BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

TERASEN GAS INC. AND
TERASEN GAS (VANCOUVER ISLAND) INC.
APPLICATION TO DETERMINE THE APPROPRIATE
RETURN ON EQUITY AND CAPITAL STRUCTURE
AND TO REVIEW AND REVISE THE
AUTOMATIC ADJUSTMENT MECHANISM

DECISION

MARCH 2, 2006

Before:

R.H. Hobbs, Panel Chair
R.J. Milbourne, Commissioner
A.J. Pullman, Commissioner

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1.0 EXECUTIVE SUMMARY

On June 30, 2005, Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") applied to the Commission to determine the appropriate return on equity and capital structure and to review and revise the automatic adjustment mechanism. TGI's return on equity and capital structure were established following a generic hearing by the Commission in 1994, at 350 basis points over the forecast long Canada bond yield and an equity component of 33 percent. The automatic adjustment mechanism was amended in 1999, with the result that when long Canada bond yields are forecast to be below 6 percent, the ROE rises and falls in step with the forecast long Canada bond yield. TGI has the lowest return on equity and smallest equity component of capital structure of any gas distribution company in Canada.

Up to 2002 TGVI's return on equity and capital structure were established by Special Direction issued by the Lieutenant Governor in Council to the Commission. Thereafter, under the Commission's negotiated settlement process, they were determined to be a 50 basis point premium over the return on equity of the benchmark low-risk utility (which the Commission determined to be TGI) and an equity component of 35 percent.

The Applicants seek the following returns on equity (based on the November 2006 consensus long Canada bond yield forecast of 4.79 percent) and equity component:

TGI	10.16%	38%
TGVI	10.91%	40%

The Commission Panel determines that both the comparable earnings standard and the capital attraction standard are equally relevant in establishing a fair return.

Accordingly, the Commission Panel gives weight to both the Equity Risk Premium and the Discounted Cash Flow approaches to establishing a fair rate of return. It is unable to give any weight to the Comparable Earnings of low-risk Canadian industrials in this proceeding, although it believes that this approach may play a role in future hearings.

The Commission Panel concludes that the appropriate return on equity for a benchmark low-risk utility is 3.90 percent over the forecast long Canada bond yield. The Commission Panel determines that TGI will continue to be the benchmark low-risk utility. The Commission Panel also concludes that a revision to the automatic adjustment mechanism is appropriate, such that the return on equity will be adjusted by 75 percent of the change in forecast long Canada bond yields, effective January 1, 2006. Accordingly, the return on equity for

TGI for 2006 will be 8.80 percent and its equity component will be 35 percent. For TGVI the Commission Panel determines that a 70 basis point premium over the benchmark low-risk utility is appropriate for a return for 2006 of 9.50 percent, and an equity component of 40 percent.

2.0 INTRODUCTION AND BACKGROUND

2.1 Introduction

On June 30, 2005 Terasen Gas Inc. ("Terasen Gas" or "TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") collectively referred to as the "Companies" or the "Applicants" jointly filed an application (the "Application" with the British Columbia Utilities Commission ("BCUC" or the "Commission") to determine the appropriate return on equity ("ROE") and capital structure, and to review and revise the automatic adjustment mechanism ("AAM").

2.2 Overview

2.2.1 TGI

In 1994 the Commission was the first in Canada to hold a generic hearing into the appropriate rates of return on common equity and capital structure for utilities subject to its jurisdiction. It determined BC Gas Utility Ltd. ("BC Gas") (now Terasen Gas Inc.) to be the benchmark low-risk utility and established rates of return on common equity and capital structure for BC Gas, West Kootenay Power Ltd. (now FortisBC Inc.) and Pacific Northern Gas Ltd. ("PNG"). In addition, its Order No. G-35-94 established an AAM for calculating the allowed ROE on an annual basis.

In 1997 the Commission, by Order No. G-49-97, amended the AAM to correct for certain problems and to make it more consistent with the practices of other Canadian jurisdictions. In that Order the Commission directed that the range of forecast long Canada bond yields over which the AAM would apply would be 6.0 percent to 12.0 percent.

In November or December of each year from 1995 through 1998 the Commission issued letters to the Utilities subject to its jurisdiction establishing the ROE allowed for rate making purposes for each subsequent year based on calculations pursuant to the AAM. Centra Gas British Columbia's (now TGVI) ROE was set by Special Direction during that period.

In 1999, following an oral public hearing into the ROE for a low-risk benchmark utility and into the AAM, the Commission issued Order No. G-80-99, which directed that the AAM should continue to be employed, with certain exceptions:

- at forecast long Canada yields of 6.0 percent or below, the equity risk premium for a low-risk benchmark utility will be fixed at 350 basis points;

- at forecast long Canada yields of greater than 6.0 percent, the current contraction/expansion factor (i.e., the sliding scale) of 0.8 of the difference in forecast long Canada yields shall be retained and shall be driven off a low-risk benchmark utility ROE of 9.5 percent;

- to determine the forecast long Canada yield, the period over which the 10- to 30-year spread is to be measured shall be redefined as all the trading days in the October preceding the November Consensus forecast; and

- the Commission will canvass interested parties on the need for a review of the automatic adjustment formula when long Canada rates exceed 8.0 percent for a period of at least six months.

On November 1, 2000, BC Gas applied to the Commission to adjust the application of the automatic ROE adjustment formula to address the then current situation of yields on 10-year Government of Canada bonds exceeding the yields on 30-year Government of Canada bonds. The Commission reviewed the submissions of the various parties and decided not to vary the application of the ROE adjustment mechanism for 2001, as stated in Letter No. L-61-00.

In Letter No. L-62-01 the Commission established a written public hearing to review the yield spread between medium and long-term bonds in 2001 to consider whether amendments should be made to the mechanism for 2002. Following that written proceeding, the Commission determined by Order No. G-109-01 that the treatment of the yield spread between 30-year and 10-year bonds did not require adjustment. The Commission also determined that the ROE for the benchmark low-risk utility, expressed as a percentage, should be rounded to two decimal places prior to adding the utility-specific risk premium.

On July 22, 2004, TGI wrote to the Commission requesting the Commission convene a hearing to review return on equity and capital structure. By Order No. G-88-04 the Commission determined that a hearing was not warranted at that time but concluded that such a review may be appropriate in the Fall of 2005 in time for implementation January 1, 2006.

By Application dated June 30, 2005, the Companies submit that since 1994, when the Commission introduced its ROE adjustment mechanism for setting rates of returns, which reflected the economic climate and circumstances of the day, much has changed and that in British Columbia, in Canada and in North America there is intense competition for capital.

The Applicants ask the Commission to move in accordance with these changed circumstances and recognize that it is not appropriate to subject investors in TGI to the lowest allowed return on equity in Canada.

Further the Applicants ask that the Commission recognize that British Columbia utilities must compete for capital with other Canadian utilities and with utilities in the U.S. and award returns on equity, and establish capital structures, that are appropriate in today's financial markets and reflect the business and financial risks of the utilities in British Columbia.

TGI requests that the Commission acknowledge changed circumstances by allowing it a common equity component of 38 percent in its capital structure, and a return on equity of 10.50 percent when long-term Canada bonds are forecast to yield 5.25 percent. TGVI requests that it be allowed a common equity component of 40 percent and be granted an additional 75 basis point increment over the allowed return on equity of TGI (i.e., 11.25 percent when the forecast yield on long-term Canada bonds is 5.25 percent).

Finally, the Applicants ask that the AAM be revised to make it comparable with other Canadian jurisdictions, both federal and provincial, which have established a sliding scale adjustment of 0.75:1 through its entire range of application.

On August 3, 2005, the Commission held a Procedural Conference, pursuant to Order No. G-69-05, to address the scope of the Commission's review of the Application, the steps and timetable associated with the regulatory review process and any other matters to assist the Commission to efficiently review the Application.

With input provided by Utilities and Intervenors at the Procedural Conference, the Commission defined the scope of the proceeding as follows:

1) The automatic ROE adjustment mechanism and all issues related thereto with respect to the establishment of the low-risk benchmark utility return used in the calculation of the appropriate ROE for utilities;

2) The capital structure for TGI and TGVI and utility-specific risk premium, if any, used in the calculation of the appropriate ROE for TGI and TGVI; and

3) The date the decision becomes effective.

A public hearing was held in Vancouver on November 14-18, 2005. Written Argument and Reply were received by January 5, 2006. Supplementary oral argument was heard by the Commission Panel on January 17, 2006.

2.2.2 TGVI

Under the terms of the Special Direction to the Commission issued under the Vancouver Island Natural Gas Pipeline Act ("VINGPA") by the Lieutenant Governor in Council through Order in Council 1510/95 the equity component of the capital structure and return on equity were set at 35 percent and 362.5 basis points over the long Canada bond yield respectively until December 31, 2002, after which time the Commission would set rates in accordance with the regulatory principles that are generally applied by it from time to time to gas distribution companies operating within British Columbia. In 2001 BC Gas Inc. (now Terasen Inc. or "TI") acquired Centra Gas British Columbia Inc. In 2003, in accordance with the negotiated settlement, the Commission approved by Order No. G-2-03 that TGVI's equity component of capital structure would be 35 percent and its ROE set at a premium of 50 points basis over the benchmark low-risk utility ROE.

2.2.3 The Law and the Jurisdiction of the Commission

Intervenors and Applicants cite four court decisions that they submit are relevant to the matters in this proceeding: *B.C. Electric Railway Co. Ltd. v. Public Utilities Commission of B.C. et al.* [1960] S.C.R. 837 ("*B.C. Electric Railway*"), *Hemlock Valley Electrical Services Ltd. v. BCUC* (1992) 66 B.C.L.R. (2d) 1 (B.C.C.A.) (*"Hemlock Valley"), Bell Canada v. Canada* (CTRC) [1989] 1 S.C.R. 1722 ("*Bell Canada*"), and *Northwestern Utilities Ltd. v. Edmonton and Board of Public Utility Commissioners of Alberta* [1929] S.C.R. 186 *("Northwestern Utilities").*

In addition, the B.C. Old Age Pensioners' Organization et al. ("BCOAPO") reminds the Commission of its duties under the Utilities Commission Act ("Act", "UCA") in setting just and reasonable rates. These are:

1. a fair and reasonable charge for service of the nature and quality provided by the utility,
2. sufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, and
3. not unjust or unreasonable for any other reason [Utilities Commission Act ("UCA"), s. 59].

The Applicants submit that the *B.C. Electric Railway* and the *Hemlock Valley* cases make it clear that the obligation to allow a utility to earn a fair and reasonable return is absolute, and that a rate is unjust or unreasonable if it fails to yield a just and reasonable return on rate base (TGI/TGVI Submissions, p. 34, para. 115).

The BCOAPO cites *Bell Canada* and *Northwestern Utilities* and submits that the Commission must balance the interests of customers to a fair and reasonable charge for services with the interests of shareholders to fair and reasonable compensation. The BCOAPO submits that the Commission should take into account the rate increases that would result if the Application is approved (BCOAPO Submission, p. 7).

The Joint Industry Electrical Steering Committee ("JIESC") submits that all of the resources TGI and TGVI require, including the capital, must be obtained at the lowest possible cost and that the return must be equal to the returns available to investors on investments of comparable risk (JIESC Submission, p. 3; T7: 995).

The Commercial Energy Consumers Association of British Columbia ("CEC") submits that the obligation to allow a utility to earn a fair and reasonable return on rate base is not absolute, and that the Commission must balance the interests of customers and shareholders. The CEC further submits that if the obligation to allow a utility to earn a fair and reasonable return on rate base is absolute it would entitle new shareholders, who have paid a premium to departing shareholders of a regulated utility, to request a fair return on their investment, including any premium paid for the investment (CEC Submission, pp. 2-3).

Commission Determinations

The Commission's mandate is to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the public utilities it regulates, and that shareholders of those public utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. The process to establish a fair return and just and reasonable rates is enshrined in the UCA where "the commission must consider all matters that it considers proper and relevant affecting the rate" and in doing so it must have due regard to the setting of a rate that "is not unjust or unreasonable" within the meaning of section 59 (of the Act) [*UCA*, s.60 (1)(a) and (b)(i)].

The reasons of Locke J. and Martland J. in the *B.C. Electric Railway* case are ad idem on the matter of the need to consider both the costs of providing service and a fair return on invested capital used or prudently incurred to provide the service. First Locke J. said:

> "...I do not think it is possible to define what constitutes a fair return upon the property of utilities in a manner applicable to all cases or that it is expedient to attempt to do so. It is a continuing obligation that rests upon such a utility to provide what the Commission regards as adequate service in supplying not only electricity but transportation and gas, to maintain its properties in a satisfactory state to render adequate service and to provide extensions to these services when, in the opinion of the Commission, such are necessary. In coming to its conclusion as to what constituted a fair return to be allowed to the appellant these matters as well as the undoubted fact

> that the earnings must be sufficient, if the company was to discharge these statutory duties, to enable it to pay reasonable dividends and attract capital, either by the sale of shares or securities, were of necessity considered. Once that decision was made it was, in my opinion, the duty of the Commission imposed by the statute to approve rates which would enable the company to earn such a return or such lesser return as it might decide to ask" (Exhibit A3-5, p. 848).

Martland J. said:

> "The rate to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on the rate base. There must be a balancing of interests. In my view, however, if a public utility is providing an adequate and efficient service [as it is required to do by s. 5 of the Act (now s. 38)], without incurring unnecessary, unreasonable or excessive costs in so doing, I cannot see how a schedule of rates, which, overall, yields less revenue than would be required to provide that rate of return on its rate base which the Commission has determined to be fair and reasonable, can be considered, overall, as being excessive" (Exhibit A3-5, p. 856).

The submissions of the Applicants and the Intervenors in this proceeding are not ad idem regarding the appropriate consideration of the "balancing of interests". The Commission Panel finds the reasons of Locke J. and Martland J. instructive, and notes that they are accepted in the *Bell Canada* case. The Commission Panel does not accept that the reference by Martland J. to a "balancing of interests" to mean that the exercise of determining a fair return is an exercise of balancing the customers' interests in low rates, assuming no detrimental effects on the quality of service, with the shareholders' interest in a fair return. In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital. As Martland J. said, "The rates to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on rate base." With the use of AAM, the determination of the cost of service and the determination of a fair return are now issues for separate processes.

As for the JIESC's lowest cost argument, the Commission Panel shares the view of the NEB, which recognized that "lowest possible" was not the appropriate test when it stated, at page 25 of its RH-2-94 Decision on generic cost of capital:

> "Contrary to what some parties advocated during the hearing, the Board is of the view that it is not appropriate to over-leverage a pipeline in order to identify the minimum acceptable deemed common equity ratio possible."

2.3 The Applications

2.3.1 Benchmark low-risk utility

The Applicants seek revised capital structures and a return on equity appropriate to a benchmark low-risk utility.

TGI (then BC Gas Utility Ltd.) was deemed the benchmark utility in 1994 when the first generic ROE adjustment mechanism was established, and has continually been regarded as such by the Commission (Exhibit B-1, Tab 1, p. 2).

TGI's expert witness, Ms. McShane, describes a "benchmark low-risk utility" as a hypothetical construct. She considers that one objective measure of what constitutes a low-risk utility would be the utility's ability, on a stand-alone basis, to achieve debt ratings of A. In her view "The benchmark return is derived from data for utilities across industries (electric, gas distribution and gas pipeline), as well as from data for non-utilities. It is based on no specific utility and hence reflects no specific business or financial risk characteristics" (Exhibit B-1, Tab 2, p. 11).

2.3.2 Basis for filing the Applications

According to the Companies, the basis for the filing of the Applications is:

1) The AAM has resulted in TGI being allowed the lowest return on investment of any regulated energy utility in Canada.

2) The AAM has had unintended consequences when forecast long Canada bond yields are below 6 percent.

3) There have been significant changes in the Canadian economy and financial markets since 1994.

4) The business risk profile of TGI has changed since 1994, while its capital structure has been weakened by the elimination of preferred shares.

5) The capital structure and ROE should enable the companies to maintain adequate debt coverage ratios to avoid alarms from debt rating agencies.

6) The Commission should give weight to all three methods of determining the cost of equity capital namely the Equity Risk Premium, the Discounted Cash Flow and the Comparable Earnings tests (Exhibit B-1, pp. 2-3).

2.3.3 TGI

TGI states that in order to be designated the benchmark low-risk utility, it requires a common equity component in the capital structure of 38 percent as compared to the current 33 percent and a ROE of 10.5 percent when long Canada bonds are forecast to yield 5.25 percent (Exhibit B-1, Cover Letter, p. 3; TGI/TGVI Submissions, p. 1). Based on the consensus long Canada bond yield forecast of 4.79 percent the determination of the formula-based allowed ROE for 2006 is 8.29 percent (Exhibit B-25; B-26). The Applicants submit that any variance from a long-term Canada forecast bond yield of 5.25 percent should be accommodated through an adjustment in the ROE by 75 percent of the variance of long-term Canada bond forecast. On this basis, the 2006 ROE for TGI should be set at 10.16 percent [10.5%-(.75*(5.25-4.79))] (TGI/TGVI Submissions, p. 26; TGI/TGVI Reply Submissions, p. 46).

2.3.4 TGVI

TGVI seeks a common equity ratio of 40 percent and equity risk premium relative to the benchmark low-risk utility of 75 basis points. The current common equity component of TGVI is 35 percent and the premium is 50 basis points relative to the benchmark utility (Exhibit B-1, Tab 2, p. 18; Exhibit B-3, BCUC IR 40.1; Exhibit B-14A; TGI/TGVI Argument, pp. 32, 33). The determination of the formula-based 2006 allowed ROE for TGVI is 8.79 percent (Exhibit B-26). TGVI submits that its ROE should be set at 10.91 percent (i.e., 10.16 percent plus 75 basis points) (TGI/TGVI Submissions, p. 62; TGI/TGVI Reply Submissions, p. 46).

2.4 Acquisition of Terasen Inc. by Kinder Morgan, Inc.

The Applicants filed their application with the Commission on June 30, 2005. On August 1, 2005 Kinder Morgan, Inc. ("KMI") and Terasen Inc., the sole shareholder of the Applicants, announced a definitive agreement whereby KMI would acquire all of the outstanding shares of TI for $35.91 per share. This amount is 2.7 times the book value of each TI share. The total purchase price, including the assumption of debt, is announced to be $6.9 billion. Following the announcement of the transaction Moody's Investors Service announced that it would place TGI on credit watch with negative implications until it had investigated the implications of the transaction on TGI's credit quality. Moody's Investors Service downgraded TGI on December 19, 2005, stating that it had evaluated TGI's credit on a stand-alone basis assuming that the regulatory ring-fencing imposed by the Commission would be effective in insulating TGI from the higher business and financial risk of its parent entities (Exhibit B-27, p. 1).

The Applicant's treasurer, Mr. Bryson commented on the transaction:

> "Well, I think that 2.7 book value was for the entire Terasen entity, which includes not just the gas utility business, but includes the pipeline business and the water business. You know, as we've indicated to investors over the past several years and demonstrated to investors over the last several years, we've got tremendous growth potential in our pipelines business...I think, you know, their public statements are clear that they saw the greatest potential in the pipelines business. When you add up the various growth opportunities that Terasen has in front of it, I mean, we're a $5-billion organization currently, with more that $5 billion of growth potential in that business segment alone" (T2: 123).

On August 17, 2005, KMI applied to the Commission under section 54 of the UCA for approval of the acquisition of the shares of TI. On November 10, 2005 the Commission approved the transaction, subject to certain conditions concerning "ring-fencing," independent governance and location of data. The ring-fencing provisions are designed to insulate TGI and TGVI from credit rating downgrades and related financial risks associated with any affiliates in the large Terasen/KMI corporate family. The conditions approved by the Commission are as follows:

1) Each Terasen Utility shall maintain, on a basis consistent with BCUC orders and accounting practices, a percentage of common equity to total capital that is at least as much as that determined by the Commission from time to time for ratemaking purposes.

2) No Terasen Utility will pay a common dividend without prior Commission approval if the result would reasonably be expected to violate the restriction in (1) above.

3) (a) No Terasen Utility will lend to, guarantee or financially support any affiliates of the Terasen Utilities, other than between TGI and TGS, or as otherwise accepted by the Commission.

   (b) TGI and TGS shall together maintain separate banking and cash management arrangements from other affiliates. TGVI shall establish separate banking and cash management arrangements from other affiliates once it has completed its proposed refinancing.

   (c) No Terasen Utility will enter into a tax sharing agreement with any affiliate of the Terasen Utility, unless the agreement has been approved by the Commission.

4) No Terasen Utility will enter into transactions with affiliates that are not in compliance with Commission guidelines, policies or directives regarding affiliate transactions, and no Terasen Utility will enter into transactions with affiliates on terms less favourable to the Terasen Utility than those available from third parties on an arms-length basis, unless otherwise approved by the Commission.

5) No Terasen Utility will engage in, provide financial support to or guarantee non-regulated businesses, unless otherwise approved by the Commission.

The intervenors filed the evidence of Dr. Booth on October 11, 2005. Dr. Booth summarizes his evidence with the following observation:

> "Kinder Morgan's (KMI) proposed takeover of Terasen Inc. is at an 11.8X expected 2006 EBITDA or 2.7X book value. This extreme valuation implies that the financial parameters applied to the Terasen companies are extremely generous and confirms my judgment that they should be reduced. The KMI takeover also calls into question the lack of ring fencing of Terasen Gas and the need for restrictions on inter affiliate cash management and transactions. Failing such ring fencing, in the face of the double leverage used by KMI to finance the transaction, there is a grave risk that Terasen Gas Inc.'s bond rating will suffer and ratepayers will be paying unfair and unreasonable debt costs" (Exhibit C2-6, p. 3).

Dr. Booth refers to a CIBC World Markets report dated August 19, 2005 that claims KMI plans a "double dip" financing structure, which would enable it to claim interest as an expense in both Canada and the U.S. which would result in lower taxes being paid by the new group (Exhibit C2-6, p. 83).

BCOAPO argues that the gas distribution companies were an integral reason that a premium was paid by KMI. This position is based on the expert evidence of Dr. Booth, who testified that because TGI represents 65 percent of the earnings of TI, "part of that 2.7 times clearly reflects the fact that they were happy with Terasen Gas" (BCOAPO Argument, p. 10).

The CEC argues that the KMI purchase at its high valuation is conclusive evidence in and of itself that the existing ROE and debt/equity structure is delivering a more than fair, just and reasonable return to departing shareholders and the new shareholders involved in the purchase (CEC Submission, p. 3).

The JIESC takes the position that when the allowed return equals the investors required return, the market to book ratio will be equal to one. The Intervenor cautions that if the ROE is set too generously, the market to book ratio will rise and the customers will pay more than is necessary to attract capital (JIESC Submission, p. 4).

The Companies in Reply Argument clarify that the KMI acquisition did not cause any change in the shareholding of either TGI or TGVI as the shares of both companies continue to be owned by TI. The Companies argue that the CEC was incorrect to suggest that TGI and TGVI are seeking to recover the premium over book value that KMI paid on the purchase of the shares of TI, and that there is no support for the Intervenors' argument that the new shareholder of TI was satisfied with the current ROE (TGI/TGVI Reply Submissions, pp. 6-7).

The Companies submit that the acquisition of TI by KMI should play no part in the Commission's determination of the requests for relief that was made in the Applications. The Companies argue that the Commission cannot infer that KMI was satisfied with the return that was in place (T7: 1031).

Commission Determinations

In considering the premium paid by KMI for the shares of TI, the Commission Panel is cognizant of the findings of the Alberta Energy Utility Board ("AEUB") in its Generic Cost of Capital Decision, July 2, 2004 (Exhibit A3-1, p. 28):

> "The Board also agrees that there may be strategic factors affecting the price that is paid to acquire a utility. The Board also recognizes that, in some cases, a premium might be paid for regulated assets in anticipation of significant future growth in rate base, to achieve geographic diversification or to obtain a foothold in a new market. The Board is not aware of the strategic factors that may have affected the price paid to acquire Alberta utilities in recent years."

The Commission Panel is aware of a number of strategic and fiscal factors that may have affected the price paid by KMI for the shares of TI. KMI can employ double leverage and can claim interest expenses in both the U.S. and Canada ("the double dip") to make the acquisition earnings accretive. TI's oil transportation business has significant growth opportunities. To protect the financial integrity of TI's gas distribution subsidiaries the Commission has initiated "ring-fencing" conditions. The Commission notes that Moody's Investors Service has announced that it is satisfied with the "ring-fencing" conditions imposed by the Commission and that the downgrading by Moody's of TGI was unrelated to the transaction. There is no evidence before the Commission that any of the premium paid by KMI will be included in either of the Companies' rate bases and recovered from their customers. The Commission's role is to determine a suitable capital structure for the Applicants and return on equity for a benchmark low-risk utility and the KMI/TI transaction is not relevant to the Commission's determination.

3.0 AUTOMATIC ADJUSTMENT MECHANISM

3.1 Evidence and Argument

TGI has applied to change the contraction/expansion factor (or "sliding scale") component of the Commission's AAM such that the ROE will be adjusted by 75 percent of the change in forecast long Canada bond yields.

In 1994 the Commission implemented an adjustment mechanism for annually setting returns on equity, with revisions to the mechanism in the interim, including in 1999 as part of the Commission's 1999 ROE and Capital Structure Decision. The current mechanism increases the annual allowed return on equity by 80 percent of the change in forecast long Canada yields above 6.0 percent, and reduces the annual allowed return on equity by 100 percent of the change in forecast long Canada yields below 6.0 percent. Through its 1999 Decision the Commission also established that it would canvass interested parties on the need for a review of the automatic adjustment formula when long Canada rates exceed 8.0 percent for a period of at least six months.

Ms. McShane recommends that the Commission implement a symmetric 75 percent sliding scale, which she states would recognize that interest rates and the cost of equity do not rise and fall in tandem. She also submits that a 75 percent sliding scale would recognize the validity of the objectives of maintaining a stable financial profile and stable rates, and would put B.C. utilities on a similar footing as their Canadian peers (Exhibit B-1, Tab 2, p. 100). In support of her recommendation, Ms. McShane points to the results of her DCF-based equity risk premium test, which she concludes suggests that the utility cost of equity is less sensitive to changes in government bond yields than implied by the current sliding scale. In support, Ms. McShane also refers to her evidence of an average 75 percent ratio of Canadian utility dividend yields to long Canada bond yields in the period 1996-2004 as well as to her demonstration that a one percentage point change in the before-tax yield on a long-term Canada bond requires roughly a 70 basis points change in the utility return on equity to maintain a similar after-tax equity risk premium (Exhibit B-1, Tab 2, pp. 98-99).

Ms. McShane recommends that the formula should be reviewed if forecast long Canada yields fall below 4 percent or exceed 8 percent on the basis that long Canada yields outside of the range of 4.0-8.0 percent may indicate a materially altered relationship between long Canada yields and the utility cost of equity (Exhibit B-1, Tab 2, p. 100).

TGI submits that the current BCUC adjustment mechanism increasingly disadvantages B.C. utilities as long Canada bond yields decline, being the only such mechanism that provides for a one to one relationship between bond yields and allowed returns on equity (TGI/TGVI Submissions, p. 64). The Companies submit that the "penalization" of B.C. utilities can only be rectified by establishing a fair and reasonable return and implementing an adjustment formula with a symmetrical 75 percent sliding scale (TGI/TGVI Submissions, p. 64).

While Dr. Booth is not aware of any research to justify adjustment coefficients of either 0.75 or 0.80, and does not believe that risk premiums vary in a mechanical fashion with interest rates, he does support adjustment mechanisms as balancing the interests of shareholders and consumers and providing a viable compromise that avoids annual repetitive rate hearings. Dr. Booth judges that whether the adjustment coefficient is 0.75 or 0.80 is not material, but submits that that these coefficients are in the right range (Exhibit C2-6, pp. 67-68).

Dr. Booth recommends a sliding scale with an adjustment coefficient of 0.75. Dr. Booth has not specified any range in long Canada yields outside of which the formula should be reviewed since such cut-off points depend heavily on the economic situation that generates them, which cannot be specified ahead of time. Instead, Dr. Booth relies on the company, intervenors and Board staff to decide when a hearing is needed, based on their analysis of ongoing economic events (Exhibit C2-7, p. 85).

The JIESC accepts Dr. Booth's recommendation to change the adjustment mechanism after the benchmark return is reset so that for future changes being made pursuant to the adjustment mechanism, the return on equity is raised or lowered by 75 basis points for every 100 basis points change in long-term Canada yields (JIESC Submission, p. 40).

Other intervenors either made no submission on the sliding scale component of the AAM, or adopted the evidence of Dr. Booth and the submissions of the JIESC.

Commission Determinations

The Commission Panel notes that aside from recommended changes to the sliding scale component of the AAM, no other changes were recommended, such as to the method used to determine the forecast long Canada bond yield.

The Commission Panel is satisfied with the reasonableness of the proposed changes to the sliding scale recommended by TGI and supported by Intervenors. The Commission Panel approves a change to the adjustment mechanism such that the benchmark return on equity is raised or lowered by 75 percent of the change in the forecast long Canada bond yield.

The Commission Panel calculates that the result of this adjustment will be to increase the ROE for the benchmark low-risk utility for 2006 from 8.29 percent to 8.60 percent. The determination of the appropriate ROE is discussed in Section 6.

3.2 Review Process

Neither the Applicants nor the Intervenors make any recommendations concerning a periodic review of the process, or concerning events that should trigger such a review. In light of the AEUB finding in its 2004 Generic Cost of Capital Decision, the Commission Panel will adopt a review period of five years, while noting that any party continues to be free at any time to apply to the Commission to consider a review of the AAM. In addition, should the AAM result in a ROE for the benchmark low-risk utility of less than 8 percent or greater than 12 percent the Commission will canvass the views of the parties on whether the AAM should be reviewed.

4.0 RISK

4.1 Risk Defined

The Applicant and Intervenors broadly agree on the definition of risk to a benchmark low-risk utility. 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" (Exhibit C2-6, p. 22, line 13).

Financial risk is measured through the debt equity ratio of a utility (Exhibit C2-6, p. 23).

Regulatory risks are those that might arise from regulatory lag, from disallowed operating or capital costs or from punitive awards.

4.2 TGI

4.2.1 TGI's Submission

TGI submits that since the generic hearing and the introduction of the AAM in 1994 the competitive environment in which it operates has greatly changed, and that its business risks have increased significantly. The Companies identify nine components to the increase in the business risks of TGI and TGVI.

1) The operating cost advantage of natural gas versus other energy sources has declined; TGI provides Exhibit B-6 to illustrate a narrowing of the gap between gas and electricity for its residential customers in the Lower Mainland and Central interior of the province.

2) TGI's gas versus electricity price advantage is the lowest among Canadian gas distribution companies. Table 1 on page 7 of Exhibit B-1, Tab 1 shows gas to have a considerable price advantage over electricity in Alberta and Ontario.

3) Price competitive trends have led to declining captive rates for new customers. In addition to a greater proportion of new construction being multifamily dwelling, where TGI has experienced lower capture rates, TGI is experiencing reduced capture rates in single-family homes and estimates

its capture rate to have declined by 10 percent from the low 90 percent to the low 80 percent (Exhibit B-3, p. 64).

4) Alternative energy sources are more prevalent now than in the early 1990s. TGI cites ground source heat pumps in the residential sector, and industrial customers' ability to switch fuel types.

5) The annual use of natural gas by residential customers has declined through the 1990s and is forecast to continue to decline in the future; TGI states that residential use declined by 12.5 percent between 1997 and 2004, with a further 2 percent decline forecast to occur by 2009 (Exhibit B-1, Tab 1, p. 12-4). In Exhibit B-2, page 43, TGI notes that despite lower average consumption, its residential customers are paying more for use of natural gas.

In addition, TGI files data regarding its actual volumes sold and transported, which show a considerable decline:

Recorded Actual TGI Volumes – TJs

	Sales	**Transport**	**Total**
1995	124,856	56,426	181,282
1996	144,084	60,377	204,461
1997	135,866	58,305	194,171
1998	129,537	58,304	187,841
1999	136,150	63,382	199,532
2000	135,216	62,268	197,484
2001	120,553	58,806	179,359
2002	124,260	64,169	188,429
2003	113,391	62,415	175,806
2004	109,799	62,914	172,713

Notes
1. Includes Fort Nelson
2. Sales includes rates 1-7
3. Transport includes rates 22-27, excludes BC Hydro and TGVI Wheeling volumes (Exhibit B-12)

6) Changes in the gas supply environment have required TGI to become very proactive in the regional gas market and to develop strict controls on acceptable transactions and credit positions with external counterparties; TGI notes that it has proposed to extend its hedging program from 24 to 36 months. This necessitates larger credit lines to support mark to market losses on forward positions, and the need to contract only with creditable counterparties (Exhibit B-1, Tab 1, pp. 15-16).

7) TGI is limited in its ability to pass costs through because of the competitive pressure from other energy sources; this has required it to invest in software applications, which enable it to capture productivity gains (Exhibit B-3, p. 77).

8) Potential accounting changes for rate regulated enterprises, such as the elimination of accounting for regulatory deferral accounts, could introduce significant volatility into the earnings of such businesses and negatively impact compliance with excessive covenants and the ability to attract capital in the future (Exhibit B-1, Tab 1, p. 17).

9) TGI rejects the suggestion that deferral accounts eliminate or substantially reduce its business risk. Almost all utilities in North America now have energy cost deferral accounts and many have weather normalization accounts. This was not the case in 1994 when TGI was deemed to be the benchmark low-risk utility. TGI claims that, when compared to other regulated utilities, it is inappropriately designated as a "benchmark low-risk utility" (Exhibit B-1, Tab 1, pp. 17-18).

Ms. McShane, the Applicant's witness, submits that a 33 percent common equity ratio is too low for TGI to be considered equivalent to the benchmark low-risk utility. Her conclusion is based on factors that were similar to those cited by TGI: an increasingly competitive business environment in which TGI operates, and the fact that all major gas distributors have deferral accounts for the commodity cost of gas and many have rate stabilization or weather protection deferral accounts. In addition, Ms. McShane cites the relatively high concentration of TGI's demand in the industrial sector (40 percent) and the concentration of industrial load in a single industry, pulp and paper (Exhibit B-1, Tab 2, p. 15; T3: 326).

4.2.2 The Intervenors' Response

Dr. Booth disagrees with TGI's assessment of its business risk and submits that there is no significant increase in risk for TGI from higher natural gas costs. Dr. Booth notes that TGI continues to add customers and to grow its customer base, and that Terasen stated in its 2004 Annual Information Form (March 2005) that "Natural gas maintains a competitive advantage in terms of pricing when compared to alternative sources of energy in British Columbia." Dr. Booth also contends that if the risk of residential customers switching to alternative fuels was a significant risk to TGI it would be expected to be tracking and monitoring the situation, and the fact that it does not indicates that this is not considered to be a serious risk (Exhibit C2-6, pp. 32-34).

In Dr. Booth's view, "...utilities have the lowest business risk of just about any sector in the Canadian economy" and notes that the costs and revenues from gas distribution are very stable so that the underlying uncertainty in operating income is very low. Dr. Booth also notes that "...in the event of unanticipated risks, regulated utilities are the **only** group that can go back to their regulator and ask for "after the fact" rate relief" (Exhibit C2-6, p. 28, emphasis in the original).

Dr. Booth addressed TGI's business risk of not earning a return of capital, and offered the following solution:

> "The second and more risky situation is if the company can not rebalance to achieve its revenue requirement. This unlikely situation might occur if industrial and commercial users refuse to pay the higher rates resulting from the loss of residential load. In this case the recovery of the rate base is in question and Terasen runs the risk of stranded assets. However, if this risk is realistic, then the correct response is to change the depreciation rate so that the cost of potentially stranded assets is recovered from the existing users" (Exhibit C2-6, p. 33).

TGI counters this suggestion by citing an excerpt from a NEB decision re TransCanada Pipelines RH-2-2004:

> "...there is a potential that a company's tolls may not incorporate sufficiently high depreciation rates because competitive factors would prevent such rates from being charged. This potential, if significant, is appropriately compensated through the cost of capital.
>
> The assessment of cost of capital should assume that the depreciation rates reflect the best assessment of economic life of the pipeline. Consequently, resetting depreciation rates to reflect a new best estimate of economic life does not, by itself, reduce business risk from what it would be absent a change in the best estimate" (Exhibit B-5, Response to JIESC et al. 7.2c).

The parties do not address the issue further in their Submissions, in the Commission Panel's view, correctly. There is nothing before the Commission Panel to suggest either that the Applicants' depreciation rates do not reflect their best assessment of the economic life of their plant in service; or that their business risks can be eliminated by a change in depreciation rates.

4.2.3 Competitiveness of Natural Gas versus Electricity

With respect to the risks related to the competitive position of natural gas versus electricity, the JIESC notes that TGI had indicated that a year ago it had determined that there was a 95 percent probability that its residential natural gas rates would remain at or below British Columbia Hydro and Power Authority's ("BC Hydro") electricity rates (JIESC Submission, p. 10; T2: 97). However, the Companies submit that this statement refers to its information a year ago and that gas prices have increased since then, further decreasing its competitiveness (T3: 290). The JIESC also notes that TGI's estimate of the competitive electricity price was based on an internal estimate that assumed that electricity prices would increase at approximately one-half the rate of increase of BC Hydro's probable scenario in its 2004/05 Electricity Load forecast (Exhibit C2-15). The JIESC argues that Ms. McShane indicated that gas prices would be expected to moderate somewhat from the current high prices resulting from "the aftermath of the hurricanes" (T3: 330).

The JIESC files a slide from TGI's 2005 Annual Review that shows the five-year forward gas prices at the AECO Hub™ declining from approximately $13.50 Cdn/GJ in January 2006 to $7.00 Cdn/GJ in October 2010 (Exhibit C2-23). This trend is directionally consistent with the opinion of the Companies' witness Ms. McShane (T3: 329-330).

The JIESC also files a page from BC Hydro's December 2004 Electric load forecast for the period 2004/05 to 2024/25. The BC Hydro forecast states that its probable scenario assumes that electricity prices will increase at the rate of inflation (Exhibit C2-15), whereas TGI assumes a rate of increase for electricity prices that was one-half the rate of inflation (T2: 84).

The CEC argues that the risk associated with electric to gas competition has existed since the deregulation of natural gas pricing and as such it is a risk for which the utility has been compensated for a long time. In the view of the CEC, recent competitive pressures reflect supply tightening in the natural gas commodity sector and the realization of underlying risks, which have remained constant (CEC Submission, p. 19). The CEC also notes that Terasen did not use electricity price forecasts available from BC Hydro, nor had it studied the anticipated cost pressures on BC Hydro's electricity rates. The CEC also cites the testimony of Ms. McShane who agreed that a forecast of electric rate increases twice as high as that used by TGI would reduce the competitive pressure (CEC Submission, pp. 20-21).

The CEC disputes Terasen's claim that the customer attachment rate as a percentage of housing starts is approximately one-half of what it was in the mid-1990s (T2: 84). The CEC argues that if one accounts for the lag between the measurement of housing starts and customer attachments the relationship is more constant (CEC Submission, pp. 22-23). The CEC also argues that declining use rates are a normal result of higher efficiency equipment, more use of thermostat controls, increased insulation and trends towards multi-family dwellings. In the view of the CEC, these trends will create lower customer bills and improve the competitiveness of natural gas, even as electricity goes through a similar process of increasing efficiency. The CEC considers the trends concerning TGI to be evidence of "...the consolidation and firming of the core market towards its more fundamental needs..." for natural gas and not a factor increasing risk (CEC Submission, p. 24).

The Companies dispute the CEC argument that accounting for the timing difference between housing starts and customer attachments eliminates the decline, and replies that there has been a significant decline in customer additions and the number of customer additions as a proportion of housing starts since the early 1990s. The Companies also argue that while high efficiency furnaces and other advances may partly explain the decline in use per account, the fact remains that use per account and throughput are decreasing, which will lead to higher unit charges (TGI/TGVI Reply Submissions, p. 16; Exhibit B-12).

The Companies submit that the price competitiveness of natural gas has deteriorated since 1994 and 1999 and that, even though Exhibit C2-23 shows the forward price of natural gas declining over time from current levels, these forward prices continue to be higher than past prices and the Companies will face greater competition from electricity than in the past. The Companies argue that whether or not BC Hydro rates will increase at 1 percent or 2 percent per year is immaterial, when compared to the dramatic change in the relative prices in the price of natural gas and electricity and the volatility of gas prices (TGI/TGVI Reply Submissions, pp. 13-14). The Companies further argue that consumers' purchasing decisions are influenced not only by the absolute level of gas prices but also by their perception of price and volatility (TGI/TGVI Submissions, p. 10).

4.2.4 Deferral Accounts

The Applicants seek no change in their deferral accounts. TGI provides a listing and description of its deferral accounts plus a comparison to Union Gas Limited ("Union"), Enbridge Gas Distribution Inc. ("Enbridge"), Gaz Metro, and ATCO Gas (Exhibit B-3, Appendix 26.5).

TGI maintains two significant commodity deferral accounts: the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA"). These commodity deferral accounts collect the difference between the actual incurred gas costs and recoveries from rates. TGI's non-commodity deferral accounts defer elements of gross margin and of costs. The most significant deferral account for TGI is the Revenue Stabilization Account Mechanism ("RSAM"). The Company describes its operation as follows:

> "The RSAM account deals with the Company's delivery margin and stabilizes the margins recovered from residential and commercial customers. The RSAM stabilizes delivery margin received from these customer classes on a use per customer basis. If customer use rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, the Company records the delivery charge differences in the RSAM account for refunding or charging through a rate rider to the RSAM rate classes over the ensuing three years. Having an RSAM mechanism does not offer the company protection against forecasting errors due to variances between recorded and forecast number of customers nor does it mitigate any forecasting risks associated with the non-RSAM customer classes such as industrial customers" (Exhibit B-3, Response to BCUC IR1 26.4.1).

TGI states that the approved 2005 delivery margin, including other operating revenues, totals $522.1 million, of which $100.5 million (21.2 percent) is subject to risk without deferral account protection. This amount comprises non-RSAM class customers of $82.4 million (15.8 percent), other operating revenues of $26.0 million (5 percent) and new customer additions of $2.1 million (0.4 percent) (Exhibit B-3, Response to BCUC IR1 26.7).

At December 31, 2004, the unrecovered balance on the RSAM Account was $59.5 million less related tax of $20.5 million (net of $39.0 million). TGI states that the balance on the account has accumulated over 11 years, with the balance being reduced in only two of those years (1996 and 1999).

Cost deferral accounts include the short-term and long-term interest rate deferral accounts which absorb interest rate fluctuations, and pension cost and insurance premiums deferral accounts, the latter two established as part of the 2004-2007 PBR settlement (Exhibit B-3, Appendix 1.5, p. 32). On the expense side, TGI states that of its 2005 test year expenses, O&M expenses of $152.1 million have no deferral protection, along with depreciation of $80.8 million (Exhibit B-5; JIESC IR No. 1, p. 15).

The JIESC argues that the Commission has allowed TGI "some of the most generous risk mitigation measures in the industry through extensive use of deferral accounts and through PBR regulation which provides an opportunity to earn returns above and beyond the allowed return" (JIESC Submission, pp. 11-13).

The CEC also submits that TGI "...has the most attractive deferral account treatment when considering that other jurisdictions are adopting some of these treatments....", and that deferral accounts contribute to providing the Company with very stable and predictable earnings. The CEC states that TGI's concern about deferral accounts is that these are ineffective in dealing with gas on electric competition, and argues that while deferral accounts provide TGI with very stable and predictable earnings, they are not intended to deal with gas on electric competition (CEC Submission, pp. 24-27). The CEC notes that only 18.1 percent of TGI's 2005 Test Year revenue is not covered through deferral accounts and consequently it has a highly predictable accounting income and a highly stable ability to earn its ROE (CEC Submission, pp.17-18; Exhibit B-5, Volume 5, Response to JIESC-BCOAPO-CEC IR1 7.1).

The JIESC notes that TGI earned its allowed return in every year since 1995, with the exception of 1998, which was due to employee severances paid out as a result of a major corporate restructuring to take advantage of PBR (JIESC Submission, p. 17; Exhibit B-5, JIESC-BCOAPO-CEC IR 7.1; T2: 79). The BCOAPO and the CEC echo this argument (BCOAPO Submission, p. 9; CEC Submission, p. 12).

The Companies agree with the CEC's submission that deferral accounts cannot deal with gas on electric competition and have not been proposed for such a purpose. The Companies also note that Dr. Booth indicated that the RSAM account should not affect the return on equity allowed (TGI/TGVI Reply Submissions, pp. 17-18).

The Companies acknowledge that PBR is beneficial to shareholders, but argue that it takes on additional risk by committing to O&M and capital targets, and by limiting its ability to seek relief from the Commission (T3: 286; TGI/TGVI Reply Submissions, p. 12).

4.2.5 The Companies' Response to Risk

The JIESC points to the TI annual report and testimony regarding the annual report to argue that:

> "The failure of Terasen to disclose any new material competitive risks in its annual report, where they must be disclosed or there will be legal penalties, should be proof that there are no new material risks the shareholders, or for that matter, there are no new material risks that the Commission should be concerned about" (JIESC Submission, p. 15).

In the JIESC's view there is no evidence that any prudently acquired asset of TGI will be economically stranded or that it will be unable to earn its allowed ROE in the future as it has in the past (JIESC Submission, p. 9).

The CEC also argues that if the risks to TGI were substantive, one would expect it to have invested in studying those risks and to have disclosed them in their Annual Report and Prospectuses where there is a legal obligation to disclose and be truthful. The CEC submits that the TI Annual Report and Prospectuses contain scant, if any, discussion of risks or disclosure of the potential to switch to alternative fuels. The CEC further argues that TGI appears not to have done any serious analysis to study or demonstrate the validity of the risk related to the price of gas relative to electricity, nor of consumer behaviour that would enable it to cope with competitive risks if they were significant (CEC Submission, pp. 32-36).

The CEC further submits that TGI has neglected to take actions that could mitigate the risks it perceives and has undertaken actions that exacerbate the problems it cites, including investment in expensive or uneconomic projects. The CEC also argues that TGI proceeded to acquire TGVI in spite of risks that were present before TGI purchased the utility. In summary, the CEC argues that TGI's response to its perceived risk is "tepid and weak" and consequently should not be granted any increased ROE or equity component at this time (CEC Submission, pp. 30-39).

The CEC dismisses TGI's claims with respect to various other risk adjustment factors, such as gas supply management challenges, cost management issues, regulatory accounting risks, and lack of growth. The CEC argues that TGI's claims with respect to these risks are either self-contradictory or unsupported by the evidence. The CEC submits that the underlying risk differs from the realized outcomes associated with risk and that the realization of a risk that has existed for some time does not change the risk of a company (CEC Submission, pp. 28-29).

The Companies contend that the risk disclosure in the TI Annual Report is appropriate in the context of Terasen Inc. and that an exhaustive discussion of TGI and TGVI's business risks comparable to the discussion in the hearing would give investors a distorted view of the overall business risk of Terasen Inc. "...given that its business risk remains relatively low compared to the broad equity market" (TGI/TGVI Reply Submissions, p. 11).

The Companies acknowledge that TGI is less risky than the "average" company (quotation marks in original) but argues that the evidence demonstrates that the relative risks of both TGI and TGVI have increased and that the risks faced by the Companies are greater than those faced by most other gas utilities in Canada (TGI/TGVI Reply Submissions, p. 10).

Commission Determinations

The Commission Panel finds that the vast majority of gas distribution companies in North America have some form of commodity deferral account, and that this protects both the utility from commodity risk and the customers from imprudent purchasing and from the utilities profiting from the purchase, transportation and storage of gas.

With the exception of the RSAM, which is discussed below, the Commission Panel finds that many of the other costs which are deferred by TGI are deferred as a result of PBR so that TGI is not penalized for underestimating or rewarded for overestimating a cost over which it has little or no control. Thus, the deferral is symmetrical. The Commission Panel finds the RSAM to be a unique account. It has two facets that the Commission Panel will consider separately.

The RSAM acts as a weather normalization account. In this regard, TGI is similar to a number of utilities in North America (including Gaz Metro and Newfoundland Power Inc., in Canada) that can defer the effects of temperature when and where it differs from a long-term norm used to set rates. The Commission Panel agrees with Dr. Booth and Ms. McShane that weather is a symmetrical risk, with equal odds of over and underachieving, that should not be taken into account when establishing the ROE for a benchmark low-risk utility.

The second function of the RSAM is to enable TGI to defer margin variances arising from residential and commercial customers consuming more or less gas than forecast. The Commission Panel considers this aspect of the RSAM to be a short-term business risk mitigant, which is not available to TGI's comparators. By "short-term", the Commission Panel means that it agrees with the Applicants that "the RSAM does not provide for recovery of the return on, or of, capital in the longer-term."

The issue is "whether the Applicants' business risk has increased," that is to say has the probability of TGI not earning a return on and of its capital increased since 1994. The evidence before the Commission Panel is clear: TGI has consistently achieved its allowed ROE in all years except one. The Commission Panel views the AAM, PBR and the RSAM as mechanisms that act to reduce the risk that TGI will not earn a return on its capital. As to earning a return of its capital, that is to say will TGI be able to recover its investment in property and plant in service through rates for service collected from its customers, the evidence is not as clear. In 1994, the evidence before this Commission was of a utility whose product enjoyed a broad competitive edge over electricity, whose long-term supply at reasonable prices seemed assured, and which was able to capture a significant share of new residential market. As Dr. Booth observed "So what happens is the growth allows more customers to lower the unit costs on the system, thereby making the distribution charge slightly lower making it slightly more competitive" (T5: 673). Today, TGI's competitive advantage has been significantly attenuated; its supply outlook has been altered by shippers moving B.C. gas east; and its capture rates in the new residential market have declined.

The Commission Panel can say with certainty that TGI's business risk has not declined in the period 1994-2005. It cannot say by how much its business risk increased, but it can say that although the probability of TGI not earning a return of its capital has increased, it continues to be very low.

The Commission Panel also shares the CEC's observation that if TGI genuinely perceives that it is facing increasing risk, it has a responsibility to undertake cost-effective actions that will mitigate risk. Such actions could include monitoring customer behaviour more closely in terms of such issues as fuel switching, disconnections, and energy efficiency and increasing efforts to offset the customer perception, cited by TGI, that natural gas is an expensive fuel.

4.3 TGVI

4.3.1 Evidence and Argument

In addition to the risks faced by TGI, the Companies set out the following risks peculiar to TGVI:

1) Building a new market on Vancouver Island;

   Ms. McShane describes TGVI as a relatively small greenfield utility, its market being built from the ground up over the past 15 years. TGVI's rates have been structured to compete with alternative energy sources and to induce potential customers to convert to natural gas. Ms. McShane summarizes that until 2003 TGVI's rates were set at a discount to competing fuels, too low to recover TGVI's cost of service and resulting in accumulations to the Revenue Deficiency Deferral Account ("RDDA"). Since 2003 TGVI's rates have been based on a cost of service model, incorporating a soft cap mechanism to maintain the competitiveness of rates in the residential and commercial sectors relative to electricity or oil alternatives (Exhibit B-1, Tab 2, pp. 18-19).

2) Continuing recovery of the RDDA:

   The Companies state that BC Hydro revenues from firm transportation of natural gas to the Island Cogeneration Project ("ICP"), in conjunction with royalty payments pursuant to the VINGPA, have allowed TGVI to reduce the RDDA to approximately $60 million at December 2004 from its peak at $88 million in 2002.

   The Companies argue that while TGVI and BC Hydro have signed a two-year transportation service agreement for the firm transportation of natural gas to ICP, there is no commitment from BC Hydro as to what will happen after the expiry of that contract. The Companies are concerned about the uncertainty of recovering roughly $16 million of the RDDA balance from BC Hydro in 2008 (TGI/TGVI Submissions, p. 19). The Companies summarize that under the approved 2006-2007 negotiated settlement agreement the RDDA balance is expected to be reduced by approximately $17.4 from a total of $52 million as of December 31, 2005 (TGI/TGVI Submissions, p. 20), or to roughly $34.6 million by the end of 2007 (Exhibit A3-6, Appendix A, Schedule 1, p. 14).

3) Planning for the elimination of Provincial royalty revenues in 2012 covering approximately 20 percent of the current cost of service;

   The Companies summarize that under VINGPA, TGVI receives royalty payments from the Provincial Government that reduce the cost of the gas commodity, which, in turn, improves the margin available to recover delivery costs. The Companies state that after the payments terminate at the end of 2011, TGVI's customers will be required to absorb the full commodity cost of gas. The Companies contend that the ability of TGVI to mitigate the impact of rising costs on customer rates will partly depend on its ability to add new customers, which hinges in large part on the competitiveness of TGVI's rates versus electricity rates. The Companies submit that given the intensely competitive market in which TGVI operates, there is a material risk that it will be unable to recover its full investment in utility assets (Exhibit B-1, Tab 2, p. 19).

   The Companies expect that the annual royalty payments will have grown to $60 million by 2012. The Companies submit that if TGVI has to apply for a $60 million revenue requirement increase in 2012 it would result in a rate increase of 35 to 40 percent across all customer classes, and that the current mechanism does not provide an adequate level of return to compensate for this risk (TGI/TGVI Submissions, p. 20).

4) High dependence on industrial load, in excess of 65 percent of throughput, two thirds of which is contracted on a year to year basis. The Companies note that 66 percent of TGVI's load and 38 percent of its margin is industrial, comprising of the ICP and seven pulp mills.

5) Security of supply risk since all gas to the Island flows from a single source on the mainland and is also dependent on the use of undersea high pressure transmission facilities. Ms. McShane describes TGVI as facing greater supply risks than the typical distribution utility, due to its dependence on a single pipeline system that traverses rugged terrain, with underwater and marine crossings (Exhibit B-1, Tab 2, p. 19).

6) Future repayment of $75 million non-interest-bearing senior government debt, currently sitting (sic) as a credit to rate base. The Companies point out that repayment will increase TGVI's rate base, contribute to higher cost of service and impact TGVI's competitive position (Exhibit B-1, Cover letter, p. 12).

The Applicants testify that, after the filing of the Application on June 20, 2005, BC Hydro has advised that it is evaluating the operation of the ICP as a peaking unit and purchasing transmission on an interruptible basis. As a consequence of this advice, TGVI states that it has elected not to proceed with its plan to sell a long-term bond issue to Canadian institutions and has chosen to refinance its debt in the amount of $350 million with short-term bank debt. This event has also caused its plan to obtain a rating for its long-term debt to be put on hold (T3: 316).

4.3.2 TGVI Deferral Accounts

A comparison of TGVI and TGI's deferral accounts to other Canadian gas utilities was provided (Exhibit B-3, Appendix 1.5). TGVI maintains a commodity deferral account called the Gas Cost Variance Account that captures the difference between actual and approved cost of gas. TGVI's most significant non-commodity deferral account is the RDDA, which has been operating for 15 years (Exhibit B-1, Tab 2, p. 18).

TGVI states that its approved 2005 delivery margin, including other operating revenues, is $118.0 million. Of this amount, $18.0 million of forecast revenue surplus is at risk without deferral account protection. The $18.0 million equates to 15.3 percent of TGVI's delivery margin.

TGVI states that the Special Direction provides for TGVI to have a RDDA funded by its shareholder. The RDDA shareholder funding mechanism has the result that in years when the revenues of TGVI are insufficient for it to earn its allowed return the shareholder funds the shortfall to cause the utility to have sufficient revenues to earn its return and vice versa (TGI/TGVI Submissions, pp. 19-20).

TGVI claims that its RDDA provides apparent protection against revenue risk, but it only does so through the shareholder funding the revenue deficiencies. Therefore, in reality, all revenues are at shareholder risk. It expects that in the longer term, if and when the RDDA balance is reduced to zero, a mechanism similar to TGI's RSAM will be put in place. The risk for TGVI is not so much delivery margins risk, but rather credit collection risk and whether its rates can ever be competitive, particularly after royalty revenues cease after 2011 (Exhibit B-3, p. 88).

Schedule 1 in TGVI's Negotiated Settlement Agreement for the 2006-2007 Revenue Requirements on line 28 (Exhibit A3-6), shows that in 2002 the RDDA reached a peak accumulated deficit of $88 million. From 2003 to 2004 TGVI has realized annual surpluses (Exhibit B-16, lines 41-42). These surpluses are expected to continue through to the end of 2007 resulting in a forecast RDDA balance of $34.7 million. Since 2003, TGVI's "soft-cap" rate design mechanism, together with revenues from the transportation agreement with BC Hydro, have allowed TGVI to incur annual surpluses. These surpluses allow TGVI to pay down the accumulated shareholder funded deficits and thus reduce the RDDA balance.

The RDDA allows TGVI to earn its allowed ROE before the VINGPA provision of $1.9 million and (Exhibit B-16, lines 1-10, col. a) which was a component in the Special Direction and agreed to in the VINGPA agreement in a negotiated arrangement (T3: 250). In a deficit year the RDDA revenue deficiency is added to earnings before revenue deficiency and in a surplus year the RDDA revenue surplus is subtracted from earnings before revenue deficiency in order to calculate net earnings (Exhibit B-16, lines 41-49, col. b).

The JIESC argues that some of the risks cited by TGVI, particularly the accumulation of a deficit that peaked at approximately $88 million in 2002, but has since been reduced approximately to $53 million in 2006 and $40 million in 2007, the planning for the elimination of the provincial royalty revenues in 2012, and the recent reductions in industrial gas throughput, could be a concern if they are taken out of context. The JIESC submits that while considering these concerns one should remember:

- That BC Hydro believes electricity rates will probably increase at the rate of inflation;
- That natural gas prices will probably decrease from current record levels; and
- That the combination of the two previous factors should make dealing with adverse factors much easier than anticipated by the Companies in the TGVI evidence (JIESC Submission, pp. 20-21).

The JIESC argues that the risks to TGVI are not new risks, but part of this project since its inception, and assumed by Terasen Inc. voluntarily when it purchased TGVI in March 2002. The JIESC stresses that in January 2003, TGVI voluntarily accepted a capital structure of 35 percent and a return on equity 50 basis points above the allowed return on equity of the benchmark utility as part of the 2003-2005 settlement agreement, and that there is no good reason to change either now. Further, the JIESC contends that the increased risks cited by TGVI are simply too remote to warrant any change in the capital structure or the return on equity of TGVI, particularly when upside opportunities are considered along with risk. The JIESC submits that both the allowed ROE and the capital structure should remain at present levels (JIESC Submission, p. 21). It also argues that to increase these components would make the utility less competitive and would affect recovery of the RDDA (JIESC Submission, p. 24).

The CEC argues that TGI proceeded with the acquisition of TGVI knowing the risks that TGVI faced and that the Commission cannot hope to deal with these risks through increasing equity and return on equity (CEC Submission, p. 38). The CEC contends that a utility that is now facing the realization of a risk for which it has been and continues to be compensated should not have access to even greater returns and even greater investment levels when the risks are being realized (CEC Submission, p. 29). The CEC also submits that TGI should work with the Provincial Government and its customers to develop long term plans for dealing with the pending materialization of risk that TGVI faces (CEC Submission, p. 45).

The Companies submit that the JIESC's statement that the TGVI risks are not new risks ignores the evidence that there has been a marked change in the risks of TGVI. While the JIESC says that risks are simply too remote, particularly when upside opportunities are considered along with risks, the Companies submit that the

Commission should not wait until an event occurs before recognizing the potential for that event to be a risk faced by a utility. The Companies contend that there is nothing remote about the loss of industrial demand, or high gas prices, or the loss of Royalty Revenues at the end of 2011 (TGI/TGVI Reply Submissions, p. 24).

The Companies argue that CEC's suggestion that TGI [sic] work with the Provincial Government and its customers recognizes that TGVI has significant risk that is materializing. The Companies submit that there is an obligation on the Commission to consider and determine those risks at this time; the Commission cannot avoid its obligations by referring TGVI's problems to the Provincial Government (TGI/TGVI Reply Submissions, pp. 30-31).

Commission Determinations

Section 3.1 of this decision deals directly with the TGI's business risks, and the Commission Panel attributes the same determinations to the change in the similar components ascribed to TGVI's business risk. The following determinations deal only with those TGVI risks summarized at the beginning of this section.

In assessing the business risk of TGVI, the Commission Panel is cognizant of the standard it set above when it defined business risk as the ability to earn a return on and of capital.

The Commission Panel finds that the uncertainty surrounding the contract with BC Hydro beyond 2007 creates a significant incremental change to TGVI's business risk together with uncertainty as to the ultimate recovery of the balance on the RDDA. In addition, the uncertainty regarding the cessation of royalty payments from the Provincial Government and the need to repay the interest free loans from senior levels of government demonstrate that TGVI is exposed to considerably greater business risk than a benchmark low-risk utility. It is evident to the Commission Panel that in TGVI's case the probability of not earning a return on and of capital is considerably higher than is the case with the five "mature" gas distribution companies in Canada.

5.0 CAPITAL STRUCTURE

This section considers the appropriate capital structures for TGI and TGVI.

Dr. Booth believes the Commission should adjust for changes in business risk through the establishment of deferral accounts, as far as is practicable, then to alter the amount of debt financing; and then to alter the allowed ROE (Exhibit C2-6, p. 24). A review of deferral accounts is outside the scope of this proceeding. Therefore, determinations in this decision with respect to capital structure and returns on equity assume the deferral accounts are not changed. Further, the Commission Panel has used both capital structure and rates of return for establishing the appropriate financial profile for the Applicants. In this decision, the capital structure of TGI will be determined so as to equate TGI to the benchmark low-risk utility. In the case of TGVI, the reasonableness of the proposed capital structure and equity premium off of the return on equity for the benchmark low risk utility will be considered.

The capital structures of other B.C. utilities are outside the scope of this proceeding, although the approved capital structures of other B.C. utilities are considered relevant to the determination of an appropriate capital structure for TGI and TGVI.

5.1 TGI

The Applicants apply for a 38 percent common equity ratio for TGI.

5.1.1 <u>Capital Structures of Other Canadian Gas Distribution Utilities</u>

The table below provides the capital structures of other Canadian Gas Distribution Utilities:

Tab 2
SCHEDULE 5
PAGE 1 of 3

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY
REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES
(Percentages)

	Decision Date (1)	Order/ File Number (2)	Debt (3)	Preferred Stock (4)	Common Stock Equity (5)		Equity Return (6)	Forecast 30-Year Bond Yield (7)	
Electric Utilities									
AltaLink	11/04	EUB 2004-423	65.00	0.00	35.00	a/	9.50	5.55	
ATCO Electric									
Transmission	11/04	EUB 2004-423	61.00	6.00	33.00		9.50	5.55	
Distribution	11/04	EUB 2004-423	56.10	6.90	37.00		9.50	5.55	
FortisAlberta Inc.	11/04	EUB 2004-423	63.00	0.00	37.00		9.50	5.55	
FortisBC Inc.	11/04; 5/05	L-55-04; G-52-5	60.00	0.00	40.00		9.43	5.53	
Newfoundland Power	12/04	PU 50 (2004)	54.06	1.39	44.55		9.24	4.96	
Nova Scotia Power	3/05	NSUARB-NSPI-P-881	53.30	9.20	37.50		9.55	na	b/
Gas Distributors									
ATCO Gas	11/04	EUB 2004-423	55.10	6.90	38.00		9.50	5.55	
Enbridge Gas Distribution Inc	1/04;12/04	RP-2002-0158; RP-2003-0203	61.91	3.09	35.00		9.57	5.81	
Gaz Metropolitain	9/04	D-2004-196	54.00	7.50	38.50		9.69	5.80	c/
Pacific Northern Gas	11/03; 7/04	L-57-03; G-69-04	60.32	3.69	36.00		9.80	5.65	d/
Terasen Gas	11/04	L-55-04	67.00	0.00	33.00		9.03	5.53	
Union Gas	1/04;3/04	RP-2002-0158; RP-2003-0063	61.50	3.50	35.00		9.62	5.68	
Gas Pipelines									
Alberta Natural Gas	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Foothills Pipe Lines (Yukon) Ltd	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
TransCanada PipeLines	11/04; 4/05	RH-3-94/RH-2-2004	64.00	0.00	36.00		9.46	5.55	
Trans Quebec & Maritimes Pipeline	11/04	RH-2-94	70.00	0.00	30.00		9.46	5.55	
Westcoast Energy	8/04; 11/04	RH-2-94; RH-1-2004	69.00	0.00	31.00		9.46	5.55	

a/ EUB 2004-052 set the equity ratio at 35% (33% for transmission plus 2% in recognition of AltaLink's tax status).
b/ The Board approved an ROE of 9.55% for ratemaking purposes and set the earnings range at 9.30-9.80%.
c/ Gaz Metro is allowed to earn an additional 1 95% based on expected productivity gains for the 2005 fiscal year.
d/ 2005 rate application currently pending.

Source: Board Decisions

Source: Exhibit B-1, Tab 2, Schedule 5, p. 1

As indicated in the above table, all the other major gas distribution utilities have preferred shares in their capital structures. Since 1994 the allowed common equity of TGI has been 33 percent. In 1999 preferred shares were redeemed that accounted for 9.4 percent of the capital structure. The preferred shares of ATCO Gas, Enbridge, and Union are perpetual preferred shares. The Commission Panel accepts the evidence of TGI that it does not have a credit rating high enough to enable it to issue perpetual preferred shares (T3: 267). Therefore, the Commission Panel concludes that the preferred shares of ATCO Gas, Enbridge and Union need to be considered when comparing the capital structures of those utilities with TGI.

Ms. McShane and Dr. Booth reach similar conclusions regarding the relative risk of Canadian utilities. Ms. McShane's view is that TGI's business risks are comparable to those of the major Alberta and Ontario distributors, and exceed those of electric transmission companies by a considerable margin (Exhibit B-1, Tab 2, p. 16). Dr. Booth is also of the view that electric transmission companies have a lower risk than TGI, and are judged to be the lowest risk regulated utilities in Canada. The AEUB has found that appropriate capital structure for electric transmission companies with no preferred shares is 33 percent.

McShane is of the view that TransCanada Pipelines and Nova Gas Transmission face no higher business risk than TGI. Dr. Booth is of the view that the gas transmission pipelines are the second lowest risk group. The allowed common equity ratio for TransCanada Pipelines, Mainline and Nova Gas Transmission are 36 percent and 35 percent respectively.

Dr. Booth then judged the local distribution companies, including both gas and electric as the next riskiest. Ms. McShane is of the view that TGI's business risks are comparable to those of the major Alberta and Ontario gas distributors. The allowed common equity ratios for the Ontario major gas distributors are in the range of 35 percent and the allowed common equity ratios for the Alberta gas distributors are higher at 38 percent.

In testimony, Dr. Booth indicated that TGI is riskier than ATCO Gas and Enbridge, roughly on par with Union, while being less risky than Gaz Metro (T5: 619-620). Dr. Booth views PNG and Gaz Metro as the riskiest regulated utilities in Canada (Exhibit C2-6, p. 36).

Although Dr. Booth recommends 35 percent for a typical local gas distribution company, he recommends 33 percent for TGI because of more comprehensive deferral accounts. The Commission Panel accepts that the TGI's earnings are less volatile than the earnings of Enbridge and Union, and such reduced volatility can be attributed, in part, to weather normalization. The Commission Panel also notes Dr. Booth's testimony that "I think they (sc Enbridge and Union) are probably happier not having weather normalization. Otherwise they would have proposed it" (T5: 639). The Applicant submits that the existence of the RSAM account is not a factor that should play a role in the determination of its allowed return on equity or its capital structure. Dr. Booth confirmed in his opening statement that weather risk should not affect the return on equity (TGI/TGVI Submissions, p. 14, para. 46 and 47).

5.1.2 Coverage Ratios and Credit Ratings

The pre-tax interest coverage ratios for the major gas distribution companies in Canada are set out below:

PRE-TAX INTEREST COVERAGE RATIOS
FOR MAJOR CANADIAN UTILITIES

Company	1995	1996	1997	1998	1999	2000	2001	2002	2003
Enbridge Gas Distribution	2.0	2.6	2.6	2.1	2.2	2.2	2.8	2.7	2.7
Gaz Metro	2.6	2.6	2.7	2.7	2.4	2.7	2.5	2.9	2.9
Pacific Northern Gas	2.1	2.7	2.6	2.3	2.3	2.3	2.3	2.5	2.3
Terasen Gas	1.8	2.0	2.3	2.3	2.3	1.9	1.8	2.0	2.0
Union Gas	2.2	2.3	2.4	2.0	1.8	2.0	1.9	2.1	2.1

Source DBRS (Exhibit B-1, Tab 2, Schedule 2)

TGI's interest coverage ratio for 2004 was 1.99 (Exhibit B-28)

TGI's Medium Term Note ratings for the years 1994, 1999 and 2004 are set out below:

Rating Agencies	**1994**	**1999**	**2004**
DBRS	A	A	A
Moody's	-	-	A2
CBRS/S&Ps	B++	A (low)	BBB (unsolicited)

Source: Exhibit B-3, Vol. 1, Appendix 2.1

On June 26, 2003, Standard & Poors downgraded TGI's rating from BBB+ to BBB. In the first quarter of 2004 TGI terminated Standard & Poors' engagement to provide credit ratings in order to manage costs. However, S&P elected to continue to publish unsolicited credit ratings on TGI debt. On December 19, 2005, Moody's lowered TGI's senior secured rating from A1 to A2 and TGI's senior unsecured rating from A2 to A3 (Exhibit B-27). Both Moody's and S&P are of the view that the low common equity component in the capital structure of TGI results in a weak financial profile. TGI submits that the December 2005 downgrading demonstrates the need for an increase to the common equity and return on equity for TGI (TGI/TGVI Reply Submissions, p. 27).

In its credit rating report on TGI dated June 22, 2004, DBRS makes the following comments on TGI from a credit analyst's (and thus bondholder's) perspective:

> "The company benefits from a supportive regulatory regime,"
>
> "The regulatory environment within which the company operates provides a relatively high degree of financial stability."
>
> "Key financial ratios are expected to continue to fluctuate within a narrow band in line with changes in working capital requirements, however, this does not pose any credit implications."
>
> "Terasen Gas has historically had the lowest allowed ROEs relative to all other gas distribution utilities in Canada. This has resulted in generally weaker financial ratios relative to its Canadian peers," and
>
> "The use of the taxes payable method of taxation (typical of rate-regulated utilities) has resulted in an unrecorded future income tax liability of $215.8 million as at December 2004. The recovery of this liability in future rates depends on regulation" (Exhibit B-5, Appendix 1.2).

The Commission Panel notes these comments by DBRS. First, the interest coverage ratios are stable and are unlikely to pose any credit implications in the future. Second, the lowest allowed returns, when combined with the lowest equity component relative to all other gas distribution utilities in Canada, have resulted in the lowest interest coverage ratios in Canada.

The Commission Panel accepts that if TGI is downgraded by one of the rating agencies to a non-investment credit that it could limit the number of investors willing to hold TGI debt securities. For that reason, investors may be reluctant to hold debt that is just one notch above BBB-. A credit rating below an S&P BBB- is considered "junk" (T3: 263-265). Therefore, TGI's credit rating would fall to non-investment grade (junk) status if S&P downgrades TGI by only two notches. In the December 19 Announcement, Moody's states:

> "TGI's rating considers the support provided by TGI's regulatory environment which limits TGI's exposure to commodity price and volume risks as well as pension funding costs and insurance costs by operation of numerous deferral mechanisms including Commodity Cost Reconciliation Account (CCRA), Midstream Cost Reconciliation Account (CCRA) and the Revenue Stabilization Adjustment Mechanism (RSAM). However, the rating also recognizes that the deemed equity and allowed ROE permitted by the regulator are among the lowest in Canada which contributes to TGI's weak financial metrics relative to its global peers" (Exhibit B-27).

The Applicants submit that TGI's hedging agreements require that collateral be posted if its rating falls to non-investment grade, which could trigger significant and sudden liquidity requirements. TGI's gas purchase agreements require that collateral be posted if the counterparty has reasonable grounds for insecurity, which could be triggered by a downgrade to non-investment grade (TGI/TGVI Submissions, p. 25, para. 85; T3: 265).

Dr. Booth believes that because bond rating agencies are concerned with accurately predicting the credit quality of a firm's debt, they take a conservative approach because of "asymmetry of risk" and sometimes over react (Exhibit C2-6, pp. 76-77). Moreover, Dr. Booth submits that S&P's decision to impose harsher credit standards has had no impact on spreads or presumably marketability of future debt issues, and notes that spreads have almost all declined since end of 2002 (Exhibit C2-6, p. 78). During the Oral Phase of Argument, TGI advised that there has been no determinable change in the market following the Moody's downgrade (T7: 984). The JIESC submits that the ratings are the agency's view of the utility, and that a more important view is the markets view as evidenced by the spreads.

The spreads of TGI with comparators including Enbridge and Union are provided at Exhibit C2-11, Exhibit C2-11 and BCUC IR No. 1, 32.1.1.2. TGI's 30-year bonds trade at spreads that are approximately 15-20 basis points higher than Enbridge and at spreads that are similar to Union's. In Reply Argument, TGI submits that TGI bonds trade at approximately 30 basis points higher than Enbridge; however, the trade spreads indicated on BCUC IR No. 1, 32.1.1.2 are 20 basis points and the estimated spreads for a new 30 year issue are approximately 30 basis points. TGI then submits that the "30 basis point spread" reflects a "particularly accommodating point in the interest cycle for TGI bonds" (TGI/TGVI Reply Submissions, p. 20).

Dr. Booth's view is that the S&P and the Moody's ratings for Terasen are out of line with what the market feels is the correct rating. During the Oral Phase of Argument, the JIESC also notes that both the Moody's and DBRS ratings are "A" ratings (T7: 978).

The Commission Panel also notes the submissions of TGI that from the perspective of independent parties, who can see there has been a change, the downgrades suggest the business risks and the financial risks of TGI have increased (T7: 980).

5.1.3 Access to Capital Markets and Financing Flexibility

The JIESC observes that TGI was able to raise 30 year debt in 2005 on reasonable terms. The Applicant's Treasurer Mr. Bryson states:

> "I think the point that I want to leave on this is that obviously one of the key standards that a fair return on equity and capital structure has to meet is the ability to raise financing even in adverse conditions. And I think that was acknowledged by this Commission in the 1999 ROE decision. And what I'd like to submit is that the ability to issue 30-year bonds once every five or ten years does not provide evidence that that test is being met" (T2: 154).

Mr. Bryson states that in 2005 at least seven BBB rated companies were able to issue 30 year debt (T2: 127).

The Commission Panel accepts the need for a utility to be able to access capital markets under most circumstances at reasonable rates.

Commission Determinations

The Commission Panel concludes that the appropriate capital structure range for consideration of TGI is in the range of 35 percent to 38 percent and that given the effect of deferral accounts in reducing the risk of TGI, the appropriate equity component for TGI is 35 percent. Given the preferred shares in the capital structure of all other Canadian gas distribution utilities, the equity component of TGI will remain the lowest in Canada for gas distribution utilities.

While the Commission Panel accepts the submissions of the JIESC that since utilities have the lowest business risk of just about any sector they should have the highest debt ratios, it nevertheless concludes that an increase to the capital structure of TGI is supported by post-1994 changes to the capital structure of TGI and by comparisons to the approved capital structures of comparable risk utilities. Credit rating downgrades by S&P and Moody's are relevant and also support a need for a change to the capital structure.

The Commission Panel requires TGI to file within 30 days of this decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission on page 49 of the KMI Decision.

5.2 TGVI

The Applicants apply for a 40 percent common equity ratio for TGVI.

TGVI is also in an increasingly competitive environment. Ms. McShane says that TGVI faces higher risk than any of the major mature gas distribution utilities, and is more comparable to the smaller mature utilities and the greenfield gas distributors in the Maritimes (Exhibit B-1, p. 20). In particular, Ms. McShane views TGVI to be somewhat less risky than either of Enbridge Gas New Bruswick or Heritage Gas and to be in the same business risk class as Gazifiere Inc. and Natural Resource Gas. Ms. McShane also views TGVI to have higher business risk than FortisBC (Exhibit B-3, Vol. 2, IR 1.45.3). Ms. McShane provides the allowed common equity ratios of these utilities, which have a range from 40 percent to 50 percent and recommends a common equity range for TGVI of 45-50 percent.

The business circumstances of TGVI have changed since Ms. McShane's evidence was filed. TGVI has not sought a thicker common equity ratio or a higher return on equity as a result of the new circumstances, but submits that the circumstances have changed the business risks and provide further evidence of the reasonableness of the capital structure and return on equity that is being sought by TGVI.

The Applicants note that TGVI has the same allowed common equity as Enbridge, has no preferred shares, and is allowed approximately the same level of equity as Enbridge. Further, that the risk profiles of TGVI and Enbridge are not remotely similar (TGI/TGVI Submissions, p. 32).

Dr. Booth did not file evidence related to TGVI. The JIESC submits that there is no justification for changing the capital structure of TGVI at this time and that it does not make sense to do so.

Commission Determinations

The Commission Panel concludes that the appropriate common equity component in the capital structure of TGVI is 40 percent.

The Commission Panel requires TGVI to file within 30 days of this decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission on page 49 of the KMI Decision.

6.0 RETURN ON EQUITY

6.1 The Applicants' Methodology

This Section considers the appropriate return on equity for a benchmark low-risk utility, and applies its determination in that regard to the return on equity for TGI and TGVI.

The Applicants introduce the evidence of Kathleen McShane (Exhibit B-1, Tab 2). Ms. McShane says that a fair return is one that provides a utility with the opportunity to:

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

According to Ms. McShane these criteria give rise to two separate standards, the capital attraction standard and the comparable returns, or comparable earnings, standard. Ms. McShane states that the two standards require the use of three tests used to develop her recommended fair return on equity for a benchmark low-risk utility:

- *Equity Risk Premium (ERP)* test, which is a generic term for a methodology that estimates the cost of equity as the sum of a directly observable yield on a security such as a government or corporate bond and a premium to compensate for the additional equity risk assumed by the investor;
- *Discounted Cash Flow (DCF)* test, which measures the equity investors' expected return as the dividend yield on a stock or group of stocks plus the expected growth in dividends in the long term; and
- *Comparable Earnings (CE)* test, which measures the experienced returns on book equity of firms that are of similar risk to the utility for which the regulator is setting the fair return (Exhibit B-1, Tab 2, lines 720-734).

6.1.1 ERP Test

Ms. McShane uses three methodologies to derive her equity risk premium as follows:

- Risk-Adjusted Equity Market
- Historic Utility
- DCF based

Risk-Adjusted Equity Market

Ms. McShane uses the period 1947-2004 to examine the average risk premium experienced in the Canadian, US and UK markets as follows (Exhibit B-1, Tab 2, Schedule 8):

	Stock Return	Bond Return	Risk Premium
Canada	12.1	6.9	5.3
United States	13.2	6.3	7.0
United Kingdom	14.9	8.9	6.0

Ms. McShane uses the arithmetic average that is the sum of each year's return divided by the number of years in the study. Ms. McShane addresses the issue of high bond returns in recent years by substituting her estimate of current long bond yields (5.25 percent) rather than historic average returns. From this she develops an indicated Canadian equity market risk of 6.75 percent, being the mid-point of a range of 6.25 percent to 7.25 percent. Ms. McShane applies a relative risk adjustment factor (beta) of 0.65, which she derives by developing "raw" betas from Canadian data which exclude Nortel. She then adjusts her "raw" beta using a formula used by major commercial suppliers of betas, which gives two-thirds weight to a stock's own beta and one-third weight to the market mean beta of 1.0. Thus, she arrives at a benchmark utility equity risk premium of 4.0 percent (Exhibit B-1, Tab 2, lines 1577-1968).

Historic Utility Equity Risk Premium

In Schedule 16 of her evidence, Ms. McShane observes actual utility equity (arithmetic average) risk premiums as follows:

1956-2004	Canada – gas and electric	4.4%
1947-2004	US – gas	6.0%
1947-2004	US – electric	5.0%

From which she determines that an appropriate historic utility equity risk premium for a benchmark low-risk utility to be in the range of 4.25-5.0 percent or approximately 4.75 percent (Exhibit B-1, Tab 2: lines 1985-2000).

DCF-Based Equity Risk Premium Test

Ms. McShane compares the estimated DCF cost of equity of seven US gas utilities over the corresponding 30-year U.S. Treasury yield on a monthly basis for the years 1993-2004 (Exhibit B-1, Tab 2, Schedule 18). This test indicates an average risk premium over the period of 4.2 percent. Since the corresponding bond return is 6.0 percent, Ms. McShane increases the observed premium to 4.7 percent to reflect her forecast yield on a 30-year (Canadian) government bond of 5.25 percent. At the same time, she tests the relationship between the spreads between U.S. long-term A-rated utility and 30-year U.S. Treasury yields and determines a utility risk premium of 4.3 percent. Ms. McShane settles on a mid-point of 4.5 percent for her DCF-based ERP test (Exhibit B-1, Tab 2, line 2140).

Financing Flexibility Allowance

To each of the three risk premiums developed by her tests, Ms. McShane adds a Financing Flexibility Allowance of 50 basis points. This allowance is intended to cover three aspects:

- flotation costs;
- a cushion for unanticipated capital market conditions; and
- a recognition of the fairness principle.

Ms. McShane's ERP test results are summarized as below (Exhibit B-1, Tab 2, p. 83):

Risk-Free Rate	5.25%
Equity Risk Premium	4.0-4.75%
"Bare-Bones" Cost of Equity	9.25-10.0%
Financing Flexibility Allowance	0.50%
Return on Equity	9.75-10.5%

6.1.2 DCF Test

Ms. McShane describes "the Discounted Cash Flow approach as proceeding from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the riskiness of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return (or capitalization rate) as the rate that equates the price of the stock to the discounted value of future cash flows."

Due to the dearth of quoted utility companies in Canada and analysts' forecasts thereof, Ms. McShane applies her test to a sample of 14 relatively low-risk U.S. gas and electricity utilities that were included to serve as a proxy for a Canadian low-risk benchmark utility (Exhibit B-1, Tab 2, Appendix C). To determine investors' growth expectations, Ms. McShane uses both Value Line (an independent research firm) forecasts of earnings growth as well as I/B/E/S (the major data base that provides long term consensus forecasts) consensus forecasts of utility equity analysts. Ms. McShane found no evidence of upward bias in the I/B/E/S consensus forecasts; indeed, she cites studies which find that investment analysts' forecasts serve as a better surrogate for investors' expectations than historic growth rates.

In her first application of the DCF model, Ms. McShane applies a constant growth DCF model to her sample which results in a DCF cost of equity of 8.8 percent (Exhibit B-1, Tab 2, Schedule 20). Her second application of the DCF model uses analysts' forecasts for five years and a normal growth in the U.S. economy of 5.5 percent per annum thereafter, which gives a result of 9.7 percent (Exhibit B-1, Tab 2, Schedule 22). Ms. McShane estimates an indicated "bare-bones" required return on equity in the range of 8.8-9.7 percent or approximately 9.25 percent. To her "bare bones" required return Ms. McShane adds 50 basis points. This is the same amount as that added to her ERP test, but arises for different reasons. Ms. McShane finds a "disconnect" between the DCF return investors expect to earn on the current market value of their common equity investments and what they expect the utility to earn on the book value of their investments. To mitigate this problem, she augments her DCF result by 50 basis points (Exhibit B-1, Tab 2, line 2393).

6.1.3 Comparable Earnings Test ("CE")

Ms. McShane describes the CE as "arising from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk."

To select a sample of Canadian companies of reasonably comparable investment risk to a benchmark low-risk utility, Ms. McShane takes all 432 companies on the Toronto Stock Exchange ("TSX") in Global Industry Classification Standard sectors 20-30 (being Industrials, Consumer Discretionary and Consumer Staples). From this list she removes companies which, in the period 1993-2003 had i) missing or negative common equity (368 companies); ii) paid no dividend in any year (21 companies); and iii) thinly traded companies, companies with betas > 1.0, companies with returns with a standard deviation of +/- -1 from average, ranked high risk or speculative, or unrated (17 companies) to arrive at her sample of 17 low-risk Canadian industrials

(Exhibit B-1,Tab 2, Appendix D).

Ms. McShane chooses the period 1993-2004 on the grounds that it covers an entire business cycle and should be representative of a future normal cycle. Ms. McShane assesses the possible need to adjust the results of her CE tests based on a review of the 17 companies' bond ratings, stock ratings and adjusted betas. Accordingly she adjusts the results of her CE tests which had indicated average levels of returns on book equity in the 13 to 13.5 percent range, down to "no less than 13 percent" (Exhibit B-1, Tab 2, line 2540).

6.1.4 Summary

To arrive at her indicated return on equity for a benchmark low-risk utility Ms. McShane applies an "indicative" weighting of 75 percent to her market based tests (ERP and DCF) and 25 percent to CE. As Ms. McShane points out "the answer is not going to come out to four places. Cost of equity doesn't lend itself to that level of precision" (T4: 506). Her indicated return on equity for a benchmark low-risk utility is 10.5 percent, or a premium of 5.25 percent over her estimate of a long Canada bond of 5.25 percent (Exhibit B-1, Tab 2, line 2573).

Ms. McShane addresses the ROE for TGVI as follows:

> "In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI. I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return. Applying the same approach as detailed in Schedule 29 for Terasen Gas, the difference between the proposed 40% common equity ratio and a 47.5% common equity ratio warrants an incremental equity risk premium for TGVI relative to the benchmark low risk utility of 60-120 basis points (mid-point of 90 basis points). Thus, the 75 basis point incremental equity risk premium proposed for TGVI is reasonable" (Exhibit B-1, Tab 2, pp. 21-2).

6.2 The Intervenors' Methodology

The Intervenors filed the evidence of Dr. Booth, CIT Chair in Structured Finance and Professor of Finance at the Joseph L. Rotman School of Management at the University of Toronto (Exhibit C2-6). Dr. Booth uses the Capital Asset Pricing Model ("CAPM") to derive his estimate of the MRP, and tests the result with a DCF test of U.S. utilities followed by Standard & Poors.

6.2.1 MRP Test

Dr. Booth uses the period 1956-2004 to determine that the Canadian market risk premium of equities over long-term bonds has averaged (on an arithmetic basis) 2.70 percent. Extending the period examined back to 1924 produces a Canadian market risk premium of 5.21 percent. Dr. Booth estimates the current market risk premium to be 4.5 percent.

Dr. Booth examines the betas for utilities based in Canada for a number of five-year periods ending 1984 to 2004, but finds the data distorted by a number of factors, including the market crash of 1987 and the technology boom and bust of 2000 and 2001. Accordingly, for beta he estimates a reasonable range for normal market conditions going forward to be 0.45 to 0.55, which would imply a risk premium in the 2.025 percent to 2.475 percent range, which he adds to his long Canada bond yield forecast of 5 percent to produce an estimate in a range of 7.0 to 7.5 percent.

In addition to his "Classic CAPM" estimate, Dr. Booth uses a two factor CAPM model, which adjusts for estimation problems in the CAPM by directly incorporating the risk of long Canada bonds through a term or interest rate risk premium. The result of this second test produces an estimation of the fair return of 7.25 percent. Dr. Booth places equal weight on both CAPM estimates and took the average (7.25 percent) as being a reasonable estimate. To this estimate he adds a 50 basis point flotation cost allowance to produce a best estimate of 7.75 percent for a 275 basis point utility risk premium (Exhibit C2-6, p. 60).

6.2.2 Other Tests

Dr. Booth did not perform any other test to determine a fair return on equity. He did however, examine the DCF estimates for U.S. utilities covered by Standard & Poors for the period 1978-2004 from which he estimates an average return on equity of 10.17 percent from which he deducts the average U.S. Treasury of yield of 7.97 percent to determine a 220 basis point U.S. utility risk premium (Exhibit C2-6, Appendix C).

6.3 Discussion

Considerable evidence was before the Commission Panel as to the most suitable methodology to determine a fair return on equity for a benchmark low-risk Canadian utility. Much of the evidence comprises detailing the shortcomings of each of the methodologies in general and of the witness's applications of the concepts in particular.

The evidence is that up to the 1960s the principal methodology to determine fair rates of return was CE, as, according to Dr. Booth, the DCF method and the ERP method which was derived from the CAPM, were developed in the 1960s. By the 1980s all three methodologies were in use in Canada. In the early 1990s capital markets in Canada fell into considerable turmoil, causing DCF and CE to give unreliable results, which resulted in the ERP becoming the main, if not the sole, methodology used by regulatory bodies in Canada to establish fair rates of return. The concept became embedded in Canadian regulatory methodology with the adoption by many regulatory bodies of the AAM whereby an individual utility's return on equity could be adjusted each year by reference to the change in the Risk Free cost of capital (namely the forecast long Canada bond yield). The DCF and CE methods have never managed to restore themselves to favour in regulatory bodies' eyes with the result that in Canada's most recent generic cost of capital hearing, neither method was accorded any weight by the AEUB in its determination of a generic return on equity. In the United States the DCF and CAPM methods got their start in the 1970s and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions [Exhibit B-3E (Vol. 4), Appendix 74.1].

In the words of Ms. McShane: "I believe that … none of the tests is so superior (sic) to the others that it should be discarded in favour of just using one or two tests … Each test should be viewed as providing some perspective on what a fair return is" (T3: 377).

The Applicants in their submission argue that "A fair and reasonable return is not an arithmetic exercise; no approach is the determination of a fair and reasonable return is perfect. Although the use of a simple test may be appealing in its simplicity, it must be realized that the concept of a fair return is not that simple … TGI and TGVI submit that the Commission should consider all three approaches and give weight to each …" (TGI/TGVI Submissions, p. 35, para. 119).

6.3.1 ERP

Conceptually, the ERP methodology has a great deal of appeal to a regulator. It is derived from the CAPM, which was described in Exhibit B-21 being Chapter 7 of *Financial Theory and Corporate Policy* by Copeland and Weston. It requires the derivation of a risk free rate; an observed risk premium, being the difference between returns on common stocks and government bonds; and a factor known as beta, which is the coefficient of a portfolio or stock's volatility compared to the market as a whole. The Applicants outline the following shortcomings of the CAPM as it is applied to the derivation of an ERP:

Risk-Free Rate

The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. However, the application of the model typically assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

Similarly, an ROE formula that is predicated on a close tracking between the allowed return and the risk-free rate assumes the risk-free rate and the return on the market are highly correlated. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

- the yield on long-term government bonds reflects the impact of monetary and fiscal policy;
- yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; and
- long-term government bond yields are not risk-free; they are subject to interest rate risk (Exhibit B-1, Tab 2, Appendix A, p. 2).

Equity Market Risk Premium

The equity market risk premium is typically measured largely by reference to historic data. There are a wide range of views on what constitutes an appropriate period for estimating the historic risk premium, on what constitutes the appropriate averaging technique, and on whether various time-specific or country-specific outcomes diminish the reliability of history as a predictor of the future risk premium (Exhibit B-1, Tab 2, Appendix A, p. 3).

A decade by decade review of Canadian historic risk premiums shows a wide range of realized risk premiums, which would indicate the desirability of using longer rather than shorter periods to measure the premiums, as follows:

Time Period	Stock Returns	Bond Returns	Risk Premiums
1940s	10.0%	3.9%	6.0%
1950s	17.0%	0.4%	16.5%
1960s	10.8%	2.9%	7.9%
1970s	12.1%	6.1%	6.0%
1980s	13.1%	13.7%	-0.6%
1990s	11.6%	11.8%	-0.2%
1995-2004	11.2%	10.9%	0.2%
1947-2004 i)	12.0%	6.9%	5.3%
1956-2004 ii)	10.7%	8.0%	2.7%

i) used by Ms McShane
ii) used by Dr Booth (Schedule 1)

In addition, certain problems exist in Canada but not in the United States when it comes to measuring historic risk premium data. The achieved equity market risk premiums in Canada have been reduced by the performance of the government bond market. The change in Canada's fiscal performance over the past decade, leading to the recent low levels of interest rates, indicates that the historic returns on long-term Government of Canada bonds overstate likely future bond returns, and therefore understates the future equity risk premium (Exhibit B-1, Tab 2, Appendix A, p. 4).

The Canadian equity market is less liquid, less diverse and less populous than the U.S. equity market. The performance of the Canadian equity market as the "market portfolio" has been unduly influenced by a small number of companies (Exhibit B-1, Tab 2, Appendix A, p. 4).

Canadian equity data were "backcast" in 1976 upon the creation of the TSE 300 back to 1956. Accordingly, data prior to 1956, and to a lesser extent data between 1956 and 1976, may be less consistent (T6: 926).

Beta

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

- the assumption that all risk for which investors require compensation can be captured and expressed in a single variable;
- the only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and

- the assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market) are a good measure of the relative return requirement.

Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have betas that are negative (Exhibit B-1, Tab 2, Appendix A, p. 5).

6.3.2 DCF

Dr. Booth points out the shortcomings of the DCF methodology. At page 58 of his testimony he states "It is generally accepted that analysts' earnings forecasts are biased high…This conflict of interest has been most evident in the Internet and Technology fiascos of the late 1990s, when prominent analysts issued strong buy recommendations on the way up and kept them in place on the way down and got sued in the process" (Exhibit C2-6, p. 58).

6.3.3 CE

In Appendix B of his evidence, Dr. Booth identifies five basic problems with the earned rate of return, namely:

- It is an accounting rate of return.
- It is an average not a marginal rate of return.
- It is earned on historic accounting book equity that does not reflect what can be earned on investments today.
- It is based on non-inflation adjusted numbers.
- It varies with the firms selected in the "comparable earnings" sample (Exhibit C2-6, Appendix B).

6.4 Commission Determinations

6.4.1 Two Standards

The Commission Panel accepts the relevance of two separate standards namely the capital attraction standard and the comparable returns standard in establishing a fair return on equity for a benchmark low-risk utility. One standard does not trump the other, neither is one subsumed by the other. Accordingly, the Commission Panel will seek to give weight to each of the three methods placed before it in determining a suitable return for a benchmark low-risk utility.

6.4.2 Relevance of Other Board Decisions

All parties refer in their evidence and their submissions to decisions of other regulatory boards in Canada concerning fair returns. The JIESC warns of the danger of circularity resulting from a regulatory board "relying on what other boards have done." The JIESC continues:

> "On the other hand, one cannot totally ignore the immense amount of effort that has gone into determining fair returns by the NEB, in its generic ROE proceeding, and the AEUB, in its recent generic ROE and capital structure hearing.
>
> The AEUB hearing is the most recent and largest generic ROE hearing ever held in Canada. It went for 33 hearing days, involved 11 utilities, and heard from six expert witness panels.
>
> The AEUB and the NEB decisions should not be applied blindly by this Commission. However, they should be considered carefully, as should evidence of market acceptance of the allowed returns, and the acceptability of their awards to investors." (JIESC Submission, pp. 7-8)

At the November 2005 consensus risk free rate for 2006 of 4.79 percent the returns allowed for 2006 under current mechanisms are as follows:

BCUC – Terasen Gas Inc.	8.29%
NEB – Generic	8.89%
AEUB – Generic	8.93%
Ontario*	8.71%
Newfoundland	8.77%

* October 2005 Consensus
Source: Exhibit B-26

The Commission Panel's view is that it holds generic hearings into a fair return on such an infrequent basis, that there is little danger of circularity should it consider the returns allowed in other jurisdictions to ensure that the return it allows for 2006 is in line with returns allowed to benchmark low risk utilities in other jurisdictions.

6.4.3 Globalization

The Applicant states that since 1994 "Globalization of capital markets means that Canadian utilities are competing for capital with alternative investments world-wide. Globalization of capital markets provides Canadian investors opportunities for higher returns at similar risk levels than available in the domestic market. The returns allowed for Canadian utilities need to recognize that Canadian investors' opportunities are not limited to domestic investments" (Exhibit B-1, Tab 2, p. 5).

Dr. Booth submitted a monograph propounding the thesis that globalization or diversification reduces risk and market risk premium in both markets (Exhibit C2-6, Appendix D).

Dr. Booth, under cross-examination, states, "I generally believe that the US estimates both for the market risk premium and the US estimates from US regulated gas and electric utilities are higher than they would be for Canada. … I would say that they're too high, which means that you cannot take them directly and apply them in Canada. … I would say they're indicative, but my personal opinion would be that they are too high" (T6: 820).

During cross-examination Ms. McShane stated "And so there are a couple of different points: one, that there are opportunities (sc for investors to commit capital globally) and two, that in measuring the risk premium, we need to look beyond Canadian data" (T4: 424).

The Commission Panel agrees with this bifurcation. On the first issue the Commission Panel agrees that while it is now possible for Canadian investors to commit their entire retirement savings capital offshore, there is no evidence that they have been in a huge hurry to do so. Canadian investors face a considerable foreign exchange risk when investing offshore and the Commission Panel does not believe that they set this risk aside on the grounds that, in a perfect world, it should be capable of being hedged or otherwise diversified away.

The Commission Panel is not convinced that the Federal Government's relaxation of foreign content rules in retirement portfolios should be a reason to increase the equity return of a benchmark low-risk utility.

As to the second issue, the Commission Panel is prepared to accept the use of historical and forecast data of U.S. utilities when applied as a check to Canadian data; as a substitute for Canadian data when those data do not exist in significant quantity or quality; or as a supplement to Canadian data when Canadian data give unreliable results. The Commission Panel bases this view on the fact that the U.S. and Canadian economy and capital markets are closely integrated.

6.4.4 Market to book ratios and acquisition premiums

In his evidence, Dr. Booth addresses the issue of market to book ratios of utility companies as follows:

> "This process is akin to someone investing in a savings account where a judge has to determine the correct savings rate each period that can be withdrawn from the fund. The important implication is that if the judge (regulator) is successful then the savings will always be worth their original investment. This is the meaning of the basic result in finance that fair means that the market to book ratio equals one. The only thing different about utilities, as compared to the savings example, is that there is some very minor business risk" (Exhibit C2-6, p. 74).

In Schedule 30 of his evidence, Dr. Booth graphically tracks the market to book ratios of a number of utility holding companies in Canada over the period. In addition, he observes the premiums paid by companies to acquire utility companies or utility assets and reaches the conclusion that regulatory bodies have been overly generous in their allowed returns on equity. In particular the Intervenors point to the acquisition of the shares of TI by KMI at an estimated market to book ratio of 2.7 to 1 to demonstrate that the Commission's formulaic approach to setting returns on equity has been overly generous and demonstrates that no upward revision to the existing ROE is warranted. Indeed, they argue that the Commission Panel accept Dr. Booth's recommendation, which would lower the benchmark return on equity.

Market to book ratios are a function of a stock's price divided by the book value of a share of its common equity. A stock's price is a function of what the market will pay for it and is either expressed by analysts and investors as a multiple of earnings or in a utility's case as the yield on its dividend. In neither case has a regulatory body any degree of control over the quantum of either the multiple or the actual dividend paid (McShane, T3: 139). Evidence before the Commission Panel is that market to book ratios of utilities (especially in the U.S.) have been below parity in the past. The Commission Panel agrees with Copeland and Weston (see Section 6.3.1 above) that all investors select efficient portfolios and that the market is simply the sum of all investors' individual holdings. Accordingly, the price paid for a utility share will vary over time depending on the changes in individual risk tolerances. The proper application of the CAPM model should remove the possibility of over generous returns, but over time will not prevent the market from valuing a utility's stock at prices which are both greater than and lower than its book value.

So far as concerns acquisition premiums, the Commission Panel has addressed the Kinder Morgan acquisition elsewhere in this Decision. So far as concerns other acquisitions the Commission Panel is mindful of the AEUB Panel's decision:

> "The Board agrees with the Applicants that there are a number of factors impacting market-to-book ratios of utility holding companies and that one has to be cautious making inferences regarding the regulated utilities. The Board also agrees that there may be strategic factors affecting the price that is paid to acquire a utility.
>
> ...The Board also recognizes that, in some cases, a premium might be paid for regulated assets in anticipation of significant future growth in rate base, to achieve geographic diversification or to obtain a foothold in a new market. However, parties are also aware of the constraints placed on regulated utilities with respect to affiliate transactions, particularly those with unregulated affiliates.
>
> In the absence of such strategic factors, the Board would not expect a prudent investor to pay a significant premium unless the currently awarded returns are higher than that required by the market. The Board acknowledges the views of some parties that payment of a premium over

> book value for a regulated utility indicates that the recent ROE awards may have been higher than required by the market. The Board is not aware of the strategic factors that may have affected the price paid to acquire Alberta utilities in recent years. Nevertheless, the experience regarding the market-to-book values of utilities and the experience ... in recent years gives the Board some comfort that its recent ROE awards have not been too low" (Exhibit A3-1, p. 28).

The Commission Panel agrees with the AEUB that acquisition premiums may result from a number of strategic factors which are unrelated to the establishment of a fair return for a benchmark low-risk utility. The Commission will continue its practice of allowing utilities subject to its jurisdiction, to earn a fair return on the value of their investment in property, the value of which does not include a premium on acquisition.

6.4.5 ERP

It is clear the ERP methodology is the "gold standard" for Canadian regulators and the Commission Panel will give primary weight to its application and results. In doing so, however, the Commission Panel will need to apply judgment to the evidence before it.

CAPM Method

Risk Free Rate

For the purposes of establishing a return on equity, the Commission Panel accepts the consensus 30-year bond yield estimate for 2006, of 5.25 percent proposed by Ms. McShane. In Section 3 of the Decision, the Commission Panel discusses the methodology it should follow in effecting the transition of its present AAM to that which it now finds appropriate.

Arithmetic vs. Geometric Average

The Intervenors introduced the concept of the use of a geometric, rather than an arithmetical average to calculate the total returns on stocks and bonds (Exhibit C2-6, Appendix E, p. 1-3). The Applicant advocates the use of the arithmetic average, citing Ibbotson Associates "the expected equity risk premium should always be calculated using the arithmetic mean" (Exhibit B1, Tab 2).

The Commission Panel notes that the AEUB in its Generic Cost of Capital decision stated:

> "In the Board's view, when a forecast is based on the historic average, the arithmetic average MRP represents the best estimate of the short-term return and the geometric average represents the best estimate of the long-term return. The Board has not been persuaded that it should change its practice of using the arithmetic average. Consequently, the Board will maintain its

practice of using the arithmetic average rather than the geometric average" (Exhibit A3-1, p. 19).

Accordingly, the Commission Panel accepts the use of the arithmetic average for the purpose of determining the MRP in this hearing.

Market Risk Premium (MRP)

The Commission Panel observes that the evidence before it consists of the following average Market Risk Premium percentages:

		Canada	**US**
Applicant	1947-2004	5.3	7.0
Intervenor	1956-2004	2.70	4.65

and that both witnesses make adjustments to these results to arrive at their recommendations. In the Commission Panel's view a MRP of 5.8 percent is appropriate, given the Canadian experienced premiums since the Second World War, adjusted upwards in part to recognize both the fact that bond returns will most likely decrease in future years, and in part to recognize U.S. returns. Dr. Booth's two-factor model is not helpful in assisting the Commission Panel in determining an appropriate MRP.

Beta

The Commission Panel agrees with the evidence that the estimation of betas using actual five-year data ending December 31, 2004 (five years being the typical period for calculating betas) would give unreliable results given the technology boom followed by the bust in the years 2000 and 2001. Both witnesses were obliged to make considerable adjustments to arrive at recommended betas, Ms. McShane to her 0.60 to 0.70 and Dr. Booth to his 0.45 to 0.55. The Commission Panel believes that an appropriate estimate of beta or the relative risk factor of a benchmark low risk factor versus the overall equity market is 0.50. The Commission Panel is hopeful that such adjustments will not be necessary since the five-year data no longer include the technology boom/bust.

Historic Utility Risk Premium Test

The Commission Panel believes that this test avoids the estimation of a beta and thus suffers from one less shortcoming than the MRP test. On the basis of Ms. McShane's evidence that utility risk premiums in Canada over the period 1956 to 2004 were 4.4 percent, the Commission Panel is prepared to give weight to this number in arriving at its ERP.

DCF-Based Equity Risk Premium Test

The Commission Panel believes that Ms. McShane's sample of seven U.S. A-rated pure-play gas distribution companies, which indicates an average risk premium of 4.2 percent, is too small to use other than as a check on her other findings.

Financing Flexibility Adjustment

Both Ms. McShane and Dr. Booth add a Financing Flexibility Adjustment of 50 basis points to their ERP test results. In Ms. McShane's view the adjustment is necessary to cover flotation costs; a cushion for unanticipated capital market conditions and recognition of the fairness principle (Exhibit B-1, Tab 2, line 2160). Dr. Booth added a 50 basis point flotation allowance (Exhibit C2-6, p. 50). Both witnesses agree that the ERP test produces a bare bones cost of capital which should result in a market to book ratio of one. In Ms. McShane's words, "At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity" (Exhibit B-1, Tab 2, p. 82).

Dr. Booth observes that flotation costs can be calculated using the constant growth model and that the allowance could vary depending on a firm's dividend payment ratio and the ability to expense certain issue costs for tax purposes. He does, however, note at page 50 of his evidence "Note that with 5% issue costs, the idea is that the stock should sell at a market to book ratio of 1.053, so that it will net out to book value on any new issue. With utility market to book ratios vastly in excess of 1.052 it is difficult to rationalize any flotation cost allowance, since it is unlikely that there will ever be any dilution" (Exhibit C2-6, Footnote 19).

He concludes "However, I normally add 50 basis points as a cushion to the direct estimates in line with this (sic) practice of many Boards" (Exhibit C2-6, p. 50).

The Commission Panel notes that this issue received some attention during the AEUB generic hearing, but that it was not enough to convince the AEUB to change the 50 basis point flotation cost allowance used in recent decisions (Exhibit A3-1, p. 29).

The Commission Panel tends to agree that it is difficult to rationalize any flotation cost allowance since there was little, if any, evidence placed before it of utilities trading at market to book ratios, which would justify a flotation cost allowance addition to their return on equity. Elsewhere in this decision the Commission Panel addresses market to book ratios and the need to establish a fair rather than lowest possible return. Accordingly, the Commission Panel will not automatically add a 50 basis point surcharge to whatever return it deems appropriate, but will exercise its judgment each time.

6.4.6 DCF Test

The Commission Panel notes that the DCF test is the most widely used test by regulatory bodies in the United States. Of the three methodologies before it, the DCF test is the only one to use current and prospective data to derive its results. The major criticism of the DCF method is that it relies on analysts' forecasts, which may be biased upwards. The Commission Panel does not find Dr. Booth's comments helpful in that his observations mostly cover U.S. technology analysts and the scandal on Wall Street concerning inappropriate analyst behaviour in an investment banking milieu. The Commission Panel finds that Dr. Booth's use of DCF estimates for U.S. Utilities covered by Standard & Poors, which included "multi-utilities" and energy marketing firms, should not be used as representative of U.S. utility returns. The Commission Panel is more persuaded by Ms. McShane's evidence which compares Value Line and I/B/E/S forecasts and finds no upward bias in the latter. Accordingly, the Commission Panel will give weight to Ms. McShane's first DCF Test, which yielded an indicated return of 8.8 percent. The Commission Panel agrees that this is a "bare bones" cost of equity, to which the addition of a "pure" flotation allowance of 25 basis points is required.

6.4.7 Comparable Earnings

Ms. McShane continues her practice of including in her evidence a study of the returns on book equity earned by a sample of low risk Canadian industrials in the period 1993-2004. This would suggest that low risk companies in Canada are earning an average of approximately 13 percent on their book equity.

On cross-examination, Dr. Booth agreed that some of the "problems" with the CE test also appear in the process of setting rates under regulation, notably that both use an accounting rate of return; it is an average, not a marginal, return; it is based on historic book equity; and based on non-inflation adjusted numbers. This leaves the sample selection itself. The Commission Panel recognizes that the sample selection can lead to very different results, which is why regulatory bodies are reluctant to re-embrace Comparable Earnings.

Dr. Booth reminded the Commission Panel that the last jurisdiction in Canada to use Comparable Earnings used to adjust the results as follows:

> "And Dr. Cannon tended to be the board (sc OEB) witness and he would do comparable earnings with market-to-book adjustments. And stretching my memory, but Ms. McShane I think estimated correctly that you'd look at rates of returns and try to work out what these rates of returns from non-regulated first would be if they had to have a market to book ratio of 1.5 or 1.2, which was sort of the target for regulated firm" (T6: 935).

The Commission Panel believes that there is not enough evidence before it to determine if such an adjustment is merited or how it might be accomplished. The Commission Panel is of the view that for these reasons it can give little or no weight to Ms. McShane's CE test results. However, the Commission Panel is not convinced that the CE methodology has outlived its usefulness, and believes that it may yet play a role in future ROE hearings.

6.4.8 Conclusion

In the Commission Panel's view, the suitable return on equity for a benchmark low-risk utility is 9.145 percent, assuming a 30-year long Canada bond yield of 5.25 percent, for a premium of 3.895 percent.

6.5 Impact of the Commission Panel's Determination

6.5.1 Impact on TGI

The Commission Panel determines that TGI is the benchmark low-risk utility. For 2006 TGI's ROE will be 8.80 percent viz 9.145 minus (.75*(5.25-4.79), on an equity component of capital structure of 35 percent, which the Commission Panel earlier determined to be appropriate. Based on Exhibit B-13, the Commission Panel believes the impact on TGI's 2006 revenue requirement will be a net increase of $1.9 million over TGI's approved 2005 revenue requirements, as follows:

	$ million
Increase in capital structure to 35%	4.742
Decrease in ROE to 8.80% from 9.03%	(2.842)
	1.900

6.5.2 Impact on TGVI

The Commission Panel determines that a suitable premium to TGVI over the benchmark low-risk utility ROE is 70 basis points. For 2006 TGVI's ROE will be 9.5 percent on an equity component of capital structure of 40 percent, which the Commission Panel earlier determined to be appropriate. Since TGVI was earning 9.53 percent in 2005, the net impact on TGVI's revenue requirement in 2006 will be approximately $1.7 million.

6.5.3 Other B.C. utilities

Other B.C. utilities whose ROE will be automatically affected by the Commission Panel's determination, effective January 1, 2006, include:

	Benchmark	**Premium**	**2006 ROE**
FortisBC	8.80	0.40	9.20
Pacific Northern Gas – W	8.80	0.65	9.45
Pacific Northern Gas – NE	8.80	0.40	9.20
BC Hydro (1)	8.80	0.00	8.80

(1) on a post-tax equivalent basis

Dated at the City of Vancouver, in the Province of British Columbia, this 2nd day of March 2006.

Original signed by:
Robert H. Hobbs
Panel Chair

Original signed by:
Anthony J. Pullman
Commissioner

Views of Commissioner Milbourne

I have had the opportunity of reading the determinations and reasons of the majority of the Panel in final draft form.

With the exception noted below, I respectfully dissent from my colleagues' findings with respect to the Capital Structure and Return on Equity for TGI and TGVI. I do not find that the totality of evidence before the Panel, and the authorities cited, make a persuasive case for any change from the status quo.

I concur with their findings in Section 3 with respect to the Annual Adjustment Mechanism. This change, if adopted for changes in long Canada bond yields above and below 6 percent would accordingly raise the allowed ROE for 2006 from 8.29 percent to approximately 8.60 percent for the Low Risk Benchmark Utility.

Original signed by:
R.J. Milbourne
Commissioner

BRITISH COLUMBIA
UTILITIES COMMISSION

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NUMBER G-14-06

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

and

Application by
Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") ("the Companies")

To Determine the Appropriate Return on Equity ("ROE") and Capital Structure to be Used in Setting the Rates of the Companies Commencing January 1, 2006

and

To Review and Revise the Automatic Adjustment Mechanism Used in Calculating the ROE Allowed in Rates for Public Utilities Regulated by the BC Utilities Commission
("the Application")

BEFORE: R.H. Hobbs, Chair
R.J. Milbourne, Commissioner
A.J. Pullman, Commissioner

March 2, 2006

O R D E R

WHEREAS:

A. On July 22, 2004, TGI wrote to the Commission requesting that the Commission convene a hearing to review return on equity and capital structure. By Order No. G-88-04 the Commission determined that a hearing was not warranted at that time but concluded that such a review would be appropriate in the Fall of 2005 in time for implementation January 1, 2006; and

B. By Application dated June 30, 2005, the Companies submit that: 1) the allowed returns on equity of both Companies should be increased to an appropriate level, 2) the common equity component in the capital structure of both Companies should be increased to properly reflect the risks of the Companies, and 3) the current ROE adjustment mechanism should be reviewed and revised to provide the Companies with a fair and adequate return on equity in future years; and

C. By Order No. G-69-05, the Commission established a Procedural Conference to be held on Wednesday, August 3, 2005 in Vancouver, B.C.; and

D. In a letter dated August 25, 2005, the Joint Industry Electricity Steering Committee ("JIESC") requested that the Chair decide not to sit on the Panel to avoid compromising the unbiased appearance of the proceeding and the procedural fairness all parties are entitled to expect; and

.../2

E. By Letter No. L-67-05 dated August 5, 2005, the Commission Panel defined the scope of the proceeding, determined that other utilities would not have the same status as other Intervenors in the proceeding, and established an approved Regulatory Timetable including an Oral Public Hearing to review the Application to commence on Monday, November 14, 2005; and

F. By Letter No. L-81-05 dated September 29, 2005, the Commission denied the request by the JIESC that the Chair should not sit on this matter; and

G. An Oral Public Hearing was held in Vancouver commencing on November 14, 2005 and ending on November 18, 2005; and

H. Written Argument was filed by the Companies on December 5, 2005 and by the Intervenors on or before December 20, 2005. Reply Argument was filed by the Companies on January 5, 2006 and an Oral Phase of Argument was held on January 17, 2006; and

I. The Commission Panel has determined that a change to the Capital Structures of the Companies, the Returns on Equity allowed a low-risk benchmark utility, and the utility-specific equity risk premium for TGVI is in the public interest.

NOW THEREFORE the Commission orders as follows to be effective January 1, 2006:

1. The appropriate common equity component allowed in the capital structure of TGI is 35 percent.

2. The appropriate common equity component allowed in the capital structure of TGVI is 40 percent.

3. The approved return on equity for the benchmark low-risk utility is 9.145 percent assuming a 30-year long Canada bond yield of 5.25 percent. For 2006 this results in an approved return on equity for TGI of 8.80 percent.

4. The approved return on equity for TGVI is 70 basis points greater than the benchmark low-risk utility return, namely 9.5 percent.

5. Other B.C. utilities whose returns on equity are established relative to that of the benchmark low-risk utility may adjust their rates accordingly subject to Commission approval.

DATED at the City of Vancouver, in the Province of British Columbia, this 2nd day of March, 2006.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

LIST OF APPEARANCES

G.A. FULTON	Commission Counsel
C. JOHNSON M. GHIKAS	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
P. MACDONALD	B.C. Old Age Pensioners' Organization Council of Senior Citizens' Organizations Federated Anti-Poverty Group End Legislated Poverty West-End Seniors Network Tenants Rights Action Coalition B.C. Coalition of People with Disabilities
G.K. MACINTOSH, Q.C. D. BENNETT	FortisBC Inc.
J.D.V. NEWLANDS	Elk Valley Coal Corporation
R.B. WALLACE	Joint Industry Electricity Steering Committee British Columbia Utility Customers
C. WEAFER	Commercial Energy Consumers Association of British Columbia
A. WAIT	Himself

J.W. Fraser R. Gorter E. Cheng D. Chong	Commission Staff
Allwest Reporting Ltd.	Court Reporters

LIST OF WITNESSES

RANDY JESPERSEN SCOTT THOMSON DAVID BRYSON	Terasen Gas Inc. (Panel 1)
KATHLEEN MCSHANE	Terasen Gas Inc. (Panel 2)
DR. LAURENCE D. BOOTH	British Columbia Utility Customers: (Joint Industry Electricity Steering Committee, Commercial Energy Consumers Association of British Columbia The Lower Mainland Large Gas Users Association The British Columbia Old Age Pensioners' Organization et al.)

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated July 8, 2005 and Order No. G-69-05 establishing a Procedural Conference
A-2	Letter dated July 8, 2005 requesting the Regulated Utilities to provide their preliminary positions on the participation and the coordination of evidence of all regulated utilities
A-3	Letter No. L-58-05 dated July 19, 2005 regarding appointment of Commissioner
A-4	Letter dated July 21, 2005 advising that Commissioner O'Hara will not be appointed to the Panel for this Proceeding
A-5	Letter dated August 2, 2005 enclosing draft Regulatory Agenda for discussion at the Procedural Conference
A-6	Letter No. L-67-05 dated August 5, 2005 defining the scope for review of the Application and issuing an updated Regulatory Timetable
A-7	Letter dated August 8, 2005 to Terasen Gas and Terasen Gas (Vancouver Island) responding to the JIESC's request (Exhibit C2-2) for a full description of the Chair's involvement, on or off the record, in British Columbia or Alberta, relating to ROE, ROE adjustment mechanisms and capital structure issues
A-8	Letter dated August 11, 2005 to Pacific Northern Gas Ltd. responding to its request for clarification of PNG's status pursuant to Commission Letter No. L-67-05
A-9	Letter and Commission Information Request No. 1 dated August 12, 2005 to Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
A-10	Letter dated August 26, 2005 requesting comments from Registered Intervenors on the JIESC request to have the Chair step down (Exhibit C2-3)
A-11	Letter dated September 13, 2005 and Commission Information Request No. 2
A2-1	Letter dated September 2, 2005 from Commission Counsel commenting on the JIESC request to have the Chair step down (Exhibit C2-3)

EXHIBIT LIST

Exhibit No.	Description
A-12	Letter dated September 29, 2005 – Reasons Regarding JIESC Request
A-13	Letter dated October 20, 2005 – Information Request No. 1 to Utility Customers
A-14	Letter dated November 10, 2005 – Commencement of Hearing
A-15	Letter dated November 10, 2005 – Appointment of Commissioner A.J. Pullman
A-15a	Commission Submission at Oral Hearing – Response to BCUC IR No. 1
A-16	Commission Submission at Oral Hearing – TGI Response to IR
A-17	Commission Submission at Oral Hearing – TGI Pricing Supplement No. 2
A-18	Commission Submission at Oral Hearing – TGI Pricing Supplement No. 3
A-19	Commission Submission at Oral Hearing – TGI-TGVI Cross Examination – Policy Panel
A-20	Commission Submission at Oral Hearing – BMO Nesbitt Burns – Consolidated Summary Sheet
A-21	Commission Submission at Oral Hearing – Adjustment to Cost of Service
A-22	Commission Submission at Oral Hearing – TGVI ROE Allowed and Achieved Calculation
A-23	Commission Submission at Oral Hearing – TGVI Statements of Earnings
A-24	Commission Submission at Oral Hearing – Witness Aid-Evidence Weights
A-25	Commission Submission at Oral Hearing – ICBC Statement of Investment Policy and Procedures
A-26	Commission Submission at Oral Hearing – Canadian Ratings Research Update-Terasen Inc. Purchase by Kinder Morgan Inc.
A-27	Submission At Oral Hearing – News Release From FortisBC Dated November 10, 2005 Announcing $100 Million Debenture Offering
A-28	Submission At Oral Hearing – Document From Standard & Poors Dated January 2002 Headed "S&P/TSX Capped Indices"

EXHIBIT LIST

Exhibit No.	Description
A-29	Letter dated December 19, 2005 approving the JIESC's request for an extension of time to file its closing argument material (Exhibit C2-22)
A3-1	Submission at Oral Hearing – Alberta Energy and Utilities Board-Generic Cost of Capital Decision dated July 2, 2004
A3-2	Submission at Oral Hearing -Decision of the Board of Commissioners of Public Utilities, Newfoundland and Labrador, in the matter of the 2003 general rate application filed by Newfoundland Power Inc., the Board order PU19-2003
A3-3	Submission at Oral Hearing - Decision of the Regis (Action Number D-99-11)
A3-4	Submission At Oral Hearing - Supreme Court Of Canada Decision re: Northwest Utilities
A3-5	Submission At Oral Hearing – B.C. Electric Railway Company Supreme Court Of Canada Decision Dated 1960
A3-6	Order No. G-126-05 and Negotiated Settlement dated November 30, 2005 on TGVI's 2006/07 Revenue Requirements Application

APPLICANT DOCUMENTS

Exhibit No.	Description
B-1	**TERASEN GAS INC and TERASEN GAS (VANCOUVER ISLAND) INC.** Application dated June 30, 2005 to determine the appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism
B-2	E-mail dated July 20, 2005 providing a letter from Terasen Gas (Whistler) Inc. and Terasen Gas (Squamish) Inc. in response to Commission letter of July 8, 2005 (Exhibit A-2)
B-3	Letter dated September 2, 2005 filing responses to Commission Information Request No. 1
B-4	Letter dated September 7, 2005 responding to the JIESC request that the Commission Chair step down from the Panel established to review the Return on Equity Application
B-5	Letter dated September 30, 2005 filing responses to the following

EXHIBIT LIST

Exhibit No.	Description
	Information Requests: Commission Information Request No. 2 Al Wait Information Request No. 1 Commercial Energy Consumers Information Request No. 1 JIESC-BCOAPO-CEC (Dr. Booth) Information Request No. 1 Vancouver Island Gas Joint Venture Information Request No. 1
B-6	Letter dated October 5, 2005 – Revised certain rate comparative Figures and Tables in June 30, 2005 Application
B-7	Letter dated October 20, 2005 – Information Request No. 1 to Dr. Laurence D. Booth
B-8	Submission at Oral Hearing – Direct Testimony of R.L. (Randy) Jesperson Direct Testimony of Scott Thomson Direct Testimony of David Bryson
B-9	Submission at Oral Hearing – Opening Statement on Behalf of TGI and TGVI
B-10	Submission at Oral Hearing – 2006 Forecast Allowed ROE & Capital Structure
B-11	Submission at Oral Hearing – 30yr Bond Issues in Canada with BBB rating
B-12	Submission at Oral Hearing – Recorded Actual TGI Volumes – TJs
B-13	Submission at Oral Hearing – Undertaking-Transcript Page 231
B-14	Submission at Oral Hearing – Undertaking Transcript Page 259
B-14A	Submission at Oral Hearing – Undertaking Transcript Page 807
B-15	Submission at Oral Hearing – Terasen Management's Discussion and Analysis dated November 3, 2005
B-16	Submission at Oral Hearing – Undertaking Transcript Page 259
B-17	Submission at Oral Hearing – Undertaking Transcript Page 260
B-18	Submission at Oral Hearing –Ratings Direct Research-Canadian Utility Regulation Reassessed as a Ratings Factor

EXHIBIT LIST

Exhibit No.	Description
B-19	Submission at Oral Hearing – Global Credit Research Document dated October 14, 2005
B-20	Submission at Oral Hearing – Kinder Morgan's Historical Equity and Debt/Total Capitalization Ratios
B-21	Submission at Oral Hearing – Financial Theory and Corporate Policy
B-22	Submission at Oral Hearing – Market and Individual Stock Graph
B-23	Submission at Oral Hearing – Commission Transcript dated April 12, 1994
B-24	Submission at Oral Hearing – GICS to Companies
B-25	Submission at Oral Hearing - Generic Roe Calculation For 2006 Based On Current Formula
B-26	Letter dated November 25, 2005 – ROE 2006 Estimates
B-27	Letter dated January 3, 2006 filing the December 19, 2005 Moody's Investors Service Announcement
B-28	Letter dated January 20, 2006 amending the TGI/TGVI January 19, 2006 letter regarding interest coverage discussed at page 1071 of the Transcript

INTERVENOR DOCUMENTS

C1-1	**CENTRAL HEAT DISTRIBUTION LIMITED** - Notice of Intervention dated July 8, 2005 from John S. Barnes
C2-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC)** - Notice of Intervention dated July 13, 2005 from R.B. Wallace
C2-2	Letter dated August 5, 2005 to Commission Counsel requesting a full description of the Chair's involvement, on or off the record, in British Columbia or Alberta, relating to ROE, ROE adjustment mechanisms and capital structure issues from the time the Chair joined West Kootenay, presumably some time before 1994 until he left Aquila in 2001 or 2002
C2-3	Letter dated August 25, 2005 requesting that the Commission Chair step down from the Panel established to review the Return on Equity Application

EXHIBIT LIST

Exhibit No.	Description
C2-4	Letter dated September 9, 2005 responding to Intervenor submissions
C2-5	Information Request No. 1 dated September 14, 2005
C2-6	Letter dated October 11, 2005 – Evidence of Dr. Laurence Booth
C2-7	E-mail dated November 4, 2005 – Responses to Terasen Gas Information Request No. 1
C2-8	E-mail dated November 4, 2005 – Responses to FortisBC Information Request No. 1
C2-9	E-mail dated November 4, 2005 – Responses to Commission Information Request No. 1
C2-10	Submission at Oral Hearing – Review of OEB Guidelines for setting ROE
C2-11	Submission at Oral Hearing – BMO Corporate Debt Research regarding Terasen Inc. – Kinder Morgan Acquisition Appears Credit Negative for Bondholders
C2-12	Submission at Oral Hearing – Globe and Mail clip from October 30, 2001 regarding "BC Gas financing proves it's the silly season"
C2-13	Submission at Oral Hearing – TGI Credit Rating Report
C2-14	Submission at Oral Hearing – OEB September 7, 1993 Transcript
C2-15	Submission at Oral Hearing – Electric Load Forecast
C2-16	Submission at Oral Hearing – BMO Research Report regarding BC Gas to Acquire Centra Gas British Columbia
C2-17	Submission at Oral Hearing – RBC Capital Markets document dated August 10, 2005
C2-18	Submission at Oral Hearing – Corporate Financial Analysis
C2-19	Submission at Oral Hearing – Basic Variables-Single Year Changes Year-End to Year-End

EXHIBIT LIST

Exhibit No.	Description
C2-11A	Submission at Oral Hearing – Gas Distribution Sector-10 yr Indicative Spreads
C2-20	Submission at Oral Hearing – Public, Power & Utilities Bulletin dated August 10, 2005
C2-21	Responses to Undertakings at Transcript Volume 6, pp. 825, 827 and 903-4
C2-22	Letter dated December 14, 2005 requesting a one day extension to the filing of the JIESC Argument
C2-23	Letter dated December 21, 2005 requesting the Commission to re-open the evidentiary record
C2-24	Undertaking at Transcript Page 1054 - Letter dated January 22, 2006 regarding the issuance of Preferred Shares
C2-25	Undertaking at Transcript Page 1071 – Letter dated January 22, 2006 regarding Interest Coverage
C3-1	**THE BC OLD AGE PENSIONERS ORGANIZATION ET AL.** - Notice of Intervention dated July 15, 2005 from Jim Quail, The British Columbia Public Interest Advocacy Centre
C3-2	Letter dated September 2, 2005 filing comments regarding the JIESC request to have the Chair step down (Exhibit C2-3)
C4-1	**ENBRIDGE GAS DISTRIBUTION** - Notice of Intervention dated July 18, 2005 from Lorraine Chiasson
C4-2	E-mail dated July 26, 2005 regarding Enbridge Gas Distribution contact information
C5-1	**ELK VALLEY COAL CORPORATION** - Notice of Intervention dated July 20, 2005 from J. David Newlands
C6-1	**UNION GAS LIMITED** - Notice of Intervention dated July 21, 2005 from Patrick McMahon

EXHIBIT LIST

Exhibit No.	Description
C7-1	**INLAND INDUSTRIALS** - Notice of Intervention dated July 25, 2005 from David Bursey, Bull, Housser & Tupper LLP
C8-1	**CANADIAN OFFICE AND PROFESSIONAL UNION** - Notice of Intervention dated July 21, 2005 from Pat Junnila
C9-1	**LOWER MAINLAND LARGE GAS USERS ASSOCIATION** - Notice of Intervention dated July 26, 2005 from Christopher Weafer, Owen•Bird
C10-1	**ALAN WAIT** - Notice of Intervention dated July 26, 2005
C10-2	E-mail dated July 26, 2005 with reasons for intervention
C10-3	Information Request No. 1 dated September 14, 2005
C11-1	**RANDALL JANG** - Notice of Intervention dated July 28, 2005
C12-1	**FORTISBC INC.** - Notice of Intervention dated July 28, 2005 from George Isherwood
C12-2	Letter dated October 20, 2005 – Information Request No. 1 to JIESC, CEC and BCOAPO
C12-3	Submission at Oral Hearing – Rates of Return on Common Equity at Various Bond Yield Levels
C13-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES** - Notice of Intervention dated July 26, 2005 from Stirling M. Bates
C14-1	**TRANSCANADA PIPELINES LIMITED** - Notice of Intervention dated July 28, 2005 from James Bartlett and Patrick M. Keys
C15-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY** - Notice of Intervention dated July 29, 2005 from Tony Morris

EXHIBIT LIST

Exhibit No.	Description
C15-2	Letter dated September 2, 2005 filing comments regarding the JIESC request to have the Chair step down (Exhibit C2-3)
C16-1	**AVISTA ENERGY CANADA** - Notice of Intervention dated July 29, 2005
C17-1	**HEATING, VENTILATING & COOLING ASSOCIATION** – Web registration dated July 29, 2005 from Nelle Maxey
C17-2	Letter of Comment dated August 10, 2005
C17-3	Letter dated August 26, 2005 supporting the JIESC's request that the Chair step down from the Panel
C18-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA** – Notice of Intervention dated July 29, 2005 from Christopher Weafer
C18-2	Information Request No. 1 dated September 14, 2005 from Christopher Weafer
C19-1	**PACIFIC NORTHERN GAS LTD.** – Notice of Intervention and Comments on the Generic ROE proceeding dated July 28, 2005 from Craig Donohue
C19-2	Letter dated August 10, 2005 requesting clarification of PNG's status in light of Commission Letter No. L-67-05
C20-1	**VANCOUVER ISLAND GAS JOINT VENTURE** – Notice of Intervention dated August 26, 2005 from Karl E. Gustafson, Lange Michener
C20-2	Letter dated September 2, 2005 filing comments regarding the JIESC request to have the Chair step down (Exhibit C2-3)
C20-3	Information Request No. 1 received September 15, 2005
C21-1	**HOWE SOUND PULP AND PAPER LIMITED PARTNERSHIP** – Notice of Intervention dated August 30, 2005 from Pierre G. Lamarche

EXHIBIT LIST

Exhibit No.	Description
INTERESTED PARTY DOCUMENTS	
D-1	Letter dated July 8, 2005 from the Rental Owners and Managers Association of BC requesting Interested Party status
LETTERS OF COMMENT	
E-1	Letter of Comment dated July 22, 2005 from Reiner Teschinsky Letter of Comment dated August 30, 2005 from Reiner Teschinsky

GLOSSARY AND ABBREVIATIONS

Acronym	**Term**
Act or UCA	Utilities Commission Act
AEUB	Alberta Energy and Utilities Board
"Applicants", "Companies"	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
"Application"	Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. - Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism dated June 30, 2005
AAM	Automatic Adjustment Mechanism
BC Gas	BC Gas Utility Ltd.
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	The British Columbia Old Age Pensioners' Organization et al.
BCUC or Commission	British Columbia Utilities Commission
CAPM	Capital Asset Pricing Model
CBRS	Canadian Bond Rating Service
CCRA	Commodity Cost Reconciliation Account
CE	Comparable Earnings
CEC	Commercial Energy Consumers Association of British Columbia
CRTC	Canadian Radio-Television and Telecommunications Commission
DBRS	Dominion Bond Rating Service
DCF	Discounted Cash Flow
Enbridge or EGDI	Enbridge Gas Distribution Inc.
EGNB	Enbridge Gas New Brunswick
ERP	Equity Risk Premium
GJ	Gigajoule
GMI	Gaz Metro
IBES	Institutional Brokers Estimates System
ICP	Island Cogeneration Project
JIESC	Joint Industry Electrical Steering Committee

GLOSSARY AND ABBREVIATIONS

KMI	Kinder Morgan, Inc.
MCRA	Midstream Cost Reconciliation Account
Moody's	Moody's Investors Service
MRP	Market Risk Premium
NEB	National Energy Board
OEB	Ontario Energy Board
O&M	Operating and Maintenance Costs
PBR	Performance-Based Rates or Performance Based Rate-Making
PNG	Pacific Northern Gas Ltd.
RDDA	Revenue Deficiency Deferral Account
ROE	Return on Equity
RSAM	Revenue Stabilization Adjustment Mechanism
S&P	Standard & Poors
Terasen Gas or TGI	Terasen Gas Inc.
TGS	Terasen Gas (Squamish) Ltd.
TGVI	Terasen Gas (Vancouver Island) Inc.
TI	Terasen Inc.
TJ	Terajoule
Union	Union Gas Limited
Value Line	Value Line, Inc.
VINGPA	Vancouver Island Natural Gas Pipeline Agreement