

**PACIFIC NORTHERN GAS LTD.  
(PNG-West Division)**

**and**

**PACIFIC NORTHERN GAS (N.E.) LTD.  
(Fort St. John/Dawson Creek and Tumbler Ridge Divisions)**

**CAPITAL STRUCTURE**

**and**

**EQUITY RISK PREMIUM APPLICATION**

**July 16, 2009**



**PACIFIC NORTHERN GAS LTD.  
(PNG-West Division)**

**and**

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(Fort St. John/Dawson Creek and Tumbler Ridge Divisions)**

**CAPITAL STRUCTURE AND EQUITY RISK PREMIUM APPLICATION**

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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 LTD.  
(PNG-West Division)**

**and**

**PACIFIC NORTHERN GAS (N.E.) LTD.  
(Fort St. John/Dawson Creek and Tumbler Ridge Divisions)**

**CAPITAL STRUCTURE AND EQUITY RISK PREMIUM APPLICATION**

**July 16, 2009**

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

**INTRODUCTION**

PNG applied for Commission approval to increase its common equity thickness for its PNG-West Division from 40 to 47.5 percent in its 2008 revenue requirements application. The 2008 revenue requirements application was settled by negotiation with the following agreement with regard to PNG's application for thicker common equity.

**"Resolution**

In order to obtain a negotiated settlement of the PNG-West 2008 revenue requirements application, PNG will base the NSP 2008 regulatory schedules on a 40 percent common equity ratio and not the applied for ratio of 47.5 percent with an offsetting deferred return on common equity deferral account.

Issue Description

The issue was whether it was appropriate to attempt to negotiate a settlement of PNG's request for a thicker common equity thickness of 47.5 percent offset by a new deferred return on common equity deferral account. It was acknowledged by the parties that it was more appropriate for the common equity issue to be dealt with by the Commission through a public hearing process and not under a negotiated settlement process."

Having regard to what transpired with respect to the 2008 revenue requirements application PNG did not seek Commission approval of a thicker common equity in its PNG-West 2009 revenue requirements application. The expectation was that the 2009 application would be more easily settled by negotiation if capital structure and rate of return issues were deferred to a public hearing process later in 2009. In fact, both the PNG-West and PNG(N.E.) 2009 revenue requirements applications were successfully settled by negotiation in late March 2009 and the settlement agreements were subsequently approved by the Commission on April 23, 2009. With respect to capital structure and rate of return matters, PNG stated the following in its PNG-West 2009 revenue requirements application narrative:

"PNG intends, however, to prepare and file a separate comprehensive capital structure and rate of return application for review by the Commission. That application would seek approval of changes to PNG's capital structure and, potentially, its rate of return, with the objective of establishing the most efficient combination of capital structure and rate of return that would allow PNG the opportunity to earn a fair and reasonable return on its investment. PNG would structure the capital structure and rate of return application in a manner which would avoid the need to adjust 2009 rates relative to those applied for in this Application. The timing of the filing of the capital structure/rate of return application is not known with certainty at this time. The expected filing date is some time in the first quarter of 2009. PNG considers the proposed bifurcation of the regulatory processes will be most efficient, with the 2009 revenue requirements Application being settled by a negotiation process and with the Commission addressing the capital structure/rate of return issues through a public hearing process."

PNG engaged Kathleen C. McShane of Fosters Associates, Inc. to render an opinion on the appropriate capital structures and equity risk premiums proposed by PNG for both the PNG-West Division and the Fort St. John/Dawson Creek and Tumbler Ridge Divisions of Pacific Northern Gas (N.E.) Ltd. Ms. McShane has appeared on a number of occasions on behalf of PNG. Her evidence is provided under Tab 1 of this Application. For ease of reference a summary of her conclusions is provided below. PNG noted in its 2009 revenue requirements application that this Application would not change the approved 2009 rates. However the test year 2009 regulatory schedules that would have resulted if K. McShane's recommendations had been implemented in 2009 are set out in Tabs 2, 3 and 4 for each of the PNG-West, Fort St. John/Dawson Creek and Tumbler Ridge Divisions.

As was done in 2008, PNG is seeking Commission approval of a deferral account to record the difference between the approved 2009 cost of service used for rate making purposes and the 2009 cost of service based on the higher common equity thickness and equity risk premium for PNG-West as supported by K. McShane's evidence. PNG(N.E.)'s 2009 revenue requirements application did not provide for making a separate capital structure and equity risk premium application later in 2009 as was the case for PNG-West. Therefore, PNG(N.E.) is not applying for Commission approval of a deferral account to record the impact of implementing K. McShane's recommendations effective in 2009.

PNG's 2009 revenue requirements application also sought Commission approval with regard to the rate treatment of an option fee of \$1.5 million that PNG was expecting to be paid prior to the end of 2008. The option fee was not paid but another similar arrangement was concluded in March 2009 under which Merrill Lynch Commodities Inc. paid PNG an option fee of \$1.5 million. PNG wishes to have its application for the rate treatment of the option fee reviewed by the Commission in the context of this Application. PNG submits that an oral public hearing process will be required for the review of this Application and given the fact the parties were unable to negotiate a settlement of the rate treatment of the \$1.5 million option fee in the context of the settlement of the 2009 revenue requirements application, PNG is requesting that the matter be dealt with concurrently with this Application. For ease of reference, the details of PNG's previous application in this regard are provided later in this Application narrative.

Tab 5 contains a draft procedural Order setting out the proposed regulatory timetable. Also included under Tab 5 is the form of Order PNG wishes the Commission to issue following a formal review of this Application.

### **PROPOSED CAPITAL STRUCTURE AND EQUITY RISK PREMIUM**

PNG is applying to have the common equity ratio for the PNG-West Division established at 47.5 percent (currently 40 percent) and to have the common equity ratio for both divisions of PNG(N.E.) set at 42.5 percent (currently 36 percent). PNG is also applying to have the rate of return on common equity set at 75 basis points above the Commission's low-risk benchmark utility return on common equity, for all three divisions. These requests are imminently reasonable when compared to the rates of return and common equity ratios that apply to other utilities regulated by the Commission. These comparisons are not reproduced here as they are fully addressed in K. McShane's evidence.

PNG submits that the combination of these common equity ratios and rates of return on common equity are necessary to allow PNG the opportunity to earn a reasonable return on its utility investments while achieving a reasonable degree of financial health. The current common equity ratios and rates of return on equity approved by the Commission do not provide this opportunity. PNG has had to maintain a much higher actual common equity ratio than approved by the Commission in order to maintain a secured debt rating on the bare cusp of investment grade. The market price of PNG's common shares is evidence that its return on investment is not reasonable, as these shares currently trade at less than 70 percent of book value.

An investment grade rating on PNG's debt is extremely important to PNG and its customers, particularly those customers that rely on PNG to arrange and purchase their gas supply. PNG's gas purchases, which are made on behalf of its customers without profit or mark-up, require very significant amounts of credit and liquidity. PNG's gas purchases overwhelm all of PNG's other obligations with, for example, gas purchase expense in 2008 being almost double the aggregate cost of service of its three utility divisions.

Maintenance of reasonable credit quality is key to PNG being able to access gas supply on reasonable terms and conditions. Generally, gas suppliers will accept a certain amount of exposure to a counterparty where the acceptable exposure limit is based on the counterparty's credit rating on unsecured debt. Given that ratings on unsecured obligations are typically one notch lower than secured debt, PNG is already considered a non-investment grade credit by a number of gas suppliers and, when PNG must acquire gas from these suppliers, provision of credit support is typically required from PNG or premiums are built into the supplier's gas prices in order to compensate the supplier for the credit risk.

It is PNG's strongly held view that a BBB secured debt rating is the lowest rating which reflects reasonable financial health as it implies a BBB(low) rating on unsecured obligations. While PNG cannot confirm that the applied-for capital structures and rates of return on equity will result in a BBB secured debt rating, it is almost certain that if the Commission denies PNG's application and PNG aligns its actual capital structure with the currently approved capital structures for rate determination purposes, PNG's debt rating will be downgraded below investment grade. This downgrade would result in higher debt costs, higher gas supply costs and would likely inhibit PNG's ability to meet its obligations to serve.

**SUMMARY OF OPINION OF K. MCSHANE ON  
CAPITAL STRUCTURE AND EQUITY RISK PREMIUM**

The purpose of K. McShane's evidence was to assess the reasonableness of the proposed capital structures for the PNG-West Division and PNG(N.E.)'s Fort St. John/Dawson Creek and Tumbler Ridge Divisions and to address the equity risk premiums relative to the low risk benchmark utility return on equity ("ROE"). K. McShane reviewed the fair return standard and applied the principles for evaluation of capital structure in the context of the specifics of each utility. K. McShane's evidence discusses the business, financial and regulatory risks of each of PNG's and PNG(N.E.)'s divisions in comparison to other utilities and concludes that:

"Based on my analysis and judgment, the proposed equity ratios for PNG-West of 47.5% and for PNG (N.E.) of 42.5% are reasonable. At the proposed common equity ratios, incremental equity risk premiums of 0.75% relative to the benchmark utility ROE for both PNG-West and PNG (N.E.), both the Fort St. John/Dawson Creek and Tumbler Ridge divisions are warranted in light of their total (business plus financial) risks." (see page 37 of K. McShane's evidence)

**IMPACT OF PROPOSED CAPITAL STRUCTURES AND EQUITY RISK  
PREMIUMS ON APPROVED 2009 COSTS OF SERVICE**

**PNG-West Division**

PNG has rerun its 2009 revenue requirements model to show the impact on the approved NSP 2009 cost of service of increasing the common equity thickness from 40 to 47.5 percent in the PNG-West capital structure together with a 10 basis points increase in the equity risk premium (i.e. 65 to 75 basis points) relative to the benchmark utility ROE approved for 2009 under the Commission's automatic ROE setting mechanism. The first page under Tab 2 compares the approved NSP 2009 cost of service to the corresponding cost of service reflecting the recommended common equity thickness of 47.5 percent and equity risk premium of 75 basis points. The increase from NSP 2009 to that proposed by PNG totals \$1.114 million. Regulatory Schedules 1 to 5 are provided under Tab 2 showing the details of the adjusted 2009 cost of service. PNG is seeking Commission approval of a deferred return on common equity deferral account to record the difference of \$1.114 million for future recovery from customers. Similarly, if the benchmark utility ROE is adjusted in 2009, then PNG would calculate the impact of this change on the NSP 2009 cost of service and record the result in the deferred return on common equity deferral account as well.

**PNG(N.E.)'s Fort St. John/Dawson Creek Division**

PNG(N.E.) has rerun its 2009 revenue requirements model to show the impact on the approved NSP 2009 cost of service of increasing the common equity thickness from 36 to 42.5 percent in the Fort St. John/Dawson Creek capital structure together with a 35 basis points increase in the equity risk premium (i.e. 40 to 75 basis points) relative to the 2009 benchmark utility ROE. The first page under Tab 3 compares the approved NSP 2009 cost of service to the corresponding cost of service reflecting the recommended common equity thickness of 42.5 percent and equity risk premium of 75 basis points. The increase compared to NSP 2009 is \$287,000. Regulatory Schedules 1 to 5 are provided under Tab 3 showing the details of the recalculated 2009 cost of service. These calculations are provided to put the applied for capital structure and equity risk premium changes in context. PNG(N.E.)'s 2010 revenue requirements application would reflect the increased common equity thickness and the risk premium accordingly for the purpose of setting 2010 rates. However, if there are any adjustments to the benchmark utility ROE in 2009, PNG(N.E.) would seek Commission approval of a deferred return on common equity deferral account to record the impact of this change on the approved NSP 2009 cost of service.

**PNG(N.E.)’s Tumbler Ridge Division**

PNG(N.E.) has performed the same analysis with respect to the Tumbler Ridge NSP 2009 cost of service as was done in respect of the PNG-West and Fort St. John/Dawson Creek Divisions. The proposed 42.5 percent common equity thickness and 75 basis points equity risk premium increases the approved NSP 2009 cost of service by \$10,000. PNG(N.E.) would reflect the impact on Tumbler Ridge 2010 rates of the capital structure and equity risk premium increases. PNG(N.E.) would apply to the Commission for approval to record in a deferred return on common equity deferral account the impact of a change in benchmark utility ROE on the approved Tumbler Ridge NSP 2009 cost of service.

**RATE TREATMENT OF OPTION FEES RECEIVED BY PNG FROM MERRILL LYNCH COMMODITIES INC.**

PNG’s September 2008 application to Commission for approval of the PNG/LNG Partners Term Sheet set out PNG’s request that the option fees to be paid by LNG Partners under the Term Sheet be allocated between PNG’s customers and shareholders. Commission Order No. G-163-08 stated that the “The treatment of option fees to be received by PNG from LNG Partners, and any cost matters with respect to PNG assets that were deactivated as the outcome of Commission Order G-99-06, will be reviewed by the Commission as part of the next PNG revenue requirements proceeding.” Commission Order No. G-174-08 approving the Term Sheet stated that “The Initial Option Fee is to be recorded in an interest bearing, non rate base deferral account for future disposition as directed by the Commission’s future determinations with respect to PNG’s 2009 Revenue Requirements Application.” PNG and its customers were unable to reach agreement on the treatment of the Merrill Lynch option fees in the context of the NSP 2009 settlement negotiations. The NSP 2009 settlement agreement stated the following in respect of this issue:

**“16. PNG/Merrill Lynch Commodities, Inc. (“MLCI”) Letter Agreement**

**Resolution:**

On March 12, 2009 PNG applied to the Commission for approval of a Letter Agreement between PNG and MLCI (the “Letter Agreement”) that reflected most of the same terms and conditions of a similar arrangement that was approved by the Commission under Order G-174-08. The similar arrangement was terminated by PNG due to the failure of the other party to pay PNG a \$1.5 million option fee.

PNG gave a detailed review of the terms and conditions of the Letter Agreement at the beginning of the NSP 2009 settlement discussions. The parties agreed that the Letter Agreement provided an arrangement that could be very beneficial to PNG and its customers over both the short and long term.

The parties hereby support a finding by the Commission that the Letter Agreement is in the public interest and that a formal hearing is not required to review the Letter Agreement given the terms and conditions thereof are the same in all material respects as those set out in the Term Sheet approved under Order G-174-08. The parties agreed that Commission approval of this NSP 2009 settlement agreement could represent formal approval of the Letter Agreement without the need for a separate standalone order. The parties' support of the Letter Agreement is predicated on the following conditions:

- The initial option fee of \$1.5 million payable by MLCI to PNG and any option extension fees paid by MLCI being recorded in an interest bearing, non-rate base deferral account for crediting to cost of service in future years as directed by the Commission's future determinations commencing with respect to PNG's 2010 Revenue Requirements Application, subject to and without prejudice to PNG's right to apply in the future for Commission approval to recover the foregone return on the facilities deactivated as result of the closure of the Methanex Corporation methanol/ammonia plant in November 2005."

PNG is reapplying at this time for Commission approval of the foregone return proposal. PNG considers it will be most efficient to consider this matter during the public hearing into the capital structure and equity risk premium issues. Consequently, PNG hereby reconfirms its original submissions on this issue as set forth in its September 2008 application which are reproduced below as follows:

"The Commission approved PNG's request in its 2006 revenue requirements application to deactivate compressor stations R2 and R4, four 10 inch loops totaling 52.8 miles, a 6 inch lateral to Kitimat of 32.97 miles and the Methanex meter and regulating station. This was one of several initiatives taken by PNG to minimize the

impact on customers of the Methanex closure in late 2005. For rate making purposes the deactivated facilities (with a net book value of \$5.05 million) were removed from rate base and accounted for in a non-rate base short term interest bearing deferral account for recovery through rates over the ten year period commencing in January 2006 instead of continuing to earn PNG's allowed return on rate base. PNG's 2006 revenue requirements application sought Commission approval to account for the difference between the short term interest rate and the allowed return on rate base that would have applied to the deactivated facilities had they remained in active service plus an adjustment for the risk the facilities would not be returned to service. If LNG Partners exercise its option to contract for firm gas transportation service, the deactivated facilities would be returned to service.

PNG further proposed in its 2006 revenue requirements application that if any of the deactivated facilities were returned to service, the unamortized cost of the facilities plus the accumulated risk-weighted foregone return would be added back to plant in service. The Commission stated at page 31 of its decision on PNG's 2006 revenue requirements application that "PNG's foregone return proposal is not accepted at this time, however, PNG may apply for Commission approval to record the foregone return should the deactivated facilities be reactivated and the merits of that application will be considered at that time."

PNG is hereby applying for Commission approval to recover foregone return to date on the deactivated facilities from the potential Option Fee and Option Extension Fee and eventually from the annual firm revenue from LNG Partners should they commence operation of their FLNG facilities. The methodology for determining the risk-weighted foregone return was described by PNG in its response to Commission IR No. 16.4 from the 2006 revenue requirements application proceeding. That information request asked PNG to "provide a calculation of the proposed notional account by return component for 2006 that tracks the risk-weighted foregone return on the deactivated facilities. Please explain how the adjustment for the risk of facilities not returning to service was determined." PNG's response detailed the mathematical methodology used to calculate the foregone return based on a 60 percent probability of reactivation of the deactivated facilities.

The Table below sets out the calculated foregone returns to the end of 2008, 2009 and 2010 using that methodology and assuming various probabilities of reactivation.

<b>Foregone Return to end of:</b>	<b>Foregone Return at Various Probabilities of Reactivation</b>			
	<b>100%</b>	<b>75%</b>	<b>60%</b>	<b>50%</b>
<b>2008</b>	\$480,594	\$640,792	\$800,990	\$961,188
<b>2009</b>	\$643,216	\$857,621	\$1,072,026	\$1,286,431
<b>2010</b>	\$800,100	\$1,066,801	\$1,333,501	\$1,600,201

The 2008 figures are based on the foregone return over the period January 2006 to December 2008. The 2009 and 2010 figures are cumulative in that they include the foregone return from the preceding year.

PNG is requesting Commission approval to allocate the initial Option Fee of \$1.5 million between customers and shareholders assuming the 100 percent probability of reactivation figure shown in the above Table through to end of 2008. This means \$1,019,406 would be credited to the 2009 cost of service for the benefit of customers and the remaining \$480,594 would be taken into income as foregone return on the deactivated facilities. If the option is extended, the Option Extension Fee of \$1.5 million would be payable to PNG in 2009. PNG is requesting the Commission to record the Option Extension Fee in a deferral account for future disposition between customers and shareholders consistent with PNG’s foregone return proposal in 2006. Similarly, if LNG Partners exercises its option to contract for firm gas transportation service, PNG would file a copy of the definitive agreement with the Commission for final approval and make submissions regarding the allocation of the demand charges payable under the agreement between customers and shareholders.”

PNG reaffirms the foregoing in the context of this Application. The only difference is that Merrill Lynch is now the party paying the option fees to PNG. In addition, given the passage of time since the original September 2008 application, PNG is now seeking Commission approval to recover the foregone return figure applicable at the end of 2009. This figure has been recalculated based on current short term interest and return on equity parameters and has increased slightly to \$652,107 from \$643,216 set forth in the 2008 application. The difference of \$1.5 million and the \$652,107 figure (i.e. \$847,893) would be applied as a credit to the 2010 cost of service. If Merrill Lynch extends the option effective January 1,

2010 by making payment of \$1 million to PNG prior to the end of 2009, then PNG proposes that the incremental foregone return for 2010 be recovered from that fee and the balance credited to the 2010 cost of service.

**DRAFT COMMISSION ORDERS**

Draft Commission Orders are set out under Tab 5. One is a procedural Order with a proposed regulatory timetable for the review of this Application. The other is the form of Order PNG and PNG(N.E.) are seeking with respect to the Commission's disposition of this Application.

All of which is respectfully submitted

DATED at Vancouver, British Columbia this 16th day of July 2009.

**PACIFIC NORTHERN GAS LTD. and  
PACIFIC NORTHERN GAS (N.E.) LTD.**



---

R.G. Dyce  
President & Chief Executive Officer

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

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**OPINION**  
**ON**  
**CAPITAL STRUCTURE AND**  
**EQUITY RISK PREMIUM**

**FOR**

**PACIFIC NORTHERN GAS LTD.**  
(PNG-West Division)

**AND**

**PACIFIC NORTHERN GAS (N.E.) LTD.**  
(Fort St. John/Dawson Creek and Tumbler Ridge Divisions)

Prepared by

**KATHLEEN C. McSHANE**

**FOSTER ASSOCIATES, INC.**



July 2009

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1 **I. INTRODUCTION AND SUMMARY OF CONCLUSIONS**

2

3 **A. INTRODUCTION**

4

5 My name is Kathleen C. McShane and my business address is 4550 Montgomery  
6 Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of Foster Associates,  
7 Inc., an economic consulting firm. I hold a Masters in Business Administration with a  
8 concentration in Finance from the University of Florida (1980) and am a Chartered  
9 Financial Analyst (1989). I have testified on issues related to cost of capital and various  
10 ratemaking issues on behalf of local gas distribution utilities, pipelines, electric utilities  
11 and telephone companies in more than 190 proceedings in Canada and the U.S. My  
12 professional experience is provided in Appendix A.

13

14 The purpose of my testimony is to assess the reasonableness of Pacific Northern Gas  
15 Ltd.'s (PNG) proposed capital structures for Pacific Northern Gas (PNG-West Division)  
16 ("PNG-West") and Pacific Northern Gas (N.E.) ("PNG (N.E.)") and to recommend  
17 equity risk premiums relative to that reflected in the BCUC's benchmark utility return on  
18 equity (ROE).

19

20 **B. CONCLUSIONS**

21

22 PNG is proposing capital structures containing 47.5% common equity for PNG-West and  
23 42.5% for PNG (N.E.) with the 42.5% applicable to both the Fort St. John/Dawson Creek  
24 and Tumbler Ridge Divisions that comprise PNG (N.E.).

25

26 In my opinion, the capital structures proposed by PNG are reasonable. Given the relative  
27 business risks of PNG-West and PNG (N.E.), equity risk premiums of 75 basis points  
28 above the benchmark ROE are warranted at the proposed capital structures.

29

30 **II. ANALYTICAL FRAMEWORK**

31

32 **A. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND ROE**

33

34 The overall cost of capital to a firm depends, in the first instance, on business risk.  
35 Business risk comprises the fundamental characteristics of the business (e.g., demand,  
36 supply and operating factors) that together determine the probability that future returns to  
37 investors will fall short of their expected and required returns. Business risk thus relates  
38 largely to the assets of the firm. For utilities, the business risks also include regulatory  
39 risks, i.e., the regulatory framework under which the utility operates. The prevailing  
40 regulatory framework effectively represents the current allocation of the fundamental  
41 business risks between investors and ratepayers. Regulatory risk can be considered either  
42 as a component of business risk or as a separate risk category along with business and  
43 financial risk.

44

45 The cost of capital is also a function of financial risk. Financial risk refers to the  
46 additional risk that is borne by the equity shareholder because the firm is using fixed  
47 income securities (i.e. debt and preferred shares) to finance a portion of its assets. The  
48 capital structure, comprised of debt, preferred shares and common equity, can be viewed  
49 as a summary measure of the financial risk of the firm. The use of debt in a firm's capital  
50 structure creates a class of investors whose claims on the cash flows of the firm take  
51 precedence over those of the equity holder. Since the issuance of debt carries  
52 unavoidable servicing costs which must be paid before the equity shareholder receives  
53 any return, the potential variability of the equity shareholder's return rises as more debt is  
54 added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises.

55

56 There are effectively two approaches that can be used to determine the fair return. The  
57 first approach entails acceptance of the utility's actual capital structure for regulatory  
58 purposes or deeming a capital structure that adequately protects bondholders but does not  
59 necessarily equate the total risk of the regulated company (fundamental business,

60 regulatory and financial risks) to those of the proxy companies used to estimate the cost  
61 of equity. If the total risk of the proxy companies is higher or lower than that of the  
62 specific utility, the proxies' estimated cost of equity needs to be adjusted upward or  
63 downward to arrive at the cost of equity of the specific utility.

64

65 The first approach, varying both capital structures and ROEs, is used by the British  
66 Columbia Utilities Commission (BCUC). The combination of capital structures and  
67 ROEs is also used by the Ontario Energy Board (OEB) and the Régie de l'Énergie de  
68 Québec (Régie).

69

70 The second approach assesses the utility's fundamental business and regulatory risks, and  
71 then establish a capital structure that is both compatible with those risks and that permits  
72 the application of a cost of equity determined by reference to proxy companies, with no  
73 adjustment to that cost. This approach can be applied to a spectrum of regulated  
74 companies within a range of combined fundamental business and regulatory risks.

75

76 The NEB employed the second approach when it established its automatic adjustment  
77 mechanism for a number of oil and gas pipelines in 1995.<sup>1</sup> It is also the approach that  
78 was adopted by the former Alberta Energy and Utilities Board (EUB) in its Generic Cost  
79 of Capital Decision 2004-052 in 2004. In that decision, the EUB set different capital  
80 structures for eleven electric and gas distribution and transmission entities, based on their  
81 different business risk profiles, and then established a common return on equity to be  
82 applied to each of the utilities under its jurisdiction.

83

84 In summary, the various components of the cost of capital are inextricably linked; it is  
85 impossible to determine if the return on equity is fair without reference to the capital  
86 structure of the utility. Thus, the determination of a fair return must take into account all  
87 of the elements of the cost of capital, including the capital structure and the cost rates for

---

<sup>1</sup> In its Reasons for Decision RH-1-2008 (March 2009), the NEB recognized the inextricable link between ROE and capital structure. However, it did not specify either an ROE or a capital structure for TransQuébec and Maritimes Pipeline (TQM). Instead, it adopted an overall cost of capital and left it to TQM to choose its optimal capital structure. The NEB also noted that the overall cost of capital approach enables comparisons of returns on an equal footing between companies of comparable risk.

88 each of the types of financing. It is the overall return on capital which must meet the  
89 requirements of the fair return standard. Both approaches used by Canadian regulators  
90 are equally valid as long as the combination of capital structure and return on equity  
91 result in an overall return which satisfies all three fair return standards.

92

93 My analysis and recommendations for PNG-West and PNG (N.E.) rely on the approach  
94 that has been adopted by the BCUC.

95

96 **B. CONCEPT OF BENCHMARK UTILITY AND BENCHMARK ROE**

97

98 The concepts of a benchmark utility and benchmark return on equity have been used by  
99 the BCUC to establish allowed ROEs for each of the utilities under its jurisdiction.  
100 Essentially, this approach (1) estimates the cost of equity for the low risk “benchmark”  
101 utility, and then (2) establishes the cost of equity for the BCUC-regulated utilities by  
102 reference to the benchmark utility’s cost of equity. With regard to (2), the costs of equity  
103 (and allowed ROEs) for the utilities other than the designated benchmark have been  
104 estimated and expressed as a premium above the benchmark ROE. Terasen Gas Inc.  
105 (“TGI”) has historically been the proxy for the benchmark utility with no risk premium  
106 relative to the benchmark ROE and each of the other BCUC regulated utilities’ allowed  
107 ROEs have reflected a premium to the benchmark ROE (i.e. to TGI’s allowed ROE).

108

109 The approach taken by the BCUC has also adopted different deemed capital structures for  
110 the utilities. To assess whether the utilities’ allowed returns are fair returns, i.e., ones that  
111 meet all three criteria of capital attraction, financial integrity and comparability of  
112 investment returns, both the capital structure and ROE have to be taken into account. To  
113 illustrate, assume that Utility A and Utility B have similar business and regulatory risks,  
114 which means their costs of capital should be similar. Both utilities are allowed the same  
115 ROE. However, Utility A has a lower deemed common equity ratio than Utility B and  
116 thus is being allowed an overall return which is lower than that of Utility B. As both  
117 utilities are of similar business risk, this outcome would not be fair and reasonable.

118 Consequently it is critical to ensure that the **overall** allowed returns for each utility meet  
119 the fair return standard.

120

121 For the purpose of my analysis, I have proceeded on the premise that the BCUC will  
122 continue to specify a benchmark return and that TGI remains the benchmark utility. As  
123 such, the capital structures proposed for PNG-West and PNG (N.E.) and the relevant risk  
124 premiums will be assessed by reference to the fair return (ROE and capital structure)  
125 applicable to the benchmark. The benchmark ROE and capital structure for TGI are  
126 currently being reviewed by the BCUC in a separate proceeding.

127

### 128 **III. CAPITAL STRUCTURES FOR PNG-WEST AND PNG (N.E.)**

129

#### 130 **A. PROPOSED CAPITAL STRUCTURES FOR PNG-WEST AND PNG (N.E.)**

131

132 PNG is requesting that the BCUC approve regulated common equity ratios of 47.5% for  
133 PNG-West and 42.5% for both the Fort St. John/Dawson Creek and Tumbler Ridge  
134 divisions of PNG (N.E.)

135

#### 136 **B. THE FAIR RETURN STANDARD AND PRINCIPLES FOR** 137 **EVALUATION OF CAPITAL STRUCTURE**

138

139 To satisfy the fair return standard the overall return must provide a regulated utility the  
140 opportunity to:

141

- 142 1. earn a return on investment commensurate with that of comparable risk  
143 enterprises;
- 144 2. maintain its financial integrity; and,
- 145 3. attract capital on reasonable terms.

146

147 The capital structure adopted for regulatory purposes should mirror the capital structure  
148 that the regulated utility would require as a stand-alone entity to allow it to attract capital  
149 on reasonable terms, to maintain its financial integrity and to have an opportunity to earn  
150 a return commensurate with those of comparable risk enterprises. To deem capital  
151 structure ratios that are not attainable by the utility contravenes the very principles that  
152 underpin a fair return. If a utility cannot obtain the financing required to actually achieve  
153 the deemed capital structure, by definition, the allowed rate of return is not a fair rate of  
154 return.

155

156 The following principles should be respected when establishing both the cost of capital  
157 generally and reasonable capital structures specifically:

158

- 159 1. The Stand-Alone Principle
- 160 2. Compatibility of Capital Structure with Business Risks
- 161 3. Maintenance of Creditworthiness/Financial Integrity
- 162 4. Ability to Attract Capital on Reasonable Terms and Conditions
- 163 5. Comparability of Returns

164

165 Each of these five principles is defined below. The five principles which apply to the  
166 determination of a reasonable capital structure include the three standards (Principles 3 to  
167 5) which govern a fair return, reflecting the interdependence between capital structure  
168 and ROE.

169

#### 170 **B.1. The Stand-Alone Principle**

171

172 The stand-alone principle encompasses the notion that the cost of capital incurred by a  
173 utility should be equivalent to that which would be faced if it was raising capital in the  
174 public markets on the strength of its own business and financial parameters; in other  
175 words, as if it were operating as an independent entity. The cost of capital for the  
176 company should reflect neither subsidies given to, nor taken from, other activities of the  
177 firm. Respect for the stand-alone principle is intended to promote efficient allocation of

178 capital resources among the various activities of the firm. The stand-alone principle  
179 applies to both the capital structure and the ROE.

180

181 **B.2. Compatibility of Capital Structure with Business Risks**

182

183 The capital structure of a utility should be consistent with the business and regulatory  
184 risks of the specific entity for which the capital structure is being set. The business risk  
185 of a utility is the risk of not earning a compensatory return on the invested capital and of  
186 a failure to recover the capital that has been invested. The fundamental business risks of  
187 a utility include demand, competitive, supply, operating, technology-related and political  
188 risks. Regulatory risk relates to the framework that determines how the fundamental  
189 business risks are allocated between the utility's customers and its investors.

190

191 **B.3. Maintenance of Creditworthiness/Financial Integrity**

192

193 Reasonable capital structures for PNG, in conjunction with the returns allowed on the  
194 various sources of capital, should provide the basis for stand-alone investment grade debt  
195 ratings. For the majority of regulated Canadian utilities, a target debt rating in the A  
196 category is optimal from both a cost and market access perspective. Debt ratings in the A  
197 category assure that the utility would be able to access the capital markets on reasonable  
198 terms and conditions during both robust and difficult, or weak, capital market conditions.  
199 In contrast to unregulated companies, utilities do not have the same flexibility to defer  
200 financing new assets. Utilities are required to provide service on demand, and must  
201 access the capital markets when service requirements demand it.

202

203 The critical nature of maintaining investment grade debt ratings arises from two factors:  
204 market access and cost. Even regulated issuers with BBB ratings can be closed out of the  
205 market at times, particularly at the longer end (20-30 year term) of the debt market. PNG  
206 is principally financing long-term assets and thus should be provided the financing  
207 flexibility necessary to be able to access longer-term debt.

208

209 For PNG, its fundamental business risks and small size would not likely permit it to  
210 achieve debt ratings in the A category, irrespective of the level of equity in the capital  
211 structure and allowed ROE. In that context, an A rating for PNG would be an unrealistic  
212 objective. However, the allowed capital structures and ROEs should be adequate for  
213 PNG to achieve a debt rating in the mid to upper end (BBB (high)) of the BBB rating  
214 category. Targeting the mid to upper end of the BBB rating category provides some  
215 cushion should the company's business and/or financial circumstances deteriorate. At a  
216 BBB (low) debt rating, a utility is only one rating notch from non-investment grade. The  
217 implications of a non-investment grade debt rating are discussed in more detail in Section  
218 III.E.

219

#### 220 **B.4. Ability to Attract Capital on Reasonable Terms and Conditions**

221

222 Not only is the ability to attract capital on reasonable terms and conditions one  
223 component of the fair return standard, a higher cost of debt to the utility translates into a  
224 higher cost of debt to ratepayers. Maintaining investment grade debt ratings benefits all  
225 stakeholders.

226

#### 227 **B.5. Comparability of Returns**

228

229 The combination of the adopted capital structure and return on capital should be  
230 comparable to the returns of comparable risk companies.

231

232 In order to be competitive in the capital markets, a regulated utility's financial parameters  
233 – which encompass both capital structure and ROE – need to be comparable to those of  
234 its peers. In this regard, it is important to recognize that PNG competes for capital not  
235 only with other Canadian regulated companies, but with regulated companies globally, as  
236 well as with unregulated companies, both within Canada and globally.

237

238 PNG will be competing for capital in markets that may be characterized by an  
239 unprecedented requirement for regulated infrastructure capital. Its peers are increasingly  
240 global, not solely Canadian. In its 2008 *World Energy Outlook*, the International Energy  
241 Agency estimated that between 2007 and 2030 close to \$4.3 trillion in investment would  
242 be required by the gas transmission and distribution (\$1.6 trillion) and electricity (\$2.6  
243 trillion) industries in North America.<sup>2</sup> To compete successfully for the required capital,  
244 that is, to continue to be able to attract capital on flexible terms and conditions, PNG  
245 requires financial metrics (which reflect the combination of capital structure and ROE)  
246 that are competitive with those of its peers. The achievement of comparability requires  
247 explicit recognition of the financial parameters of the companies of comparable risk to  
248 PNG, including regulated companies throughout North America.

249

## 250 C. **BUSINESS RISKS OF PNG-WEST AND PNG (N.E.)**

251

### 252 C.1 **Conceptual Considerations**

253

254 Business risks have both short-term and longer-term aspects. The capital structure and  
255 fair rate of return on equity should reflect both short- and long-term risks. Long-term  
256 risks are important because utility assets are long-lived. The capital structure in  
257 particular needs to compensate for longer-term risks, as the financing of a utility is  
258 premised on the longer-term risks as perceived by investors when committing capital to  
259 the enterprise. Because regulated firms are generally regulated on the basis of annual  
260 revenue requirements, there has been a tendency to downplay longer-term risks,  
261 sometimes on the grounds that the regulatory framework provides the regulator an  
262 opportunity to compensate the shareholder for the longer-term risks when they are  
263 experienced. This premise may not hold. First, customer resistance may forestall higher  
264 return awards when the risk materializes. Second, competitive market conditions may  
265 inhibit a company's ability to recover the allowed compensation in the future. Third, no  
266 regulator can bind his successors and thus guarantee that investors will be compensated  
267 for longer-term risks when they are incurred in the future.

---

<sup>2</sup> Approximately \$19 trillion world-wide (Table 2.4).

268

269 Business risk encompasses those market demand/competitive, supply and regulatory  
270 factors that expose the shareholders to the risk of under-recovery of the required return  
271 on, and/or the return of, their capital investment. While different business risk categories  
272 can be identified, they are inter-related. The regulatory framework, for example, is  
273 typically designed around the inherent market and supply/physical risks.

274

275 **C.2. Business Risks**

276

277 PNG is a very small gas transmission and distribution utility company. The PNG-West  
278 transmission/distribution system serves customers in 11 municipalities close to its  
279 transmission line which traverses B.C. from the Westcoast mainline interconnection near  
280 Summit Lake to Prince Rupert. The total population of the service area is in the range of  
281 75,000 with Prince Rupert, the largest municipality in its service area, having a  
282 population of approximately 13,000. Three large industrial customers, Rio Tinto Alcan  
283 Inc. and West Fraser Mills in Kitimat and BC Hydro in Prince Rupert are served by the  
284 PNG-West system.

285

286 The Northeast system has two divisions, Fort St. John/Dawson Creek, which serves four  
287 communities, and Tumbler Ridge. The total population in the Northeast system is  
288 approximately 60,000; the City of Fort St. John is the largest of the cities served, with a  
289 population of approximately 18,000.

290

291 PNG has a total of 39,100 customers, approximately 54% served by PNG-West, 43%  
292 served by the Fort St. John/Dawson Creek Division and 3% served by the Tumbler Ridge  
293 Division. To put PNG's size in perspective, Table 1 below compares customers, sales,  
294 and rate base of major Canadian gas distribution utilities.<sup>3</sup>

---

<sup>3</sup> AltaGas Utilities included because its stock is publicly traded; Terasen Gas (VI) has its own debt ratings.

295  
296

**Table 1**

<b>Company</b>	<b>Customers</b>	<b>Gas Deliveries (PJs)</b>	<b>Rate Base (\$ Millions)</b>
PNG-West	21,100	6.4	131
PNG-Fort St. John/ Dawson Creek	16,800	4.7	36
PNG-Tumbler Ridge	1,200	1.0	2
<b>PNG (Total)</b>	<b>39,100</b>	<b>12.1</b>	<b>169</b>
Canadian Gas Utilities:			
AltaGas Utilities (Alta.)	66,200	15.9	105
ATCO Gas	1,011,400	236.5	1,169
Enbridge Gas	1,898,200	467.3	3,746
Gaz Metro	171,200	238.4	1,770
Terasen Gas	822,500	212.2	2,505
Terasen Gas (VI)	95,000	32.7	505
Union Gas	1,309,000	528.0	3,203

297 Source: Company documents

298 As the table indicates, PNG in total is approximately one-fifteenth the size of Terasen  
299 Gas in terms of rate base. A small utility cannot diversify its risks to the same extent as  
300 larger utilities whose assets, geography and economic bases are less concentrated.  
301 Adverse circumstances are likely to have greater impact on the earnings or viability of a  
302 smaller company. The impact of smaller size for rated utilities is frequently exhibited in  
303 lower debt ratings for these companies despite financial parameters that are stronger than  
304 their larger peers.

305

306 To illustrate, in its June 2009 rating report for FortisBC, an electric utility, DBRS called  
307 the company's small size a "challenge" and stated,

308

309 *"FortisBC is a small utility compared with the dominant utility in the province,*  
310 *the Crown-owned BC Hydro, and serves a rural and low-population density*  
311 *region in south-central British Columbia. To some extent, the small size and*  
312 *franchise area limit opportunities for growth, operating efficiencies, and*  
313 *economies of scale as they relate to PBR."* (DBRS, Rating Report: FortisBC Inc.,  
314 *June 5, 2009).*  
315

316 FortisBC, which had assets of approximately \$1 billion at the end of 2008, is rated BBB  
317 (High) by DBRS, compared to a median debt rating of A for the universe of Canadian  
318 utilities rated by DBRS.

319

320 Historically, PNG-West's operations were dominated by a small number of large  
321 industrial customers. Since 2001, PNG-West has lost two of its major industrial  
322 customers. Skeena Cellulose, which had been PNG's second largest customer, declared  
323 bankruptcy in 2001 and its assets were liquidated. The pulp mill assets near Prince  
324 Rupert were purchased in 2006 with the expectation of reopening the mill; the mill has  
325 never been reopened. Methanex, which once accounted for close to 50% of PNG-West's  
326 gross margin and as recently as early 2005 accounted for 75% of throughput,  
327 permanently closed its Kitimat facilities in late 2005 and terminated its transportation  
328 agreement with PNG effective in early 2006. Methanex made a termination payment to  
329 PNG as required under the agreement of \$23.3 million. The termination payment has  
330 been amortized to rates over a 44 month period which expires on October 31, 2009.

331

332 PNG-West currently has, as noted above, three remaining large industrial customers.  
333 West Fraser, which operates a linerboard and kraft paper mill in Kitimat, has a  
334 transportation agreement with PNG which extends to 2013. The agreement, which  
335 requires minimum monthly demand charges, is subject to termination by West Fraser  
336 with six months notice and a termination payment which declines as the contract  
337 termination date approaches. During 2009, West Fraser is forecast to account for  
338 approximately 35% of PNG-West's deliveries and 7% of its gross margin.

339

340 PNG also has an agreement with Rio Tinto Alcan, which operates an aluminum smelter  
341 in Kitimat. The transportation agreement, which covers both firm (for which there is a  
342 minimum charge equal to 85% of the monthly contract demand volume) and interruptible  
343 transportation, has been on a year-to-year basis since 2004, with a one contract year  
344 notice required for termination. In 2009, Rio Tinto Alcan is forecast to account for  
345 approximately 15% of PNG-West's deliveries and 8% of its gross margin.

346

347 The agreement between PNG and BC Hydro is an interruptible sales and service  
348 agreement for BC Hydro’s stand-by gas fired electricity generation facility at Prince  
349 Rupert. The facility, which is operated for emergency purposes, accounts for less than  
350 0.5% of total deliveries and gross margin.

351

352 Table 2 below summarizes the percentages of deliveries and gross margin by customer  
353 class based on 2009 forecasts from PNG-West’s 2009 Revenue Requirements  
354 application.

355

356

**Table 2**

<b>Customer Class</b>	<b>% of Deliveries</b>	<b>% Gross Margin</b>
Residential/Rate 1	22%	48%
Commercial	18%	31%
Small Industrial	8%	5%
Large Industrial	51%	15%
Other (Rates 6 and 7)	1%	1%

357 Although PNG-West’s gross margin attributable to the industrial customer classes has  
358 declined over time, due primarily to the loss of two of its major customers, its operations  
359 are still significantly dependent on the industrial customer classes directly, particularly  
360 the forestry products sector, as well as indirectly. As noted by DBRS in its February  
361 2009 Rating Report for PNG “Economic conditions in PNG’s Western service area  
362 remain challenging, mainly due to the challenges the forestry sector has faced. This has  
363 led to the closure of some mills or a reduction in output, and a decline in the number of  
364 residential customers in the service area.”

365

366 The forestry products industry is currently facing challenges related to low lumber prices  
367 (set in global markets), the mountain pine beetle infestation, the impact of the severe  
368 economic downturn in the U.S. as well as weak economic conditions globally, and the  
369 strength of the Canadian dollar. Weak economic conditions and competitive fuel price  
370 considerations provide an incentive for PNG-West’s small industrial customers to invest  
371 capital to switch to alternative energy sources, primarily wood waste. Declines in

372 deliveries to industrial customers in turn negatively impact the commercial and  
373 residential sectors. Both the commercial and residential sectors rely on the health of the  
374 area's principal industrial sectors to which they either provide services or employment  
375 directly and indirectly. The service area, as noted by DBRS, currently has a relatively  
376 high unemployment rate and a declining population (in a region which is already sparsely  
377 populated). PNG-West has experienced a significant loss in number of customers over  
378 the past five years.

379

380 PNG-West has, similar to other gas distributors, been experiencing declining use per  
381 customer as a result of conservation efforts taken by its existing customers. Loss of load  
382 to existing customers puts upward pressure on rates to remaining customers, who have  
383 the alternative of switching to relatively low cost electricity.

384

385 Upward pressure will also be put on rates when the Methanex termination payment is  
386 fully amortized this year. In order to enhance its competitiveness, PNG-West has been  
387 drawing down its deferred income tax balance. While the drawdown is an immediate  
388 benefit to ratepayers, the previously recovered income tax expense must be recovered in  
389 future rates, putting upward pressure on future rates.

390

391 While BC Hydro's new two tiered rate structure is expected to keep PNG-West's  
392 commercial and residential rates competitive with electricity rates, competitiveness in the  
393 long-term will be dependent primarily on (1) the trends in the commodity cost of gas over  
394 time relative to electricity prices; (2) the economic health of the service area including the  
395 long-term viability of the existing industrial customers; (3) demographic/population  
396 trends and (4) the impacts of energy policy on the relative prices of natural gas and  
397 electricity. With respect to the last, the BC Energy Plan of 2007 encourages the efficient  
398 use of fossil fuels, including natural gas. A carbon tax scheme was introduced in 2008  
399 setting rates on consumption of a variety of fuels, including natural gas.

400

401 There are, as DBRS points out, several initiatives which would, if they proceed, have a  
402 positive impact on the operations of PNG-West. These include the expansion of the

403 recently constructed new container handling facility at the Port of Prince Rupert, the  
404 modernization of the Rio Tinto Alcan aluminum smelter, and the construction of the  
405 Kitimat to Summit Lake Looping (“KSL Project”). With declining global prices of  
406 aluminum and the world-wide economic downturn, the Rio Tinto Alcan modernization  
407 project has been slowed down with no firm timeline for completion. With respect to the  
408 KSL Project, which would allow natural gas to be transported from the Westcoast  
409 mainline to a planned LNG export terminal at Kitimat, significant positive steps have  
410 been taken to date with a few major milestones remaining to be achieved to obtain  
411 commercial certainty.

412

413 With respect to the regulatory framework, PNG-West benefits from a supportive  
414 regulatory framework. The BCUC implemented a Revenue Stabilization Adjustment  
415 Mechanism (RSAM) in 2003 which allows for the recovery of variances between forecast  
416 and actual deliveries to residential and small commercial customers. The RSAM  
417 mitigates the short-term impacts of declining use per customer which PNG has been  
418 experiencing. The BCUC also implemented an Industrial Customer Deliveries Deferral  
419 Account (ICDDA) in 2001. To provide PNG an opportunity to recover lost industrial  
420 margin, under-recoveries in the ICDDA may be allocated to the remaining customers. To  
421 the extent that the lost industrial margin is reallocated to existing customers, PNG-West’s  
422 rate competitiveness is reduced. In short, the regulatory framework mitigates PNG-  
423 West’s short-term risks. It cannot however change the fundamental risks nor guarantee  
424 PNG’s long-term viability.

425

426 PNG-West remains the riskiest, from a business risk perspective, of the mature Canadian  
427 gas distribution utilities.

428

429 With respect to PNG (N.E.), the health of the service area is primarily tied to the oil and  
430 gas industry and to a lesser extent to the forestry products industry, both cyclical  
431 industries. The strength in the gas industry in northeastern B.C. has supported relatively  
432 strong growth in the Fort St. John/Dawson Creek area service area. Annual growth in  
433 customers and deliveries in the Fort St. John/Dawson Creek division over the past five

434 years have been 2% and 1.0% respectively. Tumbler Ridge has also experienced growth,  
 435 but at a slower pace. Both divisions, as indicated in Table 3 below, have significant  
 436 direct exposure to the industrial customer class on both a deliveries and gross margin  
 437 basis. In the case of Tumbler Ridge, the gross margin from the industrial class is  
 438 attributable to a single customer, Canadian Natural Resources Limited (CNRL).

439

440

**Table 3**

	<b>Fort St. John/Dawson Creek</b>		<b>Tumbler Ridge</b>		<b>PNG (N.E.)</b>	
<b>Customer Class</b>	<b>Deliveries (%)</b>	<b>Gross Margin (%)</b>	<b>Deliveries (%)</b>	<b>Gross Margin (%)</b>	<b>Deliveries (%)</b>	<b>Gross Margin (%)</b>
Residential	34.9%	51.4%	8.9%	46.5%	30.3%	50.9%
Commercial	35.2%	33.5%	7.4%	26.8%	30.3%	32.8%
Industrial	29.9%	15.1%	83.7%	26.7%	39.4%	16.3%

441

442 While like other gas utilities in B.C., PNG (N.E.) competes with a relatively low cost  
 443 electricity supplier, its delivered residential and commercial rates are competitive with  
 444 electricity at current gas commodity prices and electricity rates. The maintenance of the  
 445 competitive advantage in the longer-term will depend on the future trends in gas  
 446 commodity prices, provincial energy policy and electricity rates.

447

448 The regulatory framework of PNG (N.E.) is similar to that of PNG-West; the two  
 449 divisions have an RSAM and Tumbler Ridge has an ICDDA related to CNRL, which  
 450 mitigate the short-term revenue risks.

451

452 From a relative business risk perspective, PNG (N.E.) faces lower business risks than  
 453 PNG-West but, given its relatively small size and the reliance of the service area on two  
 454 cyclical industries, faces higher fundamental business risks than the benchmark utility,  
 455 TGI, whose service area is significantly more geographically and economically  
 456 diversified.

457

458 **D. BOND RATINGS AND CREDIT METRICS**

459

460 PNG's debt is currently rated BBB (low) with a negative trend by DBRS. The negative  
461 trend was initially assigned in July 2007. The previous rating status had been "Under  
462 Review with Negative Implications", where it had been placed in 2005 following  
463 Methanex's announcement that it was closing its Kitimat facilities. The negative trend  
464 was most recently confirmed by DBRS in January 2009. The BBB (low) rating reflects  
465 DBRS' conclusions with respect to business and financial risk from a debt investor's  
466 perspective. PNG's BBB(low) rating is four notches below the median DBRS rating of  
467 A for all of the Canadian utilities that it rates; only one other Canadian utility (FortisBC,  
468 rated BBB (High)) has a DBRS rating in the BBB category. At BBB (low), PNG's rating  
469 is only one notch above non-investment grade.<sup>4</sup>

470

471 PNG's debt ratings reflect its consolidated operations, i.e., both PNG-West and PNG  
472 (N.E.). As previously noted, approximately 70% of PNG's gross margin and over 75%  
473 of its regulated rate base are related to PNG-West. As a result, the rating largely reflects  
474 the operations of PNG-West, as suggested by the challenges enumerated by DBRS and  
475 listed below.

476

477 In its most recent debt rating report,<sup>5</sup> DBRS concluded that PNG's key strengths include:  
478 (1) earnings and cash flow stability from regulated operations; (2) supportive regulatory  
479 environment; and (3) existence of deferral accounts. The challenges comprise: (1) the  
480 future outcome of the BCUC's decision on rates when the Methanex amortization ends in  
481 2009; (2) the challenging economic conditions in PNG's Western system; (3) the  
482 competitiveness of natural gas versus alternative fuel sources; (4) the negative impact of

---

<sup>4</sup> Prior to 1999, PNG was rated BBB (high) by DBRS and B++ by the Canadian Bond Rating Service (later acquired by Standard & Poor's). Its debt was subsequently downgraded to non-investment grade by both debt rating agencies due to the uncertainty surrounding the Company's large industrial customers and the resulting potential impact on its financial profile and creditworthiness. After it acquired CBRS, S&P downgraded PNG (in 2001) to BB-, with the potential for a further downgrade into the B category. S&P withdrew its BB- ratings at the request of the Company in November 2002. DBRS subsequently upgraded PNG to BBB (low) in November 2003, citing improvement in PNG's regulatory framework and the increased financing flexibility resulting from the arrangement of a new operating line of credit, which increased the Company's financing flexibility.

<sup>5</sup> DBRS, *Rating Report: Pacific Northern Gas Ltd.*, February 2, 2009.

483 the low interest rate environment on earnings through the approved return on equity; and  
484 (5) the low deemed equity component.

485

486 It bears underscoring that, despite the regulatory support which DBRS cites as the  
487 strengths of PNG, the Company's debt rating remains only one notch above non-  
488 investment grade with a negative trend. By inference, one can draw the conclusions that,  
489 although DBRS recognizes that the existing regulatory model mitigates PNG's short-term  
490 risks, (1) regulation cannot fully shield a utility from the underlying fundamental risks in  
491 the longer-run; (2) the regulatory model can change; and (3) the overall return that PNG  
492 is allowed is low for the level of risk that it faces.

493

494 The ratings reflect credit metrics which DBRS concludes are adequate for the existing  
495 rating. The most recently DBRS-reported credit metrics (12 months through September  
496 2008) included Earnings before Interest and Taxes (EBIT) coverage of 2.3 times,  
497 Earnings before Interest Taxes, Depreciation and Amortization (EBITDA) coverage of  
498 3.65 times and cash flow/debt of 11%.<sup>6</sup> The most recent reported credit metrics reflect  
499 some deterioration from the prior three-year average values of 2.5X, 3.7X and 13.4%  
500 respectively.<sup>7</sup>

501

502 Table 4 below compares the credit metrics of PNG to key credit metrics of the universe  
503 of Canadian utilities with rated debt, the sample of A rated U.S. gas and electric utilities  
504 which were used to estimate the benchmark utility ROE for TGI and the universe of U.S.  
505 investment grade natural gas utilities.

506

---

<sup>6</sup> Cash flow is equal to net income available to common equity shareholders plus non-cash items, e.g., depreciation and amortization.

<sup>7</sup> Both EBIT and EBITDA coverage ratios are a function of the corporate income tax rate. All other things equal, the lower corporate income tax rates reduce both EBIT and EBITDA interest coverage. Over the past 15 years (i.e., since the BCUC first adopted the automatic adjustment formula for ROE, the combined provincial/federal corporate income tax rate has declined from over 45% in the mid-1990s to an anticipated 28.5% in 2010. Not only does the reduction in the corporate tax rate require a higher common equity ratio (and/or ROE) in order to maintain the level of coverage ratios, conceptually, the reduction in the corporate income tax rate means that the benefit of debt financing from an overall cost of capital perspective has declined.

507 In comparison to its Canadian peers, PNG's credit metrics have been somewhat lower on  
 508 average, as shown in Table 4 below. PNG's higher business risk relative to its Canadian  
 509 peers', which is not offset by significantly stronger credit metrics, results in debt ratings  
 510 which are at the bottom end of the spectrum of investment grade.

511  
 512

**Table 4**

<b>Company/Sample</b>	<b>Ratings DBRS/Moody's/ S&amp;P</b>	<b>Common Equity Ratio (2008)</b>	<b>EBIT Interest Coverage (2005- 2007)</b>	<b>FFO to Total Debt (2005- 2007)</b>	<b>EBITDA Interest Coverage (2005-2007)</b>
PNG	BBB (low)/-/-	49.6%	2.5X	13.4%	3.7X
All Canadian Utilities with Rated Debt	A/A3/A-	40.4%	2.5X	16.7%	3.9X
U.S. Benchmark Utility Sample	-/A3/A	41.9%	3.6X	21.3%	4.8X
U.S. Benchmark Utility Sample- LDC Only	-/A3/A	43.8%	3.8X	21.7%	5.1X
U.S. BBB Rated Utility Sample	-/Baa2/BBB	44.0%	2.7X	16.5%	3.9X
U.S. Investment Grade Gas Distributors	-/Baa1/A-	48.2%	3.7X	20.6%	5.0X
All U.S. Utilities Rated BBB by S&P	-/-/BBB	43.2% <sup>1/</sup>	3.1X	17.2%	4.3X

513 <sup>1/</sup> Total equity, average 2005-2007

514 Definitions:

515 Earnings before Interest and

516 Taxes (EBIT) Interest Coverage:

517

Operating income divided by interest  
expense.

518 Cash Flow to

519 Total Debt:

520

Cash flow from operations divided by total  
debt.

521 EBITDA

522 Interest Coverage:

523

524

525

Operating income plus depreciation,  
amortization and interest expense divided by  
interest expense.

526 Source: Schedules 2, 3, 4, 5 and Standard & Poor's *CreditStats: 2007 Adjusted Key U.S. Industrial and*  
 527 *Utility Financial Ratios*, September 10, 2008.

528

529 The table above also demonstrates that the credit metrics of PNG compare unfavourably  
530 to its U.S. peers, including not only the benchmark sample of A rated utilities and the  
531 universe of gas distributors (rated on average in the A category) but BBB rated utilities as  
532 well. PNG is competing for capital with U.S. utilities with stronger financial metrics. In  
533 setting the allowed return, (the capital structure as well as the ROE), the BCUC needs to  
534 recognize that Canadian utilities generally and PNG specifically should be allowed  
535 returns which reflect a degree of financing flexibility comparable to their North American  
536 peers' and permit them to compete for capital on competitive terms.

537

538 The actual credit metrics of U.S. utilities reflect the returns (a combination of the ROE  
539 and capital structure) that are awarded by regulators as well as by their earned returns.  
540 From 2006-June 2009, the median common equity ratio adopted by U.S. regulators for  
541 gas distribution utilities with weather normalization clauses and/or decoupling was  
542 approximately 48% with corresponding awarded ROEs of 10.2%. The median common  
543 equity ratio adopted for all U.S. gas distributors over the same period was 49% with  
544 corresponding allowed ROEs of 10.25%. The actual returns on equity from 2006-2008  
545 reported for all investment grade U.S. gas utilities averaged 11.9% (median of 11.2%) on  
546 an average common equity ratio of 48.9% (median of 48.2%); see Schedule 5.

547

548 In the case of PNG, of particular concern is the fact that the Company's actual total debt  
549 ratio of 47% at the end of 2008 is materially lower than the median of its Canadian peers'  
550 (approximately 58%), and even though its allowed ROE has been slightly higher than  
551 most utilities, its credit metrics have been similar to or lower than the industry average.

552

553 PNG's credit metrics reflect a number of factors including: relatively low allowed ROEs  
554 (9.12% for 2009 for PNG-West and Tumbler Ridge and 8.87% for Fort St. John/Dawson  
555 Creek), a relatively high embedded cost of long-term debt (approximately 7.4% during  
556 2009 on a consolidated basis) compared to the level of allowed ROEs, a low effective  
557 income tax rate in 2007 and 2008, due in large part to the drawdown of deferred income

558 taxes, and low deemed regulated common equity ratios compared to PNG's actual  
559 common equity ratio.

560

561 PNG's actual common equity ratio of approximately 50% compares to the allowed  
562 deemed equity ratios of only 40% for PNG-West and 36% for Fort St. John/Dawson  
563 Creek and Tumbler Ridge (or approximately 39% on a weighted average basis).  
564 Primarily as a result of the difference between the actual and deemed equity ratios, which  
565 precludes PNG from earning an equity return on over 20% of its actual equity, the  
566 Company's actual earned ROE in 2008 was 6.7%, well below its allowed ROEs.

567

568 The conclusion by DBRS that the credit metrics are **adequate** (as opposed, for example,  
569 to strong) for the rating indicates that a deterioration in the credit metrics would likely  
570 result in a downgrade. In fact, in its October 22, 2007 Rating Report, DBRS explicitly  
571 stated that it "expects the company to keep its debt-to-capitalisation ratio in the 50%  
572 range and for its credit metrics to remain adequate for its credit rating, especially post-  
573 2009 when the Methanex amortization is completed." As a result, PNG is effectively  
574 precluded from reducing its common equity ratio to the levels that have previously been  
575 deemed for regulatory purposes without suffering a downgrade to non-investment grade.  
576 Moreover, DBRS' expectation that PNG maintain the debt/capital ratio in the 50% range,  
577 combined with its conclusion that the deemed equity ratio is low for the business risk,  
578 together support moving the deemed common equity ratios to levels which are  
579 representative of the reality of the Company's financial structure.

580

581 **E. IMPLICATIONS OF A DEBT DOWNGRADE TO NON-INVESTMENT**  
582 **GRADE**

583

584 With a rating of BBB (low) with a negative trend, PNG is on the cusp of being non-  
585 investment grade. At the lowest possible investment grade rating, the Company has no  
586 leeway to cushion or to weather the impacts of adverse circumstances. Utilities with debt  
587 ratings in the BBB category face higher costs, reduced market access and more stringent  
588 covenants attached to debt issues relative to issuers whose debt is rated in the A category.

589 The implications of ratings in the non-investment grade category are significantly more  
590 serious.

591

592 While the difference between the cost of new long-term BBB-rated utility debt and long-  
593 term A rated utility debt historically has averaged less than 0.50%, the difference  
594 between the cost of long-term BBB-rated investment grade and BB-rated non-investment  
595 grade debt is considerably higher.<sup>8</sup> Since there are very few public issues by companies  
596 with debt rated in the BB category in Canada, any estimates of the differences in cost of  
597 debt to a BBB rated company versus a BB rated company by reference to specific issues  
598 should be viewed with caution. Nevertheless, the following examples provide some  
599 perspective on the potential cost impact of a downgrade into the BB rating category.

600

601 In May 2006 and March 2007, during unusually robust debt markets, Shaw  
602 Communications, then rated in the BB category by all three debt rating agencies  
603 (Moody's, DBRS, and Standard & Poor's) raised, respectively, \$300 and \$400 million of  
604 10-year debt at spreads of 190 and 175 basis points above the 10-year Canada bond  
605 yield.<sup>9</sup> At the same times, the indicated spreads for TGI (then rated A3 by Moody's, A  
606 by DBRS and BBB by S&P) for new 10-year issues were approximately 85 and 65 basis  
607 points; the corresponding indicated spreads for new 10-year issues of TransAlta  
608 Corporation (rated mid BBB by all three rating agencies) were 105 and 100 basis points.  
609 Even at the best of times, the spreads between the cost of 10-year debt for BBB and BB  
610 rated issuers were twice the spreads between the costs of new issues for A and BBB rated  
611 issuers. There have been no public issues in Canada by BB rated companies during the  
612 financial crisis which commenced in 2008 continuing through 2009.

---

<sup>8</sup> DBRS defines debt rated BBB "as of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities." By comparison, BB rated debt is defined to be speculative and non-investment grade, where the degree of protection afforded interest and principal is uncertain, particularly during periods of economic recession. Entities in the BB range typically have limited access to capital markets and additional liquidity support. In many cases, deficiencies in critical mass, diversification, and competitive strength are additional negative considerations."

<sup>9</sup> Between the beginning of 2006 and the end of May 2009, in addition to the two Shaw Communications issues, there were only four additional new public issues (of a total 490 issues) in Canada by firms with ratings in the BB or lower category. Two of the issues were for terms of two and three years; the remaining two issues, with terms of 10-years, were 2007 issues at spreads of 346 and approximately 400 basis points.

613

614 The deeper U.S. debt market provides some perspective on the potential difference in  
615 debt cost as among A, BBB and BB rated utility issuers. In its *Global Power Financing*  
616 *Activity in 2009, First Quarter 2009* Report, CitiGroup reported that from 1999-March  
617 31, 2009, the spreads over intermediate term Treasury bond yields were as follows:

618  
619

**Table 5**

<b>Spreads with Intermediate-Term Treasury Bond Yields (1999-March 2009)</b>				
<b>Rating</b>	<b>Low</b>	<b>Average</b>	<b>High</b>	<b>March 31, 2009</b>
A	79	147	481	334
BBB	88	214	708	494
BB	167	532	1757	1195

620

621 The yield spreads provided highlight the significant increase in cost which a utility faces  
622 if it is downgraded from investment to non-investment grade.

623

624 Further, it bears noting that, if a utility experiences a downgrade, the downgrade would  
625 not only result in an increase in the cost of the additional debt that the company needs to  
626 raise, but it will affect all of the outstanding debt. An increase in the cost of debt to a  
627 utility increases the required yield on the outstanding debt and reduces the value of that  
628 debt. Since existing debt holders are the most likely purchasers of future issues, a debt  
629 rating downgrade, with the resulting negative impact on the value of their existing  
630 holdings, would likely make them less willing to purchase future issues and potentially  
631 require a higher rate than otherwise, a shorter term, and/or more stringent covenants, e.g.,  
632 higher minimum interest coverage ratios, more rapid amortization (repayment) of the  
633 issue.

634

635 Non-investment grade ratings can also negatively impact access to trade credit. Rather  
636 than requiring a letter of credit, vendors may require prepayment for services. A  
637 downgrade of PNG’s debt to non-investment grade would likely require the Company to  
638 prepay for delivery of natural gas, as has been the case in the past.

639

640 It also bears noting that, while PNG was able to negotiate a revolving five-year credit  
641 facility during 2007 (during a period of easy credit conditions) on very favourable terms,  
642 if PNG is downgraded below BBB (low) or has no credit rating, the covenants state that it  
643 must maintain a pre-tax interest coverage ratio of 2.0 times. In 2008, the pre-tax interest  
644 coverage ratio calculated per the financial covenant was only 2.14 times. If PNG were to  
645 be downgraded and were unable to maintain the coverage ratio required by the covenant  
646 of the facility, it would be in default. Under current capital market conditions, the cost  
647 and terms of any renegotiated or new facility (should one even be available) would be  
648 significantly more onerous.

649

650 Without access to capital on reasonable terms and conditions, a utility is deprived of the  
651 means to build the infrastructure required to support long-term growth in the underlying  
652 economy or from making the requisite level of investments in the existing infrastructure  
653 in order to reliably provide utility services for its customers. In short, a downgrade of  
654 PNG's debt to non-investment grade status is in no stakeholder's interest. The fair  
655 returns (capital structure and ROE) should provide the basis for maintaining PNG's  
656 investment grade debt rating.

657

658 **F. CAPITAL STRUCTURE GUIDELINES AND VIEWS OF DEBT RATING**  
659 **AGENCIES**

660

661 Both Moody's and Standard & Poor's issue guidelines for capital structures as well as  
662 other key credit metrics for their debt rating categories.<sup>10</sup> Although PNG is not rated by  
663 either Moody's or S&P, the guidelines provide a perspective on the range of capital  
664 structures that they would consider reasonable for different rating categories and thus the  
665 utilities they do rate and with which PNG competes for capital. Moody's looks for debt  
666 ratios for North American natural gas distributors in the 40-50% range for an A rating  
667 and in the 50-65% range for a Baa rating.<sup>11</sup>

---

<sup>10</sup> DBRS publishes broad guidelines for A/BBB ratings, but they do not distinguish by either business risk or investment-grade rating category.

<sup>11</sup> Moody's, *Rating Methodology North American Regulated Gas Distribution Industry (Local Distribution Companies)*, October 2006.

668

669 S&P’s current rating methodology<sup>12</sup> assigns one of five business risk rating categories to  
670 each utility that it rates. The lowest risk category is “Excellent”; the highest risk category  
671 is “Vulnerable.” The category assigned takes into account the regulatory environment in  
672 which the utilities operate. Most Canadian utilities rated by S&P, including TGI, the  
673 benchmark BC utility, are in the “Excellent” category.<sup>13</sup>

674

675 The business risk assessment is accompanied by a financial risk assessment. The  
676 financial risk assessment includes, but is not limited to, the consideration of three key  
677 quantitative credit metrics, Funds Flow from Operations (FFO)/Debt (%), FFO Interest  
678 Coverage (x), and Total Debt to Capital (%). For each of the three metrics, S&P  
679 publishes a guideline range associated with four financial risk categories. The lowest  
680 financial risk category is “Modest”; the highest financial risk category is “Highly  
681 Leveraged”. The table below presents the guideline ranges for each financial risk  
682 category. S&P notes that the guideline ranges are intended to represent the level of  
683 ranges that have been achieved historically and are expected to consistently continue.

684

685

**Table 6**

<b>Financial Risk Category</b>	<b>FFO/Debt (%)</b>	<b>FFO Interest Coverage (x)</b>	<b>Total Debt/Capital (%)</b>
Modest	40 -60	4.0 -6.0	25 -40
Intermediate	25 -45	3.0 -4.5	35 -50
Aggressive	10 -30	2.0 -3.5	45 -60
Highly leveraged	Below 15	2.5 or less	Over 50

686

687

688

689

Source: Standard & Poor’s, *U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix*, November 31, 2007

<sup>12</sup> Standard & Poor’s, *U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix*, November 31, 2007

<sup>13</sup> The other categories are “Strong”, “Satisfactory”, and “Weak”. Nova Scotia Power, rated BBB, and Maritime Electric, rated A, for example, are “Satisfactory”.

690 The matrix above is accompanied by a second matrix which indicates what the likely debt  
691 rating would be with a given business risk and financial risk profile. For example, a  
692 business risk profile ranking of “Satisfactory” and a financial risk profile of  
693 “Intermediate” corresponds to a mid BBB debt rating. A business profile ranking of  
694 “Weak” and a financial risk profile of “Modest” corresponds to a BBB- rating  
695 (corresponding to the BBB (low) designation in the DBRS rating scale).

696  
697 While S&P does not apply their guidelines mechanically, the guidelines do provide  
698 guidance as to ranges that are considered reasonable for ratings in the BBB category.  
699 Given the business risk profiles assigned to the various Canadian utilities it rates, the  
700 highest business risk category that PNG would likely be assigned is “Satisfactory”, i.e.,  
701 the same as Maritime Electric and Nova Scotia Power, but more likely “Weak”. For a  
702 “Satisfactory” business risk profile ranking, a debt ratio in the range of 35%-45% is  
703 indicated for a mid-BBB rating.<sup>14</sup>

704  
705 Although the guidelines are not applied mechanically by either rating agency, they do  
706 provide a perspective on the ranges that are considered appropriate for ratings in the BBB  
707 category. The guideline ranges demonstrate that stronger capital structures than those  
708 which have been previously adopted for regulatory purposes for PNG are warranted.  
709 Moreover, it is clear that the debt rating agencies view the credit metrics of Canadian  
710 utilities as weak for their ratings and the key elements which are determinative of those  
711 metrics, capital structure and ROE, out of line with those of their global peers.

712  
713 With specific respect to PNG, as previously noted, DBRS expects the Company to  
714 maintain a debt ratio of approximately 50% and considers its deemed equity ratios to be  
715 low given its business risk level. More generally, both DBRS and S&P have consistently  
716 commented on the highly levered nature of Canadian utilities and the low allowed  
717 common equity returns relative to their global peers, particularly those in the U.S.

718

---

<sup>14</sup> PNG’s FFO/Debt ratios as calculated by DBRS of 13.4% from 2005-2007 would place PNG in the “Aggressive” financial risk category. Its average FFO Coverage ratio over the same period of approximately 3.5 times falls in the middle of the “Intermediate” financial risk category.

719 DBRS has noted that it would like to see both the deemed common equity ratios and  
720 allowed returns increased to levels more consistent with U.S. returns.<sup>15</sup>

721

722 In December 2004, subsequent to the AEUB's Generic Cost of Capital Decision (2004-  
723 052, dated July 2004), DBRS referred to the low deemed equity and returns as a  
724 "challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated,

725

726 *"While ATCO's diversified operations, coupled with the Company's prudent*  
727 *management approach, provide a level of earnings stability, additional*  
728 *challenges over the medium term include the relatively low approved returns on*  
729 *equity (ROE) and deemed equity for the regulated businesses, continuing*  
730 *regulatory risk and lag and ATCO's merchant power exposure in Alberta."*  
731 *(DBRS, Credit Rating Report: ATCO Ltd., December 29, 2004).*

732

733 Additional DBRS reports citing the challenge of low approved common equity ratios and  
734 returns on equity were also published for the Alberta utilities subsequent to Decision  
735 2004-052) including CU Inc. (January 2007, May 2008), FortisAlberta (November 2005,  
736 May 2007, May 2008) and AltaLink (November 2005, May 2008). In reference to  
737 FortisAlberta, expressing the perspective of capital market participants on the comparable  
738 return requirement, DBRS commented that:

739

740 *"In Alberta, as well as in many other jurisdictions in Canada, the rates of return*  
741 *and equity capitalization for ratemaking purposes allowed by regulators have*  
742 *been low in recent years, largely as a result of the low interest rate environment.*  
743 *This has had a negative impact on earnings and cash flows. FortisAlberta's*  
744 *equity thickness at 37% and low ROE's directly impact shareholder returns,*  
745 *hindering the ability to attract capital for capital expenditure purposes. In*  
746 *addition, the allowed ROEs are significantly below those allowed for similar*  
747 *operations in the U.S. This acts as a disincentive for investors to allocate capital*  
748 *to Canadian utilities because they can earn higher rates of return in the U.S. from*  
749 *businesses having similar business risk profiles."* (DBRS, Credit Rating Report:  
750 *FortisAlberta, November 25, 2005).*

751

---

<sup>15</sup> DBRS, *The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities have Lower Ratios and Five Changes to Regulation Which Should be Introduced in Canada*, May 2003.

752 With respect to S&P, in early March 2003, the debt rating agency announced that it was  
753 re-evaluating its prior justification of the strong investment grade ratings of Canadian  
754 utilities (i.e., the nature of Canadian regulation).

755

756 S&P noted that Canadian utilities are among the most highly levered utilities in their  
757 global ratings universe, and that the highly leveraged financial profiles generally stem  
758 from regulatory directives. Subsequent to that announcement, S&P has commented on  
759 the low equity ratios and allowed returns of specific Canadian utilities.

760

761 For example, like DBRS, S&P has made references to the low level of equity ratios  
762 allowed in the EUB's Generic Cost of Capital decision for Alberta utilities. Subsequent  
763 to the EUB decision, S&P commented on the thin equity layers allowed the ATCO group  
764 of utilities, stating,

765

766 *The regulatory regime, although comparable with other provinces in Canada,*  
767 *typically approves less generous returns on thinner equity layers than those*  
768 *approved for ATCO's global peers. Approved returns for ATCO's regulated*  
769 *businesses are 9.6% on equity layers varying from 33%-43% of total capital.*  
770 *(S&P, Research Update: ATCO Group of Companies 'A' Ratings Affirmed;*  
771 *Outlook Stable, November 9, 2004.)*

772

773 In a report for AltaLink (rated A-), S&P stated,

774

775 *Like many regulated utilities in Canada, AltaLink's average financial profile is*  
776 *constrained by a comparatively low approved ROE (8.93% in 2006) on a thin*  
777 *deemed equity base of 35%. (S&P, Research Summary: AltaLink, June 5, 2006)*

778

779 In S&P's December 22, 2005 report for NOVA Gas Transmission Ltd., rated A-, the sole  
780 weakness cited for the pipeline was its high leverage associated with its regulated capital  
781 structure. (S&P, *Research: Nova Gas Transmission Ltd*, December 22, 2005)

782 In its report for Union Gas issued subsequent to the utility's 2006 settlement in which the  
783 allowed common equity ratio was raised to 36%, the two weaknesses referred to by S&P

784 were the high leverage associated with company's regulated capital structure and the  
785 relatively low allowed ROE compared with global peers (S&P, *Research: Union Gas*,  
786 August 24, 2006).

787 In general, S&P considers that Canadian utility financial policies tend to be aggressive  
788 with leverage, and regulators parsimonious with returns.<sup>16</sup> As noted above, the  
789 “aggressive leverage” is largely a result of regulatory directives.

790

791 In summary, the S&P and Moody’s guidelines, taken together, in conjunction with the  
792 debt rating agencies’ views on the relatively low level of regulated common equity ratios  
793 in Canada, support increasing PNG’s regulated common equity ratios.

794

#### 795 **G. CAPITAL STRUCTURES OF PEERS**

796

797 Table 4 above provides actual common equity ratios of utilities which are rated, that is  
798 their capital structures have been tested by the market. The table indicates that the  
799 median actual common equity ratio of Canadian utilities has been 40%; the most recent  
800 allowed common equity ratio of those same utilities has been approximately 39%.<sup>17</sup> The  
801 median DBRS debt rating associated with those utilities has been A, compared to the  
802 BBB (low) rating of PNG with its allowed common equity ratio of approximately 39% on  
803 a weighted average basis. Given the higher business risks and small size of PNG-West  
804 and PNG (N.E.) relative to the average rated Canadian utility, higher than average  
805 regulated common equity ratios are warranted.

806

807 For PNG-West, the proposed common equity ratio of 47.5%, as shown in Table 4 above,  
808 is well within the range maintained by investment grade U.S. gas distributors, whose  
809 common equity ratio at the end of 2008 averaged 48.2%. It is also well within the range  
810 of common equity ratios adopted for regulatory purposes since 2006, which as noted

---

<sup>16</sup> Standard & Poor’s, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

<sup>17</sup> TGI and each of the Alberta utilities currently participating in the Generic Cost of Capital Proceeding have applied for increases to their allowed common equity ratios.

811 above, averaged 48% for gas distributors with weather normalization and/or decoupling  
812 mechanisms and 49% for all gas distributors.

813

814 PNG (N.E.), which, on a stand-alone basis, would be too small to have its debt rated by  
815 the debt rating agencies, as are all of the smaller gas and electric utilities that would be of  
816 reasonably comparable business risk. Thus, the capital structures of the smaller Canadian  
817 utilities have generally not been directly “tested” by the capital markets. Nevertheless,  
818 the allowed capital structures of other Canadian utilities in a similar business risk class to  
819 PNG (N.E.) provide a basis for assessing the reasonableness of the proposed 42.5%  
820 common equity ratios for each of Fort St. John/Dawson Creek and Tumbler Ridge. As  
821 Table 7 below indicates, the proposed 42.5% equity ratios are in line with those allowed  
822 smaller gas and electric distribution utilities in Canada.

823

824

**Table 7**

<b>Company</b>	<b>Allowed Equity Ratio</b>	<b>Rate Base (\$ million)</b>
AltaGas Utilities (Alberta)	41.0%	\$105
Gazifère Inc.	40.0%	\$68
Ontario Electricity LDCs	40.0%	all sizes
Maritime Electric	40.5% <sup>1/</sup>	\$300
Natural Resource Gas	42.0%	\$10
Northland Utilities (YK)	43.5%	\$34
Northland Utilities (NWT)	44.0%	\$12
Terasen Gas (Whistler)	40.0%	\$38
Terasen Gas (VI)	40.0%	\$505
Yukon Electrical	40.0%	\$43

825

826

827 While the proposed common equity ratios are similar to those of smaller gas and electric  
828 utilities in Canada, they remain well below those maintained and allowed for U.S. natural  
829 gas distribution utilities. The ratios maintained and allowed for U.S. gas distributors,  
830 with whom Canadian gas distributors compete for capital, indicate that the proposed  
831 common equity ratios for PNG (N.E.) are relatively low.

832

<sup>1/</sup> Based on actual forecast for 2009; target of 45%

833 **H. REASONABLENESS OF PROPOSED CAPITAL STRUCTURES**

834

835 Within a reasonable range, the capital structure for a particular utility is appropriately a  
836 decision for management, because management is in the best position to assess its  
837 business risks, financing requirements and access to debt and equity capital.

838

839 In my opinion, the capital structures proposed by PNG, containing 47.5% common equity  
840 for PNG-West and 42.5% for Fort St. John/Dawson Creek and Tumbler Ridge, are within  
841 a reasonable range, albeit at the lower end, for the reasons summarized below.

842

843 1. The levels of business risk, including size considerations, warrant higher common  
844 equity ratios than have previously been adopted for regulatory purposes.

845

846 2. PNG is effectively precluded from altering its actual capital structure, containing  
847 approximately 50% common equity, without being downgraded to non-  
848 investment grade.

849

850 3. PNG is already on the cusp of being downgraded to non-investment grade, given  
851 its BBB (low) – Negative Trend rating by DBRS. The severe negative  
852 implications in terms of loss of market access and higher cost of capital of a  
853 downgrade warrant thicker regulated common equity ratios.

854

855 4. The capital structures maintained by and allowed for PNG’s North American  
856 peers indicate that the proposed capital structures are reasonable for regulatory  
857 purposes.

858

859 5. PNG should be afforded an opportunity to earn a fair return on equity on its actual  
860 equity capital as that equity reflects the financial structure that the Company must  
861 maintain to preserve its creditworthiness and financial integrity.

862

863 **IV. EQUITY RISK PREMIUMS FOR PNG-WEST AND PNG (N.E.)**

864

865 **A. CAPITAL MARKET INDICATORS OF RELATIVE RISK**

866

867 In addition to the bond rating, there are two other indicators<sup>18</sup> that demonstrate that the  
868 capital markets view PNG as a higher risk investment than the Canadian utilities which  
869 are used as inputs to the estimation of the cost of equity for a benchmark Canadian utility.  
870 PNG's market to book ratio is only 0.68; by comparison the market to book ratio of the  
871 five major publicly traded Canadian utilities is approximately 1.6 times; see Schedule 7.  
872 The fact that PNG's market to book ratio is currently less than 50% of the corresponding  
873 market to book ratios of other Canadian utilities is evidence that its cost of equity is  
874 significantly higher.

875

876 A comparison of the forward price/earnings ratios (current price divided by forecast  
877 earnings per share) tells a similar story. The price/earnings ratio reflects both investor's  
878 return expectations and their perceptions of the risk surrounding their expectations. For  
879 firms in the same industry, a very low P/E ratio relative to those of its peers is an  
880 indicator of higher risk. PNG's forward P/E ratio as of mid-June 2009 was 9.8 times  
881 compared to a median of 14 times for the five major publicly traded Canadian utilities;  
882 see Schedule 7. PNG's lower forward P/E ratio in comparison to the average for the  
883 major Canadian utilities indicates that PNG's cost of equity is higher.

884

885 **B. ESTIMATES OF EQUITY RISK PREMIUMS**

886

887 The estimate of the incremental ROE or equity risk premiums that would apply to PNG-  
888 West and PNG (N.E.) relative to the benchmark utility ROE starts with the premise that  
889 the benchmark utility is an A rated utility and the benchmark ROE is one which applies  
890 to an A rated utility. In the ongoing cost of capital proceeding before the BCUC for TGI,

---

<sup>18</sup> Since PNG's shares are relatively illiquid (not traded as frequently as those of the major Canadian utilities), its betas, which in principle are intended to measure non-diversifiable or market risk, are unreliable indicators of PNG's relative risk.

891 I selected a sample of low risk U.S. gas and electric utilities to serve as proxies for  
892 estimating the fair return for TGI as the benchmark utility. The selection criteria for  
893 these utilities are provided in Appendix B to this opinion. The selected utilities and  
894 corresponding risk measures are found on Schedule 4.

895

896 Both PNG-West and PNG (N.E.) face higher business risk than the benchmark utilities.  
897 As shown on Schedule 4 the benchmark utilities are all considered to have “Excellent”  
898 business risk profiles by S&P. As indicated in Section III.F above, PNG (on a  
899 consolidated basis) were it to be rated by S&P would likely be ranked no higher than  
900 “Satisfactory” and more likely “Weak”, the latter being three business risk categories  
901 lower than the benchmark utilities and, assuming compensatory ROEs, with notional  
902 stand-alone BBB debt ratings at the proposed capital structures. To estimate the impact  
903 on the cost of equity of the higher risk relative to the benchmarks, I selected a sample of  
904 BBB rated utilities to serve as proxies for PNG-West and PNG (N.E.). The selection  
905 criteria are set out in Appendix B. The companies in the BBB sample are listed on  
906 Schedule 6 with corresponding risk measures.

907

908 For each of the two samples, I calculated betas over various periods and then used the  
909 Capital Asset Pricing Model (CAPM) to estimate the difference in the cost of equity  
910 between the samples. The Capital Asset Pricing Model holds that the equity investor  
911 requires a return on a security equal to:

912

$$913 \quad R_F + \beta (R_M - R_F),$$

914

915 Where:

916

917  $R_F$  = risk-free rate

918  $\beta$  = investment risk beta

919  $R_M$  = return on the market

920  $R_M - R_F$  = market risk premium

921

922 The betas for the two samples are summarized in Table 8 below.

923

924

**Table 8**

<b>Sample</b>	<b>5-year Betas Ending March 2009</b>	<b>Average Betas for 5-Year Periods Ending 2004-2008</b>
Benchmark Utilities	0.61	0.59
BBB Rated Utilities	0.78	0.77

925

Source: Schedules 4 and 6

926

927 In principle, the investment risk beta reflects both business and financial risk. If there  
928 were significant differences in financial risk between the two samples, i.e., differences in  
929 capital structure, the financial risk component of the beta would need to be extracted  
930 from the investment risk beta to isolate the cost of equity differences due to differences in  
931 business risk. However, since the two samples have had virtually identical capital  
932 structures (the median common equity ratios for both samples have been approximately  
933 43%; see Schedules 4 and 6), this step is not required.

934

935 As Table 8 above indicates, on the basis of adjusted betas,<sup>19</sup> the difference between the  
936 two samples has been approximately 0.18. My estimate of the market risk premium,  
937 presented in my evidence in the TGI cost of capital proceeding, is 6.75%. The difference  
938 in beta between the benchmark and BBB rated utility samples of 0.18 equates to an  
939 incremental cost of equity of approximately 1.20%. I also calculated discounted cash  
940 flow estimates of the cost of equity for the two samples of utilities, using two models, a  
941 constant growth model and two-stage model. Appendix C attached contains a discussion

---

<sup>19</sup> “Raw” betas represent the calculated correlation between the percentage change in the prices of a particular stock and the corresponding changes in the prices of the equity market index. The “raw” betas were adjusted using the following formula:  $\frac{2}{3}$  (“raw” beta) +  $\frac{1}{3}$  (market beta of 1.0). *Value Line*, Bloomberg and Merrill Lynch, major sources of financial information for investors, all publish adjusted betas. Their formulas for adjusting the calculated raw betas are slightly different, but all give approximately two-thirds weight to the “raw” beta of the specific stock and one-third weight to the market beta of 1.0.

942 of the two models used. Schedules 8-11 show the results for the two models and for the  
943 individual companies in the two samples. Table 9 below summarizes the results.

944  
945

**Table 9**

<b>Sample</b>	<b>Constant Growth</b>	<b>Two-Stage Model</b>
	<b>Average of Mean and Median</b>	
Benchmark Utilities	10.9%	10.4%
BBB Rated Utilities	12.3%	11.1%

946 Source: Schedules 8 -11

947

948 The application of the two discounted cash flow models indicates that the difference in  
949 the cost of equity between the two samples is approximately 100 basis points.

950

951 Based on both the CAPM and DCF test results, the differential in the cost of equity is  
952 approximately 100-125 basis points.

953

954 The differences in the cost of equity estimated using the CAPM and DCF models applied  
955 to samples of relatively large market capitalization utilities are conservative relative to  
956 estimates which would explicitly account for size differences between PNG and the  
957 typical Canadian utility. Studies on small size by Ibbotson Associates Inc. (now  
958 Morningstar)<sup>20</sup> have quantified the impact of a firm’s small size on the required return by  
959 an analysis of the relationship between betas and historic returns for companies of  
960 different sizes. The analyses indicate that small companies tend to exhibit higher betas  
961 than larger companies. In the Ibbotson classification of stocks, if PNG were a stand-  
962 alone publicly traded stock, it would be a Micro-Cap stock (market value of equity of less  
963 than \$450 million). By comparison, the typical publicly-traded Canadian utility used to  
964 estimate the benchmark utility ROE would be a Mid-Cap stock (market value of equity in  
965 the range of approximately \$1.8-\$7.4 billion). Ibbotson’s analysis indicates the betas of

---

<sup>20</sup> Ibbotson Associates, *SBBI 2009: Valuation Yearbook Market Results for Stocks, Bonds, Bills, and Inflation 1926-2008*, pages 89-110.

966 Micro-Cap stocks have been approximately 0.32 higher than those of Mid-Cap stocks.  
967 An incremental beta of 0.33, when applied to my market equity risk premium of 6.75%  
968 would support an incremental equity risk premium of over two percentage points for a  
969 Micro-Cap company, e.g., PNG (6.75% x 0.32).

970

971 For PNG (N.E.), the CAPM and DCF analyses support an ROE approximately one  
972 percentage point higher than the benchmark ROE at similar capital structures. Since  
973 PNG (N.E.) is proposing a common equity ratio of 42.5%, compared to the 40%  
974 proposed by TGI, the benchmark utility, a portion of the risk differential between PNG  
975 (N.E.) and the benchmark is compensated for in PNG (N.E.)'s proposed capital structure.  
976 The differential in common equity ratios can be translated into a differential in required  
977 ROE by applying capital structure theory, as explained in Appendix D.

978

979 The difference between a 40% common equity ratio and a 42.5% common equity ratio  
980 translates into an approximately 25-40 basis point difference in ROE; see Appendix D  
981 and Schedule 12.

982

983 Based on both the application of capital structure theory with due regard for the results of  
984 the Ibbotson size impact analyses, which indicate a higher risk premium to compensate  
985 for risks related to small size, a reasonable equity risk premium for PNG (N.E.) relative  
986 to the benchmark BC utility is approximately 75 basis points (100-125 basis point cost of  
987 equity differential based on CAPM and DCF less 25-40 basis points for the 2.5  
988 percentage point difference in common equity ratio).

989

990 With respect to PNG-West, its higher business risk relative to PNG (N.E) is reasonably  
991 reflected in the higher proposed common equity ratio of 47.5%. As a result, the same 75  
992 basis point incremental equity risk premium is warranted. At the same common equity  
993 ratio of 40% as proposed by the benchmark utility, the indicated ROE for PNG-West  
994 would be approximately 1.75 percentage points higher than the benchmark utility ROE.  
995 The differential reasonably reflects the fact that PNG-West – primarily the source of  
996 PNG's BBB (low) rating – is of higher risk than the sample of BBB rated utilities, which

997 at mid BBB, are rated higher, on average than PNG. A total differential in risk  
998 compensation equivalent to approximately 1.75 percentage points relative to the  
999 benchmark utility is well within the range of results indicated by the application of the  
1000 CAPM and DCF tests and the Ibbotson size analysis.

1001

## 1002 **V. CONCLUSIONS**

1003

1004 Based on my analysis and judgment, the proposed equity ratios for PNG-West of 47.5%  
1005 and for PNG (N.E.) of 42.5% are reasonable. At the proposed common equity ratios,  
1006 incremental equity risk premiums of 0.75% relative to the benchmark utility ROE for  
1007 both PNG-West and PNG (N.E.), both the Fort St. John/Dawson Creek and Tumbler  
1008 Ridge divisions are warranted in light of their total (business plus financial) risks.

**APPENDIX A**  
**QUALIFICATIONS OF KATHLEEN C. McSHANE**

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 190 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

## **PUBLICATIONS, PAPERS AND PRESENTATIONS**

- *Utility Cost of Capital: Canada vs. U.S.*, presented at the CAMPUT Conference, May 2003.
- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.
- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24<sup>th</sup> Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.
- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.
- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

**EXPERT TESTIMONY/OPINIONS**  
**ON**  
**RATE OF RETURN AND CAPITAL STRUCTURE**

<b><u>Client</u></b>	<b><u>Date</u></b>
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
ATCO Utilities	2008
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006, 2008
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007
Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004

Gas Company of Hawaii	2000, 2008
Gaz Metropolitan	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004, 2008
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Laclede Pipeline	2006
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
MidAmerican Energy Company	2009
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007, 2009
Newfoundland Telephone	1992
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005, 2008
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993

Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994, 2005, 2009
Terasen Gas (Whistler)	2008
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company	1991, 1993, 2008
Yukon Energy	1991 1993

**EXPERT TESTIMONY/OPINIONS**  
**ON**  
**OTHER ISSUES**

Client	Issue	Date
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

<b>APPENDIX B</b> <b>SELECTION OF U.S. UTILITY SAMPLES</b>
---

**1. SELECTION OF LOW RISK BENCHMARK SAMPLE OF U.S. UTILITIES**

For the estimation of the benchmark return, a sample of low risk U.S. utilities was selected, comprised of all electric utilities and gas distributors satisfying the following criteria:

- a. Classified by *Value Line* as a gas distributor or an electric utility;
- b. *Value Line* Safety Rank of “2” or better;
- c. Standard & Poor’s business risk profile of “Excellent”;
- d. Standard & Poor’s debt rating of A- or higher;
- e. Not presently being acquired; and,
- f. Consistent history of analysts’ forecasts.

The 13 utilities that met these criteria are listed on Schedule 4.

## 2. SELECTION OF BBB RATED SAMPLE OF U.S. UTILITIES

The sample of BBB rated U.S. utilities includes every electric and gas distribution utility:

- a) classified by *Value Line* as an electric or gas distribution utility;
- b) that is rated in the BBB category;
- c) if an electric utility, which has greater than 50% of total assets (2008) in regulated activities, equivalent to the Edison Electric Institute's categories of "Regulated" and "Mostly Regulated";
- d) that has I/B/E/S<sup>21</sup> forecasts of long-term growth rates for each of the preceding 12 months;
- e) that has not omitted dividends since 1<sup>st</sup> Quarter 2008; and,
- f) is not publicly known to be an acquisition target or involved in a merger.

The 33 companies that meet these criteria are presented on Schedule 6.

---

<sup>21</sup> The consensus forecasts are obtained from I/B/E/S, a leading provider of earnings expectations data. The data are collected from over 7,000 analysts at over 1,000 institutions worldwide, and cover companies in more than 60 countries.

## APPENDIX C DISCOUNTED CASH FLOW TEST

### 1. DCF MODELS

#### a. Constant Growth Model

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries. Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value.

The constant growth model is expressed as follows:

$$\text{Cost of Equity (k)} = \frac{D_1 + g}{P_0}$$

where,

$$\begin{aligned} D_1 &= \text{next expected dividend}^{22} \\ P_0 &= \text{current price} \\ g &= \text{constant growth rate} \end{aligned}$$

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from

---

<sup>22</sup>Alternatively expressed as  $D_0(1 + g)$ , where  $D_0$  is the most recently paid dividend.

earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

**b. Two-Stage Model**

The two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1 Growth), but, in the longer-term (from Year 6 onward) to migrate to the expected long-run rate of growth in the economy (GDP Growth). All industries go through various stages in their life cycle. Utilities are considered to be the quintessential mature industry. Mature industries are those whose growth parallels that of the overall economy.

The use of forecast GDP growth as the long-term growth component is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal GDP growth for conventional corporations in its standard DCF models for gas and oil pipelines.

Using the two-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor.

The cash flow per share in Year 1 is equal to:  
**Last Paid Annualized Dividend x (1 + Stage 1 Growth)**

For Years 2 through 5, cash flow is defined as:  
**Cash Flow<sub>t-1</sub> x (1 + Stage 1 Growth)**

Cash flows from Year 6 onward are estimated as:  
**Cash Flow<sub>t-1</sub> x (1 + GDP Growth)**

## **2. INVESTOR GROWTH EXPECTATIONS**

The application of the constant growth model relies principally on the consensus of investment analysts' forecasts of long-term earnings growth compiled by I/B/E/S. The application of the two-stage model relies upon the I/B/E/S consensus earnings forecasts as the estimate of investor growth expectations during Stage 1. In the second stage, the investor growth expectations are proxied by the expected nominal long-run rate of growth in the economy (GDP) based on the consensus of economists' long-term forecasts (published twice annually) found in *Blue Chip Financial Forecasts* (December 1, 2008). The consensus forecast rate of growth in the long-term (2010-2019) is 5.0%.

## **3. APPLICATION OF THE DCF MODELS**

### **a. Constant Growth Model**

The constant growth DCF model was applied to a sample of U.S. low risk gas and electric utilities and a sample of BBB rated gas and electric utilities using the following inputs to calculate the dividend yield:

- (1) the most recent annualized dividend paid as of March 31, 2009 as  $D_0$ ; and,
- (2) the average of the high and low monthly prices for the period January 1, 2009 to March 31, 2009 as  $P_0$ .

For the expected growth rates, the March 2009 I/B/E/S consensus (mean) earnings growth forecasts were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield. The dates were

chosen to be consistent with the results presented for the benchmark sample of utilities in the TGI cost of capital proceeding.

**b. Two-Stage Model**

The two-stage model relies on the I/B/E/S consensus of analysts' earnings forecasts for the first five years (Stage 1), and forecast growth in the economy thereafter (Stage 2). The consensus long-run (2010-2019) expected nominal rate of growth in GDP, as noted above, is 5.0%.

## APPENDIX D

# ESTIMATION OF DIFFERENTIAL IN REQUIRED ROE FOR DIFFERENCES IN CAPITAL STRUCTURE

Differentials in common equity ratios for companies of similar business risk can be translated into a differential in required ROE by applying capital structure theory. The rationale for the difference in the required ROE at different capital structures begins with the recognition that the overall cost of capital for a firm is primarily a function of business risk. In the absence of the deductibility of interest expense for tax purposes and costs associated with the use of excessive debt, the overall cost of capital to a firm would not change materially if the firm were to change its capital structure.

The use of debt, however, creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. Theoretically, the sum of the cash flows, which are available to both the debt holders and equity holders, does not change when debt is added to the capital structure. In other words, the cost of capital is constant regardless of capital structure. However, the issuance of debt, which carries fixed costs which must be paid before the equity shareholder receives any return, increases the potential variability of the equity shareholder's return. Thus, as the debt ratio rises, the cost of equity rises.

The existence of corporate income taxes and the deductibility of interest for income tax purposes, in conjunction with the costs associated with potential bankruptcy or loss of financial flexibility, alter the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. When interest expense is deductible for income tax purposes, the after-tax cost of capital is reduced when debt is used. Partially offsetting this advantage, as the proportion of debt in the capital structure increases the cost of capital tends to increase due to the loss of financial flexibility and increased potential for bankruptcy. In addition, although interest expense is tax deductible at the corporate level, it is taxable to investors at a higher rate than equity, offsetting some of the net after-tax advantage of

increasing the debt component of the capital structure. Further, in the specific case of regulated companies, the benefits from the tax deductibility of interest flow through to customers.

While it is impossible to state with precision whether, within a reasonable range of capital structures, raising the debt ratio decreases the overall cost of capital or leaves it unchanged, in either case the costs of the components of the capital structure do change. An increase in financial risk will be accompanied by an increase in the cost of equity. The amount by which the cost of common equity increases for a given increase in the debt ratio can be estimated under each of the two theories.

### **Theory 1**

The cost of capital remains unchanged as the capital structure changes.

### **Theory 2**

The cost of capital declines as the percentage of debt in the capital structure increases.

Schedule 12 provides the formulas required to estimate the change in the cost of equity under each theory.

To estimate the required decrease in common equity return to compensate for a 2.5 percentage point increase in common equity ratio, the following steps were taken:

- (1) Estimate the weighted average cost of capital for PNG (N.E) using a common equity ratio of 40%, a new cost of long-term debt equal to a forecast yield on a 10-year BBB rated bond of 6.75%<sup>23</sup>, an ROE equal to the proposed benchmark BC utility ROE of 11.0% plus a 1.0% incremental risk premium, and a statutory income tax rate of 28.5%.
- (2) Estimate the decrease in ROE required to account for the difference between the benchmark utility common equity ratio of 40% and PNG (N.E)'s proposed common equity ratio of 42.5%.

---

<sup>23</sup> Equal to a forecast 10-year Canada of 3.75% plus a spread of 3.0% applicable to a BBB rated 10-year bond.

To summarize the results found on Schedule 12, based on Theory 1 (no change in cost of capital as the equity ratio changes), the difference in the ROE at an equity ratio of 40% and an equity ratio of 42.5% translates into a decrease in the required ROE of 40 basis points. Based on Theory 2 (cost of capital declines as the equity ratio declines), the difference in an equity ratio of 40% and an equity ratio of 42.5% translates into a decrease in the ROE of approximately 25 basis points. Since both theories have merit, it is reasonable to give weight to both.

**DEBT AND COMMON STOCK QUALITY RATINGS  
OF CANADIAN UTILITIES**

Schedule 1

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
<b>Gas Distributors</b>					
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Gaz Metropolitan	Senior Secured	A		A	
Pacific Northern Gas	Senior Secured	BBB(low)		NR <sup>2/</sup>	Average
Terasen Gas	Senior Secured	A	A2	AA-	
	Senior Unsecured	A	A3	A	
Terasen Gas (Vancouver Is.)	Senior Unsecured		A3		
Union Gas Limited	Senior Unsecured	A		BBB+	
<b>Electric Utilities</b>					
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enersource	Issuer	A			
ENMAX	Unsecured Debentures	A(low)		BBB+	
EPCOR Utilities Inc	Senior Unsecured	A(low)		BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1	A-	Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Hamilton Utilities	Senior Unsecured			A+	
Hydro One	Senior Unsecured	A(high)	Aa3	A+	
Hydro Ottawa Holding Inc.	Senior Unsecured	A(low)		A	
London Hydro	Issuer			A	
Maritime Electric	Senior Secured			A	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR <sup>1/</sup>	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Toronto Hydro	Senior Unsecured	A		A	
Veridian	Issuer	A			
<b>Pipelines</b>					
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A3	A-	Very conservative
Trans Quebec & Maritimes	Senior Unsecured	A(low)		BBB+	
TransCanada PipeLines	Senior Unsecured	A	A3	A-	Very conservative
Westcoast Energy	Senior Unsecured	A(low)		BBB+	
<b>Medians</b>					
<b>Gas Distributors</b>		<b>A</b>	<b>A3</b>	<b>A</b>	<b>Very conservative</b>
<b>Electric T&amp;D</b>		<b>A</b>	<b>Baa1</b>	<b>A</b>	<b>Very conservative</b>
<b>Electric Integrated</b>		<b>A(low)</b>	<b>Baa2</b>	<b>A-</b>	<b>Very conservative</b>
<b>All Electric</b>		<b>A(low)</b>	<b>Baa1</b>	<b>A</b>	<b>Very conservative</b>
<b>Pipelines</b>		<b>A</b>	<b>A3</b>	<b>A-</b>	<b>Very conservative</b>
<b>All Companies</b>		<b>A</b>	<b>A3</b>	<b>A-</b>	<b>Very conservative</b>

<sup>1/</sup> Withdrawn by company; BBB+ prior to withdrawal.

<sup>2/</sup> Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

**CAPITAL STRUCTURE RATIOS  
OF CANADIAN UTILITIES WITH RATED DEBT  
(2008)**

	Long-Term Debt <sup>1/</sup>	Short-Term Debt	Preferred Stock <sup>2/</sup>	Common Stock Equity <sup>3/</sup>
<b>Gas Distributors</b>				
Enbridge Gas Distribution	44.2%	18.1%	1.9%	35.8%
Gaz Metro	64.0%	2.0%	0.0%	34.0%
Pacific Northern Gas	45.6%	1.8%	3.0%	49.6%
Terasen Gas	55.7%	9.5%	0.0%	34.8%
Terasen Gas (Vancouver Is.)	46.3%	18.2%	0.0%	35.5%
Union Gas	56.1%	8.1%	2.6%	33.2%
<b>Electric Utilities</b>				
Altalink LP	61.7%	0.0%	0.0%	38.3%
CU Inc	56.6%	0.0%	5.2%	38.3%
Enersource	56.2%	0.0%	0.0%	43.8%
ENMAX Corp.	37.3%	4.6%	0.0%	58.1%
EPCOR Utilities Inc.	50.3%	2.6%	2.3%	44.8%
FortisAlberta	60.0%	0.5%	0.0%	39.4%
FortisBC	59.1%	0.0%	0.0%	40.9%
Hamilton Utilities <sup>4/</sup>	35.4%	0.0%	0.0%	64.6%
Hydro One Inc.	54.5%	0.0%	2.9%	42.6%
Hydro Ottawa Holding Inc.	44.1%	0.0%	0.0%	55.9%
London Hydro <sup>4/</sup>	36.5%	0.0%	0.0%	63.5%
Maritime Electric	53.6%	6.2%	0.0%	40.2%
Newfoundland Power	53.4%	0.0%	1.1%	45.5%
Nova Scotia Power	54.3%	0.8%	4.7%	40.1%
Toronto Hydro	55.2%	0.0%	0.0%	44.8%
Veridian <sup>4/</sup>	40.4%	0.0%	0.0%	59.6%
<b>Pipelines</b>				
Enbridge Pipelines	52.7%	7.0%	0.0%	40.4%
Nova Gas Transmission Ltd.	61.4%	0.6%	0.0%	38.0%
Trans Quebec & Maritimes	69.9%	0.0%	0.0%	30.1%
TransCanada Pipelines	54.1%	5.0%	1.2%	39.7%
Westcoast Energy	52.6%	1.2%	4.9%	41.3%
<b>Medians</b>				
<b>Gas Distributors</b>	<b>51.0%</b>	<b>8.8%</b>	<b>1.0%</b>	<b>35.2%</b>
<b>Electric T&amp;D</b>	<b>53.9%</b>	<b>0.0%</b>	<b>0.0%</b>	<b>45.2%</b>
<b>Electric Integrated</b>	<b>54.0%</b>	<b>1.7%</b>	<b>1.1%</b>	<b>40.6%</b>
<b>All Electric</b>	<b>54.0%</b>	<b>0.0%</b>	<b>0.0%</b>	<b>44.3%</b>
<b>Pipelines</b>	<b>54.1%</b>	<b>1.2%</b>	<b>0.0%</b>	<b>39.7%</b>
<b>All Companies</b>	<b>54.1%</b>	<b>0.6%</b>	<b>0.0%</b>	<b>40.4%</b>

1/ Includes current portion of long-term debt and preferred securities classified as debt.

2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities .

3/ Includes minority interest in common shares of subsidiary companies.

4/ Capital structures for 2007.

Source: Annual Reports to Shareholders

**FINANCIAL METRICS  
FOR CANADIAN UTILITIES WITH RATED DEBT  
2005-2007**

<b>Company</b>	<b>EBIT Coverage</b>	<b>Cash Flow/ Total Debt</b>	<b>EBITDA Coverage</b>	<b>Debt/ EBITDA</b>
<b>Gas Distributors</b>				
Enbridge Gas Distribution	2.1	11.7	3.2	4.7
Gaz Metropolitain	2.5	19.5	3.9	3.9
Pacific Northern Gas	2.5	13.4	3.7	3.4
Terasen Gas	2.0	9.0	2.7	5.4
Terasen Gas (Vancouver Is.)	2.8	13.3	4.4	4.6
Union Gas	2.1	11.9	3.1	4.5
<b>Electric Utilities</b>				
AltaLink L.P.	1.9	13.8	3.6	5.2
CU Inc.	2.5	17.4	4.1	3.6
Enersource	2.1	17.7	4.0	3.9
ENMAX Corp.	8.2	64.3	12.2	4.2
EPCOR Utilities Inc.	2.9	26.7	4.1	4.1
FortisAlberta Inc.	2.2	16.8	4.4	4.1
FortisBC Inc.	2.1	10.9	3.0	4.7
Hamilton Utilities	3.8	42.6	6.5	2.2
Hydro One Inc.	2.8	17.7	4.3	3.7
Hydro Ottawa Holding Inc.	3.4	23.1	6.5	3.1
London Hydro	2.0	19.9	5.0	2.9
Maritime Electric	2.7	10.7	3.8	4.0
Newfoundland Power	2.3	12.8	3.2	3.8
Nova Scotia Power	2.5	16.2	3.8	3.6
Toronto Hydro	2.3	17.6	4.0	3.7
Veridian	3.1	33.7	4.9	2.3
<b>Pipelines</b>				
Enbridge Pipelines	3.2	14.9	3.9	2.4
Nova Gas Transmission Ltd.	2.1	20.3	3.9	3.1
Trans Quebec & Maritimes	2.4	11.7	3.7	5.1
TransCanada PipeLines Ltd.	3.6	16.7	3.7	3.7
Westcoast Energy Inc.	2.3	15.2	3.4	4.1
<b>Medians</b>				
<b>Gas Distributors</b>	<b>2.3</b>	<b>12.6</b>	<b>3.4</b>	<b>4.5</b>
<b>Electric T&amp;D</b>	<b>2.3</b>	<b>17.7</b>	<b>4.3</b>	<b>3.7</b>
<b>Electric Integrated</b>	<b>2.6</b>	<b>16.8</b>	<b>3.9</b>	<b>4.1</b>
<b>All Electric</b>	<b>2.5</b>	<b>17.6</b>	<b>4.1</b>	<b>3.8</b>
<b>Pipelines</b>	<b>2.4</b>	<b>15.2</b>	<b>3.7</b>	<b>3.7</b>
<b>All Companies</b>	<b>2.5</b>	<b>16.7</b>	<b>3.9</b>	<b>3.9</b>

Source: Annual Reports to Shareholders, DBRS, and Standard & Poor's

INDIVIDUAL COMPANY RISK DATA FOR U.S. BENCHMARK UTILITY SAMPLE

Name	March Research Insight Adjusted Beta	Research Insight Adjusted Betas					S&P										Moody's Debt Rating <sup>2/</sup>	Forward P/E	Market To Book Ratio	Common Equity Ratio (2008) <sup>3/</sup>	Average ROE 2006-2008
		2004	2005	2006	2007	2008	Debt Rating	Business Profile	Financial Profile	Debt Ratio	EBIT Coverage	FFO/Debt	FFO Coverage	EBITDA Coverage	Debt/EBITDA						
		Average 2005-2007 <sup>1/</sup>																			
AGL Resources Inc.	0.54	0.53	0.58	0.57	0.66	0.54	A-	Excellent	Intermediate	58.2	3.7	19.6	4.4	4.8	3.6	Baa1	11.1	1.39	39.4	13.2	
Consolidated Edison Inc.	0.56	0.30	0.33	0.43	0.59	0.50	A-	Excellent	Intermediate	57.1	2.9	14.7	3.6	4.0	4.5	A2	11.3	1.01	48.5	11.1	
Dominion Resources Inc.	0.71	0.53	0.56	0.67	0.51	0.66	A-	Excellent	Aggressive	60.3	2.5	13.0	3.1	3.7	4.4	Baa2	9.9	1.84	36.3	18.3	
Duke Energy Corp.	0.59	0.75	0.82	1.16	0.96	0.55	A-	Excellent	Intermediate	44.3	3.6	22.4	4.5	4.3	3.6	Baa2	11.6	0.85	59.2	7.1	
FPL Group Inc.	0.79	0.52	0.48	0.68	0.66	0.74	A	Excellent	Intermediate	51.4	2.9	25.8	5.3	4.4	3.8	A2	13.2	1.95	40.6	13.7	
New Jersey Natural Gas	0.46	0.38	0.32	0.38	0.55	0.65	A	Excellent	Intermediate	42.8	5.4	24.2	5.5	7.2	2.6	A1	14.3	1.97	51.2	13.9	
Northwest Natural Gas Co.	0.59	0.33	0.36	0.42	0.83	0.57	AA-	Excellent	Intermediate	53.4	3.6	21.2	4.4	5.2	3.1	A3	15.7	1.82	45.3	11.5	
NSTAR	0.57	0.52	0.55	0.65	0.75	0.56	A+	Excellent	Intermediate	62.4	3.5	23.2	5.3	5.1	3.6	A2	12.9	1.81	36.8	13.5	
Piedmont Natural Gas Co. Inc.	0.55	0.40	0.48	0.58	0.63	0.41	A	Excellent	Intermediate	50.5	3.9	24.9	4.9	4.9	3.2	A3	15.1	1.93	41.9	11.8	
Scana	0.75	0.51	0.60	0.66	0.60	0.74	A-	Excellent	Aggressive	57.5	2.4	19.6	4.3	4.1	4.1	Baa1	10.6	1.17	39.3	11.2	
Southern Co.	0.64	0.02	0.00	0.29	0.55	0.58	A	Excellent	Intermediate	56.4	3.6	21.3	5.1	5.1	3.8	A3	12.0	1.68	40.5	14.1	
Vectren Corp.	0.57	0.63	0.55	0.66	0.71	0.49	A-	Excellent	Intermediate	58.4	2.8	17.1	4.0	4.2	4.2	Baa1	12.5	1.37	42.2	10.4	
WGL Holdings Inc.	0.55	0.45	0.43	0.51	0.59	0.70	AA-	Excellent	Intermediate	52.8	4.6	22.2	5.3	6.4	3.0	A2	12.8	1.45	51.7	10.8	
<b>Mean (All Companies)</b>	<b>0.61</b>	<b>0.45</b>	<b>0.47</b>	<b>0.59</b>	<b>0.66</b>	<b>0.59</b>	<b>A</b>	<b>Excellent</b>	<b>Intermediate</b>	<b>54.3</b>	<b>3.5</b>	<b>20.7</b>	<b>4.6</b>	<b>4.9</b>	<b>3.7</b>	<b>A3</b>	<b>12.5</b>	<b>1.56</b>	<b>44.1</b>	<b>12.4</b>	
<b>Median (All Companies)</b>	<b>0.57</b>	<b>0.51</b>	<b>0.48</b>	<b>0.58</b>	<b>0.63</b>	<b>0.57</b>	<b>A</b>	<b>Excellent</b>	<b>Intermediate</b>	<b>56.4</b>	<b>3.6</b>	<b>21.3</b>	<b>4.5</b>	<b>4.8</b>	<b>3.6</b>	<b>A3</b>	<b>12.5</b>	<b>1.68</b>	<b>41.9</b>	<b>11.8</b>	
<b>Mean (LDCs Only)</b>	<b>0.54</b>	<b>0.45</b>	<b>0.45</b>	<b>0.52</b>	<b>0.66</b>	<b>0.56</b>	<b>A</b>	<b>Excellent</b>	<b>Intermediate</b>	<b>52.7</b>	<b>4.0</b>	<b>21.5</b>	<b>4.7</b>	<b>5.5</b>	<b>3.3</b>	<b>A3</b>	<b>13.6</b>	<b>1.66</b>	<b>45.3</b>	<b>11.9</b>	
<b>Median (LDCs Only)</b>	<b>0.55</b>	<b>0.42</b>	<b>0.46</b>	<b>0.54</b>	<b>0.65</b>	<b>0.55</b>	<b>A</b>	<b>Excellent</b>	<b>Intermediate</b>	<b>53.1</b>	<b>3.8</b>	<b>21.7</b>	<b>4.7</b>	<b>5.1</b>	<b>3.2</b>	<b>A3</b>	<b>13.6</b>	<b>1.64</b>	<b>43.8</b>	<b>11.6</b>	

<sup>1/</sup> S&P Credit Stats

<sup>2/</sup> Rating for Vectren Corp. is for Vectren Utility Holdings Inc. and rating for WGL Holdings Inc. is for Washington Gas Light

<sup>3/</sup> Equity ratio based on total capital.

Source: S&P: *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest, March 10, 2009* and S&P, Credit Stats, September 2008, www.moodys.com, and S&P: *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest to Weakest, March 31, 2009*

## INDIVIDUAL COMPANY RISK DATA FOR U.S. NATURAL GAS UTILITIES RATED INVESTMENT GRADE

Name	S&P											
	Debt Rating	Business Profile	Financial Profile	Average 2005-2007 <sup>1/</sup>						Moody's Debt Rating	Common Equity Ratio (2008) <sup>2/</sup>	Average ROE 2006-2008
				Debt Ratio	EBIT Coverage	FFO/Debt	FFO Coverage	EBITDA Coverage	Debt/EBITDA			
AGL Resources Inc.	A-	Excellent	Intermediate	58.2	3.7	19.6	4.4	4.8	3.6	Baa1	39.4	13.2
Alabama Gas Corp.	BBB	Satisfactory	Intermediate	46.6	4.3	33.9	5.8	6.8	2.1	A1	53.3	13.1
Atmos Energy Corp.	BBB+	Excellent	Aggressive	59.6	2.6	16.6	3.7	3.9	4.1	Baa2	45.4	9.1
Energen Corp.	BBB	Satisfactory	Intermediate	42.4	8.4	52.7	9.3	11.3	1.4	Baa3	75.4	23.2
Indiana Gas Co. Inc.	A-	Excellent	Intermediate	48.0	2.8	16.4	3.6	4.3	3.7	Baa1	na	na
Laclede Gas Co.	A	Excellent	Intermediate	60.0	2.3	13.8	3.1	3.1	4.8	Baa1	34.0	9.7
Laclede Group	A	Excellent	Intermediate	57.9	3.0	17.7	3.6	3.7	3.9	Baa2	44.5	13.9
National Fuel Gas Co.	BBB	Satisfactory	Intermediate	50.3	4.8	33.3	6.2	6.5	2.4	Baa1	59.3	16.3
New Jersey Natural Gas	A	Excellent	Intermediate	42.8	5.4	24.2	5.5	7.2	2.6	A1	51.2	13.9
Nicor Inc.	AA	Excellent	Intermediate	45.3	3.9	28.3	6.0	6.5	2.7	A3	44.0	14.2
Nicor Gas	AA	Excellent	Intermediate	47.1	2.7	19.7	4.7	6.0	3.1	na	na	na
North Shore Gas	A-	Excellent	Intermediate	45.6	4.5	20.6	4.9	5.5	3.4	A3	54.8	7.1
Northwest Natural Gas Co.	AA-	Excellent	Intermediate	53.4	3.6	21.2	4.4	5.2	3.1	A3	45.3	11.5
Piedmont Natural Gas Co. Inc.	A	Excellent	Intermediate	50.5	3.9	24.9	4.9	4.9	3.2	A3	41.9	11.8
Public Service (North Carolina)	A-	Excellent	Aggressive	42.1	2.9	14.3	3.3	4.0	4.1	A3	56.9	6.0
Questar Gas Co.	BBB+	Satisfactory	Intermediate	51.9	3.5	22.7	4.4	5.0	3.0	A3	45.6	11.2
Southern California Gas Co.	A	Excellent	Intermediate	56.2	4.6	30.6	6.4	7.0	2.5	A2	50.9	16.0
South Jersey Gas Co.	BBB+	Excellent	Aggressive	49.6	3.8	17.7	3.9	4.9	3.3	Baa1	49.5	10.2
Southwest Gas Corp.	BBB-	Strong	Aggressive	62.3	2.2	17.0	3.8	4.0	4.1	Baa3	43.5	8.3
Vectren Corp.	A-	Excellent	Intermediate	58.4	2.8	17.1	4.0	4.2	4.2	na	42.2	10.4
Vectren Utility Holdings Inc.	A-	Excellent	Intermediate	53.7	2.9	19.0	4.1	4.7	3.5	Baa1	48.2	9.4
Washington Gas Light Co.	AA-	Excellent	Intermediate	50.8	4.6	24.1	5.5	6.6	2.8	A2	49.9	10.9
WGL Holdings Inc.	AA-	Excellent	Intermediate	52.8	4.6	22.2	5.3	6.4	3.0	na	51.7	10.8
<b>Mean</b>	<b>A-</b>	<b>Excellent</b>	<b>Intermediate</b>	<b>51.5</b>	<b>3.8</b>	<b>22.9</b>	<b>4.8</b>	<b>5.5</b>	<b>3.2</b>	<b>Baa1</b>	<b>48.9</b>	<b>11.9</b>
<b>Median</b>	<b>A-</b>	<b>Excellent</b>	<b>Intermediate</b>	<b>50.8</b>	<b>3.7</b>	<b>20.6</b>	<b>4.4</b>	<b>5.0</b>	<b>3.2</b>	<b>Baa1</b>	<b>48.2</b>	<b>11.2</b>

<sup>1/</sup> S&P Credit Stats<sup>2/</sup> Equity ratio based on total capital.

INDIVIDUAL COMPANY RISK DATA FOR  
BBB RATED U.S. UTILITY SAMPLE

Company	March Research Insight Adjusted Beta	Research Insight Adjusted Betas					S & P										Moody's Debt Rating	Forward P/E	Market to Book Ratio	Common Equity Ratio (2008) <sup>2/</sup>
		2004	2005	2006	2007	2008	Debt Rating	Business Risk Profile	Financial Profile	Average 2005-2007 <sup>1/</sup>		Average 2005-2007 <sup>1/</sup>		Average 2005-2007 <sup>1/</sup>						
		Debt Ratio	EBIT Coverage	FFO/Debt	FFO Coverage	EBITDA Coverage	Debt/EBITDA													
ALLETE INC	0.80	0.55	0.60	0.92	1.12	0.81	BBB+	Strong	Intermediate	51.6	4.2	20.1	4.6	5.1	3.5	Baa1	12.88	1.07	57.77	
ALLIANT ENERGY CORP	0.81	0.55	0.59	0.86	0.81	0.73	BBB+	Excellent	Aggressive	54.8	2.7	19.5	4.0	4.2	3.7	Baa1	10.55	0.94	56.04	
AMEREN CORP	0.86	0.44	0.52	0.57	0.79	0.81	BBB-	Satisfactory	Aggressive	53.0	3.7	18.0	4.6	5.4	3.7	Baa3	8.19	0.72	45.61	
AMERICAN ELECTRIC POWER	0.72	0.60	0.74	0.98	0.96	0.81	BBB	Excellent	Aggressive	62.5	2.4	16.3	3.5	3.7	4.2	Baa2	9.29	1.00	36.82	
ATMOS ENERGY CORP	0.67	0.30	0.39	0.51	0.73	0.71	BBB+	Excellent	Aggressive	59.6	2.6	16.6	3.7	3.9	4.1	Baa3	11.89	1.08	45.37	
AVISTA CORP	0.84	0.60	0.75	0.71	1.17	0.79	BBB-	Strong	Aggressive	61.6	1.8	13.6	2.8	2.6	5.1	Baa3	10.54	0.87	45.54	
CENTERPOINT ENERGY INC	0.88	0.79	0.88	1.13	1.16	0.89	BBB	Excellent	Aggressive	84.0	1.9	14.6	2.9	2.6	5.0	Ba1	9.50	1.73	16.03	
CLECO CORP	0.77	0.83	0.94	1.19	1.15	0.78	BBB	Strong	Aggressive	49.7	5.1	24.4	5.0	3.7	4.4	Baa3	12.69	1.19	47.50	
CMS ENERGY CORP	0.80	1.43	1.63	1.98	1.78	0.96	BBB-	Excellent	Aggressive	76.6	1.4	8.9	2.4	2.1	7.5	Ba1	9.14	1.06	25.91	
DPL INC	0.79	0.68	0.82	0.93	0.96	0.74	BBB	Excellent	Aggressive	66.6	3.2	18.7	3.8	4.3	3.5	Baa2	9.96	2.59	38.25	
DTE ENERGY CO	0.81	0.39	0.50	0.69	0.79	0.72	BBB	Excellent	Aggressive	61.6	1.9	13.1	3.4	3.5	5.3	Baa2	10.67	0.83	40.39	
EDISON INTERNATIONAL	0.88	0.39	0.63	0.88	0.78	0.86	BBB-	Strong	Aggressive	64.9	2.3	17.0	3.0	3.0	3.9	Baa2	9.80	1.02	40.17	
ENTERGY CORP	0.81	0.33	0.43	0.50	0.62	0.80	BBB	Strong	Aggressive	59.2	3.4	23.2	5.2	4.5	4.0	Baa3	11.09	1.77	38.75	
EXELON CORP	0.78	0.38	0.57	0.51	0.64	0.81	BBB	Strong	Aggressive	62.7	4.4	22.3	4.3	4.8	3.1	Baa1	11.60	2.86	45.49	
FIRSTENERGY CORP	0.66	0.38	0.47	0.64	0.61	0.73	BBB	Excellent	Aggressive	61.3	3.0	15.5	3.4	4.2	3.7	Baa3	9.95	1.41	37.22	
GREAT PLAINS ENERGY INC	0.84	0.75	0.69	0.89	0.87	0.77	BBB	Excellent	Aggressive	55.5	3.0	22.2	4.5	4.5	3.5	Baa2	12.78	0.72	43.97	
IDACORP INC	0.60	0.62	0.78	0.96	0.87	0.58	BBB	Strong	Aggressive	56.3	2.3	11.2	3.1	3.6	5.3	Baa2	10.09	0.86	47.82	
INTEGRYS ENERGY GROUP INC	0.91	0.43	0.44	0.58	0.71	0.65	BBB+	Excellent	Intermediate	52.6	2.8	12.4	3.3	3.6	5.2	A3	11.77	0.69	45.56	
NISOURCE INC	0.80	0.78	0.58	0.83	0.74	0.71	BBB-	Excellent	Aggressive	59.5	2.1	11.9	2.9	3.4	4.8	Baa3	10.38	0.63	38.43	
NORTHEAST UTILITIES	0.74	0.61	0.63	0.62	0.79	0.79	BBB	Excellent	Aggressive	57.5	1.9	8.7	2.5	3.3	5.3	Baa2	11.50	1.09	35.12	
OTTER TAIL CORP	1.26	0.35	0.42	0.64	0.81	1.13	BBB-	Satisfactory	Aggressive	NA	NA	NA	NA	NA	NA	A3	20.53	1.04	57.83	
PEPCO HOLDINGS INC	0.72	0.49	0.48	0.72	0.74	0.85	BBB	Strong	Aggressive	62.0	2.3	11.2	2.9	3.3	5.2	Baa3	8.92	0.67	41.36	
PG&E CORP	0.60	0.66	0.71	1.00	1.00	0.66	BBB+	Excellent	Intermediate	59.8	2.8	19.5	3.7	4.4	3.2	Baa1	11.55	1.41	43.78	
PINNACLE WEST CAPITAL CORP	0.75	0.54	0.75	0.92	0.75	0.71	BBB-	Strong	Aggressive	56.8	2.8	15.5	3.8	4.2	4.3	Baa3	12.04	0.81	47.04	
PORTLAND GENERAL ELECTRIC CO	0.91	NA	NA	NA	NA	0.91	BBB+	Strong	Intermediate	53.3	2.3	20.2	3.8	4.3	3.2	Baa2	10.17	0.85	47.29	
PROGRESS ENERGY INC	0.66	0.47	0.54	0.75	0.80	0.66	BBB+	Excellent	Aggressive	58.5	2.2	15.9	3.7	3.6	4.7	Baa2	11.76	1.08	41.93	
PUBLIC SERVICE ENTRP GRP	0.77	0.55	0.66	0.74	0.56	0.78	BBB	Excellent	Aggressive	60.8	4.2	17.2	4.1	5.3	3.4	Baa2	10.29	2.09	45.96	
SOUTH JERSEY INDUSTRIES INC	0.52	0.44	0.52	0.55	0.82	0.53	BBB+	Excellent	Aggressive	49.6	3.8	17.7	3.9	4.9	3.3	Baa1	13.90	1.96	47.46	
SOUTHWEST GAS CORP	0.86	0.52	0.49	0.47	0.70	0.77	BBB-	Strong	Aggressive	62.3	2.2	17.0	3.8	4.0	4.1	Baa3	11.73	0.90	43.49	
TECO ENERGY INC	0.96	0.57	0.66	0.80	0.85	0.85	BBB-	Excellent	Aggressive	70.0	1.8	14.3	3.0	2.4	5.7	Baa3	10.78	1.21	37.78	
WESTAR ENERGY INC	0.79	0.90	0.95	1.09	0.74	0.73	BBB-	Excellent	Aggressive	60.7	2.7	16.3	3.9	3.9	4.6	Baa3	10.30	0.88	45.17	
WISCONSIN ENERGY CORP	0.63	0.37	0.34	0.45	0.71	0.63	BBB+	Excellent	Aggressive	60.8	3.1	15.8	4.3	4.2	4.9	A3	12.68	1.38	41.17	
XCEL ENERGY INC	0.67	0.79	0.85	1.30	0.73	0.70	BBB+	Excellent	Aggressive	61.5	2.2	16.7	3.5	3.5	4.2	Baa1	11.56	1.14	44.03	
<b>MEAN</b>	<b>0.78</b>	<b>0.58</b>	<b>0.65</b>	<b>0.82</b>	<b>0.85</b>	<b>0.77</b>	<b>BBB</b>	<b>Excellent</b>	<b>Aggressive</b>	<b>60.2</b>	<b>2.8</b>	<b>16.4</b>	<b>3.7</b>	<b>3.9</b>	<b>4.4</b>	<b>Baa2</b>	<b>11.23</b>	<b>1.20</b>	<b>42.8</b>	
<b>MEDIAN</b>	<b>0.79</b>	<b>0.55</b>	<b>0.61</b>	<b>0.77</b>	<b>0.79</b>	<b>0.77</b>	<b>BBB</b>	<b>Excellent</b>	<b>Aggressive</b>	<b>60.3</b>	<b>2.7</b>	<b>16.5</b>	<b>3.7</b>	<b>3.9</b>	<b>4.2</b>	<b>Baa2</b>	<b>10.78</b>	<b>1.06</b>	<b>44.0</b>	

<sup>1/</sup> S&P Credit Stats<sup>2/</sup> Equity ratio based on total capital.

Source: Value Line Summary March 27, 2009;

Standard &amp; Poor's Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest (March 10, 2009);

Standard &amp; Poor's Issuer Ranking: U.S. Regulated Electric Utilities, Strongest to Weakest (March 2, 2009);

[www.moodys.com](http://www.moodys.com), company 10-Qs; S&P Research Insight.

**MARKET TO BOOK RATIOS OF CANADIAN UTILITIES**

<b>Name</b>	<b>Forward P/E</b>	<b>Average Price May 17, 2009- June 16, 2009</b>	<b>Book Value Per Share at December 31, 2008</b>	<b>Market to Book Ratio</b>
PACIFIC NORTHERN GAS	9.81	15.51	23.96	0.68
CANADIAN UTILITIES	11.60	35.54	22.74	1.62
EMERA INC	14.06	20.01	14.42	1.45
ENBRIDGE INC	15.83	38.60	18.66	2.22
FORTIS INC	15.31	24.13	18.41	1.34
TRANSCANADA CORP	13.60	32.69	21.12	1.56
<b>Average ex. PNG</b>	<b>14.08</b>	<b>30.20</b>	<b>19.07</b>	<b>1.64</b>
<b>Median ex. PNG</b>	<b>14.06</b>	<b>32.69</b>	<b>18.66</b>	<b>1.56</b>

Source: GlobelInvestor.com, Research Insight

**DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF  
U.S. GAS AND ELECTRIC UTILITIES  
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)**

<u>Company</u>	<u>Annualized Last Paid Dividend</u> (1)	<u>Average Monthly High/Low Prices Jan 2009-Mar 2009</u> (2)	<u>Expected Dividend Yield <sup>1/</sup></u> (3)	<u>Average I/B/E/S Long-Term EPS Forecasts</u> (4)	<u>DCF Cost of Equity <sup>2/</sup></u> (5)
AGL Resources	1.72	29.30	6.1	4.3	10.4
Consolidated Edison	2.36	38.41	6.3	2.5	8.8
Dominion Resources	1.75	32.69	5.8	7.8	13.5
Duke Energy	0.92	14.35	6.7	4.5	11.1
FPL	1.89	48.70	4.3	9.6	13.9
New Jersey Resources	1.24	36.57	3.6	7.0	10.6
Northwest Nat. Gas	1.58	42.36	3.9	4.8	8.7
NSTAR	1.50	32.61	4.9	6.0	10.9
Piedmont Natural Gas	1.08	25.89	4.5	7.1	11.6
Scana	1.88	32.05	6.1	4.6	10.7
Southern Co.	1.68	32.11	5.5	5.4	10.9
Vectren	1.34	22.87	6.3	7.2	13.5
WGL Holdings Inc.	1.42	32.05	4.6	4.0	8.6
<b>Mean</b>	<b>1.57</b>	<b>32.30</b>	<b>5.3</b>	<b>5.7</b>	<b>11.0</b>
<b>Median</b>	<b>1.58</b>	<b>32.11</b>	<b>5.5</b>	<b>5.4</b>	<b>10.9</b>

<sup>1/</sup> Expected Dividend Yield = (Col (1) / Col (2)) \* (1 + Col (4))

<sup>2/</sup> Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, Yahoo.com and I/B/E/S (March 2009)

**DCF COSTS OF EQUITY FOR BENCHMARK SAMPLE OF  
U.S. GAS AND ELECTRIC UTILITIES  
(TWO-STAGE MODEL)**

<u>Company</u>	<u>Annualized Last Paid Dividend</u> (1)	<u>Average Monthly High/Low Prices Jan 2009-Mar 2009</u> (2)	<u>Stage 1 I/B/E/S EPS Forecasts</u> (3)	<u>Stage 2 GDP Growth <sup>1/</sup></u> (4)	<u>DCF Cost of Equity <sup>2/</sup></u> (5)
AGL Resources	1.72	29.30	4.3	5.0	10.9
Consolidated Edison	2.36	38.41	2.5	5.0	10.8
Dominion Resources	1.75	32.69	7.8	5.0	11.3
Duke Energy	0.92	14.35	4.5	5.0	11.6
FPL	1.89	48.70	9.6	5.0	9.9
New Jersey Resources	1.24	36.57	7.0	5.0	8.8
Northwest Nat. Gas	1.58	42.36	4.8	5.0	8.8
NSTAR	1.50	32.61	6.0	5.0	10.0
Piedmont Natural Gas	1.08	25.89	7.1	5.0	9.7
Scana	1.88	32.05	4.6	5.0	11.0
Southern Co.	1.68	32.11	5.4	5.0	10.5
Vectren	1.34	22.87	7.2	5.0	11.7
WGL Holdings Inc.	1.42	32.05	4.0	5.0	9.4
<b>Mean</b>	<b>1.57</b>	<b>32.30</b>	<b>5.7</b>	<b>5.0</b>	<b>10.3</b>
<b>Median</b>	<b>1.58</b>	<b>32.11</b>	<b>5.4</b>	<b>5.0</b>	<b>10.5</b>

1/ Forecast nominal rate of GDP growth, 2010-19

2/ Internal Rate of Return: average I/B/E/S EPS forecast growth rate applies for first 5 years; GDP growth thereafter.

Source: Standard & Poor's Research Insight; [www.yahoo.com](http://www.yahoo.com); Blue Chip [Economic Indicators](#) (March 2009); I/B/E/S (March 2009)

**DCF COST OF EQUITY FOR SAMPLE OF  
BBB-RATED US UTILITIES  
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)**

<u>Company</u>	<u>Annualized Last Paid Dividend</u> (1)	<u>Average Monthly High/Low Prices Jan 2009-Mar 2009</u> (2)	<u>Expected Dividend Yield</u> <sup>1/</sup> (3)	<u>Average I/B/E/S Long-Term EPS Forecasts</u> (4)	<u>DCF Cost of Equity</u> <sup>2/</sup> (5)
ALLETE INC	1.76	28.95	6.5	6.5	13.0
ALLIANT ENERGY CORP	1.50	25.86	6.1	6.0	12.1
AMEREN CORP	1.54	27.93	5.7	4.0	9.7
AMERICAN ELECTRIC POWER CO	1.64	29.89	5.7	4.2	9.9
ATMOS ENERGY CORP	1.32	23.36	5.9	5.0	10.9
AVISTA CORP	0.72	16.58	4.5	4.7	9.2
CENTERPOINT ENERGY INC	0.76	11.66	7.7	18.0	25.7
CLECO CORP	0.90	21.64	4.7	12.4	17.0
CMS ENERGY CORP	0.50	11.34	4.7	6.5	11.2
DPL INC	1.14	21.55	5.7	7.4	13.1
DTE ENERGY CO	2.12	30.72	7.1	3.5	10.6
EDISON INTERNATIONAL	1.24	29.60	4.3	2.2	6.5
ENTERGY CORP	3.00	71.67	4.6	9.4	14.0
EXELON CORP	2.10	50.03	4.6	8.5	13.0
FIRSTENERGY CORP	2.20	45.34	5.3	9.0	14.3
GREAT PLAINS ENERGY INC	0.83	16.01	5.6	7.7	13.3
IDACORP INC	1.20	26.10	4.8	5.0	9.8
INTEGRYS ENERGY GROUP INC	2.72	33.46	9.2	13.6	22.8
NISOURCE INC	0.92	9.74	9.6	1.6	11.2
NORTHEAST UTILITIES	0.95	22.65	4.5	8.5	13.1
OTTER TAIL CORP	1.19	20.15	6.4	8.5	14.9
PEPCO HOLDINGS INC	1.08	15.62	7.2	4.3	11.5
PG&E CORP	1.68	37.70	4.8	7.1	11.9
PINNACLE WEST CAPITAL CORP	2.10	29.43	7.4	4.3	11.8
PORTLAND GENERAL ELECTRIC CO	0.98	17.58	5.9	6.0	11.9
PROGRESS ENERGY INC	2.48	36.85	7.1	5.5	12.6
PUBLIC SERVICE ENTRP GRP INC	1.33	29.25	4.8	6.0	10.8
SOUTH JERSEY INDUSTRIES INC	1.19	36.23	3.5	7.0	10.5
SOUTHWEST GAS CORP	0.90	22.57	4.2	6.0	10.2
TECO ENERGY INC	0.80	11.08	7.8	8.7	16.5
WESTAR ENERGY INC	1.20	18.35	6.8	3.6	10.4
WISCONSIN ENERGY CORP	1.35	41.90	3.5	9.1	12.7
XCEL ENERGY INC	0.95	17.99	5.6	6.7	12.3
<b>Mean</b>	<b>1.40</b>	<b>26.93</b>	<b>5.8</b>	<b>6.9</b>	<b>12.7</b>
<b>Median</b>	<b>1.20</b>	<b>25.86</b>	<b>5.7</b>	<b>6.5</b>	<b>11.9</b>

<sup>1/</sup> Expected Dividend Yield = (Col (1) / Col (2)) \* (1 + Col (4))

<sup>2/</sup> Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

**DCF COSTS OF EQUITY FOR SAMPLE OF  
BBB-RATED U.S. UTILITIES  
(TWO-STAGE MODEL)**

<u>Company</u>	<u>Annualized Last Paid Dividend</u> (1)	<u>Average Monthly High/Low Prices Jan 2009-Mar 2009</u> (2)	<u>Stage 1 I/B/E/S EPS Forecasts</u> (3)	<u>Stage 2 GDP Growth <sup>1/</sup></u> (4)	<u>DCF Cost of Equity <sup>2/</sup></u> (5)
ALLETE INC	1.76	28.95	6.5	5.0	11.8
ALLIANT ENERGY CORP	1.50	25.86	6.0	5.0	11.3
AMEREN CORP	1.54	27.93	4.0	5.0	10.5
AMERICAN ELECTRIC POWER CO	1.64	29.89	4.2	5.0	10.5
ATMOS ENERGY CORP	1.32	23.36	5.0	5.0	10.9
AVISTA CORP	0.72	16.58	4.7	5.0	9.4
CENTERPOINT ENERGY INC	0.76	11.66	18.0	5.0	16.2
CLECO CORP	0.90	21.64	12.4	5.0	10.9
CMS ENERGY CORP	0.50	11.34	6.5	5.0	9.9
DPL INC	1.14	21.55	7.4	5.0	11.1
DTE ENERGY CO	2.12	30.72	3.5	5.0	11.8
EDISON INTERNATIONAL	1.24	29.60	2.2	5.0	8.8
ENTERGY CORP	3.00	71.67	9.4	5.0	10.3
EXELON CORP	2.10	50.03	8.5	5.0	10.1
FIRSTENERGY CORP	2.20	45.34	9.0	5.0	11.0
GREAT PLAINS ENERGY INC	0.83	16.01	7.7	5.0	11.1
IDACORP INC	1.20	26.10	5.0	5.0	9.8
INTEGRYS ENERGY GROUP INC	2.72	33.46	13.6	5.0	16.8
NISOURCE INC	0.92	9.74	1.6	5.0	13.6
NORTHEAST UTILITIES	0.95	22.65	8.5	5.0	10.1
OTTER TAIL CORP	1.19	20.15	8.5	5.0	12.2
PEPCO HOLDINGS INC	1.08	15.62	4.3	5.0	12.0
PG&E CORP	1.68	37.70	7.1	5.0	10.1
PINNACLE WEST CAPITAL CORP	2.10	29.43	4.3	5.0	12.3
PORTLAND GENERAL ELECTRIC CO	0.98	17.58	6.0	5.0	11.1
PROGRESS ENERGY INC	2.48	36.85	5.5	5.0	12.2
PUBLIC SERVICE ENTRP GRP INC	1.33	29.25	6.0	5.0	9.9
SOUTH JERSEY INDUSTRIES INC	1.19	36.23	7.0	5.0	8.6
SOUTHWEST GAS CORP	0.90	22.57	6.0	5.0	9.3
TECO ENERGY INC	0.80	11.08	8.7	5.0	13.8
WESTAR ENERGY INC	1.20	18.35	3.6	5.0	11.5
WISCONSIN ENERGY CORP	1.35	41.90	9.1	5.0	9.0
XCEL ENERGY INC	0.95	17.99	6.7	5.0	10.9
<b>Mean</b>	<b>1.40</b>	<b>26.93</b>	<b>6.9</b>	<b>5.0</b>	<b>11.2</b>
<b>Median</b>	<b>1.20</b>	<b>25.86</b>	<b>6.5</b>	<b>5.0</b>	<b>10.9</b>

1/ Forecast nominal rate of GDP growth, 2010-19

2/ Internal Rate of Return: average I/B/E/S EPS forecast growth rate applies for first 5 years; GDP growth thereafter.

Source: Standard & Poor's Research Insight; [www.yahoo.com](http://www.yahoo.com); Blue Chip [Economic Indicators](#) (March 2009); I/B/E/S (March 2009)

**QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT  
FOR DIFFERENCES IN CAPITAL STRUCTURE**

**Formula for After-Tax Weighted Average Cost of Capital:**

$$WACC_{AT} = (\text{Debt Cost})(1-\text{tax rate})(\text{Debt Ratio}) + (\text{Equity Cost})(\text{Equity Ratio})$$

**APPROACH 1:**

The after-tax weighted average cost of capital ( $WACC_{AT}$ ) is invariant to changes in the capital structure. The cost of equity falls as leverage (debt ratio) falls, but the  $WACC_{AT}$  stays the same.

$$WACC_{AT(ML)} = WACC_{AT(LL)}$$

Where ML = more levered (higher debt ratio)  
LL = less levered (lower debt ratio)

**ASSUMPTIONS:**

Debt Cost	=	Current Cost of Long Term Debt for bbb rated utility
	=	6.75%
Equity Cost	=	Cost of Equity
	=	12.13%
Tax Rate	=	28.5%
CEQ Ratio	(1)	40.0%
Debt Ratio	(1)	60.0%
CEQ Ratio	(2)	42.5%
Debt Ratio	(2)	57.5%

**STEPS:**

1. Estimate  $WACC_{AT}$  for the more levered sample (common equity ratio of 40%)
$$WACC_{AT} = (6.75\%)(1-.285)(60\%) + (12.13\%)(40\%)$$

$$= 7.75\%$$
2. Estimate Cost of Equity for sample at 42.5% common equity ratio with  $WACC_{AT}$  unchanged at 7.75%
$$WACC_{AT} = (\text{Debt Cost})(1-\text{tax rate})(\text{Debt Ratio}) + (\text{Equity Cost})(\text{Equity Ratio})$$

$$7.75\% = (6.75\%)(1-.285)(57.5\%) + (X)(42.5\%)$$

Cost of Equity at 42.5% Equity Ratio = 11.70%
3. Difference between Equity Return at 40% and 42.5% common equity ratios:
$$11.70\% - 12.13\% = -0.43\% \text{ (-43 basis points)}$$

**APPROACH 2:**

After-Tax Cost of Capital Increases as Debt Ratio Falls; Cost of Equity Falls

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before

t = tax rate

D = debt ratio

**ASSUMPTIONS:**

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.75%
Equity Cost	=	Cost of Equity
	=	12.13%
Tax Rate	=	28.5%
CEQ Ratio	(1)	40.0%
Debt Ratio	(1)	60.0%
CEQ Ratio	(2)	42.5%
Debt Ratio	(2)	57.5%

**STEPS:**

1. Estimate  $WACC_{AT}$  for more levered sample (common equity ratio of 40%)

$$WACC_{AT} = (6.75\%)(1-.285)(60\%) + (12.13\%)(40\%)$$

$$= 7.75\%$$

2. Estimate  $WACC_{AT}$  for less levered firm (common equity ratio of 42.5%)

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times (1-t \times \text{Debt Ratio}_{LL}) / (1-t \times \text{Debt Ratio}_{ML})$$

$$WACC_{AT(LL)} = 7.75\% \times \frac{(1-.285 \times 57.5\%)}{(1-.285 \times 60\%)}$$

$$WACC_{AT(LL)} = 7.812\%$$

3. Estimate Cost of Equity at new  $WACC_{AT}$  for less levered firm:

$$WACC_{AT(LL)} = (\text{Debt Cost})(1-\text{tax rate})(\text{Debt Ratio}_{LL}) + (\text{Equity Cost})(\text{Equity Ratio}_{LL})$$

$$7.81\% = (6.75\%)(1-.285)(57.5\%) + (X)(42.5\%)$$

$$\text{Cost of Equity at 42.5\% Equity Ratio} = 11.85\%$$

4. Difference between Equity Return at 40% and 42.5% common equity ratios:

$$11.85\% - 12.13\% = -0.27\% \text{ (-27 basis points)}$$

**Pacific Northern Gas Ltd.  
(PNG-West Division)**

**Capital Structure / ROE Changes vs. NSP 2009  
COST OF SERVICE COMPARISON  
(\$000)**

<b>EXPENSES</b>	<b>CAP/ROE 2009</b>	<b>NSP 2009</b>	<b>Difference</b>
<b>Operating</b>			
Labour	4,054	4,054	0
Other	3,629	3,629	0
Sub-total	<u>7,683</u>	<u>7,683</u>	<u>0</u>
<b>Maintenance</b>			
Labour	212	212	0
Other	314	314	0
Sub-total	<u>525</u>	<u>525</u>	<u>0</u>
<b>Administrative and General</b>			
Labour	2,160	2,160	0
Total Company Benefits	2,014	2,014	0
Other	2,776	2,776	(1)
Sub-total	<u>6,950</u>	<u>6,950</u>	<u>(1)</u>
<b>Total (O, M, A &amp; G) Excluding Co. Use</b>	<b>15,158</b>	<b>15,158</b>	<b>(1)</b>
Transfers to Capital Operating	(519)	(519)	0
Transfers to Capital Admin. & Gen.	(825)	(825)	0
<b>Property Taxes</b>	3,527	3,527	0
<b>Depreciation</b>	6,675	6,675	0
<b>Amortization</b>	722	722	0
<b>Other Income</b>	(266)	(266)	0
<b>Shared Services Recovery from PNG (N.E.)</b>	(1,957)	(1,957)	0
<b>Shared Services NSP Reduction to PNG(N.E.)</b>	25	25	0
<b>Methanex Termination Payment</b>	(5,466)	(5,466)	0
<b>NSP Settlement Allowance</b>	(120)	(120)	0
<b>Total Expenses Excluding Co. Use</b>	<u><b>16,953</b></u>	<u><b>16,954</b></u>	<u><b>(1)</b></u>
<b>Income Taxes</b>	1,745 <sup>(1)</sup>	1,332 <sup>(1)</sup>	412
<b>Return on Common Equity</b>	5,754 <sup>(2)</sup>	4,792 <sup>(2)</sup>	962
<b>Short Term Debt</b>	166	259	(93)
<b>Long Term Debt</b>	4,675	4,842	(167)
<b>Preferred Shares</b>	351	351	0
<b>Total Cost of Service Excluding Co. Use</b>	<u><b>29,643</b></u>	<u><b>28,529</b></u>	<u><b>1,114</b></u>
<b>Company Use Gas Cost</b>	716	716	
<b>Total Cost of Service Including Co. Use Cost</b>	<u><u><b>30,359</b></u></u>	<u><u><b>29,245</b></u></u>	

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**UTILITY INCOME & RETURN**

**SCHEDULE 1**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Energy sales (TJ)	3,128	3,128
2	Average rate per GJ	\$16.05	\$15.74
3			
4	Transportation service (TJ)	3,463	3,463
5	Average rate per GJ	1.63	1.59
6			
7	Total deliveries (TJ)	6,591	6,591
8			
9	Utility revenue		
10	Energy sales	\$47,443	\$47,443
11	Interim rates - sales	2,757	1,782
12	Transportation service	5,255	5,255
13	Interim rates - transportation	394	255
14			
15		55,850	54,735
16	Cost of sales	25,490	25,490
17			
18	Gross margin	30,360	29,245
19			
20	Operating expenses	7,880	7,880
21	Maintenance expenses	525	525
22	Admin. & general expenses	6,125	6,125
23	Property taxes	3,527	3,527
24	Depreciation	6,675	6,675
25	Amortization	722	722
26	Investment income, other revenue	(2,224)	(2,224)
27	Shared Services NSP Reduction to PNG(N.E.)	25	25
28	Methanex Termination Pmt. Amort. & Interest	(5,466)	(5,466)
29	Settlement Allowance	(120)	(120)
30		17,670	17,670
31			
32	Earned return before income taxes	12,690	11,575
33	Income taxes	1,745	1,332
34			
35	Earned return	\$10,945	\$10,243
36			
37	Utility rate base	\$131,383	\$131,353
38			
39	Return on rate base	8.33%	7.80%

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**UTILITY RATE BASE**

**SCHEDULE 2**  
**(000'S)**

Line No.		CAP/ROE 2009	NSP 2009
1	Plant in service beginning of year	\$253,515	\$253,515
2	Additions	\$5,405	\$5,405
3	Disposals (at cost)	(1,269)	(1,269)
4			
5	Plant in service end of year	257,651	\$257,651
6	Accumulated depreciation	115,763	\$115,763
7			
8	Net plant in service end of year	141,888	\$141,888
9			
10	Net plant beginning of year	143,641	143,641
11			
12	Net plant in service midyear	142,764	142,764
13	Adjustment - expenditure/disposal timing	(99)	(99)
14	Contributions in aid of construction	(5,125)	(5,125)
15	Construction advances	0	0
16	Deferred income taxes	(12,212)	(12,212)
17	Work in progress, no AFUDC	100	100
18	Unamortized deferred charges	1,200	1,200
19	Cash working capital	2,131	2,101
20	Other working capital	2,624	2,624
21			
22	Utility rate base, midyear	\$131,383	\$131,353

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**INCOME TAXES**

**SCHEDULE 3**  
**(000'S)**

Line No.		CAP/ROE 2009	NSP 2009
1	<b>Calculation of Taxable Income</b>		
2	Earned return before income taxes	\$12,690	\$11,575
3	Interest	(4,841)	(5,100)
4	Permanent differences	81	81
5	Timing differences	886	886
6			
7	Taxable income	<u>\$8,816</u>	<u>\$7,442</u>
8			
9	<b>Calculation of Income Tax Expense</b>		
10	Income taxes payable	2,645	2,232
11	Income Tax Rate Deferral	0	0
12	Deferred income tax drawdown	(900)	(900)
13			
14	Income tax expense	<u>\$1,745</u>	<u>\$1,332</u>
15			
16	<b>Particulars of Timing Differences</b>		
17	A. Tax Effects Subject To Flowthrough		
18	Depreciation	6,675	6,675
19	Amortization	722	722
20	Capital cost allowance	(5,271)	(5,271)
21	Overheads capitalized	(1,240)	(1,240)
22	Other	(0)	(0)
23			
24	Timing differences	\$886	886
25	B. Tax Effects Subject To Deferral		
26	Deferred Tax Drawdown	3,000	3,000
27			
28	Timing and Other differences	<u>\$3,886</u>	<u>3,886</u>
29			
30	Tax rate	30.00%	30.00%
31	Surtax rate	0.00%	0.00%

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**COMMON EQUITY**

**SCHEDULE 4**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Opening balance		
2	Share capital	\$9,161	\$9,161
3	Contributed surplus	\$3,610	\$3,610
4	Retained earnings	\$71,839	\$71,839
5			
6		84,611	84,611
7			
8	Net income	7,180	6,174
9	Shares issued (redeemed), contributed surplus	(2,590)	(2,590)
10	Preferred dividends	(338)	(338)
11	Common dividends	(3,371)	(3,371)
12			
13	Closing balance	\$85,491	\$84,485
14			
15			
16	Midyear common equity	85,051	84,548
17	Investment in Non Utility	0	0
18	less: acquisition premiums	(1,355)	(1,410)
19	less: investment in subsidiary company	(8,062)	(6,826)
20			
21			
22		\$75,634	\$76,312
23			
24	Deemed utility common equity	\$62,407	\$52,541
25			
26	Equity required for KSL work in progress	\$140	\$140
27			
28	Unused Equity	\$13,087	\$23,631

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**RETURN ON CAPITAL**

**SCHEDULE 5**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Short Term Debt	\$5,213	\$7,664
2	proportion	3.97%	5.83%
3	rate of return	3.18%	3.37%
4	return component	0.13%	0.20%
5			
6	Long term debt	\$58,764	\$66,148
7	proportion	44.73%	50.36%
8	rate of return	7.96%	7.32%
9	return component	3.56%	3.69%
10			
11	Preferred shares	\$5,000	\$5,000
12	proportion	3.81%	3.81%
13	rate of return	7.01%	7.01%
14	return component	0.27%	0.27%
15			
16	Common equity	\$62,407	\$52,541
17	proportion	47.50%	40.00%
18	rate of return	9.22%	9.12%
19	return component	4.38%	3.65%
20			
21	Total capitalization	<u>\$131,383</u>	<u>\$131,353</u>
22			
23	Return on rate base	<u>8.33%</u>	<u>7.80%</u>
24			
25	Utility rate base	<u>\$131,383</u>	<u>\$131,353</u>

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

**Capital Structure / ROE Changes vs. NSP 2009**  
**COST OF SERVICE COMPARISON**  
**(\$000)**

<b>EXPENSES</b>	<b>CAP/ROE 2009</b>	<b>NSP 2009</b>	<b>Difference</b>
<b>Operating</b>			
Labour	1,490	1,490	0
Other	2,303	2,303	0
Sub-total	<u>3,793</u>	<u>3,793</u>	<u>0</u>
<b>Maintenance</b>			
Labour	71	71	0
Other	152	152	0
Sub-total	<u>223</u>	<u>223</u>	<u>0</u>
<b>Administrative and General</b>			
Labour	0	0	0
Total Company Benefits	441	441	0
Other	1,097	1,096	1
Sub-total	<u>1,538</u>	<u>1,538</u>	<u>1</u>
<b>Total (O, M, A &amp; G) Excluding Co. Use</b>	<b>5,554</b>	<b>5,553</b>	<b>1</b>
Transfers to Capital Operating	(207)	(207)	0
Transfers to Capital Admin. & Gen.	(208)	(208)	0
<b>Property Taxes</b>	977	977	0
<b>Depreciation</b>	1,430	1,430	0
<b>Amortization</b>	(45)	(43)	(1)
<b>Other Income</b>	(187)	(187)	0
<b>NSP Settlement Allowance for Shared Service</b>	(23)	(23)	0
<b>Total Expenses Excluding Co. Use</b>	<u><b>7,291</b></u>	<u><b>7,292</b></u>	<u><b>(1)</b></u>
<b>Income Taxes</b>	396	283	113
<b>Return on Common Equity</b>	1,425	1,161	264
<b>Short Term Debt</b>	(7)	82	(89)
<b>Long Term Debt</b>	790	790	0
<b>Total Cost of Service Excluding Co. Use</b>	<u><b>9,894</b></u>	<u><b>9,607</b></u>	<u><b>287</b></u>
<b>Company Use Gas</b>	542	542	
<b>Total Cost of Service Including Co. Use</b>	<u><u><b>10,436</b></u></u>	<u><u><b>10,149</b></u></u>	

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

**UTILITY INCOME & RETURN**

**SCHEDULE 1**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Energy sales (TJ)	3,526	3,526
2	Average rate per GJ	\$10.47	\$10.39
3			
4	Transportation service (TJ)	1,211	1,211
5	Average rate per GJ	\$1.09	\$1.06
6			
7	Total deliveries (TJ)	4,737	4,737
8			
9	Utility revenue		
10	Energy sales	\$36,858	\$36,858
11	Interim rates - sales	49	(202)
12	Transportation service	1,312	1,312
13	Interim rates - transportation	7	(29)
14			
15		38,226	37,939
16	Cost of sales	27,790	27,790
17			
18	Gross margin	10,436	10,149
19			
20	Operating expenses	4,128	4,128
21	Maintenance expenses	223	223
22	Admin. & general expenses	1,330	1,329
23	Property taxes	977	977
24	Depreciation	1,430	1,430
25	Amortization	(45)	(43)
26	Investment income, other revenue	(187)	(187)
27	NSP Settlement Allowance for Shared Services	(23)	(23)
28			
29		7,833	7,834
30			
31	Earned return before income taxes	2,603	2,315
32	Income taxes	396	283
33			
34	Earned return	\$2,207	\$2,032
35			
36	Utility rate base	\$36,373	\$36,360
37			
38	Return on rate base	6.07%	5.59%

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

**UTILITY RATE BASE**

**SCHEDULE 2**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Plant in service beginning of year	\$65,701	\$65,701
2	Additions	2,818	2,818
3	Disposals	(15)	(15)
4			
5	Plant in service end of year	68,504	68,504
6	Accumulated depreciation	26,132	26,132
7			
8	Net plant in service end of year	42,372	42,372
9			
10	Net plant beginning of year	41,319	41,319
11			
12	Net plant in service midyear	41,846	41,846
14	Contributions for construction	(7,179)	(7,179)
15	Unamortized deferred charges	402	402
16	Deferred income taxes	(553)	(553)
17	Reserve for damages	(69)	(69)
18	Cash working capital	1,716	1,703
19	Other working capital	210	210
20			
21	Utility rate base, midyear	\$36,373	\$36,360

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

**INCOME TAXES**

**SCHEDULE 3**  
**(000's)**

Line No.	CAP/ROE 2009	NSP 2009
<b>1</b>	<b>Calculation of Taxable Income</b>	
2	\$2,603	\$2,315
3	(782)	(871)
4	13	13
5	(515)	(514)
6		
7	<u>\$1,319</u>	<u>\$943</u>
8		
<b>9</b>	<b>Calculation of Income Tax Expense</b>	
10	\$396	\$283
11	0	0
12	0	0
13		
14	<u>\$396</u>	<u>\$283</u>
15		
<b>16</b>	<b>Particulars of Timing Differences</b>	
17	A. Tax Effects Subject To Flowthrough	
18	\$1,430	\$1,430
19	(45)	(43)
20	(1,569)	(1,569)
21	0	0
22	(332)	(332)
23	0	0
24		
25		
26	<u>(\$515)</u>	<u>(\$514)</u>
27		
28	30.00%	30.00%
29	0.00%	0.00%
30	30.00%	30.00%

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

**COMMON EQUITY**

**SCHEDULE 4**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Opening balance		
2	Share capital	\$8,295	\$8,295
3	Contributed surplus	0	0
4	Retained earnings	4,691	4,691
5			
6		12,986	12,986
7			
8	Net income	1,426	1,161
9	Shares issued	0	0
10	Preferred dividends	0	0
11	Common dividends	3,519	(954)
12			
13	Closing balance	\$17,931	\$13,193
14			
15			
16	Midyear common equity	\$15,459	\$13,090

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

**RETURN ON CAPITAL**

**SCHEDULE 5**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Short term borrowings	\$1,031	\$3,387
2	proportion	2.84%	9.32%
3	rate of return	-0.72%	2.41%
4	return component	-0.02%	0.22%
5			
6	Long term debt	\$19,883	\$19,883
7	proportion	54.66%	54.68%
8	rate of return	3.97%	3.97%
9	return component	2.17%	2.17%
10			
11	Preferred shares	\$0	\$0
12	proportion	0.00%	0.00%
13	rate of return	6.48%	6.48%
14	return component	0.00%	0.00%
15			
11	Common equity	\$15,458	\$13,089
12	proportion	42.50%	36.00%
13	rate of return	9.22%	8.87%
14	return component	3.92%	3.19%
15			
16	Total capitalization	<u>\$36,373</u>	<u>\$36,360</u>
17			
18	Return on rate base	<u>6.07%</u>	<u>5.59%</u>
19			
20	Utility rate base	<u>\$36,373</u>	<u>\$36,360</u>

**Pacific Northern Gas (N.E.) Ltd.  
(Tumbler Ridge Division)**

**Capital Structure Changes vs. NSP 2009  
COST OF SERVICE COMPARISON  
(\$000)**

<b>EXPENSES</b>	<b>CAP/ROE 2009</b>	<b>NSP 2009</b>	<b>Difference</b>
<b>Operating</b>			
Labour	233	233	0
Other	319	319	0
Sub-total	<u>552</u>	<u>552</u>	<u>0</u>
<b>Maintenance</b>			
Labour	25	25	0
Other	69	69	0
Sub-total	<u>94</u>	<u>94</u>	<u>0</u>
<b>Administrative and General</b>			
Labour	0	0	0
Total Company Benefits	44	44	0
Other	82	82	(0)
Sub-total	<u>126</u>	<u>126</u>	<u>(0)</u>
<b>Total (O, M, A &amp; G) Excluding Co. Use</b>	<b>771</b>	<b>771</b>	<b>(0)</b>
Transfers to Capital Operating	(4)	(4)	0
Transfers to Capital Admin. & Gen.	(4)	(4)	0
<b>Property Taxes</b>	79	79	0
<b>Depreciation</b>	116	116	0
<b>Amortization</b>	(37)	(37)	0
<b>Other Income</b>	(12)	(12)	0
<b>NSP Settlement Allowance for Shared Services</b>	(2)	(2)	0
<b>Total Expenses Excluding Co, Use</b>	<u><b>908</b></u>	<u><b>908</b></u>	<u><b>0</b></u>
<b>Income Taxes</b>	15	11	4
<b>Return on Common Equity</b>	61	51	10
<b>Short Term Debt</b>	3	7	(4)
<b>Long Term Debt</b>	55	55	0
<b>Total Cost of Service Excluding Co. Use</b>	<u><b>1042</b></u>	<u><b>1032</b></u>	<u><b>10</b></u>
<b>Company Use Gas</b>	100	100	
<b>Total Cost of Service Including Co. Use</b>	<u><u><b>1142</b></u></u>	<u><u><b>1132</b></u></u>	

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**UTILITY INCOME & RETURN**

**SCHEDULE 1**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Energy sales (TJ)	165	165
2	Average rate per GJ	\$11.80	\$11.75
3			
4	Transportation service (TJ)	850	850
5	Average rate per GJ	\$0.36	\$0.36
6			
7	Total deliveries (TJ)	1 015	1 015
8			
9	Utility revenue		
10	Energy sales	\$1,950	\$1,950
11	Interim rates - sales	1	(7)
12	Transportation service	304	304
13	Interim rates - transportation	0	(3)
14			
15		2,256	2,245
16	Cost of sales	1,113	1,113
17			
18	Gross margin	1,142	1,132
19			
20	Operating expenses	647	647
21	Maintenance expenses	94	94
22	Admin. & general expenses	122	122
23	Property taxes	79	79
24	Depreciation	116	116
25	Amortization	(37)	(37)
26	Investment income, other revenue	(12)	(12)
27	NSP Settlement Allowance for Shared Services	(2)	(2)
28		1,008	1,008
29			
30	Earned return before income taxes	134	124
31	Income taxes	15	11
32			
33	Earned return	\$119	\$113
34			
35	Utility rate base	\$1,566	\$1,565
36			
37	Return on rate base	7.60%	7.21%

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**UTILITY RATE BASE**

**SCHEDULE 2**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Plant in service beginning of year	\$8,323	\$8,323
2	Additions	268	268
3	Disposals	-	-
4			
5	Plant in service end of year	8,591	8,591
6	Accumulated depreciation	5,403	5,403
7			
8	Net plant in service end of year	3,189	3,189
9			
10	Net plant beginning of year	3,085	3,085
11			
12	Net plant in service midyear	3,137	3,137
13	Contributions for construction	(1,093)	(1,093)
14	Unamortized deferred charges	(36)	(36)
15	Deferred income taxes	(415)	(415)
16	Reserve for damages	(155)	(155)
17	Cash working capital	128	127
18	Other working capital	-	-
19			
20	Utility rate base, midyear	<u>\$1,566</u>	<u>\$1,565</u>

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**INCOME TAXES**

**SCHEDULE 3**  
**(000's)**

Line No.	CAP/ROE 2009	NSP 2009
1	<b>Calculation of Taxable Income</b>	
2	\$134	\$124
3	(58)	(61)
4	0	0
5	(26)	(26)
6		
7	<u>\$51</u>	<u>\$37</u>
8		
9	<b>Calculation of Income Tax Expense</b>	
10	\$15	\$11
11	-	-
12	-	-
13		
14	<u>\$15</u>	<u>\$11</u>
15		
16	<b>Particulars of Timing Differences</b>	
17	A. Tax Effects Subject To Flowthrough	
18	\$116	\$116
19	(37)	(37)
20	(99)	(99)
21	-	-
22	(6)	(6)
23	-	-
24		
25	<u>(26)</u>	<u>(26)</u>
26		
27	30.00%	30.00%
28	0.00%	0.00%
29	30.00%	30.00%

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**COMMON EQUITY**

**SCHEDULE 4**  
**(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Opening balance		
2	Share capital	\$230	\$230
3	Contributed surplus	-	-
4	Retained earnings	<u>345</u>	<u>345</u>
5			
6		575	575
7			
8	Net income	\$61	\$51
9	Shares Issued (Repurchased)	-	-
10	Preferred dividends	-	-
11	Common dividends	-	<u>(75)</u>
12			
13	Closing balance	<u>\$637</u>	<u>\$552</u>
14			
15			
16	Midyear common equity	\$606	\$564

**Pacific Northern Gas (N.E.) Ltd.  
(Tumbler Ridge Division)**

**RETURN ON CAPITAL**

**SCHEDULE 5  
(000's)**

Line No.		CAP/ROE 2009	NSP 2009
1	Short term borrowings	\$143	\$244
2	proportion	9.13%	15.61%
3	rate of return	1.95%	2.71%
4	return component	0.18%	0.42%
5			
6	Long term debt	\$757	\$757
7	proportion	48.37%	48.39%
8	rate of return	7.24%	7.24%
9	return component	3.50%	3.50%
10			
11	Common equity	\$665	\$564
12	proportion	42.50%	36.00%
13	rate of return	9.22%	9.12%
14	return component	3.92%	3.28%
15			
16	Total capitalization	<u>\$1,566</u>	<u>\$1,565</u>
17			
18	Return on rate base	<u>7.60%</u>	<u>7.21%</u>
19			
20	Utility rate base	<u>\$1,566</u>	<u>\$1,565</u>

**DRAFT**

**BRITISH COLUMBIA  
UTILITIES COMMISSION**

**ORDER  
NUMBER** G-??-09

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

and

An Application by  
Pacific Northern Gas Ltd. ("PNG") and Pacific Northern Gas (N.E.) Ltd. ("PNG(N.E.)")  
regarding Capital Structure and Equity Risk Premium

**BEFORE:** ?????????, Commissioner  
?????????, Commissioner July 23, 2009  
?????????, Commissioner

**O R D E R**

**WHEREAS:**

- A. On July 15, 2009, PNG and PNG(N.E.) filed with the British Columbia Utilities Commission (the "Commission") an application for revisions to the Capital Structure and Equity Risk Premium applicable to PNG and PNG(N.E.); and
- B. PNG is applying for approval to increase its deemed common equity thickness from 40 to 47.5 percent and its equity risk premium relative to the benchmark utility return on equity ("ROE") from 65 to 75 basis points; and
- C. PNG(N.E.) is applying for approval to increase its deemed common equity thickness from 36 to 42.5 percent and its equity risk premium relative to the benchmark utility ROE from 40 to 75 basis points in respect of both its Fort St. John/Dawson Creek and Tumbler Ridge Divisions; and
- D. PNG is seeking Commission approval to recover from option fees paid to PNG by Merrill Lynch Commodities Inc. ("MLCI") and eventually from any annual firm revenue from MLCI, the foregone return on facilities previously deactivated as a result of the loss of load and revenue due to the closure of the Methanex methanol/ammonia plant in November 2005; and
- E. The Commission has reviewed the Application and considers that a Procedural Conference is required to determine the appropriate regulatory process and timing for further review of the Application.

**NOW THEREFORE** the Commission orders as follows:

1. A Procedural Conference regarding the regulatory process for the review of the Application will be held on Wednesday, August 5, 2009, commencing at 9:00 a.m. in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, B.C. The Procedural Conference will address matters such as:
  - (i) the steps set forth in the preliminary regulatory timetable attached as Appendix A; and
  - (ii) other matters that will assist the Commission to efficiently review the Application.; and
2. PNG and PNG(N.E.) are to publish, as soon as possible, in display-ad format, the Notice attached as Appendix B to this Order in appropriate local news publications as may properly provide adequate notice to customers served in the affected service areas.
3. The Application, together with any supporting materials, will be made available for inspection at the PNG Head Office, Suite 950, 1185 West Georgia Street, Vancouver, BC., V6E 4E6 and at the Commission Office, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3, and will also be made available on the PNG and Commission websites.
4. Intervenors or Interested Parties should register with the Commission, in writing or electronic submission, by Tuesday, August 4, 2009, and advise whether they intend to attend the Procedural Conference. Intervenors should specifically state the nature of their interest in the Application and identify generally the nature of the issues that they may intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the review process.

**DATED** at the City of Vancouver, in the Province of British Columbia, this 23rd day of July 2009.

BY ORDER

????????????  
Commissioner



SIXTH FLOOR, 900 HOWE STREET, BOX 250  
VANCOUVER, B.C. V6Z 2N3 CANADA  
web site: <http://www.bcuc.com>

TELEPHONE: (604) 660-4700  
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**PRELIMINARY REGULATORY TIMETABLE**

An Application by  
Pacific Northern Gas Ltd. ("PNG") and Pacific Northern Gas (N.E.) Ltd. ("PNG(N.E.)")  
regarding Capital Structure and Equity Risk Premium

<b>ACTION</b>	<b>DATE (2009)</b>
Intervenor/Interested Party Registration	Tuesday, August 4
Procedural Conference	Wednesday, August 5
BCUC Information Request No. 1 to PNG/PNG(N.E.)	Thursday, August 20
Intervenor Information Request No. 1 to PNG/PNG (N.E.)	Thursday, August 27
Filing of Participant Assistance/Cost Award Budgets	Monday, August 31
PNG/PNG(N.E.) Response to Information Requests No. 1 from BCUC and Intervenor	Thursday, September 16
BCUC and Intervenor Information Requests No. 2 to PNG/PNG(N.E.)	Monday, September 28
PNG/PNG(N.E.) Response to Information Requests No. 2 from BCUC and Intervenor	Thursday, October 8
Intervenor Evidence, if any	Thursday, October 15
Information Request No. 1 on Intervenor Evidence from all Parties	Thursday, October 29
Intervenors Response to Information Requests	Tuesday, November 10
Oral Hearing	Monday, November 16 to Wednesday, November 18



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An Application by  
Pacific Northern Gas Ltd. ("PNG") and Pacific Northern Gas (N.E.) Ltd. ("PNG(N.E.)")  
regarding Capital Structure and Equity Risk Premium

<b>Date:</b>	Wednesday, August 5, 2009
<b>Time:</b>	9:00 a.m.
<b>Location:</b>	B.C. Utilities Commission Hearing Room 12 <sup>th</sup> Floor, 1125 Howe Street, Vancouver, B.C.

**NOTICE OF PROCEDURAL CONFERENCE  
AND  
NOTICE OF PRELIMINARY REGULATORY TIMETABLE**

**THE APPLICATION**

On July 16, 2009, PNG and PNG(N.E.) applied to the British Columbia Utilities Commission (the "Commission") for approval of the following:

1. To increase PNG's deemed common equity thickness from 40 to 47.5 percent and its equity risk premium relative to the benchmark utility return on equity ("ROE") from 65 to 75 basis points.
2. To increase PNG(N.E.)'s deemed common equity thickness from 36 to 42.5 percent and its equity risk premium relative to the benchmark utility ROE from 40 to 75 basis points in respect of both its Fort St. John/Dawson Creek and Tumbler Ridge Divisions.
3. For PNG to recover from option fees paid to PNG by Merrill Lynch Commodities Inc. ("MLCI") and eventually from any annual firm revenue from MLCI, the foregone return on facilities previously deactivated as a result of the loss of load and revenue due to the closure of the Methanex methanol/ammonia plant in November 2005.

**THE REGULATORY PROCESS**

The Commission has established a Procedural Conference and Preliminary Regulatory Timetable for the regulatory review of the Application. The Preliminary Regulatory Timetable can be viewed on the Commission's web site at [www.bcuc.com](http://www.bcuc.com).

The Commission will hold a Procedural Conference regarding the further regulatory process for the review of the Application on Wednesday, August 5, 2009 commencing at 9:00 a.m. in the Commission Hearing Room on the 12<sup>th</sup> Floor, 1125 Howe Street, Vancouver, B.C.

**INTERVENTION**

Persons who expect to actively participate in the PNG/PNG(N.E.) proceeding should register as Intervenors with the Commission, and should identify the issues that they intend to pursue as well as the nature and extent of their anticipated involvement in the review process indicating whether they plan to attend the Procedural Conference. Intervenors will receive email notice of all correspondence, filed documentation and should provide an e-mail address, if available.

Persons not expecting to actively participate, but who have an interest in the proceeding, should register as Interested Parties.

Intervenors and Interested Parties should register in writing, no later than Tuesday, August 4, 2009. Notification by mail, courier delivery, fax or email is acceptable.

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.

The deadline for filing budgets for participation funding/cost awards is Monday, August 31, 2009.

**PUBLIC INSPECTION OF THE DOCUMENTS**

The Application and supporting material, including Commission correspondence, will be made available for inspection at the at PNG's Head Office, 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](http://www.png.ca) and on the Commission's website at [www.bcuc.com](http://www.bcuc.com).

For further information, please contact Ms. Erica Hamilton, Commission Secretary, as follows:

Telephone: (604) 660-4700  
Facsimile: (604) 660-1102

BC Toll Free: 1-800-663-1385  
E-mail: [Commission.Secretary@bcuc.com](mailto:Commission.Secretary@bcuc.com)



**NOW THEREFORE** the Commission orders as follows:

1. PNG is hereby authorized to increase its deemed common equity thickness from 40 to 47.5 percent and its equity risk premium relative to the benchmark utility return on equity (“ROE”) from 65 to 75 basis points; and
2. PNG(N.E.) is hereby authorized to increase its deemed common equity thickness from 36 to 42.5 percent and its equity risk premium relative to the benchmark utility ROE from 40 to 75 basis points in respect of both its Fort St. John/Dawson Creek and Tumbler Ridge Divisions; and
3. PNG is hereby authorized to record in deferred return on equity deferral account the difference between the approved NSP 2009 cost of service for PNG and the cost of service determined for 2009 on the basis of the increased common equity and equity risk premium authorized under section 1 of this Order. The balance to be subject to future disposition by the Commission
4. PNG and PNG(N.E.) are directed to record the impact of the change in the 2009 benchmark utility ROE on the approved NSP 2009 costs of service for PNG and PNG(N.E.) in deferred return on equity deferral accounts subject to future disposition by the Commission.
5. PNG can recover from option fees paid to PNG by Merrill Lynch Commodities Inc. (“MLCI”) and eventually from any annual firm revenue from MLCI, the foregone return on facilities previously deactivated as a result of the loss of load and revenue due to the closure of the Methanex methanol/ammonia plant in November 2005 as determined in accordance with the methodology set forth in the Application. The balance of such fees to be credited to customer rates subject to future Commission direction.

**DATED** at the City of Vancouver, in the Province of British Columbia, this ?????? day of January 2010.

BY ORDER

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Commissioner