN SERVICE - CONTINUITY OF ACCUMULATED DEPRECIATION

(000's)

<u>Line</u>	<u>Description</u>	<u>Test Year 2012</u>	<u>Forecast 2011</u>
1	Balance, Beginning of Year	(28,776)	(27,207)
2	CIAC Accumulated Balance, Beginning of Year	5,284	5,026
3	Utility Accumulated Depreciation, Beginning of Year	<u>(23,491)</u>	<u>(22,181)</u>
4	Depreciation Provision:		
5	Plant	(1,635)	(1,678)
6	Contributions in Aid of Construction	236	258
7	Depreciation Adjustment Deferral		
8	Total Additions	<u>(1,400)</u>	<u>(1,420)</u>
9	Plant Retirements:		
10	Normal Course	84	137
11	Deactivated Assets		
12	CIAC Retirements		
13	Removal Costs		
14	Proceeds on Disposals	(17)	(27)
15	Total Retirements	<u>67</u>	<u>110</u>
16	Balance, End of Year	<u><u>(24,824)</u></u>	<u><u>(23,491)</u></u>
17	Closing Balance Consists of:		
18	Accumulated Depreciation - Plant	(30,344)	(28,776)
19	Accumulated Amortization - CIAC	<u>5,520</u>	<u>5,284</u>
20	Balance, End of Year	<u><u>(24,824)</u></u>	<u><u>(23,491)</u></u>

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

CONTINUITY OF DEFERRED CHARGES

		YEAR 2011 (000's)				
Line	Description	Gross Actual Balance '10	Gross Additions	Future Income Tax	Gross Amortization	Forecast Balance '11
1	Rate base items					
2	RSAM	423	(301)		-	122
3	Plant Gains and Losses	(238)	(5)		-	(242)
4	Investigative Digs	-	-		-	-
5	IFRS / US GAAP	83	89		-	172
6	Sub-total Gross Rate Base deferrals	268	(217)	-	-	52
7	Related Future Income Taxes (FIT)	(135)		56	(0)	(79)
8	Rate Base deferrals, net of FIT	133	(217)	56	(0)	(28)
9						
10	Average rate base for the year					53
11						
12	Interest bearing deferrals					
13	BCUC Fees	4	(8)		4	(8)
14	Short Term Interest Rate	2	(4)		3	(5)
15	Long Term Interest Rate	(128)	(72)		(131)	(69)
16	Consolidated Gas Tariff Transition	-	(59)		-	(59)
17	2011 Depreciation Adjustment	-	(48)		0	(48)
18	Property tax variance	25	10		24	10
19	DC Industrial Deliveries	16	11		15	11
20	BCUC Hearing costs & CAP/ROE	44	1		44	1
21	Common Equity	390	7		385	11
22	Old Revolving Debt Issue Costs	29	1		30	(0)
23	Reserve for Damages	(69)	(2)		(71)	-
24	GCVA	(543)	514		-	(29)
25	Sub-total gross interest bearing deferrals	(230)	351	-	303	(183)
26	Related Future Income Taxes (FIT)	68		(93)	(91)	66
27	Interest Bearing deferrals, net of FIT	(162)	351	(93)	212	(117)
28						
29	Total gross deferrals (excl. debt issue)	38	134	-	303	(131)
30	Future Income Taxes on deferrals (excl. debt issue)	(67)	-	(37)	(91)	(13)
31						
32	Total deferrals, net of FIT (excl. debt issue)	(29)	134	(37)	212	(144)
33						
34						
35	Debt Issue Costs	322	-	-	63	258

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

CONTINUITY OF DEFERRED CHARGES

TEST YEAR 2012
 (000's)

Line	Description	Gross Actual Balance '11	Gross Additions	Future Income Tax	Gross Amortization	Forecast Balance '12
1	Rate base items					
2	RSAM	122	(41)		-	81
3	Plant Gains and Losses	(242)	62		(24)	(156)
4	Investigative Digs	-	-		-	-
5	IFRS / US GAAP	172	36		55	152
6	Sub-total Gross Rate Base deferrals	52	57	-	32	77
7	Related Future Income Taxes (FIT)	(79)		(14)	(14)	(79)
8	Rate Base deferrals, net of FIT	(28)	57	(14)	18	(3)
9						
10	Average rate base for the year					(15)
11						
12	Interest bearing deferrals					
13	BCUC Fees	(8)	(0)		(8)	(0)
14	Short Term Interest Rate	(5)	(0)		(5)	(0)
15	Long Term Interest Rate	(69)	(1)		(70)	0
16	Consolidated Gas Tariff Transition	(59)	(1)		(60)	(0)
17	2011 Depreciation Adjustment	(48)	(1)		(49)	0
18	Property tax variance	10	0		10	(0)
19	DC Industrial Deliveries	11	0		12	0
20	BCUC Hearing costs & CAP/ROE	1	0		1	0
21	Common Equity	11	0		11	(0)
22	Old Revolving Debt Issue Costs	(0)	-		-	(0)
23	Reserve for Damages	-	-		-	-
24	GCVA	(29)	651		-	622
25	Sub-total gross interest bearing deferrals	(183)	647	-	(157)	622
26	Related Future Income Taxes (FIT)	66		(155)	33	(123)
27	Interest Bearing deferrals, net of FIT	(117)	647	(155)	(124)	499
28						
29	Total gross deferrals (excl. debt issue)	(131)	704	-	(126)	699
30	Future Income Taxes on deferrals (excl. debt issue)	(13)	-	(170)	19	(202)
31						
32	Total deferrals, net of FIT (excl. debt issue)	(144)	704	(170)	(107)	497
33						
34						
35	Debt Issue Costs	258	-	-	62	197

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL

FOR THE YEAR ENDED DECEMBER 31, 2012
(\$000's)

Line No.	Description	Lag /(Lead) Days	<u>Expense</u>	<u>Working Capital</u>
1	Revenue	57.5		
2	Expense		<u>(38.5)</u>	
3	Operating working capital	19.0	24,463	\$1,273
4	Adjustments:			
5	Budget Billing Plan			(\$524)
6	Carbon Tax			\$71
7	HST			<u>\$296</u>
8	Cash working capital			<u><u>\$1,116</u></u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

REVENUE LAG DAYS

FOR THE YEAR ENDED DECEMBER 31, 2012
(\$000's)

Line No.	Revenues	Revenue Lag Days	Revenue	Extended Revenue
1	Residential - monthly	47.4	\$4,958	\$235,019
2	- bimonthly	63.7	9,167	584,065
3				
4	Small commercial - monthly	61.2	1,341	82,141
5	- bimonthly	63.7	6,884	438,194
6				
7	Large commercial - firm	45.7	2,129	97,382
8				
9	Small industrial	47.6	2,975	141,522
10				
11	Revenue Deficiency	57.5	331	19,008
12				
13	Other operating revenue	<u>57.5</u>	<u>260</u>	<u>14,952</u>
14				
15	Average revenue lag days	<u><u>57.5</u></u>	<u><u>\$28,045</u></u>	<u><u>\$1,612,284</u></u>

**Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)**

EXPENSE LEAD DAYS

**FOR THE YEAR ENDED DECEMBER 31, 2012
 (\$000's)**

Line No.	Expenses	Expense (Lead) Days	Normalized Expenses	Extended Expenses
1	Gas purchases-baseload	(40.2)	\$270	(\$10,840)
2	Gas purchases-seasonal	(40.2)	15,322	(615,937)
3	Operating payrolls	(5.0)	1,872	(9,359)
4	Employee benefits	(20.9)	725	(15,146)
5	Uncollectible accounts	(58.2)	47	(2,736)
6	Other operating expenses	(31.4)	4,330	(135,968)
7	Expenses credited/capitalized	(10.6)	(305)	3,220
8	Insurance	182.5	96	17,434
9	Property taxes	(1.0)	1,109	(1,109)
10	Franchise Fees	(242.5)	687	(166,709)
11	Income taxes payable	(15.2)	311	(4,730)
12	Average expense lag days	<u>(38.5)</u>	<u>\$24,463</u>	<u>(\$941,881)</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL - CARBON TAX

FOR THE YEAR ENDED DECEMBER 31, 2012
(\$000's)

Line No.	Taxable GJs	Carbon Tax	Receipt <u>Lag Days</u>	Payment <u>(Lead) Days</u>	Net <u>Lag/(Lead)</u>	Working <u>Capital</u>	
Gas sales subject to Carbon Tax							
1	Residential sales - January to June	929 013	\$1,153	17.7	(15.0)	2.7	8.6
2	- July to December	707 807	1,054	17.7	(15.0)	2.7	7.9
3	Commercial sales - January to June	816 250	1,013	22.2	(15.0)	7.2	20.1
4	- July to December	617 225	920	22.2	(15.0)	7.2	18.2
5	FSJ Small Industrial sales - January to June	125 912	156	33.2	(15.0)	18.2	7.8
6	- July to December	127 194	189	33.2	(15.0)	18.2	9.5
7	DC Small Industrial sales - January to June	19 169	24	39.0	(45.4)	(6.4)	(0.4)
8	- July to December	15 331	23	39.0	(45.4)	(6.4)	(0.4)
9	Carbon Tax Total	3357 901	4,533	21.0	(15.3)		71.2

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

OTHER WORKING CAPITAL ITEMS

FOR THE YEAR ENDED DECEMBER 31, 2012
(\$000's)

Line No.	Description	Transmission Line Pack	Materials & Supplies	Total
1	MONTH END BALANCES			
2	January	0	\$209	\$209
3	February	0	210	210
4	March	0	198	198
5	April	0	201	201
6	May	0	213	213
7	June	0	222	222
8	July	0	245	245
9	August	0	255	255
10	September	0	271	271
11	October	0	243	243
12	November	0	201	201
13	December	0	215	215
14	Total	<u>\$0</u>	<u>\$2,683</u>	<u>\$2,683</u>
15	Average balance	<u>\$0</u>	<u>\$224</u>	<u>\$224</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTRIBUTIONS IN AID OF CONSTRUCTION

(000's)

Line No.	Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	Gas Plant In Service					
2	Beginning balance	\$13,651	\$13,525	\$12,957	\$11,655	\$11,423
3	Additions	145	642	\$568	1,302	\$232
4	Ending balance	\$13,797	\$14,167	\$13,525	\$12,957	\$11,655
5	Accumulated Amortization					
6	Beginning balance	(\$5,284)	(\$5,026)	(\$4,754)	(\$4,510)	(\$4,255)
7	Additions	(236)	(258)	(\$272)	(308)	(\$255)
8	Ending balance	(\$5,520)	(\$5,284)	(\$5,026)	(\$4,818)	(\$4,510)
9	Net Total					
10	Beginning balance	\$8,367	\$8,499	\$8,203	\$7,145	\$7,167
11	Additions	(90)	384	\$296	993	(22)
12	Ending balance	\$8,277	\$8,882	\$8,499	\$8,139	\$7,145
13	Average balance	\$8,322	\$8,690	\$8,351	\$7,642	\$7,156

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)
Tomslake Cost Overrun Disallowance
 (000's)

Line No.	Description	Test Year 2012	NSP 2011
1	Opening net plant disallowance	(\$56)	\$0
2			
3	Original gross plant disallowance	(\$56)	\$0
4	Accumulated amortization at distribution mains rate	1	
5	Closing net plant disallowance	(\$55)	\$0
6			
7	Average balance	(\$55)	\$0

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

PENSION CONTRIBUTIONS AND EXPENSE
 (000's)

Line No.	Description	Test Year 2012	NSP 2011
1	Cash contributions to plan	\$323	\$353
2	Expense (recovered in rates)	287	186
3	Additions/(reductions) in B/S asset	<u>\$36</u>	<u>\$167</u>
4			
5			
6	Pension asset/(liability) components		
7	Funding status		
8	Opening balance	(\$1,429)	(\$651)
9	Change in funding status	140	(778)
10	Closing balance	<u>(\$1,289)</u>	<u>(\$1,429)</u>
11			
12	FIT associated with funding status		
13	Opening balance	\$357	\$163
14	Change in FIT associated with funding status	<u>(35)</u>	<u>195</u>
15	Closing balance	<u>\$322</u>	<u>\$357</u>
16			
17	Accumulated OCI - pension		
18	Opening balance	\$1,645	\$916
19	Amortization of OCI - pension	<u>(136)</u>	<u>729</u>
20	Closing balance	<u>\$1,509</u>	<u>\$1,645</u>
21			
22	Net after-tax pension asset/(liability) - closing balance	\$542	\$573
23			
24			
25	Rate Base debit/(credit)		
26	Opening Balance	\$539	\$0
27	Pre-tax additions	36	0
28	Current income taxes	<u>(9)</u>	<u>0</u>
29	Closing Balance	<u>\$566</u>	<u>\$0</u>
30			
31			
32	Average rate base balance	<u>\$553</u>	<u>\$0</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

NON-PENSION POST RETIREMENT BENEFITS
(000's)

Line No.	Description	Test Year 2012	NSP 2011
1	Cash contributions to RCA/tax account	\$0	\$109
2	Cash cost of retiree benefits	\$20	\$24
3	Expense (recovered in rates)	(7)	(21)
4	Change in unfunded status of NPPRB plans	27	154
5	Current income taxes	(7)	(39)
6	Related future income taxes	\$7	\$39
7			
8			
9	NPPRB asset/(liability) components		
10	Funding status		
11	Opening balance	(\$1,013)	(\$925)
12	Change in funding status	(88)	(88)
13	Closing balance	(\$1,101)	(\$1,013)
14			
15	FIT associated with funding status		
16	Opening balance	\$253	\$231
17	Change in FIT associated with funding status	22	22
18	Closing balance	\$275	\$253
19			
20	Accumulated OCI - NPPRB		
21	Opening balance	\$316	\$246
22	Amortization of OCI - NPPRB	(17)	70
23	Closing balance	\$299	\$316
24			
25	Net after-tax NPPRB position - closing	(\$527)	(\$444)
26			
27			
28	Rate Base debit/(credit)		
29	Opening Balances:		\$0
30	- historical unrecovered NPPRB expense net of tax	\$325	
31	- stranded NPPRB transitional obligation net of tax	119	
32	- Net NPPRB position after tax	(444)	
33	Jan 1, 2012 amortization of historical unrecovered NPPRB expense & transitional obligations	(444)	
34	Pre-tax additions	(111)	0
35	Current income taxes	28	0
36	Closing Balance	(\$527)	\$0
37			
38	Average rate base balance	(\$485)	\$0

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

DEFERRED INCOME TAX BALANCES
(000's)

Line No.	Description	Test Year 2012	NSP 2011
1	Rate Base debit/(credit)		
2	Opening Balance		
3	- historical recovered deferred income tax expense	(\$453)	(\$553)
4	Jan 1, 2012 amortization of historical recovered deferred income tax expense	444	
5	Current year amortization	9	100
6	Closing Balance	(\$0)	(\$453)
7			
8	Average rate base balance	(\$5)	(\$503)

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

INCOME TAXES

SCHEDULE 3
(000's)

Line No.	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source
1	Calculation of Taxable Income					
2	\$3,379	\$3,151	\$2,845	\$2,330	2,988	Tab 1, page 1, line 33
3	(1,345)	(1,266)	(1,007)	(827)	(1,511)	Tab 5, page 1, lines 1, 3, 6 & 8
4	17	18	\$12	12	11	
5	(771)	(163)	(610)	(551)	(616)	Tab 3, page 1, line 26
6						
7	<u>\$1,280</u>	<u>\$1,740</u>	<u>\$1,240</u>	<u>\$964</u>	<u>\$872</u>	
8						
9	Calculation of Income Tax Expense					
10	\$320	\$461	\$353	\$289	\$270	
11	-	-	-	-	5	
12	(9)	(100)	-	-	0	
13						
14	<u>\$311</u>	<u>\$361</u>	<u>\$353</u>	<u>\$289</u>	<u>\$276</u>	
15						
16	Particulars of Timing Differences					
17	A. Tax Effects Subject To Flowthrough					
18	\$1,334	\$1,393	\$1,517	\$1,440	\$1,363	Tab 1, page 1, line 24
19	(126)	314	43	(44)	(216)	Tab 1, page 1, line 25
20	(1,979)	(1,870)	(1,740)	(1,611)	(1,430)	
21	-	-	-	-	0	
22	-	-	(430)	(336)	(333)	
23	-	-	-	-	0	
24						
25						
26	<u>(\$771)</u>	<u>(\$163)</u>	<u>(\$610)</u>	<u>(\$551)</u>	<u>(\$616)</u>	
27						
28	25.00%	26.50%	28.50%	30.00%	31.00%	
29	0.00%	0.00%	0.00%	0.00%	0.00%	
30	25.00%	26.50%	28.50%	30.00%	31.00%	

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

COMMON EQUITY

SCHEDULE 4
 (000's)

Line No.	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

RETURN ON CAPITAL

SCHEDULE 5
 (000's)

Line No.		Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source
1	Short term borrowings	\$2,276	\$1,940	\$1,484	\$2,852	\$528	
2	proportion	5.29%	4.72%	3.89%	7.84%	1.61%	
3	rate of return	4.78%	4.65%	0.72%	2.21%	3.06%	Tab 5, page 2, line 12
4	return component	0.25%	0.22%	0.03%	0.17%	0.05%	
5							
6	Long term debt	\$23,535	\$22,696	\$21,654	\$19,883	\$19,951	Tab 5, page 3, line 34
7	proportion	54.71%	55.28%	56.76%	54.68%	60.67%	
8	rate of return	5.25%	5.18%	4.60%	3.84%	7.49%	Tab 5, page 3, line 36
9	return component	2.87%	2.86%	2.61%	2.10%	4.54%	
10							
11	Common equity	\$17,207	\$16,424	\$15,009	\$13,625	\$12,407	
12	proportion	40.00%	40.00%	39.35%	37.47%	37.73%	
13	rate of return	9.90%	9.90%	9.89%	8.91%	9.69%	
14	return component	3.96%	3.96%	3.89%	3.34%	3.65%	
15							
16	Total capitalization	<u>\$43,018</u>	<u>\$41,059</u>	<u>\$38,147</u>	<u>\$36,360</u>	<u>\$32,886</u>	
17							
18	Return on rate base	<u>7.09%</u>	<u>7.04%</u>	<u>6.53%</u>	<u>5.61%</u>	<u>8.25%</u>	
19							
20	Utility rate base	<u>\$43,018</u>	<u>\$41,059</u>	<u>\$38,147</u>	<u>\$36,360</u>	<u>\$32,886</u>	Tab 2, page 1, line 23

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

SHORT TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	
1	Customer Security Deposits					
2	Average annual balance	\$1,295	\$1,297	\$1,280	\$1,270	\$1,206
3	Interest rate applicable to deposits	1.79%	0.69%	0.25%	0.25%	2.69%
4	Annual Interest Expense	\$23	\$9	\$3	\$3	\$32
5						
6	Operating Line / Other					
7	Average annual draw	\$981	\$643	\$203	\$1,581	\$80
8	Interest rate	5.54%	4.44%	3.69%	3.78%	8.68%
9	Annual Interest Expense	\$54	\$29	\$7	\$60	\$7
10	Other expenses*	\$31	\$53			
11						
12	Average short term interest rate	4.78%	4.66%	0.72%	2.21%	3.06%

* service fees, standby fees, renewal expenses

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

LONG TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1 Secured Debentures Series 2018					
2 Liability beginning of year	\$1,387	\$1,456	\$1,524	\$1,592	\$1,660
3 Sinking fund payments	(68)	(68)	(68)	(68)	(68)
4 Average Capitalization	1,379	1,447	1,515	1,583	1,651
5 Annual Interest Expense	121	127	133	139	145
6 Issue costs beginning of year	8	9	6	8	(9)
7 Amortization of Issue Costs	1	1	1	1	2
8					
9 Effective Cost Rate	8.89%	8.89%	8.89%	8.89%	8.89%
10					
11 Roynat 2017 Loan					
12 Liability beginning of year	\$9,827	\$10,707	\$11,000	\$11,000	10,707
13 Sinking fund payments	(880)	(880)	(293)	-	(880)
14 Average Capitalization	9,387	10,267	10,853	11,000	10,267
15 Annual Interest Expense	404	435	383	373	802
16 Issue costs beginning of year	193	244	299	359	433
17 Amortization of Issue Costs	45	51	55	61	74
18					
19 Effective Cost Rate	4.83%	4.78%	4.15%	3.95%	8.00%
20					
21 2010 5-year Term Intercompany Loan					
22 Liability beginning of year	\$11,120	\$9,466	\$7,300	\$7,300	\$9,466
23 Issue during the year	1,800	1,654	2,166	-	-
24 Sinking fund payments	-	-	-	-	-
25 Average Capitalization	12,770	10,982	9,286	7,300	10,982
26 Annual Interest Expense	616	521	367	171	406
27 Stand-by fees	28	24	27	-	-
28 Issue costs beginning of year	57	68	73	66	87
29 Amortization of Issue Costs	15	11	9	19	21
30					
31 Effective Cost Rate	5.17%	5.06%	4.43%	2.59%	6.39%
32					
33 Total Actual Debt					
34 Total Average Capitalization	23,535	22,696	21,654	19,883	19,951
35					
36 Effective Cost Rate	5.25%	5.18%	4.60%	3.84%	7.49%



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VANCOUVER, B.C. V6Z 2N3 CANADA
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**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-???-11

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

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

and

An Application by Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek and Tumbler Ridge Divisions)
For Approval of its 2012 Revenue Requirements
for the PNG (N.E.) Service Area

BEFORE: [REDACTED], Panel Chair/Commissioner December [REDACTED], 2011
[REDACTED], Commissioner
[REDACTED], Commissioner

O R D E R

WHEREAS:

- A. Pacific Northern Gas (N.E.) Ltd. [PNG (N.E.)] Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) Divisions filed on November 30, 2011 with the British Columbia Utilities Commission (BCUC or Commission), pursuant to sections 58 to 61 of the *Utilities Commission Act* (the Act), its 2012 Revenue Requirements Application (Application) seeking Commission approval to increase its delivery rates;
- B. The Application also seeks refundable interim relief pursuant to section 58 to 61, 89 and 90 of the Act to allow PNG (N.E.) to amend its rates on an interim basis, effective January 1, 2012, pending the hearing of the Application and orders subsequent to that hearing, on the basis that on January 1, 2012 PNG (N.E.)'s rates would otherwise no longer be fair, just and not unduly discriminatory;
- C. PNG (N.E.)'s FSJ/DC Division forecasts a 2012 revenue deficiency of approximately \$0.331 million comprised of a net increase in cost of service of \$0.121 million and a decrease in margin of \$0.2100 million;
- D. PNG (N.E.)'s FSJ Division seeks Commission approval to increase the delivery charge for residential service by \$0.111/GJ from \$3.360/GJ to \$3.471/GJ representing an increase of 3.3 percent compared to the 2011 delivery rate, and for small commercial service by \$0.075/GJ from \$2.777/GJ to \$2.852/GJ corresponding to an increase of 2.7 percent compared to the 2011 delivery rate;
- E. PNG (N.E.)'s DC Division seeks Commission approval to increase the delivery charge for residential service by \$0.111/GJ from \$3.162/GJ to \$3.273/GJ representing an increase of 3.5 percent compared to the 2011 delivery rate, and for small commercial service by \$0.075/GJ from \$2.240/GJ to \$2.315/GJ corresponding to an increase of 3.3 percent compared to the 2011 delivery rate;

- F. The PNG (N.E.) TR Division forecasts a 2012 revenue deficiency of approximately \$0.323 million comprised of a net increase in cost of service of \$0.342 million and an increase in margin of \$0.019 million;
- G. The PNG (N.E.) TR Division seeks Commission approval to increase the delivery charge for residential service by \$1.602/GJ from \$4.502/GJ to \$6.104/GJ representing an increase of 36 percent compared to the 2011 delivery rate, and for small commercial service by \$1.186/GJ from \$3.982/GJ to \$5.168/GJ corresponding to an increase of 30 percent compared to the 2011 delivery rate;
- H. The Commission considers that establishing a Preliminary Regulatory Timetable for the registration of Interveners and for the preliminary review of the Application, and to allow Interveners to make written submissions on a formal review process, is necessary and in the public interest.

NOW THEREFORE pursuant to sections 58 to 61, 89 and 90 of Act the Commission orders as follows:

1. The Commission approves for PNG (N.E.) the delivery rates and the RSAM riders set forth in the Application on an interim basis, effective January 1, 2012. Any differences between the 2012 interim and permanent delivery rates that are determined by the Commission following final disposition of the Application are subject to refund/recovery, with interest at the average prime rate of PNG (N.E.)’s principal bank for its most recent year, in the manner as set out by a Commission Order that establishes permanent rates.
2. The Preliminary Regulatory Timetable for the Application is as set out in Appendix A to this Order. The dates and events in Appendix A after January ??, 2012 are subject to further Order establishing the review process and the regulatory timetable for review of the Application.
3. The Commission will hold a Workshop to review the issues in the Application on ?????????? commencing at 9.00 a.m. in the BCUC Office Hearing Room, ?????????? Howe Street, Vancouver, BC.
4. PNG (N.E.) is to provide a copy of this Commission Order, by e-mail where possible, to all parties who participated in the PNG (N.E.) 2011 Revenue Requirements Application proceedings.
5. PNG (N.E.) will publish in display-ad format the Notice of Application and Workshop as attached as Appendix B to this Order, as soon as reasonably possible following the issuance of this Order but by no later than ??????????, in such appropriate news publications as may properly provide adequate notice to the public in its service area.

- 6. PNG (N.E.) will make the Application and supporting materials available for inspection at public libraries in Fort St. John, Dawson Creek and Tumbler Ridge, and at the Head Office of PNG (N.E.) at Suite 950, 1185 West Georgia Street, Vancouver, B.C., V6E 4E6, and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3. PNG (N.E.) will also make the Application available at <http://www.png.ca>.
- 7. Interveners and Interested Parties should register with the Commission via E-Mail or in writing, by [REDACTED], of their intention to intervene. Interveners should specifically state the nature of their interest in the Application, and identify generally the nature of the issues that they intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the Application. The Commission is to receive submissions from Interveners by [REDACTED] on the appropriate regulatory review process that should be followed in the review of the Application.
- 8. Interveners intending to apply for participant assistance must submit a budget estimate by January [REDACTED], 2012 consistent with the Commission's Participant Assistance/Cost Award Guidelines and Order G-72-07. Copies are available upon request, or can be downloaded from the Commission's website at <http://www.bcuc.com>.
- 9. The Commission will accept, subject to timely filing by PNG (N.E.), amended Gas Tariff Rate Schedules in accordance with the terms of this Order. PNG (N.E.) is to provide notice of the interim 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 day of December, 2011.

BY ORDER
Original signed by:

Commissioner

Attachments

Pacific Northern Gas (N.E.) Ltd.

Application for Approval of 2012 Revenue Requirements
for PNG (N.E.)-Service Area

PRELIMINARY REGULATORY TIMETABLE

ACTION

DATES

Workshop No. 1

Intervener and Interested Parties Registration

Commission Information Request No. 1

Intervener Information Request No. 1

PNG (N.E.) Responses to Information Requests No. 1

Intervener Comments regarding Regulatory Process

Workshop No. 2 – pending

Announcement of Review Process

NOTICE OF WORKSHOP

Date:	
Time:	9.00 a.m.
Location:	BCUC Office Hearing Room ????? Howe Street, ?? Floor Vancouver, BC



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Pacific Northern Gas Ltd.

Application for Approval of 2012 Revenue Requirements
for PNG (N.E.) Service Area

NOTICE OF REVENUE REQUIREMENTS APPLICATION AND WORKSHOP

NOTICE OF WORKSHOP

Date:	
Time:	9.00 a.m.
Location:	BCUC Office Hearing Room ???? Howe Street, ??? Floor Vancouver, BC

THE APPLICATION

Pacific Northern Gas (N.E.) Ltd. [PNG (N.E.)] Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) Divisions filed on November 30, 2011 with the British Columbia Utilities Commission (Commission), pursuant to sections 58 to 61, 89 and 90 of the *Utilities Commission Act* (the Act), its 2012 Revenue Requirements Application (Application) to increase delivery rates on an interim and refundable basis effective January 1, 2012 to be made permanent following the Commission's review process.

The Commission wishes to ensure that affected parties have an opportunity to understand the Application and its implications for customer rates. The Commission also wishes to hear from affected parties before determining the public process necessary for the disposition of the Application.

For the FSJ/DC Division, the delivery rate increase is estimated to be approximately \$0.111 per GJ for a residential customer. Based on the gas cost recovery and GCVA rate riders effective October 1, 2011 thru December 31, 2011 the overall bundled rate increase for a typical residential customer consuming 106.6 GJ per year, is 0.8 percent, an increase of \$8 per year. The delivery rate increase for a small commercial customer is estimated to be \$0.075 per GJ. Similarly, a small commercial customer consuming 472.9 GJ per year, the increase is 0.5 percent or \$17 per year.

For the TR Division, the delivery rate increase is estimated to be approximately \$1.602 per GJ for a residential customer. Based on the gas cost recovery and GCVA rate riders effective October 1, 2011 thru December 31, 2011 the overall bundled rate increase for a typical residential customer consuming 86.7 GJ per year, is 17 percent, an increase of \$129 per year. The delivery rate increase for a small commercial customer is estimated to be \$1.186 per GJ. Similarly, a small commercial customer consuming 460.0 GJ per year, the increase is 15 percent or \$495 per year.

THE REGULATORY PROCESSES

The Commission will hold a Workshop on [REDACTED] in Vancouver, BC to discuss issues in the Application.

PUBLIC INSPECTION OF THE APPLICATION

The Application and supporting material will be made available for inspection at the at public libraries in Fort St. John, Dawson Creek, and Tumbler Ridge, and at the Head Office of PNG (N.E.) at Suite 950, 1185 West Georgia Street, Vancouver, B.C., V6E 4E6, and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3.

The Application will also be available for viewing on the PNG website at www.png.ca, (www.png.ca/ir_utilities.cfm) and on the Commission's website at www.bcuc.com, which also contains detailed materials related to the Application including Commission Orders and Intervener materials (<http://www.bcuc.com/Proceeding.aspx?ApplicationType=Current>).

REGISTERING TO PARTICIPATE

Persons who expect to actively participate in the review process and the Workshop should register as Interveners. Interveners will receive copies of the Application, all correspondence and filed documents. Persons not expecting to actively participate should register with the Commission as Interested Parties and will receive a copy of the Application summary and the Commission's Decision.

Interveners and Interested Parties should inform the Commission Secretary, in writing or by online web registration, by [REDACTED] of their intention to become Interveners or Interested Parties with respect to the Application.

All submissions and/or correspondence received from active participants or the general public relating to the Application will be placed on the public record and posted to the Commission's web site.

FURTHER INFORMATION

For further information, please contact Ms. Alanna Gillis, Acting Commission Secretary, or Mr. Philip Nakoneshny, Director, Rates and Finance, as follows:

Telephone:	(604) 660-4700 or (B.C. Toll Free) 1-800-663-1385
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