Q. **In reply to CA-NP-296 (asked on June 20, 2007 in the 2008 GRA), Ms. McShane provided extracts from various Board decisions which commented upon the evidence and recommendations of Ms. McShane. The last excerpt provided was attachment R in relation to a decision dated March 2, 2006.**

(a) **Does Ms. McShane adopt the reply to CA-NP-296 in this proceeding as being complete as of the date these materials were filed in NP's 2008 GRA?**

(b) **If not, please provide any materials that were not provided in replay to CA-NP-296 that should have been included.**

(c) **Please also provide such extracts from Board Decisions filed since June 20, 2007.**

A. (a) Ms. McShane adopts the reply to CA-NP-296 in the 2008 GRA with the addition of ATCO Pipelines' 2001-2002 GRA. This is included as Attachment A.

(b) See response to part (a).

(c) Extracts from Board Decisions since June 20, 2007 are attached as follows:

Attachment B: Ontario Energy Board, EB-2006-0501 Hydro One Networks 2007-2008 Electricity Transmission Revenue Requirements, Aug 16 2007

Attachment C: Public Utilities Board of the Northwest Territories, Decision 13-2007 Northwest Territories Power, Aug 29 2007

Attachment D: BC Comptroller of Water Rights, Order 2166 EPCOR White Rock Water Approval of Revenue Requirements for 2008-2010, Aug 14 2008

Attachment E: Public Utilities Board of the Northwest Territories, Decision 25-2008 Northland Utilities (NWT) General Rate Application, Oct 27 2008

Attachment F: Public Utilities Board of the Northwest Territories, Decision 24-2008 Northland Utilities (YK) General Rate Application, Oct 27 2008

Attachment G: Ontario Energy Board, EB-2007-0905 Ontario Power Generation, Nov 3 2008

Attachment H: Yukon Utilities Board, Order 2009-2 Yukon Electrical Company For Approval of Revenue Requirements 2008-2009, Feb 2009

Attachment I: Nova Scotia Utility and Review Board, Heritage Gas, NSUARB-NG-HG-R-08, Feb 12 2009

Attachment J: BC Utilities Commission, Terasen Gas (Whistler) Application for 2009 Revenue Requirement, Apr 7 2009

Alberta Energy and Utilities Board, Decision 2001-97
ATCO Pipelines South 2001-2002 General Rate Application, Dec 12 2001

Alberta Energy and Utilities Board

DECISION 2001-97

ATCO PIPELINES SOUTH

2001/2002 GENERAL RATE APPLICATION
PHASES I AND II

Views of the Board

The Board agrees with Calgary that it is not appropriate to change the assessment of the relative risk facing ATCO merely on the basis that it has restructured its business into two divisions. The Board is of the view that the most important issue with respect to these divisions is whether or not the business risks facing the still legally integrated entity have changed relative to previous GRA applications.

However, having reviewed the risks of the company as a whole, the Board also agrees with Calgary that it is appropriate to allocate the allowed return on equity between the divisions on the basis of their relative risk. This is consistent with the past practice of the Board in other cases involving the notional separation of previously integrated utility functions into separate divisions. The Board is of the view that a similar approach would be appropriate in this case.

5.2 Appropriate Return on Equity for AGS and APS

Position of ATCO

For AGS, based on common equity financing rate base of 37.4% in 2001 and 39.4% in 2002, ATCO requested a return on common equity of 11.5% for both 2001 and 2002.

For APS, based on common equity financing rate base of 45.4% in 2001 and 50.1% in 2002, ATCO requested a return on common equity of 12.0% for both 2001 and 2002.

ATCO presented estimates of fair rate of return on common equity for 2001 and 2002 based on an application of equity risk premium tests, discounted cash flow tests, and comparable earnings tests. In support of its requests, evidence was filed by Ms. K. McShane, Senior Vice President of Foster Associates Inc., who recommended a fair rate of return on common giving primary weight to the equity risk premium and discounted cash flow tests, but also with significant weight to the comparable earnings test.

Since AGPL is not a publicly traded company, Ms. McShane stated that its cost of equity could not be estimated directly from capital markets, and since it does not have its own debt rating, there was no independent market assessment of its business and financial risk. Therefore, the determination of a fair return was made by reference to proxies that do have market data. Ms. McShane used market data available for a sample of publicly traded utilities including data from U.S. utilities in her evaluations.

Ms. McShane stated that the standards that set the parameters of fair return on equity necessary to induce investment in public utility assets must provide the opportunity to attract capital on reasonable terms; maintain its financial integrity; and earn a return on the value of its property commensurate with that of comparable risk enterprises. She noted that during the past decade in Canada, the comparable earnings test has effectively been replaced by the cost of attracting capital test. Factors noted to contribute to this change were the sharp decline in inflation in 1992, industrial restructuring, and severe recession in the early 1990's which resulted in a significant decline in earnings. Ms. McShane stated that these lowered earnings were unrepresentative of future earnings, and unreliable indicators of investor expectations for future returns. On this basis, Ms. McShane stated that the results of the comparable earnings test were of limited reliability. She stated that the same factors had a similar effect on the discounted cash flow test.

Ms. McShane stated that with the shift in reliance onto the equity risk premium test, the approved returns of utilities in Canada were tied almost exclusively to interest rates, which had declined between 1992 and 1999. Approved returns can be broken into the real cost of capital, compensation for inflation and equity risk premium components. The effective risk premium declined by close to 2% since the risk premium test become the sole methodology relied upon in the mid-90’s. She noted that with declining inflation and interest rates, and a strong economy, earnings of competitive firms have rebounded from the early 1990’s to a point where in unregulated industries, the gap between the comparable earnings test and approved returns has widened considerably. She stated the opportunity cost (the return foregone) by investing in utility assets rather than the next best alternative has also widened. Ms. McShane stated that the comparable earnings standard provides a measure of such an opportunity cost and should be given weight. The equity risk premium test estimates a return expected or required on the market value of the investment. Ms. McShane stated that, for utilities, replacement cost is higher than book value, thus the market value of utility shares should be higher than book value.

The comparable earnings test recognizes return as applied to an original cost rate base. Ms. McShane recommended that weight be given to both the cost of attracting capital (through the application of both the equity risk premium and discounted cash flow tests) and the comparable earnings standard.

<u>Equity Risk Premium Test</u>

Ms. McShane stated that the equity risk premium test is a measure of the market-related cost of attracting capital. She noted that an equity investment in a utility is more risky than a bond investment and requires a higher return. As utility assets are long-lived and are committed to public use over the life of the asset, long-term Government of Canada bond yield becomes the basis for applying the risk premium test. Ms. McShane stated that the risk premium required by investors tends to widen and narrow with factors such as inflation, productivity, profitability and investors’ willingness to take risks. In addition, she stated that it was a prospective concept that reflects investors' requirements to compensate for risk on a future basis.

The starting point of applying the risk premium test is to project the expected nominal long Canada yield, which serves as a proxy for the “risk free rate.” Ms. McShane used a forecast of long Canada yield at 6.25%. Her estimation of required market risk premium resulted from analyzing U.S. and Canadian data from 1947 to 1999, which showed that risk premiums varied in the range of 6.3% to 6.9% (adjusted for exchange rates and impact of annual data based on a weighted average of 70% and 30% Canadian and U.S. stock and bond returns respectively). On a forward looking basis, Ms. McShane’s analysis of the expected market returns over the past 10 years in relation to bond yields (weighted at 70% - 30% for Canadian and U. S forward-looking premiums respectively) resulted in a risk premium in the range of 8.25% - 8.75%. Her estimate of the current market risk premium based upon historic premiums was 6.5%. She noted that this premium needed to be adjusted to reflect the risk of utilities relative to the market risk premium. Using several models and regression analyses, Ms. McShane recommended 65% of market risk premium as the "bare bones" utility risk premium above long Canada bonds. Her adjusted equity risk premium for typical Canadian electric/gas utilities was approximately 4.25%.

Ms. McShane conducted a review of the historic risk premiums for the Canadian and U.S utilities for the period of 1947–1999, giving primary weight to the Canadian data. She found that, using arithmetic averages, a compound risk premium was achieved in the range of 4.0% - 5.8%.

Ms. McShane also conducted an analysis of investor growth expectations for a sample of U.S. gas distributors for the period from 1993 to 2000 with similar investment risk to typical Canadian gas/electric utilities. She stated that this indicated an average risk premium of 4.8%.

The results of the three approaches studied by Ms McShane indicated an equity risk premium for a typical Canadian utility of 4.25% - 4.5%, above a long Canada yield of 6.25%. Her estimate of the resulting cost of equity was in the range of 10.5% - 10.75%, before any adjustment for financial flexibility.

Discounted Cash Flow Test

The discounted cash flow (DCF) test proposes that the price of a common stock is the present value of the future expected cash flows discounted at a rate reflecting risk of the cash flows.

Ms. McShane applied the DCF test to a sample of eight LDC's. She found the average and median expectations of long-term earnings growth were both 5.8%. The average and median adjusted dividend yields were 5.2% for both. She stated that adding the adjusted dividend yield to the expected growth rate results in an estimated required return on common equity of 11.0% unadjusted for financial flexibility for AGS. Applying the discounted cash flow test to APS led Ms. McShane to recommend a 11.0-11.5% return, without adjustment for financing flexibility.

Comparable Earnings Test

The comparable earnings test measures a fair return based on the concept that invested capital should earn a return commensurate with alternative ventures of comparable risk.

The application of the comparable earnings test requires the selection of industrials of reasonably comparable risk to regulated firms, selection of an appropriate time period over which returns are to be measured to estimate prospective returns and the determination of relative risk of the industrials as compared to regulated firms.

Ms. McShane selected 17 companies from 95 Canadian industrial firms that met certain selection criteria. The earnings for the selected low risk industrials were evaluated over the most recent business cycle from 1991 to 1999. She found that the average annual returns for the selected sample of low risk industrials were 12.8%.

Ms. McShane noted that the business risks of industrials were typically higher than of regulated firms. She stated that the purpose of the analysis of relative risk of selected industrials was to determine to what extent the differences in risk should result in a risk adjustment to the industrial returns. She stated that statistical measures of risk for six major publicly traded Canadian gas/electric utilities suggested that these utilities are in about the same risk class as the typical low risk industrial sample, and that the data indicated that the gas/electric utilities have experienced greater book and market return stability than the low risk industrials. She argued that, therefore, a quantification of the risk differences on the return requirements was appropriate. This adjustment was made using the Capital Asset Pricing Model (CAPM), using an adjusted beta,[14] giving 2/3 weight to the raw beta and 1/3 weight to the market beta, applied to the comparable earnings test for Canadian industrials. Ms. McShane stated that this would indicate an appropriate return of 12.5% - 12.75%.

Ms. McShane considered the returns of U.S. industrials as a relevant input factor to the comparable earnings test due to the relatively low number of low risk consumer-oriented industrials in Canada, and the contrast of returns for low risk U.S. industrials as compared to low risk Canadian industrials for the most recent business cycle. Adjusting for corporate tax differences and differential risk with Canadian utilities, Ms. McShane determined that the applicable return was in the range of 12.5% - 13.0%

Ms. McShane gave primary weight to the Canadian results. Based upon the comparable earnings test and before adjustment for financial flexibility, she stated that the fair return would be in the range of 12.5% – 12.75%.

Financial Flexibility

Ms. McShane stated that to avoid equity dilution, the "bare bones" cost of equity derived from the risk premium test should be adjusted upward to maintain financial flexibility and integrity. She stated that the adjustment should include an amount for administrative expenses related to equity issues; an amount for market pressure to avoid the tendency for the price of the stock to fall as an additional supply of stock is issued; and an additional margin to cover unforeseen events such as a sharp rise in interest rates. She stated that financing costs for high-grade Canadian firms are in the range of 4% - 5% corresponding to an after tax rate of approximately 2.5%. The allowance for market pressure was evaluated in the range of 4% - 5%. Her sum of financing costs and market pressure costs was 7%. Adding a minimal increment for unforeseen events results in a flotation cost allowance of approximately 10%. Ms. McShane stated that the flotation cost adjustment was approximately 45–50 basis points for a 7% floatation cost, and was approximately 65–70 basis points for a 10% flotation cost.

ATCO rejected Drs. Booth and Berkowitz recommended rate of return on equity as being inadequate to reflect a sufficient premium over the cost of long-term debt. It stated that the tests applied by Calgary relied on the past, and did not take in to account investors' current expectations.

[14] In the CAPM model "beta" is the measure of the variance of a given stock or portfolio relative to that of the overall market. It is defined as the covariance of the stock or portfolio with the overall market, divided by the variance of the market. A beta equal to 1 implies that the stock in question has the same variance (is as volatile) as the market as a whole. A beta equal to 0.5 implies that the stock in question is 50% as volatile as the market. The theory behind the CAPM model is that stocks with a smaller beta require less return to attract investors.

Positions the of Interveners

Calgary

In support of its position on rate of return on equity, Calgary submitted evidence from its witnesses Dr. Booth and Dr. Berkowitz.

Drs. Booth and Berkowitz stated that the foundations for fair rate of return on equity were:

1) A regulated utility should be allowed to earn a fair return on the actual capital invested in the enterprise that should be equivalent to what the stockholders could get if they took their book value and invested it elsewhere.
2) The rate of return should be sufficient to attract new capital without impairing the existing investments.
3) The rate of return should be sufficient to maintain its financial integrity at a level that attracts capital at reasonable terms.

Drs. Booth and Berkowitz calculated the fair rate of return in relation to the market risk or beta and the risk free rate compared to long Canada bond yields. They forecast the long Canada bond yield rate at 5.75% over the next two years. Drs. Booth and Berkowitz studied two risk premium models. The CAPM estimate based upon the historic average market risk premium, adjusted for the changing risk profile of long Canada bond showed a fair return on equity in the range of 8.00% - 8.16%. A newer, multi-factor model showed a fair rate of return on equity in the range of 7.68% - 8.13%. Drs. Booth and Berkowitz recommended a "bare bones" rate of return of 8.00% based on the results of their tests.

Adjusted for flotation costs, Drs. Booth and Berkowitz recommended a fair rate of return on equity at 8.25% for both 2001 and 2002, on a 35% common equity capitalization ratio for AGS and 34% for APS. This rate of return was judged as sufficient to maintain the financial integrity of a gas LDC and would be broadly consistent with the NEB awards for class 1 pipelines.

In their evidence, Drs. Booth and Berkowitz criticized Ms. McShane's use of the comparable earnings test due to the accounting practices and relative risk of the sample firms studied, the time period of the study, the screening method to select the sample of firms studied, and an inability of the comparable earnings test to measure opportunity cost. Calgary disagreed with ATCO's method of arriving at market risk premium using the arithmetic rate of return versus the geometric rate of return method, and the weighting of U. S. data used in arriving at the recommendation. Furthermore, Calgary disagreed with the adjustment of 50 basis points to the risk premium for financial flexibility.

In rebuttal evidence, Calgary evaluated the difference between the recommendations of AGS and Calgary. In its view, the difference was attributable to several adjustments used by AGS' witness, all tending to increase the rate of return requested by AGS.

Calgary criticized Ms. McShane's comparable earnings test stating that the sample used did not eliminate those firms that exhibit market power, thus violating the premise that regulation is a surrogate for competition. Calgary submitted that the comparable earnings test did not provide an insight into what earnings investors require in the future, and results in an upward bias of the risk premium, and therefore should be given no weight by the Board. Furthermore, Calgary submitted that the Board should reject Ms. McShane's result of the DCF model on the grounds that it relied heavily on U.S. data and was biased upward as a result of reliance on IBES analysts' forecasts, which could be optimistic.

Calgary submitted that Ms. McShane's Market Risk Premium test was biased upward due to her selection of data from the Canadian Institute of Actuaries and her disregard of the data from the Task Force on Retirement Income and the Canadian Stocks, Bonds and Inflation. Similarly, Calgary criticized Ms. McShane's selection of the Blume report and her disregard of the study by Gombola and Kahl, which Calgary suggested resulted in an upward bias to the recommended rate of return on equity.

Calgary submitted that Ms. McShane's addition of 50 basis points for financial flexibility was unwarranted since no evidence was provided that CU Inc. experienced any market pressure when raising common equity on behalf of AGS. Calgary agreed with the result of using Canadian data to measure market risk premium as presented in the evidence of Ms. McShane. Calgary was critical of the weight given by Ms. McShane to U.S. data and recommended that the Board reject the reliance on U.S. data and base AGS' allowed return on Canadian data.

AIPA

AIPA considered that AGS overstated the risk free rate in comparison to the average of the 10-year Canada Consensus forecast of 5.6%. AIPA submitted that a risk free rate of 5.7% would be appropriate for the test years of 2001 and 2002.

CCA

The CCA supported Calgary's recommendation of 8.25% return on equity for ATCO.

FGA

The FGA did not support the use of data from U.S. markets to evaluate investor's perceptions about raising capital in Canada. As a consequence, FGA recommended that the Board should consider 50 points as an adjustment to the risk premium for financial flexibility.

MI

The MI were critical of AGS' request for 11.5% and 12.0% return on equity for AGS and APS, respectively. The MI agreed with Calgary regarding the equity risk premium and the adjustment for financial flexibility and supported Calgary in recommending a fair return on equity of 8.25% for 2001 and 2002.

Views of the Board

As noted in the previous section, the Board is of the view that it is appropriate to consider the rate of return on common equity for AGS and APS as a combined entity, then look to the relative risks of AGS and APS in establishing their respective allowed capitalization ratios.

The Board has reviewed the evidence of Ms. McShane for ATCO, and Drs. Booth and Berkowitz for Calgary. The Board is concerned that the nature of the expert evidence provided is of little probative value to the Board in establishing this important determinant of the utility's revenue requirement.

In particular the Board notes the effect that the application of professional judgement has on the outcome of the equity risk premium test, a test which has been noted to be the mainstay of this Board and other Canadian regulatory boards over recent periods, and is also the one test undertaken by both parties. Ms. McShane provides an estimate of adjusted beta for the CAPM of .65 as appropriate for ATCO, resulting in an equity risk premium of 425 basis points. Drs. Booth and Berkowitz criticize Ms. McShane's conclusions regarding this adjustment and note:

> The beta estimate used by Ms. McShane in this hearing is too high. To raise her estimated beta of .45 to a level of .65, she applies Blume's (1975) finding that in the long run, U.S. equities in general tend to regress toward the market. … If we now repeat Blume's analysis using the 1994-98 and 1989-93 periods…these results suggest an overall regression tendency towards an overall beta of .582 [using data from 16 Canadian utilities].[15]

This beta estimate of 0.582 is further averaged with other data on current market utility betas to arrive at an adjusted beta of .50. This is compared to another direct estimate of beta in the range of 52-56%.[16] In the final analysis, the value for beta used by Drs. Booth and Berkowitz is .50, associated with a return on equity of 8.00%, adjusted for the changing risk profile of long Canada bonds (an adjustment of 50 basis points).

Although the Board is of the view that Calgary's criticism of Ms. McShane's beta adjustment has merit, it finds that the further adjustments made by Calgary present their own difficulties. It is evident that the range of professional judgement that can be applied to this one aspect of one of the tests can account for a substantial difference in the estimated required return. This one difference accounts for nearly 100 basis points on return on equity, or approximately $1.5 million per year, between Ms. McShane's beta estimate of .65 and Drs. Booth and Berkowitz' estimate of .50. The Board has examined the other evidence brought forward by parties on the issue of rate of return and has found that parties' views are similarly far apart in every instance.

The Board notes Calgary's submission that the adjustments made by Ms. McShane increase the requests for rate of return for ATCO. However, the Board also notes that on the same page in evidence where Calgary makes a recommendation of 250 basis points being adequate for a risk premium for ATCO, it notes that comparable recent awards in other Canadian utility jurisdictions have ranged from 300-387.5 basis points.[17] The Board view is that the application of professional judgement to rate of return evidence must not just be a "one way street". The Board is of the view that the requests by ATCO for between 525 and 550 basis points above their long Canada bond forecast and the Calgary recommendation for 250 basis points above their long Canada bond forecast are both outside of what the Board would consider to be reasonable.

[15] Calgary Evidence, Appendix B. pp.11-12
[16] Calgary Evidence, pp.51-52
[17] Calgary Evidence, p.68

Further, these estimates are far enough apart that the underlying evidence is of little value to the Board in establishing an accurate and well justified estimate of the utility rate of return required to maintain the financial integrity of the utility in the eyes of investors and the market. Subsequently, the Board must rely on an examination of past awards to CWNG to determine if there is a requirement for adjustments to those awards. The Board is also of the view that alternative methods of determining appropriate utility return may need to be examined for use in future rate cases.

In Decision 2000-9, the Board awarded a risk premium of 375 basis points above the forecast long Canada rate for 1998. This was inclusive of an amount for financing flexibility. The Board notes that this premium is near the upper end of the range of current awards noted by Calgary. The Board has no reason to believe that investors or the market would see a need for ATCO to receive a risk premium that would be above these other awards, based on either the business or regulatory climate in Alberta. Therefore, lacking evidence that would suggest a measured adjustment up or down, the Board is satisfied that this previous risk premium award is reasonable and may be used for AGS and APS for 2001 and 2002.

The Board notes that the estimates provided for long Canada bond rates are relatively close together, Calgary has forecast 5.75% and ATCO has forecast 6.25%. The Board notes that both estimates have involved the use of judgement by the expert witnesses to account for various recent financial trends. The Board finds that it is reasonable to average these estimates, to establish a forecast long Canada bond rate of 6.0% for the test period.

The Board therefore determines that a rate of return on common equity of 9.75% is reasonable for both AGS and APS for the period of 2001/2002.

5.3 Appropriate Capital Structure for AGS and APS

Position of ATCO

ATCO applied for approval of its forecast capital structure for 2001 and 2002 in comparison to the capital structure approved in Decision 2000-9. The proposed capital structure consolidated by the Board (exclusive of no-cost capital) is as follows:

	Forecast 2001	Forecast 2002	Decision 2000-9
Debt	53.8%	51.1%	45 - 50%
Preferred Equity	6.5%	6.5%	12 - 17%
No Cost Capital	0.5%	0.4%	
Common Equity	**39.2%**	42.0%	32 - 37%

Ms. McShane testified that with a capital structure with a common equity ratio of 40% and a preferred share component in the 5–10% range, AGS would contribute its fair share to the creditworthiness of CU Inc. She testified that a capital structure with a common equity ratio of 50% and a preferred share component of approximately 5% would be appropriate for APS.

Ontario Energy Board, EB-2006-0501 Hydro One Networks 2007-2008 Electricity Transmission Revenue Requirements, Aug 16 2007

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0501

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

FOR 2007 AND 2008 ELECTRICITY TRANSMISSION REVENUE REQUIREMENTS

DECISION WITH REASONS

August 16, 2007

7. HYDRO ONE TRANSMISSION ROE AND CAPITAL STRUCTURE

Return on Equity (ROE)

Hydro One Transmission's revenue requirement for the year 2000, the last time the Board conducted a cost-of-service review of the transmission business, was based on a return on common equity ("ROE") of 9.88%. The Company is requesting an increase to 10% in 2007 and 10.25% in 2008.

Hydro One provided evidence in support of its request through Ms. Kathleen McShane of Foster Associates, who initially argued that an ROE of 10.5% in both 2007 and 2008 was appropriate for Hydro One Transmission. In updates of February 23, 2007 and March 1, 2007, Ms. McShane revised her recommendation on the basis that prevailing market conditions warranted lower ROEs of 10.0% in 2007 and 10.25% in 2008.

Ms. McShane's study made use of the equity risk premium, discounted cash flow and comparable earnings tests. Ms. McShane took the position that her recommendation was demonstrably reasonable in light of returns allowed for Hydro One Transmission's U.S. peers (range of 10.5%-12.5%), with whom she submits Hydro One would have to compete for capital to finance close to $2 billion in transmission-related capital expenditures in the 2006-2008 timeframe, and potentially similar levels for the several subsequent years.

CCC and VECC provided evidence through Dr. Laurence Booth of the University of Toronto, who took the position that a fair ROE for Hydro One Transmission would be approximately 7.50%, including a 50 basis point cushion. Dr. Booth submitted that most of Hydro One Transmission's risk comes from its rate design and the amount of debt financing, not its underlying business risk. Dr. Booth saw underlying business risk to be minimal for Hydro One and most regulated utilities in Canada.

The *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* of December 20, 2006 (the "Cost of Capital Report") incorporates an ROE methodology that, when applied to Hydro One Transmission, produces ROEs considerably lower than the levels proposed by Hydro One and somewhat higher than the level proposed by Dr. Booth. Based on an answer to an undertaking provided by Hydro One, application of the Board's distribution formula to Hydro One Transmission would produce an ROE of 8.53% in 2007 and 8.64% in 2008.

Capital Structure

Hydro One Transmission has a current deemed capital structure of 60% debt, 4% preference equity, and 36% common equity. It is requesting Board approval for a more favourable deemed capital structure of 56% debt, 4% preference equity and 40% common equity.

Hydro One provided evidence in support of its proposed capital structure, again by Ms. McShane, who argued that Hydro One's proposed capital structure was justified in light of its need to maintain an 'A' bond rating. Ms. McShane stated that this bond rating was critical in light of Hydro One's need to access debt markets to finance extraordinary capital expenditures, the more limited market for BBB debt, and the lesser ability of BBB-rated companies to access the long-term (30-year) debt market.

CCC and VECC provided evidence by Dr. Booth on this matter, who recommended that the Board should reduce Hydro One Transmission's allowed common equity ratio to 34%, with a 66% debt ratio. Dr. Booth noted that his recommended common equity ratio was 1% higher than that imposed on the Alberta transmission companies regulated by the Alberta EUB. During his examination-in-chief, Dr. Booth stated that he viewed transmission assets as the lowest risk regulatory assets in Canada, mainly because transmission is a natural monopoly and an essential component in the distribution of electricity. Dr. Booth also noted that Hydro One had the highest bond rating of any regulated utility in Canada. The Board notes that while Hydro One owns over 97% of the transmission system in Ontario, it is not, strictly speaking, a “monopoly”.

The Cost of Capital Report incorporates a capital structure policy for distributors of 60% debt and 40% equity. This is in line with Hydro One Transmission’s presently approved deemed capital structure.

Transmission versus Distribution Risk Differentials

In the course of this proceeding, Board staff retained Professors Fred Lazar and Eli Prisman of York University to undertake a study of whether or not there is a determinable risk differential between Hydro One’s distribution and transmission businesses that would justify differences in the allowed capital structures and cost of capital for the respective businesses.

Professors Lazar and Prisman concluded that “at this time, the results are too mixed, and most often statistically insignificant to reach any conclusion other than to award the same ROEs for both the Transmission and Distribution segments of Hydro One.”

Ms. McShane took a similar view noting that the difference in the level of risk between Hydro One Transmission and Distribution is not material enough to distinguish between the two in terms of either recommended capital structure or return on equity.

Dr. Booth expressed the view that Hydro One Transmission is of lower risk than Hydro One Distribution. During his cross-examination, Dr. Booth stated that he would be amenable to the use of the Board’s distribution rate of return mechanism to set Hydro One Transmission’s ROE, but only on the basis that the Board adjust for Hydro One Transmission’s lower risk through a lower common equity ratio.

Cost of Debt and Preference Shares

Hydro One provided its derivation of the forecast yields for each of the debt issues anticipated for 2007 and 2008, which were based on forecast Government of Canada yields for 5, 10 and 30 year debt with a Hydro One spread applied to them.

Although Ms. McShane updated her evidence on February 23, 2007 and March 1, 2007, and concluded that prevailing market conditions justified a lowering of her ROE recommendation, Hydro One did not update its debt and preference share costs to reflect the changes in market conditions that had occurred since its evidence had been filed in September 2006.

During cross examination, Hydro One acknowledged that it had not updated these costs and had issued new 30-year debt in March of this year. The Company acknowledged that there would be a difference between the cost of that new debt compared to the cost of debt assumed in the evidence. Specifically, the coupon rate of the 30-year debt assumed in the evidence was 5.53%, but the new debt had been issued at a coupon rate of 4.89%.

Hydro One explained that the reason it had not updated these costs while updating its ROE estimate was that the impact of any such update would be far more significant on the ROE than it would be on the cost of debt, as the cost of debt is based on a full portfolio of outstanding bond issues that incorporate placements going back a number of years. Also, Hydro One stated that it viewed the cost of debt as but one of a bundle of assumptions embedded in its Application, and it did not propose to revisit the full suite of its planning assumptions as the revision of some may have been more favourable to one stakeholder, while the revision of others may have been more favourable to another.

Treatment of Designated Projects – Impact on Capital Structure/ROE

Ms. McShane's initial evidence on ROE was submitted with the presumption that three designated capital projects would receive the special treatment applied for. The NRP was not initially included among these projects or as part of her assumptions.

Hydro One subsequently updated its evidence to include the NRP in its request for special treatment of the designated projects; however Ms. McShane's evidence update did not make any reference to this apparent reduction in Hydro One's risk profile.

During cross-examination Ms. McShane was asked about the impact on her recommendations if Hydro One's request for the special designated project treatment was denied. She stated that the ROE calculation would have to be adjusted upward by 25 to 35 basis points, or alternatively that a two-and-a-half to three percentage points increment in the equity ratio would be necessary. Ms McShane noted that her preference was for an adjustment to the equity ratio.

The Board's consideration of the proposed treatment of the designated projects, including the NRP, is dealt with in Chapter 6 in this Decision.

Board Findings

Hydro One asserted that its proposed increase in ROE is necessary to enable it to access capital markets effectively, and to borrow the very large sums needed to fund the expansion and reinforcement of the transmission system at interest rates that are as low as possible.

Access to these markets, and the costs of borrowing, are often seen to be dependent on the opinions expressed by various bond rating organizations. One of the key factors used by these agencies to assess the credit-worthiness of a borrower is the adequacy of its ROE in light of the business risk associated with the borrower. If the ROE is seen to be low given an entity's business risk, the cost of borrowing will rise to account for it. If the disparity is too great between the ROE and the inherent business risk, funds may not be available at all.

In this way, the Company's proposal for an increased return on equity, and an increase in the equity portion of its deemed capital structure, is bound up in many of the other proposals forming part of this rates proceeding.

It is also true that the comparative risk faced by the transmission business of the Company was an overarching theme of this Application. The Company sought to limit or eliminate the regulatory risks it is facing. Hydro One was concerned that the Company would not be granted recovery for expenditures prudently incurred. This is seen in the proposals for the designated projects, and in the assurances requested for portions of the capital projects budget, and in the Company's RRAM proposal.

To consider the Company's proposal, it is necessary to consider the riskiness of its operating environment, the perception of that environment by market analysts, and the appropriateness of the Board's methodology in establishing the appropriate ROE and capital structure.

As the operator of the vast majority of the transmission system in the province, the Company is uniquely capable, and uniquely positioned, to make a wide range of informed decisions respecting system growth and reinforcement. The ratepayer is entitled to expect that the Company makes careful, engineering-based plans, founded on its best judgement as to what the system needs.

Where line connection enhancements are made, the TSC provides a formulaic approach directed to assessing the prudence of a project, and the extent to which those directly benefited by the project are required to contribute capital. This serves to limit the exposure of the transmitter to risk. Although the same formulaic methods do not exist to assess prudence and cost recovery for large capital projects, Hydro One has ample opportunity to address these issues in Leave to Construct applications and rate cases.

A utility which has followed reasonable engineering and financial practice, and has applied the TSC appropriately, is unlikely to be denied recovery of prudently incurred costs. Similarly a utility which is confronted with unusual circumstances is unlikely to be denied relief when events out of the utility's control occur. Indeed, the response of the Board and the intervenors to the Company's dilemma respecting the NRP is evidence of a regulatory approach in the province that is flexible and responsive. This positive regulatory environment is noted in one of the bond rating agency reports.

The Board recognizes that some of the projects the Company becomes involved in are very large, both in terms of their related costs, and their potential impact on the effectiveness of the overall provision of electricity to the province's residents and businesses. It is understandable that the Company has concerns respecting its ability to recover the very large sums that it commits to such projects; however, the Board cannot discern any significant risk for the Company that it will be unable to recover prudently incurred costs.

Under the concept of just and reasonable rates, the Company has a reasonable and enforceable expectation that its prudently incurred costs will be recovered in a timely fashion. This includes an expectation that in considering the prudence of expenditures, the Board will assess the Company's judgement in light of the circumstances prevailing at the time the expenditure is made, and without the distraction of hindsight. The Company's prudence should be adjudicated on the basis of what it knew or ought to have known at the time the expenditure was made, not on the basis of subsequent events or conditions, which may have the effect of making the expenditure appear to be unwise.

There is always a risk that if the Company fails to use good judgement in formulating its plans, or otherwise incurs costs imprudently, it will not be authorized to recover such costs. That is a risk that the Company must bear on its own. No responsible regulator can protect a utility from imprudence, poor judgement or laxity. Nor, to be fair, does Hydro One appear to be asking for protection from these.

The evidence respecting the observations of the bond rating services suggests that they are much more confident than the Applicant in the regulatory regime governing the company's operations. This was particularly evident in the examples cited during the cross-examination of Ms. McShane by counsel for CCC.

One analytical tool useful in determining the appropriate ROE and deemed capital structure lies in assessing the extent to which the transmission business can be considered to be more or less risky than the distribution business. The Board's recent consideration of cost of capital in the Cost of Capital Report is of assistance in determining an appropriate ROE and capital structure for the applicant's transmission business.

The Board has examined the fundamentals of its ROE methodology on a number of occasions in the recent past. The Cost of Capital Report is only the most recent example. In each case, the Board's use of its current methodology has been confirmed.

The Cost of Capital Report was generated to inform the Board with respect to the appropriate ROE and capital structure for the local distribution companies, including Hydro One in its operation of a substantial distribution network. It follows that a consideration of the relative risks as between the transmission business and the distribution business should inform a consideration of the appropriate ROE and deemed capital structure for the transmission business.

Importantly, most of the experts providing evidence in this case were unable to conclude that there was any material difference in the level of risk between the distribution and the transmission undertakings. Dr. Booth alone suggested that transmission was less risky, and therefore should be subject to a lower overall ROE.

With respect, Dr. Booth's view seemed to be analytical, and not data based. He referred to the approach taken by the Alberta Board in the case of Altalink, a comparator that was not demonstrated to be apt.

It is the Board's view that there really is no convincing quantitative evidence before us which suggests that transmission is more or less risky than distribution. It is true that distribution has greater and more immediate exposure to the possibility of bad debts. On the other hand, in absolute terms, the transmission system involves very large capital projects of significant complexity, which can be subject to delay in completion, and consequential delay in expected revenues. On balance, the Board concludes that the evidence before us does not provide a basis upon which we can make a finding that there is any meaningful difference in risk as between distribution and transmission.

The Company is in a unique position compared to other utilities in the province. It alone among all of the utilities in Ontario operates a major transmission business and an equally large distribution business. If the Company believes that there is a significant risk differential between its two business segments, it should have been able to present much more convincing evidence respecting the relative risks. The fact that it did not is telling.

It follows that the ROE for the transmission arm of the company should not enjoy a different ROE than that governing its distribution business.

Accordingly, the Board finds that the ROE formula for electricity distributors, as documented in the December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism, shall be applied to Hydro One Transmission. The Board has determined that Hydro One's ROE shall be derived based on an application of the Board's formula as of January 1, 2007, using December 2006 *Consensus Forecasts* and Bank of Canada data. This should result in an ROE of 8.35% for both 2007 and 2008.

The Board notes that all of the consumer intervenor groups were receptive to the use of the Board's distribution formula for setting ROE, although most also argued that Dr. Booth's lower recommended common equity ratio should be applied in establishing Hydro One Transmission's capital structure. However, as has been discussed, the Board has not been presented with any convincing quantitative evidence in this proceeding which suggests that transmission is more or less risky than distribution. Accordingly, the Board will also apply the distribution capital structure to Hydro One Transmission.

The Board has further determined that Hydro One's debt costs will not be updated. The Board notes the comments of some intervenors that the Board should require Hydro One to update its forecast debt costs, as is done for the regulated natural gas utilities. The Board notes that in recent gas proceedings where this has been done, it has usually arisen out of rates agreed to by the respective parties and included in the Settlement Agreements. In the absence of such a settlement on this issue in this proceeding, the relative magnitude of the amounts involved, and the uncertainties surrounding changes in interest rates and Hydro One's financing plans, the Board is not convinced that the cost of debt should be updated and will use the rates contained in Hydro One's application for the purpose of rate-setting.

Public Utilities Board of the Northwest Territories, Decision 13-2007
Northwest Territories Power, Aug 29 2007

THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

DECISION 13-2007 **August 29, 2007**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided to its customers within the Northwest Territories.

4.4 Fair Return On Equity

NTPC requested allowed returns on equity of 10.5% and 10.75% for test years 2006/07 and 2007/08 respectively. Ms. McShane filed expert testimony supporting the NTPC proposed returns on equity. Drs. Kryzanowski and Roberts, who filed evidence on behalf of the HC, recommended returns on equity of 6.75% for 2006/07 and 7.20% for 2007/08.

Ms. McShane used the equity risk premium method; the discounted cash flow method and the comparable earnings test to estimate the returns on equity applicable to a benchmark utility as follows:

> "Ms. McShane's recommended returns on equity are based on the application of five different tests, three risk premium tests, the discounted cash flow test and the comparable earnings test. Ms. McShane used these tests to develop a fair return on equity for a benchmark Canadian utility, that is, a utility which, in light of its business and financial risks, would be able on a stand-alone basis, to achieve debt ratings in the A category. The returns on equity applicable to a benchmark utility would be approximately 10.0% for 2006/07 and 10.25% for 2007/08. A summary of the results of the tests applied by Ms. McShane (as updated in her Rebuttal Evidence, Ex. 12) are set out in the table below.

	Equity Risk Premium (ERP)
Test Year 2006/07	9.5%
Test Year 2007/08	9.75%
Discounted Cash Flow	9.0-9.5%
Comparable Earnings	12.0%"

(NTPC Argument, p.41, *ll*. 35 – p. 42, *ll*. 10)

Ms. McShane added a 50 basis points risk premium to the returns on equity applicable to the benchmark utility to reflect NTPC's higher risk in relation to the benchmark utility and came up with recommended returns on equity for NTPC of 10.50% for 2006/07 and 10.75% for 2007/08.

Drs. Kryzanowski and Roberts relied primarily on the equity risk premium test for their recommended returns. However, Drs. Kryzanowski and Roberts used the DCF Test to provide additional estimates of the Market Equity Risk Premium using both historical and forward-looking estimates of dividends and dividend growth at the market level.

Comparable Earnings ("CE") Test

The HC argued the results of the CE test should be given no weight in the determination of a fair return for the Corporation because the method is devoid of scientific merit, lacks theoretical underpinnings and suffers from substantive implementation difficulties.

> "Drs. Kryzanowski and Roberts point out that the basic problem is that there is neither a theoretical underpinning nor any empirical support for the comparable earnings approach to estimating a regulated fair rate of return for a utility. As an *ad hoc* approach to estimating a regulated fair rate of return, there are no agreed-upon rules for deciding upon how the Comparable Earnings Test should be implemented. They not only review 11 problems encountered in implementing a Comparable Earnings Test in their evidence but they illustrate the net effect of these problems by calculating the performance of the sample of 20 low risk Canadian industrials used by Ms. McShane over the 1994-2005 period to calculate accounting ROEs. They find that her sample outperforms the S&P/TSX Composite in that it not only has a higher mean return but also less risk. Thus, Ms. McShane has used a sample that has outperformed the S&P/TSX Composite over her test period both in terms of realized return and risk. Thus, Drs. Kryzanowski and Roberts recommend that the Board should not apply any weight to the Comparable Earnings evidence submitted by Ms. McShane. The method is not only devoid of scientific merit and theoretical underpinnings but its substantive implementation difficulties make it unsuitable to play a role in the determination of a fair rate of return for a utility." (HC Argument, p. 36)

Ms. McShane responded in detail to the HC's criticism of the CE test in her rebuttal evidence. (Ex.12 McShane Rebuttal) In essence, Ms. McShane's view as to the usefulness of the CE test may be summarized as follows:

> "…Regulation relies on an original cost rate base construct, or convention, rather than the market values to which the "scientific" cost of attracting capital tests apply. The comparable earnings test measures comparable returns measured in a manner compatible with the regulatory construct for measuring the equity investment in a utility, that is, on the basis of original cost. The cost of attracting capital tests do not." (Ex.12 McShane Rebuttal, p. 54, *ll*. 1581 - 1586)

Discounted Cash Flow ("DCF") Test

The HC submitted the DCF tests are unreliable when applied to specific firms in the same industry because of circularity problems and due to subjectivity in analysts' growth forecasts.

> "Ms. McShane also generates DCF estimates of a fair return on equity for a sample of U.S. gas and electric distributors. Due to a number of disadvantages, including circularity, discounted cash flow (DCF) tests are unreliable when applied to specific firms in the same industry." (HC Argument, p. 35)

In response, Ms. McShane submitted circularity is mitigated by using a sample of companies instead of the specific company and subjectivity is addressed by using a consensus growth forecast.

> "…However, circularity is mitigated by (a) using samples of companies, not the specific company to which the DCF test is being applied and (b) using the consensus of growth forecasts for the companies in the samples. With regard to the second, the use of the available consensus of analysts' earnings forecasts for the growth component eliminates the possibility that the results are colored by an analyst's own subjective views

of what the regulator should allow." (Ex.12 McShane Rebuttal, p. 44, *ll*. 1299 – p. 45, *ll*. 1305)

Equity Risk Premium ("ERP") Test

The benchmark equity return estimates under the ERP test provided by Ms. McShane are as follows:

	McShane	
	2006/07	2007/08
Risk free rate	4.25%	4.50%
Market equity risk premium	6.50%	6.50%
Beta	65% to 70%	65% to 70%
Equity risk premium	4.75%	4.75%
Allowance for financing flexibility	0.50%	0.50%
Benchmark utility return	9.50%	9.75%

The estimates for equity returns under the ERP test provided by the Drs. Kryzanowski and Roberts are as follows:

	Kryzanowski & Roberts	
	2006/07	2007/08
Risk free rate	4.20%	4.65%
Market equity risk premium	4.90%	4.90%
Beta	50.0%	50.0%
Equity risk premium	2.45%	2.45%
Allowance for financing flexibility	0.10%	0.10%
Benchmark utility return	6.75%	7.20%

The significant differences between the two sets of estimates are explained by differences in the estimates included for the market equity risk premium ("**MERP**"), the beta value (which is a measure of the risk of an average risk utility stock relative to the market) and the allowance for financing flexibility

Ms. McShane indicated her 6.5% market equity risk premium estimate recognizes the expected value of the equity market return developed from historic values in conjunction with the current and forecast low levels of interest rates.

> "Based on the analysis of the historic risk premiums, primarily in Canada and the U.S., with focus on the arithmetic averages and with consideration given to trends in the equity and government bond markets in both countries, a reasonable estimate of the expected value of the equity market risk premium at the forecast levels of long-term government bond yields is approximately 6.5%. The 6.5% estimate of the equity market risk premium explicitly recognizes the expected value of the equity market return developed from historic values in conjunction with the current and forecast low levels of interest rates." (Ex. 2, Appendix B, McShane Evidence, p.33, *ll*. 900 - 907)

The HC witness expressed several concerns with Ms. McShane's forecast MERP.

> "In contrast, Ms. McShane uses the historic average MERP for Canada, the U.S. and the U.K. over the period 1947-2006 to obtain an estimate of the MERP going forward of 6.5%. Her estimate is inappropriately high for four reasons. First, the chosen time period results in an inflated estimate of the going-forward likelihood of achieving the high realized returns on equities and low realized returns on bonds that followed World War II. This period begins with rapid economic growth due to pent up demand from the war period and administered low interest rates. Using the mean gives an equal weight to each year in this early period. Second, minimal or no weight is placed on the declining trend of MERPs for the three markets over this time period. Third, no adjustments are made for differences in risks across the market proxies used to calculate the MERP in the different countries. Fourth, no adjustments are made for the effect of equity re-valuations over this period of time unless one believes that price-to-dividend multiples will exhibit a similar three-fold increase over the next 60 years." (HC Argument, p. 30 - 31)

In her rebuttal evidence, Ms. McShane responded to the first 3 concerns of the HC. First, with regard to the time period chosen for the analysis, Ms. McShane stated as follows:

> "…It would be inappropriate to "cherry pick" the post World War II period. Equally, it could be argued that other sub-periods are not representative of future expectations and whose inclusion or exclusion might inflate or deflate the estimate of the expected long-term forward looking returns or risk premium..." (Ex.12 McShane Rebuttal, p.38, *ll*. 1131 - 1134)

Ms. McShane explained that observed risk premiums have declined because the achieved returns on long-term Canada bonds reflect historic yields that were much higher than they are expected to be and the significant capital gains that have occurred since long Canada bond yields began to decline.

> "..The reason that the observed risk premiums have declined is because the achieved returns on long-term Canada bonds reflect (1) historic yields that were much higher than they are expected to be; and (2) the significant capital gains that have occurred since long Canada bond yields began to decline…." (Ex.12 McShane Rebuttal, p. 40, *ll*. 1191 - 1194)

With regard to the HC's view, no adjustments have been made for the market proxies used because Ms. McShane did not consider such adjustments were needed.

> "With respect to the benefits of international diversification, one of the principal reasons for investing abroad is the opportunity to earn similar or higher returns than available in the domestic market while bearing similar or lower risk. From this perspective, there is no rationale for concluding that the returns and risk premiums that Canadian investors would anticipate from investing abroad would be reduced from those anticipated from domestic markets only. (Ex.12 McShane Rebuttal, p. 42, *ll*. 1236 - 1241)

Ms. McShane explained one of the reasons for difference between her estimate of market equity risk premium and Drs. Kryzanowski and Roberts' estimate relates to the weight given to the arithmetic versus geometric averages in the estimation of historic market risk premiums. Drs. Kryzanowski and Roberts gave more weight to geometric averages based on their finding that historically returns have been mean reverting. Mean reverting essentially means that low returns can be expected to be followed by high returns, so that investors can reasonably expect that, over time, returns will return to some long term average. Therefore, the estimate of the required future equity risk premium should take into account the predictability of future returns as indicated by the mean reversion, by giving some weight to the historic compound, or geometric, return.

Drs. Kryzanowski and Roberts indicated they had conducted a number of tests of robustness of their MERP estimate and conclude that it should not be increased from their estimate of 4.9%.

With respect to the beta values, the difference between the McShane approach and that of Drs. Kryzanowski and Roberts relates mainly to the fact Ms. McShane adjusted her raw beta estimates upwards to provide a better correlation between utility risk and return.

> "Using adjusted betas can mitigate the deficiencies in "raw" betas. Adjusting betas entails moving betas above and below the market mean of 1.0 toward the market mean. The adjustment that is used by the major commercial suppliers of betas uses a formula that gives approximately two-thirds weight to the stock's own beta and one-third weight to the market mean beta of 1.0. Use of adjusted betas implicitly recognizes that "raw" utility betas are not adequate explanators of utility returns. For example, "raw" betas do not capture utilities' interest rate sensitivity. The objective of the relative risk adjustment is to predict the investors' required return. Adjusted betas provide a better correlation between utility risk and return than "raw" betas." (Ex. 2, Appendix B McShane Evidence, p. 38, *ll*. 1031 - 1040)

Drs. Kryzanowski and Roberts disagreed with the upward adjustment of raw betas recommended by Ms. McShane.

> "…McShane uses the Value Line method to adjust her betas upwards when she should not. Drs. Kryzanowski and Roberts provide various rationales in Sections IV and VI of their evidence why the beta of an average-risk (never mind low-risk) utility should not be adjusted towards one. Not only is it logically inconsistent to assume that the average beta of a mature industry is equivalent to that of the overall market but empirical findings upon which this adjustment is based reveal that individual betas revert to the sample mean, which in the case of an average-risk utility is itself. Drs. Kryzanowski and Roberts also demonstrate why the interest-rate sensitivity rationale for using a variant of the adjusted beta method for utilities is flawed and is based on a misunderstanding of asset pricing theory and empirical tests. Since Ms. McShane basically uses the sample average utility beta as her beta estimate for a low-risk utility benchmark, no upward adjustment is needed to offset the tendency of the beta of a specific utility to regress to that same sample average utility beta..." (HC Argument, p. 32)

Drs. Kryzanowski and Roberts explained why in their view adjustment of beta's for interest rate sensitivity is not necessary.

> "…Over the long run, we would expect the average return on long Canada's to be equal to the yield on long Canada's (the proxy for the risk-free rate in rate of return settings). This is because our expectation is that rates would fluctuate randomly so that returns would be above yields to maturity in some periods and below them in others. Thus, while it is true that utility returns are sensitive to interest rates, it is not true that interest rate risk will have a positive risk premium over the long run. (Ex. 8; p. 83)

With respect to the financing flexibility allowance of 50 basis points recommended by Ms. McShane, Drs. Kryzanowski and Roberts noted the Board should consider the excess returns earned by utility investors when establishing the financing flexibility add-on to the return on equity ("**ROE**") in this rate hearing.

> "…In other words, providing generous rates of return allowances to enhance the financial integrity and flexibility of these utilities (without requiring these utilities to establish a reserve account to capture these insurance premiums) just over-compensates investors given the high dividend payout practices of many Canadian utilities. Drs. Kryzanowski and Roberts do not recommend the establishment of such a reserve account. Instead, they recommend that the Board consider the excess returns earned by utility investors when establishing the financing flexibility add-on (or kicker) to the ROE in this rate hearing..." (HC Argument, p. 38)

Additional Risk Premium on Benchmark Return Estimates

Ms. McShane recommended an additional 50 basis points risk premium on the returns on equity applicable to the benchmark utility to reflect NTPC's higher risk in relation to the benchmark utility. In her view, NTPC would be a BBB rated utility at the proposed capital structure and therefore she indicated an additional risk premium is required on the basis of cost of debt differentials between a BBB rated utility and a benchmark A rated utility.

> "The estimation of the difference in return that would be warranted for NTPC's higher business risks is in part a matter of professional judgment, but should be constrained by factual support. Ms. McShane's direct evidence demonstrates that the difference in the cost of debt as between a utility with debt ratings in the A category and a utility whose debt is rated in the BBB category is approximately 0.60%. The difference in the cost of debt between an A rated benchmark utility and a BBB rated utility (which NTPC would be on a stand-alone basis) serves as a proxy for the incremental return that an equity investor would require to invest in NTPC. On the basis of cost of debt differentials, Ms. McShane's incremental equity risk premium of 0.50% for the Corporation should be viewed as the minimal differential return required relative to a benchmark utility. Her proposed differential is fully consistent with the 0.60% differential adopted by the Board in respect of the allowed return for NUL in Decision 9-2006 (March 2006)." (NTPC Argument, p. 45, *ll*. 13 - 23)

Drs. Kryzanowski and Roberts did not agree that an incremental risk premium on the benchmark return is required because in their view Ms. McShane's estimated benchmark returns would have the effect of rewarding NTPC twice for the same incremental risk that is already reflected in the capital structure of an average-risk utility.

> "When she estimates the risk premium, she incorrectly uses a sample or an industry index, which is really for an average and not low-risk utility. Recognizing her error, Drs. Kryzanowski and Roberts challenged her view that an incremental equity risk premium is required. Such an equity risk premium would have the effect of rewarding NTPC twice for the same incremental risk that is already reflected in the capital structure of an average-risk utility." (HC Reply, p. 21)

Views of the Board

The Board notes the CE method provides a measure of the actual realized returns on the book value of comparable risk securities. In this regard the CE test differs from other tests such as the equity risk premium test, which attempt to measure the expected return on the market value of securities. In an original cost rate base jurisdiction where the fair return is established on the basis of the book value of assets, the awarded returns must reflect investors' expectations of market returns on comparable risk securities. These expectations of market returns cannot, in the Board's view, be measured by the book returns of comparable risk securities because of differences between the book values and market values. Rather, the investors' expectations are appropriately measured in relation to the market value of comparable risk securities. In the Board's view the CE method fails to meet this requirement. Therefore the Board will not give any weight to the CE method in determining the fair return on equity.

The Board notes the DCF test, similar to other tests, has certain drawbacks. However, in view of the mitigating factors referred to by Ms. McShane, the Board considers it appropriate to consider the DCF test among other tests in determining the fair rate of return on equity.

The Board notes NTPC's submission that based on the British Columbia Utilities Commission's ("**BCUC's**") automatic adjustment mechanism, the market equity risk premium would be much closer to Ms. McShane's 6.5% than Drs. Kryzanowski and Robert's 4.9%.

> "The most recent regulatory determination of the market risk premium was in 2006 by the British Columbia in which, having heard all the evidence, concluded that the market risk premium was 5.8% at a long-term Canada bond yield of 5.25%. The forecast yield on long Canada bonds in this proceeding is considerably lower than 5.25% (4.5% and 4.65% for 2007/08 by Ms. McShane and Drs. Kryzanowski and Roberts respectively). Based on the BCUC's automatic adjustment mechanism, which, similar to those used by other Canadian regulators, is premised on an inverse relationship between interest rates and risk premiums, the indicated market risk premium at a 4.5% to 4.65% long Canada yield would be higher than 5.8%, much closer to Ms. McShane's 6.5% than Drs. Kryzanowski and Roberts's 4.9%." (NTPC Reply, p. 29, *ll*. 25 - 33)

The Board notes NTPC's submission that the risk premium looking forward should be higher than the historic values when bond market returns are expected to be lower.

> "…Ms. McShane's Rebuttal evidence pointed out that Drs. Kryzanowski and Roberts acknowledged that there has been no material change in the equity market return. If equity market returns are approximately the same, but bond market returns are expected to be lower, then it follows that the risk premium looking forward should be higher than the historic values." (NTPC Reply, p. 29, *ll*. 10 - 14)

The Board considers Drs. Kryzanowski and Roberts' estimated market equity risk premium to be downwardly biased since the witnesses do not appear have given recognition to market equity risk premium increases resulting from lower prospective bond market returns, compared to the historic period.

The Board, having reviewed the foregoing, considers a market equity risk premium of 6% to be appropriate under current long-term interest rate conditions.

The Board also considers Ms. McShane's adjusted beta values to be on the high side when viewed in relation to the raw beta estimates based on observations during a relatively stable interest rate environment such as the 30 month periods, January 2003 to June 2005 and July 2003 to December 2005. (Ex.12 McShane Evidence, p.36, Table 7)

The Board notes Drs. Kryzanowski and Roberts' view that beta values need not be adjusted for interest rate risk because interest rate risk will not result in a positive risk premium over the long run. However, the beta estimates provided by the witnesses in Schedule 4.10 of Exhibit 8 show wide variations in beta values for each 5-year period analyzed. This indicates inference of average beta values from such wide dispersions in beta values may not produce reliable results.

The Board considers a 50 basis point addition for financing flexibility is consistent with similar allowances awarded in other jurisdictions and is appropriate in order to maintain the financial integrity of the utility. The Board is not persuaded that past excess earnings need to be considered in assessing the appropriateness of an allowance for financing flexibility for a utility that is regulated on a forward test year basis. Under forward test year regulation, there is an expectation the probability of actual returns being higher or lower than the allowed return is about the same.

The Board notes Ms. McShane's view that the proposed capital structure would result in a BBB rating for the Corporation. The Board notes the high cost of debt in NTPC's capital structure and considers the 50 basis points upward adjustment recommended by Ms. McShane is reasonable under the circumstances to compensate for the relatively high financial risk of the utility.

Although the Board has accepted an upward adjustment to the equity return estimates as noted above, in future proceedings, the Board would prefer to see all of the business risk adjustment reflected in the capital structure rather than in the capital structure as well as in the return on common equity.

The Board notes NTPC filed its Application in November of 2006, about eight months into the first test year. Since the Corporation would have had knowledge of actual events pertaining to a substantial part of the first test year, the Board considers the Corporation's forecast risks were mitigated to some extent. Therefore the Board considers it reasonable to reduce the allowed rate of return on equity for 2006/07 by 40 basis points to recognize this risk reduction.

Having considered the ERP test and the DCF test and the factors discussed above, the Board determines the fair rate of return on equity to be 8.60% for 2006/07 and 9.25% for 2007/08.

For purpose of calculating the return component of the DPC lease payments, the Board does not consider the 40 basis point reduction in NTPC's return on equity for 2006/07 noted above should apply because this is a specific adjustment applicable to NTPC's particular circumstances in 2006/07. Accordingly, the Board directs NTPC to use fair returns on equity of 9.00% for 2006/07 and 9.25% for 2007/08 in order to calculate the DPC lease payments in the Phase 1 refiling.

BC Comptroller of Water Rights, Order 2166 EPCOR White Rock Water Approval of Revenue Requirements for 2008-2010, Aug 14 2008

Order No. 2166

PROVINCE OF BRITISH COLUMBIA

OFFICE OF THE DEPUTY COMPTROLLER OF WATER RIGHTS

IN THE MATTER OF the *Water Utility Act* and

the *Utilities Commission Act*

and

IN THE MATTER OF

Applications by

EPCOR White Rock Water Inc.

For Approval of Revenue Requirements for 2008, 2009 and 2010 and Amended Water Tariff Rates and Terms and Conditions effective January 1, 2008; January 1, 2009 and January 1, 2010
And
For Approval of a Cost of Service and Rate Design Application filed on April 8, 2008

DECISION WITH REASONS AND ORDER

Dated this 14th day of August, 2008

Written Hearing:

April 9, 2008 to August 8, 2008

BEFORE:

Pieter J. Bekker, Deputy Comptroller of Water Rights
PO Box 9340 STN PROV GOV'T, Victoria, BC V8W 9M1

File: 0321042

of the shared costs." EWR is applying for inter-corporate charges of $228,455, $233,252 and $238,150 for the Test Years. EWR provided details of the costs.

Deputy Comptroller Determination:

The more detailed information in this Application demonstrates that EWR is receiving good value for money from its inter-corporate service contracts. Indeed, the Deputy Comptroller is left with a general impression that EWR is being well managed for the future. The applied for inter-corporate charges are accepted. The Utility adequately supported its projected Inter-corporate Services charges on its financial schedule 2.3 and the amounts are reasonable.

D.1.3 Capital Structure and Return on Equity (ROE)

In Order 2021, the Deputy Comptroller's Direction to EWR was as follows (Section C.3.5):

"It is also in order to require EWR to file a capital structure and cost of capital study with the Comptroller supporting a debt/equity structure appropriate to the risks and returns associated with EWR on a go forward basis in the next revenue requirements and rate application to be filed in 2007."

EWR retained Ms. Kathleen McShane of Foster Associates Inc. to provide an estimate of the appropriate capital structure, cost of common equity and cost of debt for EWR for the 2008-2010 Test Period. Ms. McShane's written evidence (the "Capital Structure and Cost of Capital Study") is included as Appendix E to the Application. In Order 2021, the Comptroller approved a capital structure of 60% debt and 40% equity for EWR for the period 2005-2007. Based on recommendations in the Capital Structure and Cost of Capital Study, EWR is applying for a capital structure of 55% debt and 45% equity.

The approved ROE in Order 2021 is two times the risk premium of Pacific Northern Gas Ltd. (PNG) or 130 basis points (bp) above the ROE for a low risk benchmark utility of the BC Utilities Commission. EWR is applying for a risk premium of 175 bp.

Ms. McShane is a well known and respected expert witness for many utilities across Canada and the USA, providing evidence on Capital Structure and ROE. In this study she relied on the regulatory approach of the BCUC to allow for both different capital structures and different equity risk premiums among the various utilities it regulates.

In recommending an appropriate Capital Structure for EWR she applies three principles: the stand-alone principle; compatibility of Capital Structure with the business risks of the utility; and maintenance of the creditworthiness and financial integrity of the utility.

In considering the business risks of EWR, she states that business risk encompasses those market demand, supply, and regulatory factors that expose the shareholders to the risk of under-recovery of the required return on, and the return of, their capital investment. In discussing these risks she notes that White Rock has limited economic diversity and long-term growth is limited. The small size of the utility magnifies the risks of its operations.

She acknowledges that the competitive risks are very low, as alternative supply sources are limited to drinking water, which accounts for a small percentage of water consumption. In addition, the Consumption Deferral Account (CDA) mitigates short term revenue risks related to deviations from forecast consumption.

In recommending a capital structure and ROE for EWR, there are no water utilities in Canada that have rated debt and whose capital structures have been tested by the capital markets. In considering the higher ROEs for water utilities compared to gas/electric utilities, she speculates that the small size of water utilities results in limited ability to diversify risks arising from geographic and customer concentration, a lack of market power, limited growth opportunities, and limited ability to benefit from economies of scope and scale. The various analyses indicate to her that a reasonable equity risk premium for a small water utility would range from 1% to 2.5-3%.

Deputy Comptroller Determination:

In considering the evidence on Capital Structure and ROE, it is apparent that considerable judgement is required. The evidence with respect to US utilities is less persuasive than the Canadian experiences.

EWR compared itself with PNG in its 2005 application and Ms. McShane refers to PNG in her evidence. PNG West is a small natural gas utility with a long transmission line extending from near Prince George to Prince Rupert and Kitimat. The two largest customers have left the system, reducing sales by nearly 2/3. The remaining customer rates are challenged by the prices of alternative fuels. The approved Capital Structure is 40% equity and the equity risk premium is 65bp.

PNG (NE) is a smaller utility serving Dawson Creek and Ft. St. John. Its business risks are significantly less than PNG West and the approved Capital Structure is 36% equity and the equity risk premium is 40bp.

PNG Tumbler Ridge is a very small town utility served from local gas wells. The town is rebuilding customers after a downturn when NE Coal closed. It has a Capital Structure of 36% equity and an equity risk premium of 65bp.

In contrast, EWR distributes a vital resource (water) at low rates and has no significant competitive alternatives. The deferral accounts offset most risks faced by EWR. In particular the CDA safeguards the Utility from variances in sales volumes. However, considerations for water utilities are the relatively small size, the public health and safety implications, and the heavy financial reliance placed on the credit worthiness of the owners. Ms. McShane points out that long-term growth for the Utility is limited. There is no undeveloped land and the service territory is only about five square kilometers. She

argues that the very small size of the Utility magnifies the fundamental risks of its operations.

Given all this information, the Deputy Comptroller finds that the existing Capital Structure of 40% equity and 130bp equity risk premium remains appropriate and generous for the risks faced by EWR.

D.1.4 Cost of Debt

EWR has both external debt and inter-company debt provided from its parent company. New debt is obtained from EUI through inter-company loans.

Order 2021 allowed a debt rate at the cost of debt to EUI plus a risk and transaction premium of 0.13%. This Application reflects a forecast cost of new issues of inter-company debt of 6.07% based on published long bond yields and spreads at January 2008. The basis of the forecast is the 20 year Government of Canada bond yield of 4.05%, plus EUI's debt spread of 1.77%, plus a risk premium of 0.20%, plus a transaction cost of 0.05%.

The EWR risk premium of 0.20% represents the spread between the cost of a new 20-year issue by EUI and the cost of the same issue to a BBB rated company. Ms. McShane's evidence states that if EWR were to access third-party debt on its own, the options would be limited to banks or life insurance companies at a significantly higher cost than indicated by the proposed BBB spread, with a relatively short term to maturity (e.g. five years or less) and with more stringent covenants.

Deputy Comptroller Determination:

The provision of new debt from EWR's parent company at the proposed risk and transaction premium of 0.25% is beneficial to both the Utility ratepayers and the Utility shareholders. As such, it is approved.

D.1.5 Capital Additions – Arsenic reduction

Arsenic levels for some of the wells in the EWR system exceed new Canadian Drinking Water Quality Guidelines maximum contaminant limit for arsenic. EWR has been working proactively with its quality regulator Fraser Health for the last three years on this issue. Schedule 2.4 of the Application proposes a $32,100 capital expenditure in 2008 to assess arsenic reduction, followed by a proposed implementation in 2009 at a cost of $907,360.

Appendix F of the Application provides a technical assessment of the arsenic treatment implementation. It identifies that the treatment is unidentified and depends on a current EPCOR study. A provisional allowance of $800,000 was provided by EPCOR.

Public Utilities Board of the Northwest Territories, Decision 25-2008
Northland Utilities (NWT) General Rate Application, Oct 27 2008

THE PUBLIC UTILITIES BOARD

OF THE

NORTHWEST TERRITORIES

DECISION 25-2008 **October 27, 2008**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northland Utilities (NWT) Limited for changes in the existing rates, tolls and charges for electrical energy and related services provided by Northland Utilities (NWT) Limited to their customers within the Northwest Territories, by seeking approval of the Phase 1 General Rate Application.

4. RETURN ON RATE BASE

Having determined the rate base for NUL for the test years, the Board is required, pursuant to section 50 of *the Act*, to fix a fair return on the rate base.

Section 50 of *the Act* provides as follows:

> "50. (1) The Board shall fix a fair return on the rate base of a public utility.
> (2) In fixing a fair return, the Board shall consider all the facts that it considers relevant."

The Board's objective in fixing a fair return on rate base is to enable NUL to recover its cost of servicing those portions of the rate base financed by long and short term debt and to provide an opportunity to earn a fair return on the portion of rate base deemed to be financed by common equity.

4.1 Capital Structure and Return on Equity

Northland proposed a capital structure containing a common equity ratio of 50% in conjunction with an allowed return of on equity of 9.6% for the test period.

Ms McShane, expert witness for Northland concluded Northland was of higher than average business risk relative to the typical Canadian Utility. She indicated NUL's higher than average business risk relates to the very small size of the utility and the fact that it operates in a service territory with an undiversified economic base tied to a single industry and it faces significant physical/operating challenges. NUL noted the company's higher risk relative to its sister company NUY relates to its ownership of generation assets. Ms McShane noted that since NUL's debt is raised by CU Inc. NUL should contribute its fair share toward the maintenance of CU Inc's debt rating. Ms McShane indicated the common equity ratio that would fully compensate for Northland's higher business risk lies at the upper end of a range of 50.0% to 55.0%. Ms McShane arrived at her recommendations having regard to data from other electric utilities, rating agency guidelines and rating agency commentary.

Ms McShane did not recommend a move to the 55% equity ratio. She expressed two concerns with moving the common equity ratio to 55%. First, in her view, the shareholders considered the benchmark rate of return to be too low; therefore she questioned why they would want to invest additional equity in order to have the opportunity to earn an inadequate return. Second, in Ms McShane's view, requiring minority shareholders to make an equity infusion would create an additional level of risk to those shareholders. Accordingly Ms McShane recommended the benchmark rate of return on equity of 9.1% should be increased by 50 basis points to 9.60% rather than increasing the common equity ratio.

Mr. Marcus, expert witness for the Town recommended an equity ratio of 40 to 42% for NUL's operations – a figure that is, in Mr. Marcus' view, modestly but not inordinately higher than the benchmarks for large utilities in Canada, that is consistent with the OEB's determination for small electric distribution companies and consistent with the Alberta determination for AltaGas, also a small gas utility. Mr. Marcus submitted the Board should reject the increased return on equity recommended by Ms. McShane in lieu of a further increase in the equity percentage.

With respect to the separate systems operated by Northland, one being Northland Utilities (Yellowknife) Limited and the other being Northland Utilities (NWT) Limited, Mr. Marcus stated the Board should not be paying Northland

Utilities Limited more money just because it operates similar types of utilities in two different towns and raise the equity percentage further by considering that each individual utility is smaller than the entire Northland Utilities Limited system. Mr. Marcus stated it is unreasonable to balkanize the system in this way. Mr. Marcus did not see any reason why Northland Utilities Limited should be different than NTPC which is treated as a unified system. However, Mr. Marcus noted if the two utilities were not considered together, taking certain offsetting factors into account, NUL might have slightly more risk than NUY but these small differences are subsumed within the range of 200 basis points:

> "NUL NWT has slightly more cost risk because NUL-Yellowknife has a capital deferral account for the distribution system rebuild and there is no similar account for NUL-NWT. However the additional cost risk must be considered modest because NUL-NWT also does not have the large capital program to rebuild its distribution system that is covered by the deferral account in NUL-Yellowknife.
>
> NUL-NWT has somewhat more cost risk because it owns generation plants. However, generation risk is modest (considerably less than in other parts of the U.S. and Canada) because (1) the plants are diesel and are therefore less complex than thermal or hydro generation plants owned by other utilities and would also not have the cash flow or regulatory risk of a large central station generator accruing AFUDC until it comes into service, (2) plants in Hay River provide back-up service and are operated infrequently, thereby reducing both capital and O&M risks; (3) the cost of diesel overhauls is covered through reserve accounting in the remote communities where the plants are run more frequently; and (4) most importantly, there are no competitive generation options in the Northwest Territories.
>
> NUL-NWT has somewhat less demand risk than NUL-Yellowknife because the Yellowknife economy has more mining-related volatility, and loads have been more variable in Yellowknife. Per capita residential loads also have been decreasing in Yellowknife, unlike Hay River.
>
> Overall, if the two utilities were not considered together, taking these offsetting factors into account suggest that NUL-NWT might have slightly

more risk than NUL-Yellowknife but these small differences are subsumed within the range of 200 basis points presented by Mr. Marcus" (BR HR 1b)

NUL submitted looking only at the equity ratios adopted by regulators renders Mr. Marcus' analysis completely circular. Moreover, Mr. Marcus' analysis failed to take into consideration the following:

- The quantitative impact on capital structure of the additional fifty basis points in return on equity that the Board allowed NTPC
- Other relevant allowed capital structure benchmarks such as that of Newfoundland Power
- Any bond rating or interest coverage analysis
- Debt rating agency guidelines for capital structure
- The actual capital structure maintained by Canadian utilities
- Any relevant changes in income tax rates, allowed returns on equity or capital cost allowance rates since the 2004 Alberta Decision that have negatively impacted interest coverage ratios for the Alberta utilities used as benchmarks in his analysis

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Views of the Board

The Board notes both NUL and the Town agree that NUL's business risks are somewhat higher than those applicable to an average electric utility primarily due to its small size and economic characteristics of the service area. However, they differ in their assessment of the extent to which the various risk factors contribute to NUL's overall business risk.

The Board agrees NUL's business risks are somewhat higher than those of an average electric utility due primarily to its small size and economic characteristics of the service area. The Board notes Mr. Marcus' assessment NUL's business risks are somewhat higher than those of NUY.

In terms of peer comparisons, the Board notes the 41% equity ratio awarded by the AEUB to AltaGas, a gas utility that is of relatively small size although larger than NUL in terms of size. The Board also notes Newfoundland Power was awarded an equity ratio of 44.5% together with an equity risk premium of 0.15%. (Table 5 McShane Testimony) Maritime Electric was awarded 42.7% with an equity premium of 1.25% higher than the average Canadian utility. (Table 5 McShane Testimony) In reviewing peer comparisons, the Board is also cognizant of the impact of changes in tax and capital cost allowance rates on coverage ratios.

The Board notes the following coverage ratios for NUL for the years 2006 Actual and 2007 Forecast and for the forecast test years 2008 to 2010 under the proposed capital structure and proposed return on equity:

Table 1 NUNWT Proposed Coverage Ratios
($000s)

	2006A	**2007**	**2008**	**2009**	**2010**
Total Return	811	854	935	975	976
Income Tax	174	201	129	332	309
EBIT	985	1,055	1,064	1,307	1,285
Depreciation net of Amortization of Contributions	730	754	807	859	903
Funds from Operations	1,715	1,809	1,871	2,166	2,188
Debt Interest	420	430	420	390	390
Interest Coverage	2.35	2.45	2.53	3.35	3.29
FFO Interest Coverage	4.1	4.2	4.5	5.6	5.6

Note: Based on original filing

The Board notes from Table 1 NUL achieved interest coverage ratio of 2.35 and a funds from operations ("**FFO**") interest coverage of 4.1 in 2006. The Board recognizes that coverage ratios are one set of factors among many others that rating agencies have regard to in assessing investment risk.

Having weighed all of the evidence, the Board considers that an equity ratio of 44% together with the benchmark return on equity of 9.1% would result in a fair return on rate base for NUL in 2008, 2009 and 2010 that is consistent with the company's investment risks. The resulting approximate coverage ratios are set out below:

Table 2-NUNWT Return on Rate Base
($000s)

	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
2008 Test Period				
Long-term debt	53.58%	6494	6.40%	416
Common stock	44.00%	5333	9.10%	485
Customer Deposits	1.02%	124	4.59%	6
No Cost Capital	1.40%	170	0.00%	0
Total	100.00%	12,120	7.48%	907
2009 Test Period				
Long-term debt	53.65%	6642	6.39%	424
Common stock	44.00%	5447	9.10%	496
Customer Deposits	1.05%	130	4.59%	6
No Cost Capital	1.30%	161	0.00%	0
Total	100.00%	12,380	7.62%	926
2010 Test Period				
Long-term debt	53.81%	6680	6.39%	427
Common stock	44.00%	5462	9.10%	497
Customer Deposits	0.89%	110	4.59%	5
No Cost Capital	1.30%	161	0.00%	0
Total	100.00%	12,414	7.70%	929

Table 3 Coverage Ratios Based on Board Approved Equity Ratio and ROE
($000s)

	2006A	**2007**	**2008**	**2009**	**2010**
Total Return	811	854	907	926	929
Income Tax	174	201	117	295	272
EBIT	985	1,055	1,023	1,221	1,201
Depreciation net of Amortization of Contributions	730	754	807	859	903
Funds from Operations	1,715	1,809	1,830	2,080	2,104
Debt Interest	420	430	421	430	432
Interest Coverage	2.35	2.45	2.43	2.84	2.78
FFO Interest Coverage	4.1	4.2	4.3	4.8	4.9

Note: Based on original filing

The Board notes the coverage ratios resulting from a 44% common equity ratio together with a 9.1% return on equity will be comparable to or higher than those achieved by NUL in 2006 and estimated for 2007. The Board notes the FFO interest coverage ratios in 2008, 2009 and 2010 of 4.3, 4.8 and 4.9 would be higher than those applicable to the average Canadian utility of about 3.8 times.(McShane Testimony, p. 29;*I.,* 762)

Accordingly, the Board determines a common equity ratio of 44% in conjunction with a return on equity of 9.1% for each of the years 2008, 2009 and 2010. NUL is directed to reflect the above determinations respecting capital structure and rate of return on common equity in its Phase I refiling Application.

4.2 Cost of Debt

With respect to cost of debt NUL stated there are no new debt issues included in the filing. However, given that there could potentially be some debt issues as a result of this Board Decision, NUL agreed to use the debt rate approved by the Board in the NUY proceeding, should these circumstances arise.

Views of the Board

In light of the Board's determination on capital structure, the Board considers NUNWT may need to raise new debt within the test period. The Board considers that it would be appropriate for NUNWT to include any new debt at the cost rate for new debt approved for NUY in Decision 24-2008. NUNWT is accordingly directed to reflect this determination in its Phase I refiling application.

4.3 Customer Deposits

Fort Providence submitted inasmuch as customer deposits are used more for working capital purposes i.e. to fund shorter-term operational requirements rather

Public Utilities Board of the Northwest Territories, Decision 24-2008
Northland Utilities (YK) General Rate Application, Oct 27 2008

THE PUBLIC UTILITIES BOARD

OF THE

NORTHWEST TERRITORIES

DECISION 24-2008 **October 27, 2008**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northland Utilities (Yellowknife) Limited for changes in the existing rates, tolls and charges for electrical energy and related services provided by Northland Utilities (Yellowknife) Limited to their customers within the Northwest Territories, by seeking approval of the Phase 1 General Rate Application.

4. RETURN ON RATE BASE

Having determined the rate base for NUL for the test years, the Board is required, pursuant to section 50 of *the Act*, to fix a fair return on the rate base.

Section 50 of *the Act* provides as follows:

> "50. (1) The Board shall fix a fair return on the rate base of a public utility.
> (2) In fixing a fair return, the Board shall consider all the facts that it considers relevant."

The Board's objective in fixing a fair return on rate base is to enable NUL to recover its cost of servicing those portions of the rate base financed by long and short term debt and to provide an opportunity to earn a fair return on the portion of rate base deemed to be financed by common equity.

4.1 Capital Structure and Return on Equity

NUL proposed a capital structure containing a common equity ratio of 47.5% in conjunction with an allowed return of on equity of 9.6% for the test period.

Ms. McShane, expert witness for NUL, concluded NUL was of higher than average business risk relative to the typical Canadian Utility. She indicated NUL's higher than average business risk relates to the very small size of the utility and the fact that it operates in a service territory with an undiversified economic base tied to a single industry and it faces significant physical/operating challenges. Ms. McShane noted that since NUL's debt is raised by Canadian Utilities Inc. ("**CU**"), NUL should contribute its fair share toward the maintenance of CU Inc's debt rating. Ms. McShane indicated the common equity ratio that would fully compensate for NUL's higher business risk lies at the upper end of a range of 47.5% to 52.5%. Ms. McShane arrived at her recommendations having regard to data from other electric utilities, rating agency guidelines and rating agency commentary.

Ms. McShane did not recommend a move to the 52.5% equity ratio. She expressed two concerns with moving the common equity ratio to 52.5%. First, in her view, the shareholders considered the benchmark rate of return to be too low; therefore she questioned why they would want to invest additional equity in order to have the opportunity to earn an inadequate return. Second, in Ms. McShane's view, requiring minority shareholders to make an equity infusion would create an additional level of risk to those shareholders. Accordingly Ms. McShane recommended the benchmark rate of return on equity of 9.1% should be increased by 50 basis points to 9.60% rather than increasing the common equity ratio.

Mr. Marcus, expert witness for Yellowknife, recommended an equity ratio of 40 to 42% for NUL's operations – a figure that is, in Mr. Marcus' view, modestly but not inordinately higher than the benchmarks for large utilities in Canada, that is consistent with the Ontario Energy Board's determination for small electric distribution companies and consistent with the Alberta determination for AltaGas, also a small gas utility. Mr. Marcus submitted the Board should reject the increased return on equity recommended by Ms. McShane in lieu of a further increase in the equity percentage.

With respect to the separate systems operated by Northland, one being Northland Utilities (Yellowknife) Limited and the other being Northland Utilities (NWT) Limited, Mr. Marcus stated the Board should not be paying Northland Utilities Limited more money just because it operates similar types of utilities in two different towns and raise the equity percentage further by considering that each individual utility is smaller than the entire Northland Utilities Limited system. Mr. Marcus stated it is unreasonable to balkanize the system in this way. Mr. Marcus did not see any reason why Northland Utilities Limited should be different than NTPC which is treated as a unified system.

With respect to business risk, Yellowknife submitted NUL is basically a distribution utility and provides none of its own generation. It purchases its power from the NTPC and has full deferral account protection on both the amount and cost of purchased power. The City submitted NUL faces less regulatory risk than a company owning considerable amounts of generation. The complexity of generation projects results in the potential for prudence reviews by regulators as well as temporary disallowances or phase-ins because of excess capacity. The City stated the Yellowknife system has less weather-related demand risk than a gas distribution company but somewhat more demand forecasting risk than a typical electric utility “due to its location in a limited area with dynamic economic conditions that can change relatively quickly.” The City submitted, despite the cold climate, Northland did not experience unusual weather-related risks when compared to utilities facing events such as ice storms, hurricanes, tornadoes, and earthquakes.

The City stated NUL’s cost control and cost forecasting risks appear to be similar to other Canadian distribution utilities with future test year ratemaking (which places Northland in a less risky position relative to those US utilities using historical test year ratemaking). The City submitted NUL’s distribution capital deferral account reduces risk slightly relative to both other Canadian utilities and Northland Utilities (NWT) Limited.

NUL submitted looking only at the equity ratios adopted by regulators renders Mr. Marcus' analysis completely circular. Moreover, Mr. Marcus' analysis failed to take into consideration the following:

- The quantitative impact on capital structure of the additional fifty basis points in return on equity that the Board allowed NTPC
- Other relevant allowed capital structure benchmarks such as that of Newfoundland Power
- Any bond rating or interest coverage analysis
- Debt rating agency guidelines for capital structure
- The actual capital structure maintained by Canadian utilities
- Any relevant changes in income tax rates, allowed returns on equity or capital cost allowance rates since the 2004 Alberta Decision that have negatively impacted interest coverage ratios for the Alberta utilities used as benchmarks in his analysis

Views of the Board

The Board notes both NUL and the City agree that NUL's business risks are somewhat higher than those applicable to an average electric utility primarily due to its small size and economic characteristics of the service area. However, they differ in their assessment of the extent to which the various risk factors contribute to NUL's overall business risk. Mr. Marcus, for the City, summarized the key differences between Ms. McShane's and his assessment of NUL's business risks as follows:

> "Ms. McShane identifies the same risks as listed above. She specifically states that demand risks are the greatest, followed by regulatory risks and then by physical and supply risks.

> Among the demand risks, she places more emphasis on the pure size of the utility than does Mr. Marcus. She also places more emphasis on alleged potentially detrimental effects of the Government's energy conservation policies, while Mr. Marcus believes that energy conservation policies have only a small short-term forecasting impact on NUL. Both Ms. McShane and Mr. Marcus place emphasis on the volatility in growth rates and the composition of the service area.
>
> Ms. McShane places considerably more emphasis on the physical system risk of NUL – that it is served by a single transmission line and is therefore more subject to outages and is subject to severe weather conditions. We place less emphasis on this factor because costs associated with weather risks appear to be modest as compared to other utilities that face ice storms, hurricanes, etc., while the risks associated with transmission are largely NTPC risks to get the power to Yellowknife. Mr. Marcus recognizes a cost containment risk is related to the physical system – that the utility's ability to earn authorized returns is related to its ability to meet its forecast costs.
>
> Ms. McShane believes that regulatory risk is higher than does Mr. Marcus for a utility engaged in power distribution; Mr. Marcus believes that such risk tends to be considerably lower for utilities who do not own significant amounts of generation. Mr. Marcus and Ms. McShane agree that the risk in Yellowknife is mitigated by the deferral account for the rebuilding of the distribution system but disagree regarding the magnitude of the remaining risk.
>
> Ms. McShane believes that franchise risk is important and could significantly harm shareholders if the system were to be municipalized. Mr. Marcus does not believe that shareholder harm would be material given existing rate of return regulation of the utility – the shareholders would receive at least a return of capital for reinvestment if not a higher amount for the difference between original cost less depreciation and replacement cost new less depreciation." (BR YK 1a)

The Board agrees NUL's business risks are somewhat higher than those of an average electric utility due primarily to its small size and economic characteristics of the service area. On the other hand NUL does not own generation assets, which suggests, lower regulatory risks compared with an integrated utility. Further NUL's purchased power costs and certain significant capital additions are subject to deferral account treatment. In the Board's view these factors would tend to have an offsetting effect on the increased risk resulting from small size and economic characteristics of the service area.

In terms of peer comparisons, the Board notes the 41% equity ratio awarded by the Alberta Energy Utilities Board to AltaGas, a gas utility that is of relatively small size although larger than NUL in terms of size. The Board also notes Newfoundland Power was awarded an equity ratio of 44.5% together with an equity risk premium of 0.15%. (Table 5 McShane Testimony) Maritime Electric was awarded 42.7% with an equity premium of 1.25% higher than the average Canadian utility. (Table 5 McShane Testimony) The Board notes although both Newfoundland Power and Maritime Electric are larger utilities they also own generation assets. In reviewing peer comparisons the Board is also cognizant of the impact of changes in tax and capital cost allowance rates on coverage ratios.

The Board notes the following coverage ratios for NUL for the years 2006 Actual and 2007 Forecast and for the forecast test years 2008 to 2010 under the proposed capital structure and proposed return on equity:

Table 1 NUY Proposed Coverage Ratios
($000s)

	2006A	**2007**	**2008**	**2009**	**2010**
Total Return	1,828	1841	2292	2579	2947
Income Tax	326	272	182	408	433
EBIT	2,154	2,113	2,474	2,987	3,380
Depreciation net of Amortization of Contributions	1,215	1,302	1,582	1,787	2,047
Funds from Operations	3,369	3,415	4,056	4,774	5,427
Debt Interest	838	920	981	1079	1225
Interest Coverage	2.57	2.30	2.52	2.77	2.76
FFO Interest Coverage	4.0	3.7	4.1	4.4	4.4

Note: Table 1 reflects original filing

The Board notes from Table 1 NUL achieved interest coverage ratio of 2.57 and a funds from operations ("**FFO**") interest coverage of 4.0 in 2006. The 2005 and 2006 test years were the subject of a negotiated settlement. The Board recognizes that coverage ratios are one set of factors among many others that rating agencies have regard to in assessing investment risk.

Having weighed all of the evidence, the Board considers that an equity ratio of 43.5% together with the benchmark return on equity of 9.1% would result in a fair return on rate base for NUL in 2008, 2009 and 2010 that is consistent with the company's investment risks. The resulting approximate coverage ratios are set out below:

Table 2- NUY Return on Rate Base
($000s)

	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
2008 Test Period				
Long-term debt	54.40%	16670	5.79%	966
Common stock	43.50%	13329	9.10%	1,213
Customer Deposits	1.07%	328	4.59%	15
No Cost Capital	1.03%	316	0.00%	0
Total	100.00%	30,643	7.16%	2,194
2009 Test Period				
Long-term debt	54.66%	18501	5.79%	1,071
Common stock	43.50%	14724	9.10%	1,340
Customer Deposits	0.95%	322	4.59%	15
No Cost Capital	0.89%	301	0.00%	0
Total	100.00%	33,848	7.17%	2,426
2010 Test Period				
Long-term debt	54.84%	20986	5.82%	1,221
Common stock	43.50%	16646	9.10%	1,515
Customer Deposits	0.87%	333	4.59%	15
No Cost Capital	0.79%	302	0.00%	0
Total	100.00%	38,268	7.19%	2,751

Table 3 Coverage Ratios Based on Board Approved Equity Ratio and ROE
($000s)

	2006A	2007	2008	2009	2010
Total Return	1,828	1841	2,194	2,426	2,751
Income Tax	326	272	141	341	346
EBIT	2,154	2,113	2,335	2,767	3,097
Depreciation net of Amortization of Contributions	1,215	1,302	1,582	1,787	2,047
Funds from Operations	3,369	3,415	3,917	4,554	5,144
Debt Interest	838	920	981	1,086	1,236
Interest Coverage	2.57	2.30	2.38	2.55	2.51
FFO Interest Coverage	4.0	3.7	4.0	4.2	4.2

Notes:
1. Based on original filing
2. The embedded cost of debt in Table 2 has been adjusted to reflect the Board approved cost of new debt

The Board notes the coverage ratios resulting from a 43.5% common equity ratio together with a 9.1% return on equity will not be out of line with those achieved by NUL in 2006. The Board notes the FFO interest coverage ratios in 2008, 2009 and 2010 of 4.0, 4.2 and 4.2 would be higher than those applicable to the average Canadian utility of about 3.8 times. (McShane Testimony, p. 29, *l*. 762)

Accordingly, the Board determines a common equity ratio of 43.5% in conjunction with a return on equity of 9.1% for each of the years 2008, 2009 and 2010. The Board notes the 9.1% equity return reflects a 5% long Canada bond rate. However, the Board has not adjusted the rate of return on equity to reflect lower forecasts of the long Canada bond rate in 2008 and 2009 determined in Section 4.2, having regard to the volatility in the credit markets. NUL is directed to reflect the above determinations respecting capital structure and rate of return on common equity in its Phase I refiling Application.

4.2 Cost of Debt

NUL forecast new debt issues of $2.45 million in 2008, $2.20 million in 2009 and $1.7 million in 2010. For each of these issues NUL forecast coupon rates of 7% and effective costs rates of 7.05%. NUL's forecasts were based on a long Canada bond yield of 5% plus 200 basis point spread difference for CU's corporate bonds plus 5 basis point issue costs.

Yellowknife, through the evidence of Mr. Bruggeman, recommended NUL's forecast cost of new debt should be updated to reflect the best and most recent information available to assess the debenture rate for new issues in the test years. Yellowknife submitted at the time the evidence was prepared in April 2008, the long Canada bond yield was 4.05% and there was no evidence on the record

Ontario Energy Board, EB-2007-0905 Ontario Power Generation, Nov 3 2008

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

DECISION WITH REASONS

November 3, 2008

any other regulated Ontario energy utility, thereby recognizing the higher risk of OPG. The Board notes that this deemed capital structure will be applied to the rate base which is net of the specific treatment to be applied to the nuclear liabilities related to Pickering and Darlington (which is discussed in Chapter 5).

8.4 Return on Equity

8.4.1 Introduction

Ms. McShane used three tests: the Equity Risk Premium ("ERP") test, the Discounted Cashflow ("DCF") model test and the Comparable Earnings ("CE") test. For the ERP test, she used three approaches:

- Capital Asset Pricing Model ("CAPM")
- Historical utility risk premium test
- Discounted Cash Flow ("DCF") risk premium test

Although Ms. McShane updated her estimates of the various tests in April 2008, the result was no change in the aggregate ROE recommendation: in her view, the lower government interest rate is partially offset by a higher risk premium which is reflected in a higher spread between government bonds and long-term A-rated utility bonds.

Pollution Probe submitted that the Board should prefer and accept the recommendations of Drs. Kryzanowski and Roberts. They used four methods to estimate the market equity risk premium: the Equity Risk Premium (including CAPM) methodology and three other methods to support the "directional conservatism" of the estimate derived from the ERP method. Pollution Probe noted that OPG acknowledged that this was now the dominant methodology used for regulated energy utilities in Canada.

CCC submitted that the Board should prefer the testimony of Dr. Booth to that of Ms. McShane. Dr. Booth estimated that OPG will have sufficient financial flexibility to access capital markets on reasonable terms with an ROE of 7.75% and an equity ratio of 40%. Dr. Booth relied on a CAPM risk premium model and a two-factor model, with the CAPM estimate based on an historic average market risk premium adjusted for the changing risk profile of the long Canada bond, and the two factor model taking into account the interest rate sensitivity of utility stocks.

CCC noted that the average return on the Canadian equity market has been 10.42% over the period 1924-2007 and that current allowed ROEs are generally less than 9% for utilities on a formula mechanism. CCC submitted that Ms. McShane's recommendation of 10.5% ROE on a 57.5% equity ratio implies that OPG's risk exceeds that of other regulated Canadian assets by a considerable margin. In CCC's view, there is no factual basis for this view. VECC supported CCC's submissions.

SEC submitted that the critique by Drs. Kryzanowski and Roberts of Ms. McShane's evidence and the cross-examination of Ms. McShane, which revealed the utility-side biases in her evidence, lead to the conclusion that her evidence is not credible and should not be relied upon by the Board. SEC also expressed concern with Dr. Booth's continuing view that Canadian allowed utility ROEs are too high, due to incorrect analysis by regulators of the risk mitigation effect of the ROE method being used, and noted that this conclusion has generally not been accepted. SEC concluded that Drs. Kryzanowski and Roberts' evidence was the most thorough and rigorous, and should be adopted by the Board in setting ROE.

OPG submitted that there was a fundamental contradiction in the evidence of Dr. Booth and Drs. Kryzanowski and Roberts, in that both recognized that OPG was of higher risk than other Canadian utilities, yet both made recommendations for ROE below that of any regulated Canadian utility.

First, the Board will address the alternative approaches to setting the ROE proposed by CME, AMPCO, and Dr. Schwartz and Energy Probe. We will then turn to a discussion of the various analytical tools used by Ms. McShane, Dr. Booth and Drs. Kryzanowski and Roberts.

8.4.2 Alternative approaches (CME, AMPCO, Dr. Schwartz and Energy Probe)

AMPCO submitted that the use of CAPM and DCF models is inappropriate for OPG's heritage assets.

> AMPCO submits that OPG is a financial hybrid with a government-assigned ROE reflective of its character as a government-owned, but commercially structured body. In AMPCO's view, the initial conditions established in O.Reg. 53/05 were well considered at the time of issuance and remain appropriate…The setting of the ROE was a fair solution that recognized the role consumers had played in assuming stranded debt obligations while at the same time providing for OPG's financial needs.[110]

In AMPCO's view, the current ROE has not prevented OPG from undertaking capital projects and the credit rating agencies have indicated that OPG's financial performance has improved under the current arrangements. AMPCO concluded that "the ROE should be set to the true cost to the shareholder of having assumed this segment of OPG's debt obligation to the OEFC, namely the interest rate on this debt, which is 5.85%."[111]

CME submitted that the ROE should be between 5.85% and 8.57% (the most recently approved level for Hydro One), and should be set at the lower end of the range given the acknowledgement by the government in its February 23, 2005 announcement that the 5% ROE ensures a fair return to taxpayers.

OPG responded that a return of 5.85% violates the stand-alone principle, regulatory principles, and finance principles:

> CME and AMPCO miss the central point: that the return the government or any other investor would expect from its investment is one that reflects the riskiness of the project it is investing in, not the cost incurred to raise the capital for the investment.[112]

OPG also pointed to Mr. Goulding's testimony that "OPG should not be compelled by the regulator to suppress what would otherwise be just and reasonable equity returns to serve other policy objectives."[113] With respect to the upper bound of CME's proposed range, OPG responded that OPG's ROE should be no less than Hydro One's.

In applying the CAPM test, Dr. Schwartz used a Treasury bill rate (3.24%) and estimated the equity market risk premium at 6.7% over the Treasury bill yield. He

[110] AMPCO Argument, p. 29.

[111] AMPCO Argument, p. 31.

[112] OPG Reply Argument, p. 11.

[113] Tr. Vol. 12, pp. 111-112.

adjusted this premium by the 0.65 adjusted beta (the median of Ms. McShane's range for the median Canadian utility). Dr. Schwartz's evidence was that the long-term bond yield overstates the risk free rate unless the premium for holding a longer-term instrument is removed.

Energy Probe submitted that the test of whether Dr. Schwartz's recommendations are more appropriate than Ms. McShane's is whether the ROE and capital structure "produce a plausible and reasonable estimate of fair market asset value."[114] Energy Probe submitted that Ms. McShane's recommendations support a fair market value of $6.2 billion, which is below book value, and hence results in the shareholder being over-compensated. Dr. Schwartz's recommendations support a fair market value of $9.9 billion, or 1.3 times book value, which is more reasonable in Energy Probe's view.

SEC submitted that Dr. Schwartz's evidence was of limited value given his unfamiliarity with the standard regulatory approach. Although a private sector analysis of OPG would be a useful approach, SEC submitted that "the expert will still have to be able to articulate the differences between that fresh, private sector point of view, and the regulated entity point of view that it is proposed to supplant."[115]

Board Findings

The Board agrees with OPG that it would be inappropriate to set OPG's ROE at 5.85%. This rate does not represent the cost of capital for OPG's regulated facilities; it is the interest rate on OPG's prior debt obligation to the OEFC. The Province may have assumed this debt, but that is related to the shareholder's cost of capital, not OPG's cost of capital.

The Board finds while it is relevant to consider Hydro One's ROE, and the ROEs of other regulated utilities, they are not determinative of the appropriate ROE for OPG. It is appropriate to determine OPG's ROE using the standard tests for establishing a benchmark return. This reflects the Board's long-standing approach to these issues.

The Board concludes that while Dr. Schwartz presented novel ideas, he was unable to address his recommendations within a regulatory context. As a result, the Board did not rely on his evidence for purposes of setting the cost of capital.

[114] Energy Probe Argument, p. 18.

[115] SEC Argument, p. 7.

8.4.3 Review of standard tests for establishing a benchmark return

The Discounted Cashflow ("DCF") Test

PWU noted Ms. McShane's testimony that the DCF test has the advantage of estimating the cost of equity directly because it relies on analysts' projections. PWU pointed to Ms. McShane's testimony that her examination of the analysts' forecasts back to 1993 (for the DCF risk premium test) found the average forecast was about 60 basis points lower than the consensus forecast for economic growth, concluding there is no reason to believe investors would view analysts' estimates as systematically optimistic.

Pollution Probe noted the testimony of Drs. Kryzanowski and Roberts to the effect that the DCF model is more appropriately used at the level of the overall market, rather than the firm or industry level. Pollution Probe also submitted that Ms. McShane has not adjusted the results for the bias in analyst forecasts: "This bias is widely documented for samples that include utilities, and, absent evidence showing that the bias does not apply to utilities, there is no reason why an adjustment should not have also been made in this case."[116]

CCC noted that Dr. Booth used the DCF method (estimating a DCF return for the market as a whole) as a check only, because of the endemic data problems and the lack of pure play utilities. CCC pointed to Dr. Booth's testimony that the latest research indicates the forecast bias at an average of 2.84% and that Ms. McShane's estimates have not been adjusted for this bias.

OPG responded that there was no need to make an adjustment for optimism bias because there was no evidence or reason for such a bias in the utility context. OPG also noted that the DCF test is the one relied on by US regulators who would presumably be aware of this alleged optimism bias but continue to find the DCF test, based on the analysts' forecasts, compelling.

Comparable Earnings Test

Pollution Probe noted Drs. Kryzanowski and Roberts' criticisms of the CE test and maintained that the Alberta Utilities Commission gives no weight to the CE test. Pollution Probe submitted that "when common finance tests are applied, the rate of

[116] Pollution Probe Argument, p. 6.

return in Ms. McShane's sample abnormally outperforms the S&P/TSX Composite, especially given that this sample represents firms with low risk relative to the market."[117] Energy Probe also submitted that the Board should disregard the CE test approach.

CCC noted Dr. Booth's testimony that while it is appropriate to examine the returns of Canadian companies to establish where we are in the business cycle, it is not appropriate to use this data to establish a fair ROE.

OPG responded that all of the tests have their drawbacks, but the CE test is useful in the context of the fair return standard as a measure of fair return based on the concept of opportunity cost. OPG noted that some of the criticisms of the CE test by Drs. Kryzanowski and Roberts (disagreements as to the appropriate time period and treatment of structural changes in the economy, and the fact that the rates are backward looking) are equally applicable to the CAPM. OPG maintained that formula returns driven by the CAPM test alone are too low.

Equity Risk Premium ("ERP") Test
The ERP test considers three factors: the long-term risk free rate, the market equity risk premium, and the relative risk adjustment for a benchmark Canadian utility (or beta coefficient). There was some disagreement amongst the experts as to the forecast of the risk free rate, but the differences were more marked in relation to the estimation of the market equity risk premium and the appropriate beta coefficient. These differences result in material differences in the recommendations. AMPCO noted that having started with essentially the same data, Ms. McShane ends up with a much higher "bare bones" ROE recommendation of 9.25%-10.25% than Dr. Booth (7.25%) or Drs. Kryzanowski and Roberts (6.35% and 6.75% for 2008 and 2009, respectively).

Ms. McShane estimated the market risk premium at 6.5%; Dr. Booth and Drs. Kryzanowski and Roberts estimated it to be 5%. AMPCO submitted that the evidence based on Canadian data over long time periods indicates a market risk premium of 4.5%-5.5%, and that a shorter time period yields a lower market risk premium.

OPG noted that achieved equity returns have remained relatively constant. This, coupled with increasing long Canada returns, has tended to shrink the achieved market equity risk premium. Forecast long Canada yields are much lower, and therefore, in

[117] Pollution Probe Argument, p. 7.

OPG's view, Drs. Kryzanowski and Roberts' estimate is downwardly biased: "They have not given sufficient recognition to market equity risk premium increases resulting from lower anticipated bond market returns."[118]

OPG submitted that Dr. Booth's evidence regarding government budgets and the bond market supports a conclusion that bond returns in the future are expected to be lower than historically. OPG concluded that "the Canadian equity risk premium under current capital market conditions is higher than the observed risk premium."[119] OPG concluded that the equity risk premium must be substantially higher than Dr. Booth's estimate of 5%, and must be at least 6.5% if equity returns remain stable at 11.2%-11.6% and the forecast yield on government bonds is 4.5%.

While both Dr. Booth and Ms. McShane use adjusted betas for the relative risk adjustment, they adjust their beta data differently. Ms. McShane adjusted the betas to estimate a relative risk adjustment of 0.65-0.70; Dr. Booth and Drs. Kryzanowski and Roberts estimated the adjustment to be 0.50.

CCC submitted that because Ms. McShane adjusts the raw betas by averaging them with 1.0, they are generally increased because utility betas are almost always less than 1.0. Dr. Booth also adjusts his beta estimates upwards, but based on recent market conditions.

AMPCO pointed to the evidence of Drs. Kryzanowski and Roberts and Ms. McShane which indicate a downward trend in beta. AMPCO noted Ms. McShane's adjustment to correct for interest sensitivity of regulated utilities introduces a bias towards the value of one, whereas Dr. Booth and Drs. Kryzanowski and Roberts's adjustments for the same issue do not alter their beta estimates significantly.

OPG responded that Dr. Booth and Drs. Kryzanowski and Roberts's betas are too low and maintained that use of adjusted betas "recognizes that 'raw' utility betas do not adequately explain utility returns; their use mitigates the deficiencies in raw betas as a predictor of future returns."[120] Dr. Booth and Drs. Kryzanowski and Roberts only adjusted their betas by taking averages of 'raw' betas, which is not the appropriate adjustment in OPG's view.

[118] OPG Reply Argument, p. 28.

[119] OPG Reply Argument, p. 29.

[120] OPG Reply Argument, p. 31.

Board Findings

It is important to emphasize that the establishment of the ROE is for purposes of the prescribed assets only; it is not related to OPG's unregulated businesses, nor is it related to attracting capital for new generation build which is unregulated.

The Board finds that each of the analytical tests has value as each provides a different perspective on the question of the appropriate ROE. However, each test also has its weaknesses. For example, there is evidence of analyst bias, which although not conclusive with respect to utilities, suggests that the DCF cannot be relied upon wholly. These weaknesses were highlighted during the testimony of the experts and in references to other studies in the financial literature. In all cases, significant judgment is brought to bear by the experts because historical data are being used to estimate the future. In addition, the data may not be sufficiently comparable; if, for example, it is U.S. data, or there may be varying time periods under consideration. As Ms. McShane acknowledged, each test is a "blunt instrument."[121]

The Board concludes that the various expert recommendations provide the reasonable range of results, but the extremes of the range (both highest and lowest) should not be adopted given these inherent limitations in the methodologies.

The Board concludes that the ERP test is the most reliable test upon which to base its determination. The Board has the benefit of having had a number of experts develop their recommendations based on this approach. As noted above, each test includes important elements upon which the expert must apply judgment. For the ERP test, judgment is applied in determining the appropriate adjustment to the raw betas and in estimating the appropriate market equity risk premium. The Board accepts that an upward adjustment of the raw betas is warranted, and, similarly, that changes in the anticipated bond yields may require an adjustment to the observed market equity risk premium. However, the Board concludes that no particular approach by a single expert is wholly reliable. The Board considers it reasonable to consider the range of risk premiums in determining the appropriate level, but neither extreme of the range is appropriate. The estimates of the risk premium range from about 2.5% to over 5%, although these are applied to different forecasts of the risk free rate. The Board concludes that a risk premium of 3.4% is appropriate in the circumstances, based on the Board's judgment of the evidence before it and the previously discussed factors.

[121] Transcript Vol. 10, p. 17.

Using a forecast long-term risk free rate of 4.75% and a risk premium of 3.4%, the resulting “bare bones” ROE would be 8.15%.

8.4.4 Adjustment for financing flexibility

The purpose of adding an adjustment for financing flexibility to the “bare bones” cost of equity is to compensate the utility for potential equity flotation issuance costs and to protect the financial integrity of the utility against any adverse impacts from potential unexpected events in the capital markets and the economy.

Energy Probe submitted that adding 50 basis points for financial flexibility was unwarranted as OPG will not issue shares and therefore requires no compensation for floatation costs. AMPCO agreed with Dr. Schwartz that the reasons given for adding 50 basis points for financial flexibility are unconvincing: all of OPG’s borrowing will be from the OEFC and there is no expectation that equity will be raised in the test period.

OPG responded that the 50 basis point allowance does not turn on whether the utility is actually forecast to enter the market or not. It is a margin for unanticipated market conditions and “recognizes the basic principle of regulation, that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value.”[122] OPG maintained that this principle is well established and noted that Drs. Kryzanowski and Roberts, Dr. Booth and Ms. McShane all included the provision and that it has been included in setting the ROE for Hydro One and the electricity LDCs.

Board Findings

The Board will include this adjustment of 50 basis points. The adjustment has been used in the past and forms part of the recommendations made by Drs. Kryzanowski and Roberts, Dr. Booth and Ms. McShane. Adding 50 basis points to the “bare bones” ROE of 8.15% results in an ROE of 8.65%. The Board concludes that this result is also reasonable because it is comparable to the levels of return allowed to other Ontario regulated energy utilities, and although OPG is of higher risk, that risk has been recognized through the higher equity ratio.

[122] OPG Reply Argument, p. 35.

8.4.5 Should there be separate costs of capital for regulated nuclear and regulated hydroelectric?

GEC-Pembina-OSEA took the position that OPG should recognize the higher risks of the nuclear business in its capital and OM&A expenditure decisions. GEC-Pembina-OSEA sponsored the evidence of Mr. Paul Chernick on this issue. GEC-Pembina-OSEA concluded:

> The Board should select an acceptable combined cost of capital (with the deferral accounts it finds acceptable in place) and then adjust the nuclear division equity ratio and RoE upward and make a corresponding balancing downward adjustment to the hydraulic division values in accord with Ms. McShane's estimates.[123]

GEC-Pembina-OSEA submitted if the Board does not set a separate cost of capital for each division, then the Board should direct OPG to use project-specific discount rates to reflect the relative risk level. GEC-Pembina-OSEA also suggested that in a future proceeding it might be appropriate to consider Mr. Chernick's proposal that deferral accounts be minimized, that the risk be reflected in the cost of capital, and that the added revenue be segregated to mitigate those risks if they arise.

Pollution Probe submitted:

> For purposes of cost allocation and rate design, separate and distinct costs-of-capital should be used since: 1) the nuclear assets are riskier than the hydro assets; and 2) OPG is already proposing different charges per MWh for its nuclear and hydro-electric assets [due to separate costs of production].[124]

Pollution Probe noted OPG's testimony that it did not object to this approach in principle, although it expressed concern as to whether such an approach was pragmatic in terms of the necessary calculations. Pollution Probe was of the view that the Board has the necessary evidence for such an approach and submitted that the evidence of Drs. Kryzanowski and Roberts should be accepted as they did determine separate capital structures for nuclear and hydroelectric as part of their analysis.

[123] GEC-Pembina-OSEA Argument, p. 7

[124] Pollution Probe Argument, p. 2.

SEC submitted that there would be value in setting separate capital structures in terms of reviewing investment decisions, but noted that the nuclear costs are not "real" in any event because the liabilities were shifted from OPG when it was created. SEC concluded that whether or not the Board sets separate structures,

> …it should direct OPG to maintain records of the relative costs of production and investment using separate equity ratios, and to carry out business case and similar forward-looking expenditure analyses using those technology-specific equity ratios.[125]

SEC submitted that the same ROE should apply to both, because the difference in risk is appropriately captured through the equity ratio.

CME submitted that there was no need to set separate capital structures for the nuclear and regulated hydroelectric when they are operated by a single business entity.

OPG responded that alleged benefits of technology-specific cost of capital either do not exist or are insignificant. For example, there is no evidence that a higher nuclear payment amount would impact operating decisions, and OPG already has a strong incentive to meet its production targets. Further, OPG's project specific risk analysis provides more rigour than a technology-specific discount rate would.

Board Findings

Although the regulated hydroelectric and regulated nuclear businesses are held by the same entity, in many respects they are operated quite separately. The rate base is separate; the production forecasts, capital budgets and OM&A forecasts have been established separately; the corporate cost allocation is done separately; and the payments are set separately. The two businesses also face different risks. The Board finds that there may be merit in establishing separate capital structures for the two businesses. It would enhance transparency and more accurately match costs with the payment amounts.

However, the Board also finds that the evidence in this proceeding is not sufficiently robust to set separate parameters at this time. Drs. Kryzanowski and Roberts developed separate estimates, but concluded with a combined recommendation. Ms.

[125] SEC Argument, p. 9.

McShane developed separate estimates, but cautioned that she was not as confident with the analytical results because they had been derived from working backwards.

The Board concludes that this is an approach worthy of further investigation which will be explored in OPG's next proceeding. In examining whether to set separate costs of capital, the Board intends only to examine whether separate capital structures should be set for the regulated hydroelectric and nuclear businesses. The Board expects that the same ROE would be applicable to both types of generation. This is consistent with the general approach of setting a benchmark ROE and recognizing risk differences in the capital structure.

The Board recognizes that this approach will not alter the overall cost of capital for OPG's prescribed facilities. However, in all other significant respects the specific costs or the hydroelectric and nuclear businesses are used to derive the specific payments for each type of generation. Specific and separate costs of capital for hydroelectric and nuclear would be consistent with the separate nature of these businesses and would provide a more transparent link between the payment amounts for each type of generation and the underlying costs.

8.4.6 Should the Board adopt a formula to determine the ROE in future?

OPG proposed that the Board adopt an ROE adjustment formula for purposes of determining OPG's ROE in future proceedings. Specifically, OPG proposed adoption of the existing ROE adjustment formula outlined in the Board's report on cost of capital and 2nd generation incentive regulation for Ontario's electricity distributors.[126] That formula results in a 75 basis point change in ROE for every one hundred basis point change in the 30-year Long Canada Bond forecast.

OPG noted that it would seek a review of the formula returns if its business risk or access to capital changed materially and submitted that the adoption of a formula should not preclude it or another party from seeking a review. SEC supported the use of Board's formula approach to adjusting the ROE for years after 2009. CME also submitted that the formula approach was reasonable.

[126] *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors,* December 20, 2006.

Board Findings

The Board agrees that adoption of a formula approach to setting the ROE is appropriate in the circumstances. The Board will adopt the existing ROE adjustment formula outlined in its report on cost of capital and 2nd generation incentive regulation for purposes of determining OPG's return on equity. The Board intends to examine whether the regulated hydroelectric and nuclear businesses should have separate capital structures. Setting the ROE through a formula is consistent with the Board's expectation that risk differences in the regulated businesses are appropriately addressed through the capital structure rather than the ROE.

8.5 Cost of Debt

8.5.1 Short-term debt

OPG forecast the cost of short term debt at 5.83% for 2008 and 5.98% for 2009.

AMPCO submitted that OPG's short-term rate on commercial paper of 8.4% appears excessive given the prime corporate paper rate was 3.17%. AMPCO also submitted that OPG's cost for Account Receivable securitization of 5.54% appears to be above current short-term rates. AMPCO submitted that a target cost of about 4% is more consistent with current conditions. SEC and CME supported AMPCO's submissions.

OPG responded that it uses commercial paper and Account Receivable securitization as its main source of short-term financing, but it also has a bank credit facility that has a forecast $1.4 million fixed cost. OPG noted that AMPCO had inappropriately rolled in this fixed cost with the forecast cost of commercial paper to derive its "implicit cost rate" of 8.4%. The rates on commercial paper are forecast to be 5.13% in 2008 and 5.32% in 2009, based a forecast of bankers' acceptances rate, the corporate spread and the dealer fee. OPG concluded its proposed short-term debt rate was reasonable as it is based on independent forecasts.

Board Findings

The Board will accept OPG's forecast cost of short term debt. The rates are based on independent forecasts. The Board finds that there is no evidence to support AMPCO's proposed level of 4%; that level is derived from an examination of then-current market conditions, not an assessment of conditions over the test period.

Yukon Utilities Board, Order 2009-2 Yukon Electrical Company For Approval of Revenue Requirements 2008-2009, Feb 2009

IN THE MATTER OF the *Public Utilities Act*
Revised Statutes of Yukon, 2002, c. 186, as amended

and

An Application by Yukon Electrical Company Limited
For Approval of Revenue Requirements for 2008 and 2009

REASONS FOR DECISION

APPENDIX A TO BOARD ORDER 2009-2

The Board considered the statement[70] in the Foster Report that YECL is of similar business risk to NUL(YK). Oral testimony from YECL confirmed that the actual equity ratio had been approximately 40% and that the last approved (based on a Decision in 2005) equity ratio for NUL(YK) was 40%[71].

The Board is not convinced that the YECL situation or risk profile has changed since its last approved equity ratio for 1997[72] to warrant a substantial increase in the equity ratio.

For these reasons, the Board cannot accept the equity ratio as proposed by YECL. Given current market conditions which are discussed in the Cost of Debt Section, the Board directs YECL to use the last approved[73] equity ratio of 40% which is similar to the more recent (2005) PUBNWT Decision for the equity ratio of NUL(YK).

Finally, in arriving at its finding on this issue, the Board did not consider comments in reply argument by CW and YEC relating to PUBNWT Decisions 24-2008 and 25-2008. The Board considers these comments as new evidence that had not been discussed at the hearing.

5.7.1.2 Cost of Equity

The cost of equity is strongly linked to the capital structure. This was the position of YECL and largely acknowledged by the Intervenors. As noted above, Attachment 1 of Section 8 contains the Foster Report which provides the recommendation for the cost of equity for YECL. YECL accepted the recommendation in the Foster Report, that is, a capital structure of 47.5 % equity and a return on equity (ROE) of 9.25%. Much of the evidence on cost of equity is contained in the Capital Structure section and will not be repeated here.

In argument, UCG submitted that the benchmark rate of return proposed in YECL's application be denied. UCG made a recommendation for an overall rate of return but did not make a recommendation specific to the return on equity.

YEC expressed the following concerns in its argument:

> More specifically, the approach adopted in the Application fails to follow past YUB practice with regard to determining a fair rate of return for YECL (based on Board decisions issued when YECL was previously reviewed by the YUB: 1992-1; 1992-2; 1993-8 and 1996-6), significantly deviates from the AUC benchmarking methodology which it "uses as a point of departure" for determining a fair return, and moves away from the approach utilized by YEC in 2005 to determine its return on equity during the Required Revenues and Related Matters hearing[74].

[70] Section 8, Attachment 1 - Foster Report, page 22.
[71] Transcript Volume 2, October 8, 2008. Page 169 lines 5 to 27 inclusive
[72] Board Order 1996-6, page 11 of 17, Schedule 4B.
[73] Board order 1996-6.
[74] YEC Argument, page 35

YEC argued that historically the Board has concluded that the business risk of YECL does not differ from that of a high-grade utility. YEC labeled the YECL approach as hybrid as it used a benchmarked rate from one jurisdiction and then made adjustments. YECL is a lower-risk utility when compared to YEC. YEC recommended that YECL use either the AUC benchmarked rate or the BCUC benchmarked rate plus premium (total return on equity would be 9.02%).

LE stated in argument: "A fair return on equity for YECL is probably lower for the proposed capital structure than is being requested"[75].

CW recommended in its argument a return on equity of 8.75%.

YECL stated in its argument:

> The proposal to base the ROE on the AUC formula rather than re-determining the ROE from first principles recognizes that (1) a formula ROE similar to the AUC's currently governs most of the major Canadian utilities and (2) the validity of the existing formulas is currently undergoing review in two major jurisdictions, before the NEB and the AUC. The proposal to rely on the generic ROE as a point of departure was intended to be the most efficient means of addressing what is inherently a complex and costly matter, given the current state of ROE determination throughout Canadian regulatory jurisdictions[76].

In reply argument, CW reaffirmed its position that an ROE of 8.75% is appropriate.

YEC noted that although the formula-based approach is being review by the National Energy Board (NEB) and by the AUC, it was last reviewed by the BCUC in 2006 and hence is not under current review. YEC added that YECL stated the NEB, AUC and BCUC formulae within a range yield similar results. YEC recommended an 8.75% ROE with a deemed equity ratio of 40-43%.

LE did not accept YECL arguments that it is a higher risk than other Canadian utilities but did state that the recommendation made in its final argument is appropriate.

YECL disagreed with the position of YEC in its reply argument. YECL did state that it was prepared to accept a return of 9.14% based on the BCUC formula.

Views of the Board

The Board strongly agrees with the part of the YECL argument that states:

> The proposal to rely on the generic ROE as a point of departure was intended to be the most efficient means of addressing what is inherently a complex and costly matter, given the current state of ROE determination throughout Canadian regulatory jurisdictions[77].

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[75] LE Argument, page 6
[76] YECL Argument, page 23
[77] YECL Argument, page 23

YECL covers a geographically dispersed area with a relatively small customer base. It is incumbent upon the Board to explore ways that yield regulatory efficiency and yet provide fairness to all interested parties. In this regard, the Board supports a formula-based approach to determining ROE issues. YECL used the AUC Generic Cost of Capital as its starting point while YEC supports the BCUC formula[78]. CW was also supportive of the BCUC generic cost of capital[79]. Both YECL and YEC have argued that reference to a formula approach is efficient from a regulatory efficiency perspective. To reference a generic cost-of-capital approach from another jurisdiction, the Board must answer the following questions:

- Which generic cost-of-capital model should be used and from which jurisdiction?
- Should a risk premium be applied?
- If a risk premium is applied, what risk premium level should be applied to YECL?

Which generic cost-of-capital model should be used and from which jurisdiction?

Of the three models discussed (NEB, AUC, and BCUC) the BCUC model has been the most recently reviewed and is not under current review. In reply, YECL said it was prepared to accept a return based on the BCUC formula. Therefore, the Board directs that the BCUC generic cost of capital is the most appropriate as it has been the most recently reviewed, and is generally accepted by the parties.

Should a risk premium be applied?

In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation. The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.

What risk premium should be applied to YECL?

In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk[80]. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.

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[78] Appendix A to Board Order 2005-12, page 43. "Therefore, in their Application, YEC is proposing that the allowed return on equity be set by reference to the BCUC formula approach …"

[79] CW Argument, page 28 where CW stated: "For regulatory consistency with YEC, CW would have preferred that YECL use the BCUC generic cost of capital as the appropriate point of departure."

[80] Transcript Volume 2, October 8, 2008. Page 206 lines 4-7 inclusive

Nova Scotia Utility and Review Board, Heritage Gas, NSUARB-NG-HG-R-08, Feb 12 2009

DECISION

NSUARB-NG-HG-R-08
2009 NSUARB 15

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE GAS DISTRIBUTION ACT

- and -

IN THE MATTER OF AN APPLICATION by **HERITAGE GAS LIMITED** for the approval of amendments to its Schedule of Rates, Tolls and Charges and Service Rules

BEFORE: Roland A. Deveau, LL.B, Panel Chair
Kulvinder S. Dhillon, P. Eng., Member
Murray E. Doehler, CA, P. Eng., Member

APPLICANT: **HERITAGE GAS LIMITED**
John C. MacPherson, Q.C.
Noelle England, LL.B.

INTERVENORS: **CANADIAN OIL HEAT ASSOCIATION**
Gary Highfield, P. Eng.
David Graham

ECOLOGY ACTION CENTRE
Cheryl Ratchford

HALIFAX REGIONAL MUNICIPALITY
Martin C. Ward, Q.C.
Mary Ellen Donovan, LL.B.
Julian Boyle

NOVA SCOTIA POWER INC.
Nicole Godbout, LL.B.

NOVA SCOTIA DEPARTMENT OF ENERGY
Stephen T. McGrath, LL.B.
Scott McCoombs
Bill O'Halloran, P. Eng.

QUETTA INC.
John H. Reynolds, P. Eng.

CONSUMER ADVOCATE
John Merrick, Q.C.
William L. Mahody, LL.B.

BOARD COUNSEL: S. Bruce Outhouse, Q.C.

BOARD COUNSEL'S CONSULTANTS:

Multeese Consulting Inc.
Melvin C. Whalen, P. Eng.

Energy Consultants International Inc.
James D. Sandison
Brady S. Ryall, P. Eng.

HEARING DATE: December 1 and 2, 2008

CLOSING ARGUMENT: December 17, 2008

DECISION DATE: **February 12, 2009**

DECISION: **Pursuant to Section 22 of the *Gas Distribution Act*, the Board approves Heritage's Schedule of Rates, Tolls and Charges and Service Rules as amended.**

[44] The new depreciation study should incorporate the suspension of depreciation charges, the remaining economic life of plant in service, and the salvage in order to calculate the depreciation charges in the revenue requirement after 2011.

(iii) Return on Equity and Capital Structure

[45] The Application proposes to maintain the return on debt of 8.75% and the return on equity of 13.0%. It also proposes to maintain the debt to equity ratio of 55:45. These returns and the debt to equity ratio were established by the Board in the Franchise Decision. The Company does not believe that today's financial risks are any less than they were then:

> (Smith) ... I mean I guess I'd like to go back to the principles under which the franchise were accepted by the shareholders and Ms. McShane was involved in setting the established rates at that time. She did a complete study in terms of what was agreed upon and the shareholders moved forward, made an investment in this business based on that and it is fundamental to compare the risk factors that were in place at that time and where we are today. And that's really what -- why Ms. McShane is here. So I think it's the risk that was in place in 2004, when the franchise was accepted and moved forward with that fundamentally has not changed.
>
> [Transcript, December 2, 2008, p. 503]

[46] In the pre-filed rebuttal evidence of Ms. McShane, the risk factors were discussed:

> Q. Has anything occurred since the franchise decision and the first tolls and tariffs decision which indicate that Heritage faces lower risk than was anticipated?
>
> A. No. In fact, it has proven more difficult to attract the market on the timeline which Heritage initially forecast, as Heritage has indicated in this GTA (See pages 2-4 to 2-8 of GTA application) and in the 2006 GTA.
>
> [Exhibit HG-13, p. 4]

[47] Part of the financial risk identified in GTA-06 was the extension of the complete retirement of the RDA to 2019. This was an important factor in Heritage's consideration of its expansion in the Halifax market. As was stated:

> (Smith) There was a desire to confirm with this Board that the ability to continue to utilize the revenue deficiency account would be extended from the original plan of 2008 to what was then proposed as 2019, prior to proceeding with that capital investment into Halifax. ...
>
> And with that endorsement of this Board with the extension and the recovery period of the RDA, the decision was then made, ... an expansion to Halifax would occur. But it was with that assurance from this Board that the RDA would be -- continue to be utilized until 2019, or until it was recovered, that was an important consideration at the time.
>
> [Transcript, December 2, 2008, p. 507]

[48] It is posited by Ms. McShane that this may change if Heritage is considered to be a "mature" utility. In a footnote to her pre-filed rebuttal evidence, she supplied the following potential description of the factors for distinguishing between "greenfield" and "mature" utilities:

> In response to British Columbia Utilities Commission Information Request No. 1, Question 41 in Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.'s Application regarding ROE and Automatic Adjustment Mechanism, the company cited four conditions which indicate that a utility has transformed from a "greenfield" to a mature utility: (a) it is able to set rates for different customer classes at revenue/cost ratios of approximately 1.0, and is no longer reliant on price-setting mechanisms that expressly set rates to be competitive with alternative energy sources; (b) its customer growth rates have reached levels that are in line with those of mature utilities; (c) it has been able to recover the preponderance of any accrued revenue deficiencies; and, (d) the excess capacity originally built into the system to accommodate future growth and take advantage of economies of scale has been reduced to a minimal level.
>
> [Exhibit HG-13, pp. 8-9]

[49] When Ms. McShane was questioned as to whether this definition of a "mature" utility is appropriate or not, she stated as follows:

> They are not authoritative criteria because I don't think that there have ever been enough green field utilities to warrant having adopted a specific set of criteria for that purpose.
>
> ...

> Q. So if the Board were looking for a criteria as to when it should consider Heritage a mature utility, what should it be looking for?
>
> A. (McShane) I think these -- I can't think of any other criteria that would fit the bill, so it seems to me that these would work, recognizing that it's not, you know, one -- if they meet one, then it's a mature utility. It really is looking at the composite of the four. And having said that, it's still going to be a matter of some judgement as to whether maturity has been reached.
>
> [Transcript, December 2, 2008, p. 526]

[50] The Company addressed the issue as to whether they should be considered as a "greenfield" or a "mature" utility:

> (Ritcey) ... In terms of the overall marketplace, though, even in 2011, in terms of the total potential of the marketplace, we're still a fairly -- you know, we still have a fairly small footprint in that marketplace, but at that point in time, in terms of how we operate, how we operate our system, how we build out our pipe, we would be characterized as a, you know, mature operating utility, again with more growth coming to the organization as we continue to build out the system.
>
> A. (Smith) And the only other point I would make on that is that I would not suggest that we're a mature utility until we've completely recovered the revenue deficiency account.
>
> [Transcript, December 1, 2008, p. 236]

[51] The matter of whether the RDA, and its change in status (cross-over and/or elimination), would be a milestone on the way to being a "mature" utility was explored:

> Q. If you've reached the point where you are recovering your RDA as opposed to amassing it, would that be a milestone, a very significant milestone in terms of whether or not the utility has matured?
>
> A. (McShane) I think it's a milestone, but I don't think that having reached that crossover point would be an indication that you've reached maturity because there's still a chance that you could flip back the other way.
>
> [Transcript, December 2, 2008, p. 527]

[52] Regardless as to whether the Company is a "greenfield" or a "mature" utility, questions were raised about its allowed return on debt. Of particular concern was whether the shareholder loans could have been financed by a bank at a lower rate. Ms. McShane commented on the cost of debt as follows:

> And Mr. Smith quite correctly said that there was -- I'm probably putting words in his mouth -- little chance that they could have gotten debt at a better rate through going to the bank.
>
> And even if -- from my perspective, even if they could have gotten it at the same rate, chances are that they would have had to incur much more stringent covenants on that debt.
>
> One of the ones that one sees most frequently is that they would have to repay that debt year after year, you know, in equal amortizing amounts so that they would have to come up with the cash every year, to bring down the balance of that debt.
>
> [Transcript, December 2, 2008, p. 517]

[53] Ms. McShane was questioned about the equity risk premium for a "greenfield" utility:

> Q. All right. So, that's what we would find across the country. With respect to the Greenfield risk premium, back in 2003 you had pegged that between 2.5 and 4.5?
>
> A. Yes.
>
> Q. And it's your position that the Greenfield risk still applies to this utility?
>
> A. Yes.
>
> Q. And what do you put that premium at today?
>
> A. (McShane) I don't particularly have any reason to conclude that it would be significantly different. If I look at what some of these new pipelines are negotiating for new investments, it seems that that's in the ballpark.
>
> [Transcript, December 2, 2008, pp. 538-539]

[54] There is a reduced need for a risk premium for a "greenfield" utility as it becomes "mature". As explained by Ms. McShane under questioning:

> Q. And then the item that -- the premium you were paying for Greenfield would disappear once Heritage Gas becomes a mature gas utility, which there's no true definition other than we have one here, the Terasen Gas VI, I came up with.
>
> A. Well, that's a two-part question. Let me try each part separately.
>
> I would say that as a mature utility then, yes, you'd no longer need a premium for a Greenfield, and with respect to the other part, that being these criteria for being a mature utility, they came up with them because they were asked by their regulator to define what constitutes a mature utility.

> Those criteria were set forth, those criteria, to my recollection, were not contradicted in any way. The BCUC did not take exception to them, and I -- you know, I think, from my own perspective, they cover the circumstances that would define what's mature quite well.
>
> [Transcript, December 2, 2008, pp. 544-545]

[55] However, the risk premium does not suddenly drop to zero once a utility is "mature". It is a gradual process. As explained by Ms. McShane:

> I think that's fair, and it's a very good point that you would expect the risk profile to gradually develop over time, and that if everything goes as planned, then the business risk should gradually fall toward the level of a mature utility.
>
> [Transcript, December 2, 2008, p. 554]

[56] A consultant for the CA, in pre-filed evidence, had calculated the effect on revenue requirement if the return on equity was reduced by 1%. Heritage addressed this issue as follows:

> Heritage does not believe that this scenario should be considered as there has been no evidence provided that would suggest that the current return on equity is inappropriate. The risk factors that were enunciated at the time of the Franchise Application remain in place. In fact, it could be argued that under the current economic environment, the return on equity should be increased.
>
> [Heritage Post-Hearing Submission, p. 14]

[57] The Consumer Advocate requested:

> ... that the Board address the material concerns related to the authorized rate of return by commissioning a broad rate of return study to be completed for consideration prior to the end of 2009 so as to allow for adjustment of 2010 and 2011 rates as required.
>
> [Consumer Advocate Post-Hearing Submission, p. 7]

[58] In its post-hearing rebuttal submission, the Company stated:

> Heritage submits that all of the evidence currently before the Board confirms that the rate of return of 13%, in the context of a debt equity ratio of 55:45 and a cost of debt of 8.75%, as approved in the Franchise Application, continues to be appropriate and, if anything, is lower than that which Heritage should receive in the current environment.
>
> [Heritage Post-Hearing Rebuttal Submission, p. 6]

Findings

[59] At paragraph 84 of the Franchise Decision, the Board stated:

> ... The Board notes that the approved ROE and debt equity ratio will be subject to review at the conclusion of the five year initial period in any event and possibly earlier should circumstances warrant.

[60] The Board understands that if the ROE is reduced by 1%, as calculated by the CA's consultant, the revenue requirement would decrease, with a subsequent overall reduction of costs to ratepayers. No evidence was submitted to suggest what an alternative return on debt or equity should be. Nor was there any suggestion about changing the debt to equity ratio. To the contrary, evidence was submitted by Heritage that supports the present capital requirements and returns and suggests that, maybe in today's economic environment, they could be considered low. Therefore, the Board finds that the return on debt and equity, as well as the debt to equity ratio, should be maintained at this time. However, the Company is ordered to file a complete study on these matters for the next rate hearing.

[61] The Board also recognizes that the Company is far from being considered a "mature" utility. Heritage has stated that it is still in a "greenfield" status. As it slowly increases its serviced area, it will eventually become a "mature" utility. The Board accepts Ms. McShane's evidence that there is no hard and fast definition as to what is a "mature" utility. The Board does take some guidance from the definition developed by Terasen Gas, which was referred to by Ms. McShane.

[62] The Board accepts that there is a risk premium on the return on equity for a "greenfield" utility. The Board expects that this premium will reduce as Heritage approaches maturity. The Board does not expect that this elimination of the "greenfield" risk premium will occur as soon as the Company becomes a "mature" utility. Accordingly, the Board orders the Company, as part of the next rate application, to develop a set of criteria along with definitions, as to when it would consider itself to be a "mature" utility. In addition to the requirement to define what is a "mature" utility, the Company needs to identify the transition milestones which Heritage should meet as it moves from a "greenfield" to a "mature" utility.

b) Revenue Projections

(i) Past Revenue Projections

[63] Heritage, at this time, is a "greenfield" utility and it cannot generate sufficient revenue to meet all of its financial requirements from the present customers. The Board recognizes this and has allowed the Company to record the revenue shortfall in the RDA. A major element in determining the addition to (or subtraction from) the RDA in any one year is the actual revenue earned. In both GTA-04 and GTA-06, the Company was overly optimistic in projecting the amount of revenue that it would earn. As stated in this Application:

> The research over estimated the number of customers that would be captured in the initial development of the franchise and it over estimated the amount of revenue that those customers would generate.
>
> The research also assumed that customers would consume larger quantities of natural gas than they actually are using.
>
> [Exhibit HG-1, p. 2-9]

BC Utilities Commission, Terasen Gas (Whistler) Application for 2009 Revenue Requirement, Apr 7 2009

IN THE MATTER OF

TERASEN GAS (WHISTLER) INC.

AND

AN APPLICATION FOR 2009 REVENUE REQUIREMENTS AND FOR A RETURN ON EQUITY AND CAPITAL STRUCTURE

DECISION

April 7, 2009

Before:

Peter E. Vivian, Panel Chair/Commissioner
Anthony J. Pullman, Commissioner
Michael R. Harle, Commissioner

TGW stated that it did not believe that it would be cheaper to acquire financing from a third party lender, noting that if it were to obtain a loan from a third party, it would incur legal fees, agency fees and rating agency fees, which are either minimized or avoided through the inter-company loan structure, as a result of which it expected the loan from Terasen Inc. to be more cost-effective (Exhibit B-4, BCOAPO 1.6.1). TGW also stated that its parent company does not directly allocate legal, agency, or rating agency fees to it. (Exhibit B-4, BCOAPO 2.6.0)

9.4 Return on Equity

TGW includes as Attachment 2 to its Application the evidence of Ms. McShane, president of Foster Associates, the purpose of which is to assess the reasonableness of TGW's proposed capital structure and to recommend an equity risk premium relative to that of the Commission's benchmark low risk utility ROE. Ms. McShane states that her assessment of TGW's proposals relies on the approach that has been adopted by the Commission, and that the proposed capital structure and equity risk premium for TGW should:

- respect the stand-alone principle;
- be consistent with TGW's business risks; and
- notionally allow TGW to access the capital markets on reasonable terms and conditions.

In addition, the assessment in her opinion accepts as a given the Commission's benchmark low risk utility ROE and automatic adjustment mechanism adopted in Order G-14-06 as a point of departure (Exhibit B-1, Attachment 2, p. 3).

Business Risk of TGW

Ms. McShane characterizes TGW as a small distribution company serving the municipal area of Whistler, which is committing significant new capital (relative to its size) to convert its system (from propane to natural gas) which is expected to cause the rate base to double between 2007 and 2009.

Ms. McShane states that a small utility cannot diversify its risks to the same extent as larger utilities whose assets, geography and economic bases are less concentrated, with the result that negative events are likely to have greater impact on the earnings or viability of a smaller company. The impact of smaller size for rated utilities is frequently exhibited in lower debt ratings for these companies despite financial parameters that are stronger than their larger peers. (Exhibit B-1, Attachment 2, pp. 4-5)

Ms. McShane considers TGW's customer base and notes that its deliveries are largely to the commercial sector, and that its delivery margin is also derived largely from that sector. The economic base of Whistler is largely focused on tourism, nine of TGW's largest ten customers are either condominium developments or resort-style hotels, and all current commercial development in Whistler is related directly, or indirectly, to tourism. Whistler is considered a prime tourist destination, with a positive economic outlook, particularly in light of the upcoming 2010 Winter Olympics and the potential to garner significant benefits from Chinese tourism over the longer term. Nevertheless, Ms. McShane observes that tourism is a cyclical industry, whose fortunes are dependent on the availability of discretionary income, and thus on the economic strength of the markets from which it draws revenues. It is also dependent on weather, exchange rates, cost of travel, and other external factors over which the industry has no control. The long-term viability of Whistler, as with any tourist destination, will be a function of its appeal compared to alternatives. (Exhibit B-1, Attachment 2, pp. 6-7)

Ms. McShane states that "the concentration of TGW's service area in a single cyclical and highly competitive industry which is subject to the impact of a number of exogenous factors creates uncertainty with respect to long-term natural gas demand" (Exhibit B-1, Attachment 2, p. 7).

Ms. McShane states that long-term demand uncertainty also arises from the focus in Whistler on limiting future growth and reducing reliance on fossil fuels, consistent with a plan for Whistler to the year 2020 and beyond encompassing social, economic and environmental objectives ("Whistler 2020").

Ms. McShane addresses load growth and states that in the absence of NGV demand, load growth in the near term will be well below the levels forecast in the 2008 Resource Plan, and that over the remainder of the planning period (2012-2028), demand is forecast to decline slightly as commercial customers convert to ground-source heat pump (GSHP) systems, offsetting overall customer growth. (Exhibit B-1, Attachment 2, p. 7)

Ms. Mc Shane notes that a number of lodges have installed electric boilers in order to take advantage of lower BC Hydro rates. They use propane (and natural gas upon system conversion) either as a back-up or for fireplace and cook-top load only. While she states that following conversion, natural gas is expected to be more competitive with electricity than propane, both from a pricing and environmental policy perspective, she expects that competitive challenges with electricity will continue after the conversion of the system. (Exhibit B-1, Attachment 2, p. 8)

Ms. McShane expects natural gas to remain competitively challenged with electricity based on forecasts of natural gas commodity prices, but states that the outlook is complicated by uncertainty related to government initiatives to discourage the use of all fossil fuels, including natural gas, citing the Carbon Tax Act, effective July 1, 2008, which applies to the retail purchase or use in British Columbia of all fossil fuels, including natural gas and which will add $0.50 per GJ to the cost of natural gas in the first year, rising to $1.50/GJ in the third year of implementation. (Exhibit B-1, Attachment 2, pp. 8-9)

Ms. McShane considers the uncertainty around the future price of natural gas, and states that:

> "Given the change and volatility in price, there is a risk that actual prices could exceed the forecast by a significant margin. Moreover, the observed change in the level and volatility of gas prices exposes TGW to uncertainty with respect to future demand/customer usage. With respect to supply risks, while TGW's supply risks are expected to be lower as a natural gas distribution system than as a piped propane system, they will remain higher than those of the typical local distribution company ("LDC"). TGW, like TGVI, will be dependent on a single pipeline system that traverses rugged terrain and incorporates numerous stream crossings."
> (Exhibit B-1, Attachment 2, p. 9)

Ms. McShane examines TGW specifically and notes that its rate structure is characterized by lesser assurance of recovery of its fixed costs through a fixed charge than the typical LDC. As rates for all customer classes are currently designed, approximately 7.5 percent of fixed costs (delivery margin) are recovered through a basic charge or a demand charge. In comparison, approximately 30 percent of TGVI's fixed costs are recovered through a basic charge or a demand charge. (Exhibit B-1, Attachment 2, pp. 9-10)

In summary, Ms. McShane considers that having a less diverse customer base and a greater exposure to competitive factors exposes TGW to higher business risks than the large mature gas utilities in Canada (such as TGI, ATCO Gas in Alberta, and Enbridge Gas and Union Gas in Ontario), which she contends should translate into a higher required common equity ratio and/or a higher common equity return (Exhibit B-1, Attachment 2, p. 10).

TGW addressed the additional risks associated with the delivery of natural gas service that are not associated with propane service, and stated that**:**

> **"**With respect to the regulatory/business risks of operating a propane system versus a natural gas system, the risks of the former are higher. Thus, had TGW not proposed to convert the system, the appropriate common equity ratio and/or equity risk premium would have been higher than that for an operating natural gas distribution system.
>
> "There are, however, risks associated with the construction of the natural gas system that were not considered in the analysis presented in the CPCN application, specifically the risks of cost overruns that may accrue to the shareholder as a result of the imposition of the cost cap and sharing mechanism in the order granting a CPCN. The capital structure and risk premium that have been recommended by Ms. McShane have not factored in those risks, but have focused solely on the business risks associated with an operating distribution system, and the implicit assumption that the utility would have the opportunity to recover all prudently incurred costs. All things equal, these additional business risks would directionally suggest a further increase in the risk premium for TGW." (Exhibit B-3, BCUC 1.35.2)

Deferred Charges

TGW stated that its business risk analysis and proposed capital structure and risk premium were based on the risks associated with operating its system and was premised on the continuation of the previously approved deferral accounts for interest rates, property taxes and sales margins differentials and the GCRA. If the Commission were to decline to adopt the four new requested accounts, or were to decline to continue the accounts for which TGW seeks continuation, the risks would be higher in the short-term due to the increased uncertainty around TGW's ability to earn its allowed return in the years those costs are incurred due to the difficulty in forecasting those costs. The longer term regulatory risks would likely be perceived as higher because a decision not to allow those accounts would be viewed as a departure from previous practice. All things equal, the increase in short term and longer term risks associated with requested new deferral accounts, and the existing accounts for which continuation is sought, not being in place would directionally suggest a further increase in the risk premium for TGW (Exhibit B-3, BCUC 1.34.2).

TGW stated that:

> "While it is impossible to accurately isolate and measure the return requirement of a single risk element, the BCUC has ascribed a value of 10 basis points to the existence of TGI's and PNG's [Pacific Northern Gas] RSAMs, which include the impact of both weather and decline in customer usage by weather-sensitive customers. Similar values have been attributed to decoupling mechanisms by the public utility commissions in the U.S. (states of Illinois and New York). Since TGW's mechanism only accounts for declines in customer usage, the impact on the ROE for the mitigation of short-term risks would be less than 10 basis points. However, unless a third party such as the government is prepared to backstop the revenue requirements it would be impossible to fully mitigate the risk associated with lower average use." (Exhibit B-4, BCOAPO 1.13.b)

Capital Structure

Ms. McShane addresses TGW's proposal for a deemed common equity ratio of 40 percent and states that TGW is too small to have its debt rated by the debt rating agencies or its capital structure directly "tested" by the capital markets, as are all smaller gas and electric utilities that would be of reasonably comparable business risk to TGW. Nevertheless, Ms. McShane states that the allowed capital structures of other Canadian utilities in a similar business risk class to TGW provide a basis for assessing the reasonableness of TGW's proposed 40 percent common equity ratio and sets out the table below which indicates that TGW's proposed 40 percent equity ratio is in line with those allowed smaller (approximately $500 million of rate base and less) electric and gas distribution utilities in Canada.

Table 3

Company	Allowed Equity Ratio	Rate Base ($ million)
AltaGas Utilities	41%	$100
Gazifère Inc.	40%	$65
Maritime Electric	42.7%	$250
Natural Resource Gas	42%	$10
Pacific Northern Gas (West)	40%	$133
TGVI	40%	$505

Notes: All data 2007 except TGVI (forecast 2009). The rate base for Gazifère was estimated as the net book value of regulated property, plant and equipment.

(Exhibit B-1, Attachment 2, p. 11)

In addition TGW stated that the Commission established a 36 percent equity ratio for the Fort St. John/Dawson Creek and Tumbler Ridge divisions of Pacific Northern Gas, and that in 2006, its final year before amalgamating with TGI, Terasen Gas (Squamish) Inc. had a deemed capital structure containing 40 percent equity (Exhibit B-3, BCUC 1.36.1).

Return on Equity

Ms. McShane states that the quantification of the incremental equity risk premium required for TGW requires professional judgment, since available market data for utilities that are directly comparable to TGW do not exist' and that, in her judgment, to equate TGW to the benchmark low risk utility, an allowed common equity ratio in the range of 45-50 percent would be required.
Ms. McShane considers that the difference between a required 45-50 percent equity ratio and the proposed 40 percent common equity ratios can be translated into a differential in ROE by applying

capital structure theory, which is based on the following premises:

- that the overall cost of capital for a firm is primarily a function of business risk;
- 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.

(Exhibit B-1, Attachment 2, p. 12)

Ms. McShane states that an increase in financial risk will be accompanied by an increase in the cost of equity, and that 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:

- the cost of capital remains unchanged as the capital structure changes; and
- the cost of capital declines as the percentage of debt in the capital structure increases.

(Exhibit B-1, Attachment 2, p. 13)

Ms. McShane calculates that using the first theory (no change in cost of capital as the equity ratio declines), the difference in the proposed equity ratio of 40 percent and an equity ratio of 47.5 percent translates into an increase in the required ROE of approximately 80 basis points, while using the second theory (cost of capital declines as the equity ratio declines), the difference in a common equity ratio of 40 percent and a common equity ratio of 47.5 percent translates into an increase in the required ROE of approximately 40 basis points. Since both theories have merit, it is reasonable to give weight to both. Based on both, the increase in the ROE is in the range of 40-80 basis points. (Exhibit B-1, Attachment 2, p. 14)

Ms. McShane considers an alternative approach to estimating the incremental ROE by having reference to the studies on small size by Ibbotson Associates Inc. which have attempted to quantify the impact of a firm's small size on the required return by an analysis of the relationship between betas and historic returns for companies of different sizes, and whose analyses indicate that the betas of Micro-Cap stocks have been approximately 0.33 higher than those of Mid-Cap stocks.
Ms. McShane calculates that an incremental beta of 0.33, when applied to a market risk premium

of 5.8 percent, as determined by the BCUC in Order G-14-06, supports an incremental equity risk premium of about 190 basis points for a company, such as TGW, (5.8 percent x 0.33), which she reduces by 50 basis points to reflect the fact that a portion of the 190 basis point risk premium would be already compensated for in TGW's proposed higher common equity ratio. (Exhibit B-1, Attachment 2, pp. 14-15)

Ms. McShane states that the remaining differential return of 140 basis points represents an alternative estimate of the required incremental risk premium for TGW relative to the low risk benchmark utility ROE, and summarizes as follows:

> "While it is not possible to pinpoint the equity return differential that an investor would require to commit capital to TGW (at the proposed 40 percent common equity ratio) relative to the low risk benchmark utility, the above analyses demonstrate that an incremental equity risk premium of no less than 65 basis points is warranted, with an upper end of the range at 140 basis points. In my judgment, a 75 basis point incremental risk premium for TGW is reasonable. A 75 basis point incremental equity risk premium in conjunction with the 40 percent equity ratio slightly reduces TGW's total "business risk compensation" (equity ratio plus equity return) relative to TGVI compared to what has historically been allowed by the BCUC" (Exhibit B-1, Attachment 2, p. 16).

<u>Other Metrics</u>

Ms. McShane states that pre-tax interest coverage is one measure of the ability to attract debt capital and of financial integrity, and calculates the indicated pre-tax interest coverage ratio for TGW to be 2.5 times using:

- an embedded cost of debt for TGW of 6.0 percent;
- the proposed 40 percent common equity ratio;
- a return on equity of 9.32 percent; and
- a corporate income tax rate (combined federal and provincial) of 31 percent.

Ms. McShane states that 2.5 times pre-tax interest coverage ratio is higher than the average interest coverage ratio maintained by Canadian gas distributors with rated debt, but similar to that of rated regulated entities generally (Exhibit B-1, Attachment 2, p. 17).

BCOAPO addresses TGW's proposed ROE and capital structure and states that the impact on the 2009 revenue requirement of these proposals is to increase the 2009 revenue requirement by $124,000 relative to the baseline case of a 60 basis point equity premium and a 35 percent equity component in capital structure as currently approved for TGW. (BCOAPO Argument, para. 8)

BCOAPO addresses a number of issues surrounding business risk capital structure and ROE. Concerning business risk it considers RSAM and submits "BCOAPO does not understand why TGW would apply for an increase in risk premium and, at the same time, not apply for a regulatory instrument that would reduce its risk and that has been approved for its related utilities." (BCOAPO Argument, para. 21)

BCOAPO notes TGW's statement that the regulatory/business risks of operating a propane system are higher than for a natural gas system and wonders, if that is indeed the case, "why a just and reasonable ROE and equity thickness for a propane system need to both be increased when it is converted to a natural gas system" (BCOAPO Argument, para. 27).

BCOAPO addresses the possible cost overruns on the conversion that TGW is facing and notes the increased costs in the amended Application above the cap, the deferral proposed, the update to cost estimates, and the suggestion that TGW may decide to try to recover overruns. As such, BCOAPO submits that TGW should absorb all cost overrun risk if it wishes to obtain a higher ROE and thicker equity. (BCOAPO Argument, para. 28)

BCOAPO notes TGW's statement that it will determine whether to seek recovery of conversion costs in excess of $6.231 million once the full extent of the conversion costs is known. BCOAPO submits that this risk does not appear to be in any sense similar to the project-specific cost overrun risk that a private, unregulated price-taking firm would face, and submits that the existing thickness and equity risk premium are more than sufficiently generous, "especially since TGW does not expect to absorb this one-time conversion cost risk” (BCOAPO Argument, paras. 28-32).

So far as TGW’s proposed capital structure and ROE are concerned BCOAPO relies on TGW’s response to BCOAPO IR 2.18.5 which asked for information regarding the last ten cases in which Ms. McShane provided ROE and/or capital structure on behalf of a Canadian utility, and whose response provided the requested information for the last thirteen such cases.

BCOAPO states that in eleven of the thirteen cases provided, it compared Ms. McShane’s recommended ROE with the regulatory outcome and submits that in only two of them were the approved ROE equal to Ms. McShane’s recommendation while in the other nine cases, the regulatory outcome was for a lower ROE than Ms. McShane recommended. (BCOAPO Argument, para. 12)

Similarly, BCOAPO notes that in nine of the cases Ms. McShane made recommendations with respect to capital structure and that in one case, the regulator determined a higher equity thickness was required than Ms. McShane recommended, in three cases the regulator accepted Ms. McShane’s recommendations, in four cases the regulator determined a lower equity thickness than Ms. McShane recommended was appropriate, and in one case the outcome was unknown. (BCOAPO Argument, paras. 17, 18)

BCOAPO therefore submits that the evidence indicates that Ms. McShane’s ROE recommendations should be taken as an upper limit rather than an unbiased estimate of the appropriate ROE. (BCOAPO Argument, para. 16)

While BCOAPO accepts that there can be some trade-off between equity thickness adjustments and ROE adjustments, we note that in the cases in which Ms. McShane made recommendations with respect to both capital structure and ROE, in four of these cases the approved ROE and the approved equity thickness were both lower than the McShane recommendations. BCOAPO further notes that in only one of the cases were Ms. McShane’s capital structure and ROE recommendations both accepted.” (BCOAPO Argument, paras. 11-19)

In Reply, TGW describes BCOAPO as purporting to conduct “a quasi-empirical analysis of Ms. McShane's expert evidence in other proceedings”, from which it extrapolated that Ms. McShane's ROE and capital structure evidence in this proceeding should be regarded as an "upper limit rather than an unbiased estimate” of the appropriate outcome, and submits that “BCOAPO's extrapolation is flawed and not instructive.” In summary, TGW submits that the evidentiary record is simply insufficient to support the type of extrapolation being advanced by BCOAPO. The extrapolation is meaningless without an understanding of (1) whether the regulator chose a different combination of ROE and capital structure than originally proposed but ended up in virtually the same place in terms of the utility's overall cost of capital; (2) the extent to which the recommendations and the decisions are different because of changes in the underlying forecasts of long Canada bond yields between the time of the testimony and the time of the decision—resulting in an overstatement of the differential between recommendation and decision; and (3) whether the difference is due to a divergence of opinion between Ms. McShane and the regulator as to the benchmark return at the time, which is not pertinent to this proceeding (TGW Reply paras. 8-14).

TGW discusses business risk and submits that its SMDA still provides a measure of weather related risk mitigation.

TGW addresses the risk associated with operating a natural gas system being lower than for a propane utility, and submits that TGW’s current ROE and capital structure are adequate. It notes that Ms. McShane's evidence supports the proposed ROE and capital structure and focuses on the business risks associated with operating a natural gas distribution system. TGW submits that if it were a propane utility its appropriate ROE would be higher than the one it proposed (TGW Reply para. 15).

TGW addresses BCOAPO’s submission that it “should absorb all cost overrun risk if it wishes to obtain a higher ROE and thicker equity", and states that Ms. McShane's evidence assumes that TGW would have the opportunity to recover all prudently incurred costs, with the import of this assumption being that, should any risk exist above the recovery of conversion cost overruns,

"[a]ll things equal, these additional business risks would directionally suggest a further increase in the risk premium for TGW [beyond the proposed risk premium]" [Emphasis in original.]
(TGW Reply para. 23).

Commission Determination

The Commission Panel will first address TGW's business risk, its appropriate capital structure, and the appropriate premium over the benchmark low risk utility ROE.

The Commission Panel notes that while TGW's response to BCUC IR 1.35.2 spoke of the regulatory/business risks of operating a propane system being higher than operating a natural gas system, Ms. McShane's evidence addressed supply risks which she expected to be lower as a natural gas distribution system than as a piped propane system, but to remain higher than those of the typical LDC.

In its Reasons for Decision attached to Order G-14-06, the Commission found that the Applicant and Intervenors broadly agreed on the definition of business risk to a benchmark low-risk utility, namely that investment risk comprises the sum of business risk, financial risk, and regulatory risk.

Business risk is the risk that the utility will not be able to earn a return on its capital or of its capital. Dr. Booth summarized those elements that constitute business risk as:

> "…stemming from uncertainty in the demand for the firm's product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method used by the firm and the uncertainty in the firms' cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials. Financial risk is measured through the debt equity ratio of a utility. Regulatory risks are those that might arise from regulatory lag, from disallowed operating or capital costs or from punitive awards" (G-14-06, p. 17).

The Commission Panel notes that the risk that the utility will not be able to earn a return on its capital is generally considered to be a short-term risk while the risk that the utility will not be able to earn a return of its capital is considered to be a long-term risk. The short-term risk is considered to be mitigated by the approval by the Commission of various deferral accounts. TGW's deferral accounts are reviewed in Section 4.3 of these Reasons and the Commission Panel accepts the use of deferral accounts as proposed by TGW. Accordingly the Commission Panel finds that no adjustment is necessary to TGW's capital structure or ROE in this regard.

So far as concerns the long-term risk of earning a return of its capital, the Commission Panel accepts TGW's arguments that its service area and customer base is concentrated in a single cyclical and highly competitive industry – tourism, and that it lacks the diversity of service area and customer base enjoyed by the benchmark low-risk utility-TGI.

The Commission Panel finds that while TGW's supply risk may be reduced following conversion, its business risk will have increased by virtue of the fact that its rate base will have doubled as a result of the conversion while its customer base remained largely unchanged.

The Commission Panel also finds that TGW is exposed to business risk by virtue of the bonus/penalty condition in the CPCN which it accepted in 2006.

For these reasons the Commission Panel agrees with TGW that a more suitable capital structure should comprise 40 percent common equity and 60 percent debt.

Before addressing TGW's ROE, the Commission Panel will address the submissions made by the BCOAPO in its Argument. The Commission Panel has considered TGW's response to BCOAPO IR 2.16.5 and BCOAPO's submissions in the matter of Ms. McShane's recent "track record" and does not find them to be determinative largely for the reasons set out in TGW's Reply.

The Commission Panel finds no compelling reason to award TGW the same premium (75 bps) as it allowed TGVI in Order G-14-06 as it finds the business risks faced by TGVI to be greater than those faced by TGW. The Commission Panel also notes TGW's observation that as a propane utility its

ROE should be higher than as a natural gas utility. The Commission Panel considers that a comparable utility can be found in Terasen Gas (Squamish) Inc. whose ROE after conversion from propane to natural gas was established at 50 bps over the benchmark ROE.

Accordingly, the Commission Panel orders that the ROE for TGW be established at 50 bps over the benchmark low-risk utility.